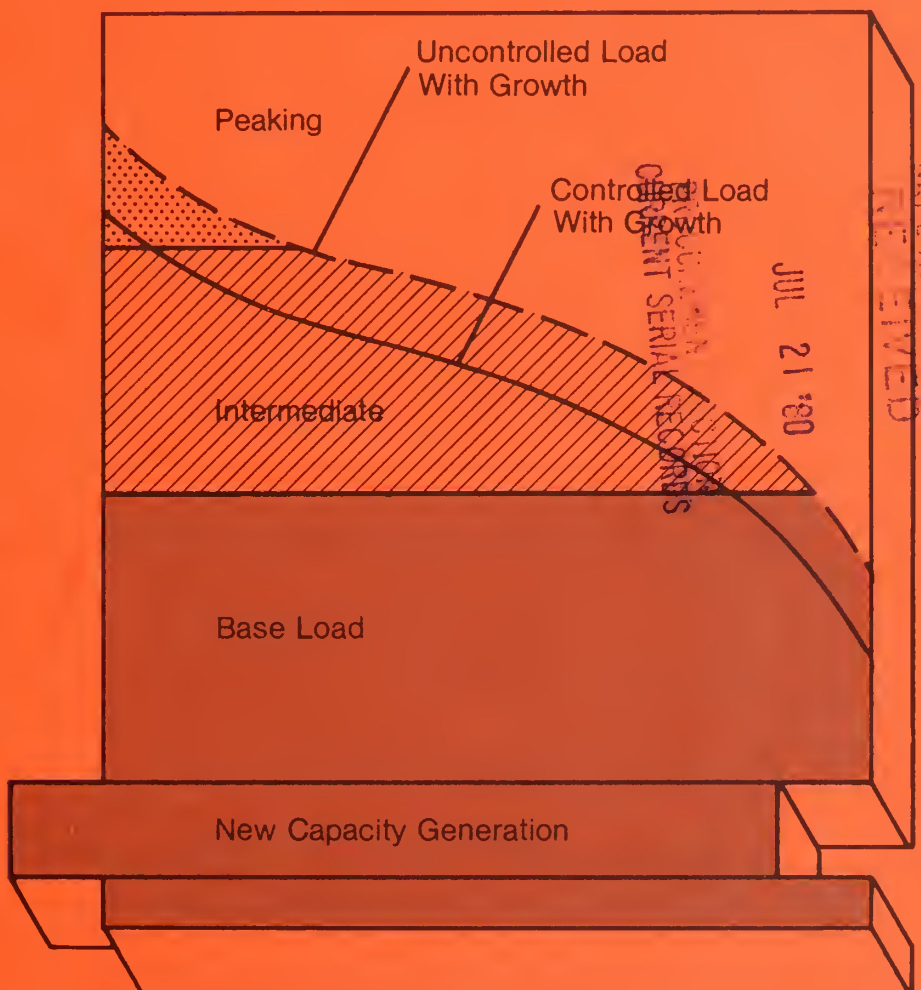
POWER SYSTEM COMMUNICATIONS:

LOAD CONTROL SYSTEMS



REA BULLETIN 66-9

RURAL ELECTRIFICATION ADMINISTRATION • U.S. DEPARTMENT OF AGRICULTURE

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FOREWORD

REA Bulletin 66-9, "Power System Communications: Load Control Systems," is one of a series of REA bulletins dedicated to power communications and control systems. This publication is the first of its kind to specifically deal with rural electric cooperatives' planning and implementation requirements for load control systems and is an excellent reference guide for fundamental engineering considerations. The subject area covers applications of specific system types, equipment and facilities, planning and implementation, cost analysis, and system investment costs.

The comprehensive presentation of material in this bulletin should benefit all cooperative engineers, and engineering firms and should be particulary helpful to relatively inexperienced engineers beginning their careers in control system communications.

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ENERGY MANAGEMENT AND UTILIZATION DIVISION
RURAL ELECTRIFICATION ADMINISTRATION
U.S. DEPARTMENT OF AGRICULTURE

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I. GENERAL

A. Introduction

The concept of load control is not new, but rather, it is a re-emerging technology with its inception over fifty years ago. It ceased as a viable electric system management tool during the late 1950's when the utilities' goals were to promote all "electric living" in an atmosphere of cheap energy and nondiminishing resources. The almost unprecedented technological growth and population expansion, coupled with the increased standard of living are reflected in the U.S. electricity consumption. During the 1920's the U.S. used about 60 billion kilowatthours (kWh) of electric energy. As of 1978, the U.S. electricity consumption was approaching 2,500 billion kWh. With generation costs for new plants exceeding $1,000 a kilowatt, increased dependence on foreign energy resources, increased competition for capital, resulting in higher capital carrying charges, and environmental constraints, the necessity to alter demand has become a reality. The most promising short-term or immediate means of load control being adopted by electric utilities, in conjunction with modern energy conservation planning, is to reduce consumption during peak periods of electric energy usage by shifting electric system peak useage to off-peak periods.

Load control, as an instrument of load management, deals with the direct control of the consumer loads. It is the actions taken to shift, shed, or shave loads in order to shape the load curve to a more efficient configuration.

This bulletin presents a comprehensive treatment on the subject of load control. Load management is discussed herein to the degree necessary for the reader to formulate an understanding of the overall subject and to provide the transition from the more broad concepts of load management to the application of load control technology.

The need for this bulletin is predicated on both the widespread interest shown by electric system borrowers and the extensive application of load control to rural electric systems. Current estimates indicate that electric system borrowers may spend upwards of 900 million dollars for load control equipment and their associated communications equipment and facilities.

B. Scope

The purpose of this bulletin is to provide a complete and concise overview of load control technology. This bulletin provides data and information on all major systems currently in use. It also provides guidelines for planning, system engineering, engineering design considerations, costs, and implementation.

The bulletin does not provide a comparative analysis between the competing technologies for the purpose of passing judgment on the relative merits of the various offerings. All of the systems descussed herein will do the tasks for which they are designed. Rather, it is the responsibility of the borrower to select the system and methodology which most nearly meets his criteria for system security, reliability, feasibility, and economy.

The bulletin is written for borrower management and engineering staffs and consultants. However, it has been made as complete and detailed as possible for the benefit of all readers.

C. Organization and Content of Bulletin

This bulletin is organized into seven discrete stand-alone sections. Each section deals with a specific facet of load control and is self contained, not relying on the previous sections for referral information.

Section I provides an introduction to load management and load control detailing the differences and interrelationships of the two concepts. A synopsis of current systems in use, applications, and trends is also provided for the reader wishing to forego the more detailed treatment.

Section II is a comprehensive description of the characteristics and uses of present day load control systems. The specific applications of control systems, their attendant communications systems, the controller, and the "on-premise" control unit are addressed as they apply to generation/transmission and distribution systems.

Section III addresses load control system design considerations. Among the subjects covered are: coordination, system functions, man/machine interface, configuration analysis, facilities, design goals, staffing and training.

Section IV deals with the system engineering. Especially significant are the topics covering: requirements, consumer education, cost relationships, wholesale power cost savings, cost benefit analysis, selecting the system, and implementation.

Section V delineates the cost data for the purchase of various types of load control systems. Costs are provided for: master station (hardware, software and facilities), remote metering equipment, load control units, communications equipment, and operating expenses.

Section VI is a glossary of terms taken in part from the IEEE Load Management Working Group.

Section VII is a comprehensive bibliography on the subjects of load management and load control.

D. History of Load Management

The recent emphasis on load management stems from several causes. Perhaps the most demanding emphasis results from the rapid increase in the cost of building electric generating capacity in the decade of the 70's. The high cost of new capacity, together with significantly higher costs for financing and longer lead time to design and build a new plant require much higher demand charges to recover the fixed charges associated with this new capacity. Conversely, higher demand charges provide greater economic justification for the equipment or overhead expenses to accomplish load management.

Load management is not new to the electric utility industry. In the earliest days of central station electric service, the load was principally electric lighting and the utility operator managed the load by simply not running the plant except during the evening hours. The load factor was very high while the plant was running and service was available. As new uses were developed to utilize electric energy, it became necessary to run the generating plant 24 hours a day, but for many years, the peak demand coincided with the evening lighting load.

Electric refrigerators, ranges and storage water heaters were among the appliances developed for the residential market and the water heater seemed well suited to be "managed" or "controlled" by the utility to improve its load factor. An incentive rate was usually offered if the customer would permit a time clock in the water heater circuit to prevent one or both of the elements from being energized during the utility system's normal peak load period.

For several decades, the industry promoted the use of electricity for more and more applications in the home and in business and industry. These load building efforts provided growth and economies of scale in the operation of the system and a natural diversity among different types of loads and customers.

The demand and energy rate was a type of load management. Knowledgable commercial and industrial customers realized that significant savings could be made if they sized their equipment and operated it to maximize their load factor. Utilities employed industrial engineers, "power use advisors" and home economists to sell more kilowatthours. These employees helped to insure that the equipment purchased and installed by the customers was properly sized to handle the load and to operate with an acceptable load factor and power factor. Eventually, some systems developed sufficient load that diversity among different types of loads provided an acceptable load factor, without need for load management.

Time-clock control of water heaters also lost popularity with customers and utilities alike. With improvements in the standard of living and the affluence of customers, increased use of hot water, increased overall usage of electricity for other appliances and reductions in the price of the final block of energy, the differential between the special water heater rate and the end block of the regular rate was not sufficient incentive to compensate for frequent periods when there was not enough hot water for the automatic laundry machines, dishwashers and more frequent baths. From the utilities' point of view, the time clock and the second kWh meter required maintenance which increased in cost every year, while the benefits derived from their use declined. The time clocks available did not function during outages and after several hours' outage on a feeder, the clocks would be behind and the water heaters on that feeder would be turned on during the system's peak load and turned off after the peak was past. Meter reading expense was increased as meter readers were required to reset all the clocks on any feeder which had suffered a service interruption in the previous month.

During the decades of the 50's and 60's, the practice of load management by direct means was largely dormant. The incremental cost of electric generating capacity had been decreasing steadily and was frequently under $100 per kW of base load units with the highest fuel conversion efficiency in the history of the industry. With low $ per kW and kWh costs, a program of direct control did not seem economically feasible during this period. Daily and monthly load factors were generally acceptable, although systems in the south were developing pronounced summer peaks due to air conditioning loads while systems in the north developed winter peaks from electric space heating. Peaks from irrigation pumping equipment were becoming a problem in certain areas where irrigation could substantially improve a farmer's profits. However, load management was largely restricted to load building programs designed to develop loads to fill the valleys between the existing peaks in the load curve.

From 1965 to 1978, the industry has seen costs increase in some cases from under $100 to over $1,000 per kW.

During the middle 70's, load management and conservation reached paramount importance because of the accumulative effect of:

- Increases in the cost of building electric generation plant capacity

  - Normal inflation in the cost of building plant;

  - Additional costs for hardware to comply with Federal and State laws and regulations designed to protect the environment;

  - Increased interest during construction resulting from higher interest rates and the longer construction periods required to comply with the new laws and regulations;

  - Increased costs passed on by other basic industries (steel, concrete, coal, oil, etc.) as they attempt to comply with new Federal and State regulations.

- The Energy Crisis

  - National recognition of our growing dependence upon foreign oil;

  - Recognition that the nation's demands for natural gas and gas transmission capacity has grown to exceed supply in many geographic areas during peak periods;

  - Recognition that the nation's welfare requires that future generating capacity must rely on coal or nuclear fuel in all geographic areas to conserve oil and gas for applications which cannot utilize coal or nuclear;

  - Curtailments by gas suppliers, which forced generating plants to burn oil, increasing costs significantly and adding to our dependence upon foreign oil;

  - Rapidly escalating costs for gas, oil, coal, and nuclear fuels.

- Consumer and Regulatory Commission Pressure to Minimize Rate Increases

  - National Association of Regulatory Utility Commissioners Resolution 9 passed in 1974 called for a comprehensive "study of the technology and cost of time-of-day metering and electronic methods of controlling peak-period usage of electricity and also a study of the feasibility and cost of shifting various types of usage from peak to off-peak periods;"

- Rate Design Study sponsored by EEI, APPA, NRECA and EPRI;

- D.O.E. grants for experiments and pilot programs to determine the results of a variety of load management and conservation programs.

° National Policy Objectives

- The Energy Independence Policy of the Federal Government which seeks to reduce the use of oil and gas and limit the growth in consumption of other nonrenewable sources of energy in order to reduce the nation's dependence upon foreign oil;

- The need to limit imports of oil and reduce trade deficits to bolster the strength of the dollar;

- The need to limit the demands of the electric utility industry for capital in order to reduce inflationary pressures and competition for capital.

E. Load Management

The concept of load management is based on the premise that a smoothing out of system loads will reduce the use of peaking and some intermediate generating units, permitting the use of base-load units to provide the same amount of energy more efficiently, at lower unit cost, and with more abundant domestic energy resources as fuel, recognizing that:

° Base-load units are generally high capital cost, high efficiency units designed to operate continuously at or near their maximum capacities; these units are generally coal, nuclear or heavy oil-fired;

° Intermediate-load units are generally lower efficiency units - often older units originally installed for base-load operation - which typically operate with some overnight-shutdown; these units are usually coal or oil-fired; and

- Peaking units are low capital cost, typically less efficient units which are intended to operate during relatively short periods of peak system load, or during emergencies; these units are either light oil or gas-fired.

The concept of load management embraces the principle of altering or controlling electrical load shapes in order to improve electrical power system performance.

For a system such as most REA-financed distribution systems which purchase power at wholesale to distribute and sell to its members at retail, the objectives of load management are generally limited to reducing the systems peak demand, in order to reduce the cost of wholesale power.

An understanding of the nature of electric power use and the system that is necessary to provide this power is important in an analysis of utility costs and rates.

Most electric utilities face a time variation in use of electric energy (measured in kilowatthours or kWh) and in electric power demand (measured in kilowatts or kW). The kilowatt variation is related to the daily, weekly, and seasonal use patterns of living for most people and the resulting use patterns of appliances or other machines by the customers.

The kilowatthour variation occurs as appliances or machines are used for longer or shorter periods of time. The kilowatt demand may be viewed as the level at which power is demanded while kilowatthour use measures the amount of energy consumed.

For many electric utilities, daily peak demand is significantly greater than daily off-peak demand. Although installed capacity must be able to meet the peak demand, it is most always underused for much of the day. In addition to daily peak and off-peak periods (loads), many electric utilities experience differences in seasonal load patterns with summer or winter peaking. The variation in the load placed on the system by the customers means that the utility finds various types of generating plants an economical means to meet varying load demands.

In general, load shape improvement can most effectively be aimed at two distinct areas. These are daily load shape and seasonal load shape.

- Potential for Daily Load Shape Improvement - the objective of load management is to reduce peak usage, and fill the off-peak load valley. The amount of filling that can be attained while reducing overall costs depends on the kind of generation available to produce the energy. Thus, as the generation mix changes, the amount of off-peak load addition that will reduce average costs and improve earnings the most will also change.

- Potential for Seasonal Load Shape Improvement - a second objective of load management would be to "flatten" the seasonal load shape. This seasonal flattening can be obtained by reducing the seasonal peak(s) by building up the load in the other seasons or by a combination of both.

  As a practical matter, anything short of requiring customers to turn off their appliances on the peak days would have little effect on the seasonal load shape. For example, increased electric storage heating load could build up the winter season load and higher efficiency air conditioning could reduce the summer season load for a summer peaking utility.

- Relationship of Load Shapes to System Load Factor - for load management analysis it is beneficial to look at the system load factor as approximated by the multiple of the following items:

  1. Daily Load Factor $= \dfrac{\text{24 hour average load}}{\text{daily peak load (weekday)}}$

  2. Weekly Diversity $= \dfrac{\text{average daily peak load}}{\text{average weekly peak load}}$

  This ratio primarily recognizes that weekends and holidays reduce the average daily load for the week to a value significantly below that of the typical weekday.

  3. Seasonal Diversity $= \dfrac{\text{average weekly peak load}}{\text{system seasonal peak load}}$

  This ratio recognizes the large difference between the average weekly peak and "the" peak and also the difference between the average weekly peak during the peak season and the weekly peaks for the other seasons.

Weekly Diversity is probably unmanageable for "behind-the-meter" load management. Supply management may be the only possibility for significantly leveling the weekend load valleys.

- Daily Load Factor

  Improvement of the daily load factor appears to be the most promising load management target. Daily load factors vary relatively little between seasons. Although they are already relatively high, load management tools to improve them further can be developed. Additionally, generating units which are available during the peak period are usually also available during the same day off-peak period. Major unit maintenance is not usually performed during one day periods. Off-peak energy is therefore generally readily available on a daily basis making daily load factor improvement an attractive target for many utilities.

- Seasonal Diversity

  The relationship of the weekly peak variations and the system's seasonal peak is best analyzed on a seasonal basis to determine if it is amenable to load management. The difference between these average seasonal weekly peaks and the maximum season's peak is an obvious load management target. To a certain extent, peaking capacity used to supply this difference was only designed for limited use, principally, the peak days. It is marginally expensive energy to produce.

  Another load management target is revealed by examining the difference between the average peak season weekly peak and the average weekly peaks for the other seasons. Reduction of this difference over the long term is desirable. The goal would be to reduce the adverse effects that temperature sensitive appliances had on the system by either building the other seasons' load up or reducing the peak season peak load.

- Lower the cost of providing services:

  Electric distribution cooperatives, being member-owned, would logically expect an extensive program such as load management to provide some benefit to the ultimate consumer. From the consumer's point of view, cost is of vital importance during this decade when rate increases are frequent. The cooperative's management is aware of, and sympathetic to, the consumer's wishes.

REA distribution systems which purchase their power at wholesale from an investor-owned company are usually billed on a demand and energy rate, and frequently the billing demand is ratcheted at 50% to 100% of the highest measured demand in the month or the preceding 11 months. Assuming the rate remains constant, the distribution system has a relatively simple problem in isolating and identifying advantages and disadvantages as well as costs and benefits of load management. If the distribution system has a poor load factor which can be improved sufficiently with load management to reduce wholesale power costs and effect savings within a relatively short time adequate to reimburse the costs of planning, purchase, installation and operation of the load management system, it would appear to have adequate feasibility and should at least be studied more carefully. However, wholesale electric rates are subject to change. If the wholesale supplier's costs are not reduced by as much (or more) as the customer's savings when a customer utilizes load management techniques, the supplier will likely modify the rate of the earliest opportunity in order to recover the full cost of providing service. Thus, the dollar savings required to make the load management system feasible may be lost after the expenditures have been made.

Distribution systems which are members of a G&T system may have a similar dilemma. Because of their wholesale rate structure, it is conceivable that the distribution system could, through load management, effect savings adequate to make load management feasible under the premise that wholesale rates will not change. However, the G&T's costs might, in the short run, remain the same, with or without the load management activities of the distribution system. For example, a G&T with adequate capacity to serve its member's requirements has certain fixed and variable costs which must be recovered through a rate applied to the member-systems' usage. The demand charge portion of the wholesale rate is normally allocated to cover the G&T's fixed charges. If one member-system reduces its wholesale power costs with a load management approach which reduces its peak demand, the G&T's revenues would be reduced without reducing its costs. In the short run, the interest, depreciation, amortization, taxes, etc., remain substantially the same regardless of minor variations in demand which are within the capacity of the G&T.

Thus, it appears that distribution systems might be ill advised to unilaterally embark on a program of load management. The savings in demand charges under the present wholesale rate can evaporate if the rate structure is modified. There will be pressure to modify the rate unless the savings enjoyed by the distribution system also results in a similar or greater savings to the generating system, whether investor owned utility or G&T cooperative.

One G&T system has advised as follows:

> "The planned control of use of capacity and energy for the consumers' benefit and satisfaction (economically and socially), results in the optimum use of capacity and energy resources supplied by the utility, and which further results in a system efficiency match of installation and availability of new resources.
>
> It is suggested that to meet an objective as described for load management, a generation and transmission cooperative must enjoy the confidence of its member distribution systems; it must have available a control/communications/monitoring system capability to or with its member system; and it must utilize said facilities to provide optimum load match (shedding load as and if needed, with available hourly resources).
>
> With this shared confidence and the resulting operation, economies will be realized for existing systems and the best economic planning will obtain for future additions to resources."

- Most Efficient Utilization of Plant Facilities:

The generating systems of many large electric utilities are comprised of many stations of different age and containing units of different size, primary fuel, efficiency, original cost, etc. Dispatching involves knowing the capabilities and costs associated with the various generating units and operating the units in a manner that meets the load demands at the lowest overall cost. Supply management dictates that each new generating unit built by a system should improve that system's ability to operate with maximum efficiency while serving their load with its particular characteristics. A system operating for 50 years or more has usually seen its load characteristics change through the years.

Certainly, fuel costs and availability change, as do requirements for emission control. The state of the art also changes. Thus a large "old" utility may have a diverse mix of plants, while a younger, smaller utility may have predominantly one type of plant, because its load characteristics have not seen the same transition.

In dispatching for a large, old utility or pool, hydro units on rivers with an abundant water supply, nuclear units or large fossil fired steam units with high efficiency or burning low cost fuel would normally be utilized to carry the base load and would be operated at or near full capacity continuously because these units can produce power and energy at the lower cost. Older or smaller, or less efficient fossil fired steam units might be utilized as intermediate load units or reserve units. Newer or larger and relatively efficient units might be relegated to intermediate load service because of high fuel cost or a limited supply of fuel. Diesel or combustion turbine units would normally be reserved for peaking or emergency use because of high fuel and maintenance costs, lower efficiency and short life, as compared to hydro, nuclear or fossil fired steam turbines.

Load management activities by these large interconnected systems, which can shift loads from peak time to off-peak, may enable the dispatcher to largely avoid operating high unit cost peaking plants and sell the same kWh at off-peak from lower unit cost plants. Unfortunately, the typical G&T is smaller and younger and has less plants and less flexibility to take advantage of this form of supply management. Therefore, its ability to effect savings from load management is reduced.

- Postpone New Investments:

An electric system with inadequate generating (or transmission or substation) capacity to carry the system's present or imminent peak load may postpone the need for an additional capacity by load management which shifts loads from peak time to off-peak time. However, when the next unit is ultimately built, if it costs significantly more because of inflation during the delay interval, the savings may be offset. The load management activity will have a permanent benefit only if it continues to allow the supplier to defer building an increment of capacity.

- Maintain Adequate and Dependable Electric Service:

  A system with load management equipment designed to enable it to control load during the peak load period can use the same equipment to shed load during any emergency, including those which might threaten a blackout or brownout on the system. Thus, the load management system can be used to improve the utilities stability. It has been argued that the ability to manage load by direct control is equivalent to a like kW amount of spinning reserve. However, the ability to control 10,000 kW of water heater load during an 8:00 p.m. winter peak may result in no spinning reserve whatsoever during an emergency at 3:00 a.m., when all the water heaters would already be turned off by their thermostats. The ability to control 10,000 kW of air conditioning or heating load during their peak load times would provide no equivalent to spinning reserve except when the air conditioners or heaters were operating. Thus, the load management system is not equivalent to reserve capacity except in certain limited circumstances.

- Encourage Prudent Use of the Nation's Resources:

  As stated earlier, assuming a complete mix of generating plants in a system, peaking plants will tend to be gas or oil fired combustion turbines or internal combustion engines. Intermediate load plants are likely to be the smaller, less efficient of the systems oil or gas fired steam turbine plants. Base load plants will likely be large, efficient coal or nuclear fueled steam turbine plants. Thus, a load management program which removes load during peak-load time will likely conserve oil or gas which is in short supply and is imported in large quantities. If the load is shifted to off-peak time, the kilowatt hours can be produced from less expensive coal or nuclear fuel in more efficient plants.

  Table I-1 highlights some of the techniques and methods available in load management.

<u>The Techniques of Load Management</u>

The many methods used in load management can be subdivided according to different schemes:

(a) <u>Indirect Control by the Utility</u>

- <u>Load Building</u>

TABLE I-1

Methods Available for Load Management

Direct Methods	
1) Voltage Control	a) Capacitor control b) Line regulator control
2) Variable Control of Load	a) Stepped control of appliances such as water heaters, storage heaters, and storage cooling
3) On/Off Control of Load	a) Water b) Air Conditioners c) Storage heaters d) Storage cooling
4) Plant or Building Control	a) Fixed interval demand control b) Sliding interval demand control c) Energy control d) Interruptible service
Indirect Methods	
1) Appliance Efficiency	a) Trade association specification b) National standard c) Statutory regulation
2) Time-Differentiated Rates	a) Time of day differentiation b) Seasonal differentiation c) Household demand meeting d) Customer rate indicator e) Rate of expenditure indicator
3) Local Cogeneration	a) Solar heating and cooling b) Windpower c) Hydro power d) Photovoltaic

Load characteristics have been changed in past years by the utilities promotional programs on load building activities.

For almost 20 years, load building was the primary load management activity. By concentrating on loads which fill the valleys and miss the peak of the load curve, the power use personnel could improve the system's load factor. The addition of air conditioning, irrigation pumping or crop drying loads would improve the load curve and load factor of a winter-peaking system, while electric heat would improve the load factor of a summer-peaking system. Load building does not conserve energy or reduce the need for new generation or capital, and is therefore not the favored load management activity from the national energy independence point of view.

- <u>Rates</u>

Rate Levels, rate structures or other price signals can be used to manage load to some degree over the long run. Rate design and total rate structure are broad descriptive terms for the manner in which revenue is collected from customers. Total rate structure includes both rate form and rate level. Rate form refers to the shape of the total rate structure; it is a function of the load characteristics of the customer classes and the utility's demand, energy, and customer unit cost components. Examples of rate form include declining-block rates, time-differentiated rates, and inverted rates. Rate level refers to the magnitude of a rate in a specific rate form. Assuming a flat rate of 5¢ per kWh, for example, the rate level is 5¢. Revenue level refers to the total dollar amount recovered by the total rate structure (rate form and rate level).

Electricity rate designs in the past, and to some extent still prevail, have traditionally taken the form of the declining-block rate. The following example is a relatively simple illustration of a declining-block schedule for residential users, who generally are metered only for kilowatthours of use:

$6.00 fixed charge per month

400 kWh or less per month...............8¢ per kWh
For the next 600 kWh per month..........6¢ per kWh
For all kWh over 1000 kWh per month.....3¢ per kWh

In this illustration, the fixed charge, which is independent of use, reflects customer costs, and the declining-block charges based on usage reflect demand (capacity) costs and energy costs. A two-part demand rate is used for large and medium-sized industrial and commercial users of electricity. This type of rate schedule is composed of (1) a declining-block demand charge per kilowatt of maximum demand in any month, and (2) a declining-block energy charge per kilowatthour of total consumption in any month. The historic and governing principle for the declining-block rate structure is that the larger the amount of power demanded and the larger the consumption of electric energy, the cheaper the price per unit of power and energy.

Declining-block tariffs may have been appropriate and adequate throughout most of the history of the electricity industry, when conditions of decreasing costs and technological change were believed to be present and significant. The energy crisis, capital shortages, increases in system peak demand, general inflation, and strong environmental and consumer concerns have led to questions about the propriety of the declining-block rate structure. The primary limitation, based on cost considerations, associated with the application of a declining-block rate structure is its failure to provide consumers with price signals that clearly indicate that the cost of providing electricity varies between peak and off-peak periods. The following dicussion concerning the system load factor gives some insight into this limitation.

The system load factor is the ratio of average load to maximum or peak load for the system for a stated time period. Peak load primarily determines the total amount of capacity required by the system. If increased usage occurs during times of system peak demand, the system load factor falls, new capacity is required, and increases in rates are typically requested by the utility. However, if there is greater use of existing generating capacity during off-peak periods, the system load factor increases and the operating efficiency of existing plants improves.

Assuming that the costs of providing electricity vary by time-of-day, a misleading and inadequate price signal relative to the cost of production is communicated to customers by the declining-block rate structure and other block rate forms. This price signal does not clearly motivate customers to help the typical electric utility achieve the following objectives: (1) to shift a portion of its load from inefficient peaking units to more efficient baseload units, thereby obtaining savings in gas and oil peaking fuels; and (2) to reduce its growth in peak demand, thereby cutting its requirements for capacity expansion.

Time-differentiated pricing refers to tariff designs that assign higher costs and prices to usage occurring at the times of day (peak periods) when the utility system must meet its maximum demands and that assign lower costs to usage occurring at the times of day (off-peak periods) when idle or excess capacity exists. The following is an illustration of a time-of-day rate for monthly residential consumption:

$5.50 fixed charge per month

10¢ per kWh per month during peak periods (6:00 a.m. - 9:00 a.m. and 3:00 p.m. - 7:00 p.m.).

2.5¢ per kWh per month during off-peak periods (12:00 a.m. - 6:00 a.m., 9:00 a.m., and 7:00 p.m. - 12:00 p.m.).

Differences in seasonal (summer-winter) rates are a form of time-differentiated pricing that reflects differences in costs associated with seasonal variations in load shapes.

Assuming that the costs of providing electricity vary by time-of-day, time-differentiated pricing is a type of electricity pricing that reflects costs in a more accurate way than do traditional block-rate structures. Time-differentiated pricing attempts to price a kilowatthour of electricity for each customer on the basis of the actual cost incurred by the utility in providing service to that customer. Time-differentiated pricing of electricity logically follows from marginal or incremental cost pricing theory, but it is also compatible with embedded (historical average) costs. In addition to cost justifications, time-differentiated rates will probably motivate customers to reduce electricity consumption during peak times and to increase consumption during off-peak times when there is idle capacity. These potential changes in consumer behavior caused by a cost-based price signal would help the electric utility to achieve the previously discussed objectives of cutting growth in system peak demand and moving load from peak to off-peak periods, thereby improving the system load factor.

Recent regulatory activities related to the implementation of time-differentiated electricity rates for residential customers can be categorized as: (1) pricing experiments, and (2) mandatory implementation for residential customers with relatively large usage levels.

- Temperature Sensing Devices Used to Control Loads

  Thermostats have been used to activate mechanisms which cycle air conditioning compressors when the temperature exceeds a pre-set level. This approach has been used successfully where the annual peak is currently due to air conditioning loads and is directly related to the temperature. This approach avoids control on most days of the year when control is really not necessary. Thermostats have also been used to control irrigation pump motors, but with considerably less success than with other more direct methods of control.

  Although the thermostats are installed and set by the utility, the control rests largely with the weatherman, and not the utility, so they are not considered a direct control method.

- Time Clocks

  Time clocks are still being used with a degree of success to control water heaters and storage type space heaters when the peak load can be predicted to fall within a time band on most days. Even with spring driven carry-over to limit timing errors due to outages, this method has limitations. This approach may lead to over-control (control may not be necessary on weekends or holidays). From a practical standpoint, the utility has a limited ability to change the settings and thus has no real time direct control.

- Consumers May be Induced to Manage Their Own Loads

  Several utilities have designed public information programs to inform their customers of the relation between the demand for power on the hottest day (or the coldest, or the driest) of the year, the investment required to insure the availability of adequate capacity to meet the peak demand, and the requirement that the utility have sufficient revenue to pay the fixed charges on this capacity which may be nonproductive for most of the remainder of the year. Especially in this decade of rapidly escalating costs for power and energy, member and public education is good, but it is very difficult to accurately determine the effectiveness of such a program or how lasting the impression will be.

- Weatherization

  The energy crisis and increases in the cost of all forms of energy has prompted the Federal government, some state regulatory commissions and a number of cooperatives and investor-owned companies to encourage the public to utilize their buildings to conserve energy. Substantial reductions in the amount of heat transfer through building perimeters will obviously reduce the peak demand attributable to air conditioning and heating. To the degree that these peaks contribute to the system peak, these programs will benefit the utility by reducing the needle peaks during "heat storms."

- Improved Design of Buildings and Equipment

  As the cost of generating capacity and fuel increase, and force the cost of electric demand and energy up, there is more pressure for more energy efficient buildings and electrical appliances. The law of diminishing returns, the cost of insulating materials and the price of energy used to heat and cool buildings has governed the amount of insulation which could be economically justified for buildings.

  In this century, we have progressed from no ceiling insulation in the typical residence to recommendations for at least four inches, then six inches, ten inches, and now twelve inches or more. Storm windows, double glazing, storm doors, weatherstripping and other efforts to reduce heat loss have followed in step. Insulation recommended for walls has increased to the point that 2 x 6 studs are replacing 2 x 4 studs in perimeter walls in order that more insulation may be placed in the walls.

  In past years when energy was relatively cheap, the consumer was often more interested in the original cost of housing and appliances than in the operating costs. With the low cost final block kWh rates and before the advent of central air conditioning and electric central heat for residences, the first cost might have been more important than operating costs.

When the computer program determines that load management is required, coded signals can be sent to receivers with decoders at the customers load, and service to the selected loads interrupted. With some equipment, service to these loads is automatically restored after a predetermined interval as a fail safe approach to prevent undue inconvenience to the customer. With some equipment, the minicomputer sends a coded signal to restore service at the selected time.

When it is necessary to control loads for an interval greater than would be acceptable to the consumers, the consumers are separated into two or more groups and service interrupted to first one group and then the next for as long as load control is necessary. When air conditioning units are the loads being controlled, the "off" interval might tend to shorten the equipment life by requiring a restart before the head pressure had equalized.

There are many different types, makes and models of hardware that can be assembled into a load management system to control one or more types of loads. This is the subject of the next section and the balance of the bulletin.

o <u>Energy Storage Devices</u>

The most promising consumer-owned load management techniques involve utilizing electric power during off-peak hours to heat or cool water (bricks, sodium hydroxide or some other medium) with the stored energy to be utilized later as required. The most common application is to heat water for bathing, laundry, dishwashing and other domestic purposes. The insulated tank must hold sufficient water to meet the normal requirements during peak load hours and until power is restored. With a larger storage tank, water could be heated off-peak to provide hot water space heating for the entire building. A similar concept would be a small refrigeration compressor running constantly off-peak, freezing blocks of ice to air condition a building during peak-load hours. In Europe, there has been extensive use of space heaters which heat a storage medium during eight off-peak hours and release the stored heat under thermostatic control as required. Room units are available in 2 kW through 8 kW ratings and central units of 24 through 36 kW.

As with other approaches, the key seems to be in providing sufficient incentive and impetus for the consumer to buy a more expensive appliance which imposes utilization limitations over and above the standard type of appliance. If this technique is employed, the utility will benefit from load management, the consumers would benefit from lower power costs, and the national energy position would be enhanced if use of oil or gas peaking plants was avoided and the required power produced with higher efficiency plants powered by coal, nuclear or hydro power.

(b) Direct Control by the Utility

The direct control of consumer loads by the utility allows positive control when it is deemed most beneficial to the utility, or when it is absolutely necessary to avoid collapse of the interconnected system during an emergency which treatens a brownout or blackout. Direct control usually involves signals transmitted by the dispatcher or automatically by a mini-computer in response to indications of the need to control load buildup.

The incoming data might be data on total system load of loading on a statistical sample of substations which can be extrapolated to reliably indicate the total load. The data may be automatically received and analyzed by the mini-computer as often as every minute.

Recent emphasis on the energy shortage and electric rate increases may motivate consumers to insist on more efficient appliances. Heat pumps are gaining acceptance rapidly because they are more efficient space heaters than resistance heaters in central electric furnaces. A number of manufacturers are now offering higher efficiency refrigerators, freezers and air conditions.

These efforts are to the ultimate benefit of the consumer and the national energy independence effort by overall conservation, but do little to improve the load factor; there is thus more conservation than load management.

F. Load Control (Direct)

As pointed out in the previous section, load control falls into two categories:

- Indirect and
- Direct

Indirect load control leaves the load reduction or control (the shifting of the time of maximum demand) to the discretion of the consumer. The customer is given an incentive to alter his usage in the form of time of day pricing, rate levels, rate structure or voluntary control. Conservation measures such as promotion of increased thermal insulation of homes and buildings and publishing of appliance efficiency ratings may also be used.

Direct load control enables the utility to exercise real-time control over the connected loads. One method of control of system demand, and to some extent system energy, is voltage reduction. Direct methods of controlling and end-use devices on the consumer's premises include radio, power-line carrier over the distribution system, ripple control, phase shifting techniques, wired systems using telephone lines or cable TV.

Direct load control involves the management of interruptable or curtailable load by the utility. This is accomplished by connecting the controllable load to a load control receiver through a relay. Energizing or deenergizing the relay by the utility from a control center in effect controls the consumer's end load or appliance.

The concept of direct load control involves the cycling or deferment of certain customer appliances or equipment by the utility (or, alternately, by customer-owned equipment) during the time of highest system peaks or electric system emergency. The anticipated effect of direct load control is to reduce power production costs and high system losses during peak period electricity use. Additionally, some time deferment of generation additions by the utility may be expected. The total amount of electric energy used by the consumer may remain constant. In some cases, however, a kWh conservation effect may result because some uses, once postponed, will be eliminated or diminished. Consumers who are willing to have certain loads controlled regularly may be offered economic incentives by the utility. These incentives are properly related to the reduced cost to serve.

Those customer loads considered for direct control by utilities generally exhibit one of two characteristics: they are either nonessential or possess inherent or designed storage characteristics. Examples include air conditioning, space heating, water heating, irrigation pumping, certain industrial loads, and swimming pool pumps and heaters. Although direct load control may appear to be the most desirable approach in terms of its ability to shape the use of electric power to the supply, it runs counter to the present utility-customer relationship, whereby the customer expects the utility to supply all the electricity he requires when he (the customer) desires it. However, under normal operation, a customer's life-style generally will not be affected by direct load control, since he will be unaware of the load control function, particularly if the controlled load has inherent or designed-energy storage characteristics. Under emergency conditions, direct load control allows the utility to maintain essential "societally-critical" loads while dropping less essential loads for brief periods to maintain system integrity.

Thorough assessments are needed of: the capital and operational costs of the necessary communication control system (e.g., ripple, telephone, power line carrier, radio, satellite, etc); the impacts on the electric energy system including savings in production costs and reduced capacity requirements, the pricing of interruptable/deferrable power; and the associated costs before load control is undertaken. It is also anticipated that future electric loads (for example, electric vehicles) will require direct control to be efficiently supplied by the power system. This, too, will require extensive analysis.

Public acceptance (or the lack thereof) of direct load control is also an important consideration, even though the customer will generally be unaware of the control function and most probably will be provided with an appropriate economic incentive for participation.

Figures I-1 and I-2 illustrate an example of a daily demand load profile and a load generation curve. Note the large percentage of load served by both intermediate and peaking generation sources. It is the peaking load the utility is attempting to shave in order to improve the overall load factor.

The selection of the method most suitable for a particular application is a matter of optimizing the savings-cost relationship, considering all factors which bear upon the load management program to be instituted. Any system of direct control involves a communication link between the utility and the control unit which operates the load. The planning function must consider the physical and electrical configuration of the utility system, the information to be transmitted, the required speed of transmission, and the required security or accuracy

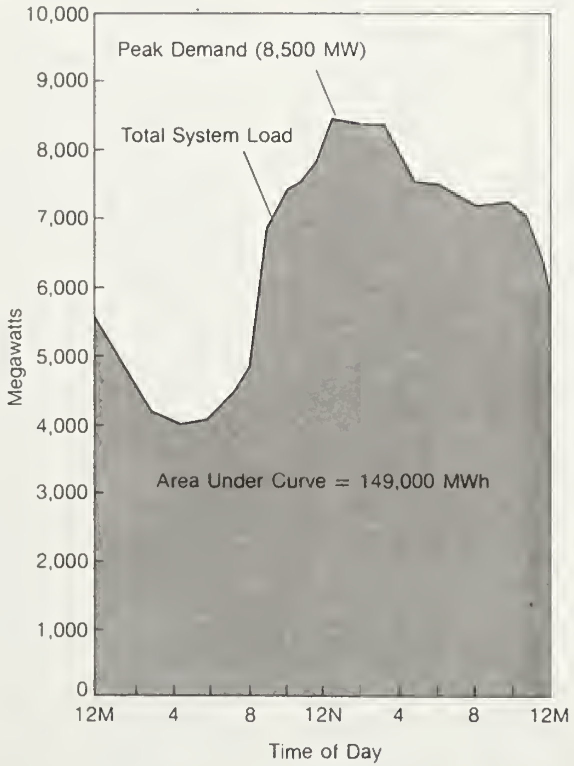

Figure I-1

Daily Load Curve

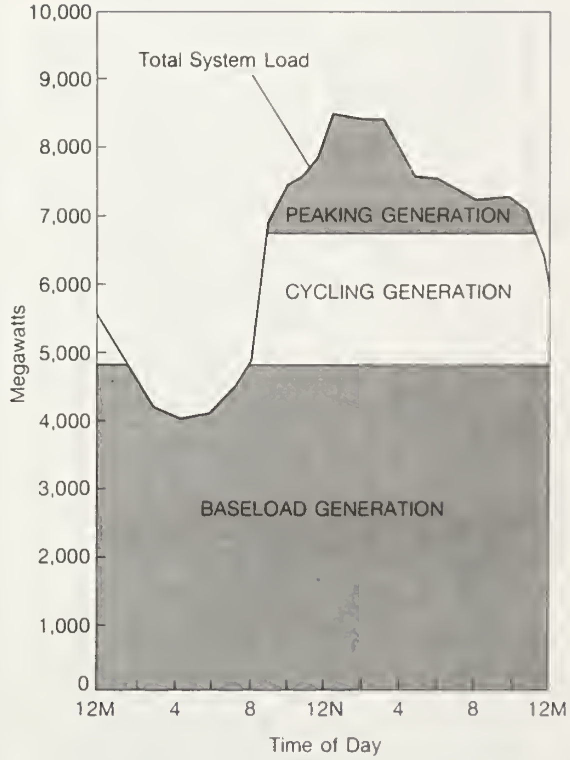

Figure I-2

Load Generation Curve

of the transmitted data. The ability of a load management system to respond rapidly to commands when a generation or supply deficiency occurs can effectively add spinning reserve capability, and this too enters into the benefit calculations.

Loads suitable for direct control are:

- Air conditioning
- Electric space heating
- Water heating
- Deferrable loads, such as irrigation pumps and swimming pool pumps
- Municipal loads, such as water and sewer pumps
- Recreational lighting
- Farm loads
- Industrial loads.

The abovementioned loads are examined in more detail below:

- <u>Air Conditioning</u>

  Air conditioning comprises a large part of the summer peak load. It is natural that air conditioning should surface for application of load control. If the compressor and outside fan of central air conditioning units are switched off for several minutes out of the hour, leaving the internal fan running to circulate the air, a small temperature rise will occur. Control of the air conditioning compressor is utilized only during those times when the electrical power system is expected to experience a peak and only for the duration of that peak. Residential and commercial central air conditioning installations are candidates for load management except where the air conditioner performs a critical function where temperature and humidity must be controlled within given constraints.

- <u>Electric Space Heating</u>

  Electric space heating in the form of heat pumps, duct heaters, and electric furnaces can be controlled in much the same way as air conditioners are controlled during summer months.

- <u>Water Heating</u>

  Electric water heaters, because of their inherent storage capacity, can be shut off for periods up to several hours without causing inconvenience to the customer.

- Irrigation Pumps and Swimming Pool Pumps

  The use of electric pumps for irrigation systems can often be deferred to off-peak hours but with some disruption of working schedules. Swimming pool pumps may be shut off during peak hours without affecting the performance of the filtration system.

- Water and Sewer Pumps

  Where adequate storage capacity exists, it is often possible to shut off water and sewer pumps completely or to reduce the number of pumps in service during peak hours.

- Recreational Lighting

  Floodlights at recreational parks create large demands on power systems which can be deferred.

- Farm Loads

  Farm loads are difficult to control. Crops are often being harvested and processed during the latter part of the summer when the system electrical demand is also at its highest. Operations relating to the processing of agricultural products must be evaluated to determine the possibility for postponement, deferral, or curtailment of the activities during peak load periods.

- Industrial Loads

  Industrial plants, because they are on a demand rate, may have already instituted load management programs within their organizations. The deferral of certain industrial processes to off-peak hours is already being practiced. For system peaks occurring late in the afternoon, it may be possible to institute flexible working hours so that the work period ends earlier to avoid adding the plant load to a late afternoon system peak.

The effects of load control may be any of the following:

- Reshaping the load curve to keep energy use constant;
- Lowering the total load curve with resultant reduction in energy use;

- Lower costs of electric service;
- Conservation of scarce natural resources.

Evaluations must be made as to the technical feasibility and applicability of available load control techniques, based upon the particular features and characteristics of the load patterns of each system.

While a number of load control techniques are feasible, economic feasibility and cost-benefit analyses must be performed which determine benefits and costs. This involves a complete and comprehensive analysis of the load control program.

A reduction of the peak load may mean postponement of construction of facilities required to supply the anticipated demand. The improved system load factor may change the necessary mix of generating resources, reducing the peaking capacity requirements and increasing intermediate or base load capacity requirements. The effect on fixed and operating costs must be ascertained.

Where a load control system provides an immediate response to a generation deficiency, the benefits to reserve requirements may be taken into account.

The effects on the wholesale supplier's fixed charge allocation factors among various customer classes should also be evaluated. Simply controlling the peak demands used for billing purposes may produce an immediate cost savings that would be eliminated in the next rate hearing. If only the demand costs are reduced without consideration of other factors, the results may be higher purchased power unit costs. If the load control program reduces the purchaser's demands at the time of the supplier's peak demands, long run cost savings may be realized.

As the load factor increases, adverse effects on maintenance schedules may result. Routine load shifting between transmission lines and substations for maintenance may require added facilities.

Load control tends to defer energy consumption. In the case of air conditioning and electric heat, the units will run for longer periods after load management is discontinued for the day in order to compensate for heat gained or lost during the period of load control. Water heaters also use about the same energy after being off as they would if allowed to run during the control period.

Wholesale power cost savings may result from the decrease in system losses as a result of decreased current flow during the load control period.

In order for a load control system to be effective, it is necessary to analyze the effect of load control implementation on the cost components involved in providing electric service. That is:

- Energy Related Costs: Costs associated with fuel and operation of generating equipment;

- Demand-Related Costs: Costs associated with the capital requirements for generation capacity, transmission, distribution, and other equipment to meet temporal power demand;

- Fixed Costs: Other costs not directly dependent on load patterns.

The components of cost - generation, transmission, and distribution - are divided into three billing classifications: demand, energy, and customer. This allocation process provides the requisite understanding of electricity costs and is a necessary tool for understanding the impact of load control rate making.

Allocation of costs consists of assigning costs to the functions of generation, transmission, and distribution.

The generation component consists of capital costs for the actual installed generating facilities and for related areas such as maintenance and fuel. Transmission and distribution components include poles, lines, substations, and transformers and expenses such as right-of-way and maintenance costs.

The division of the generation, transmission, and distribution costs into categories identifiable with customer use requires information about customers' consumption patterns and the development of customer classes for billing purposes. Utilities are generally readily able to identify the demand (kilowatts) and/or energy (kilowatthours) used by a customer or customer class. This process is accomplished by using either billing meters (for large commercial or industrial users) or survey meters (for small customers). Using this information, the utility is to allocate elements of cost to the demand, energy and customer categories.

Classification of costs consists of assigning costs to the demand, energy, and customer categories.

Demand (capacity) costs include the installed physical plant, the transmission system and some elements of the distribution system. Demand costs can be viewed as fixed costs (at least in the short run). Energy costs are generally variable costs and include all fuel costs and some maintenance items. Customer costs are costs that can be associated with service itself. They include billing, sales, and administrative expenses; items such as meters and certain elements of the distribution system.

To summarize the cost of a load control system is only one factor in the overall implementation process. How load control affects other cost elements may be more important or even paramount.

G. Present Systems and Applications

This section provides a synopsis of the present load control systems available and in use by REA borrowers. All systems consist of the following:

- Load measuring transducer
- Central processor
- Transmission equipment
- Receiver control switch

The communications and control systems have inherent design differences which must be considered. These are discussed in detail in Section II. Since the load measuring transducer and central controller are common to all systems covered herein, treatment of the subject will begin with a generic discussion on these components and then proceed to different types of systems (radio, ripple, power line carrier, etc.).

1. Load Measuring Transducer

To effectively control demands, the system must be provided with information on when the peak is going to occur and how long it will last. This may be done by continuous measurement of the power system load.

A watt-hour meter equipped with a contact device that produces contact closures proportional to the rate at which energy is flowing can provide the central controller with the information required. The central controller can integrate the pulses over a time interval and determine the average kilowatt demand in that interval. The resulting demand signal, in addition to being used for control purposes, can be used for display and recording of the kW demand. The watt-hour meter and contact device can be the equipment installed by the power company for billing purposes and equipped with auxiliary relays to give the additional output or it can be a separate metering installation by the customer that also serves as a check meter on the power company meter.

Another method of providing a load signal to the central controller is by the use of a watt transducer connected to the current and potential transformers at the metering point. In this case, a metering transformer is installed. The transducer produces a DC milliamp or millivolt signal proportional to the power system load. This signal can be fed directly to the controller or converted for transmission over a communication circuit.

2. The Central Processor

The "central processor" is a term used to describe a device performing a number of control functions at a central location in the load control system. These functions may be better understood by a description of a typical control system common to electric system installations. There are several configurations and options available that allow the processor to be tailored to fit a specific need.

A signal processor receives the metering pulses and converts them to a value equivalent to the system load at each delivery point. This load signal is displayed and recorded on a strip chart recorder and is also analyzed in a comparator circuit so that when the load reaches a level which has been set into the comparator, an output signal is generated.

The signal from the signal processor activates the programmer which contains timing circuits, a user-programmable switching matrix, manual control features, tone generators, and transmitter keying circuits. Upon command from the signal processor, the programmer turns on the transmitter and modulates it with a signal to which the receivers located on the customer premises respond. The result is that, beginning with a fixed reduction, the demand of the controlled load is reduced until the desired level is reached. When the peak has passed, all receivers will have been deenergized and the system will be restored to normal. To enhance reliability, two processors may be provided so that a backup unit will automatically take over on failure of the prime unit. Redundant units may be provided, with dual signal lines taking separate routes from the delivery points' metering equipment.

A computer programmed with a daily load curve developed from past load patterns may be used to activate a load control system, though real-time control based on actual system load is the most used method of initiating load control.

3. Radio Control

Radio-controlled systems have been used for several years for control of consumer appliances in load control systems and have proven themselves both reliable and effective. The typical radio control system consists of:

- Load measuring transducer
- Central processor
- Radio Transmitter
- Radio control switch

The typical radio transmitter used in load control systems is the same as is used for mobile VHF communications systems. The frequency used is 154.46375 mHz with a maximum allowable transmitter output power of 300 watts. In some systems, two transmitters are installed complete with separate antennas. One transmitter serves as a backup to the other. A monitoring device connected to both transmitters senses malfunctions in the output of the prime transmitter and automatically switches the backup transmitter into service.

The radio switch is an FM receiver set to the transmitter frequency, containing a tone decoding element that responds to one particular audio tone discrete digital address signal transmitted by the load control transmitter. When the signal is received, the output relay is energized and its contact opens the power circuit or control circuit of the equipment causing it to stop operation. The output relay remains energized through an internal timing circuit for approximately seven minutes ± 20%, unless another signal is received, in which case another seven-minute period is started. The timing period is deliberately made inexact through design of the timing circuit so that, among a group of radio switches, the load will not be restored simultaneously after a timing interval, but will be spread out over a period of about 1.5 minutes, thus avoiding excessive inrush currents.

Several manufacturers provide radio switches with multi-decoding elements that permit two, three or four output functions and provide independent control of loads.

Because of the type of timing circuit used, should the central controller or transmitters fail during a load management period, all switches will have timed out and restored the load within seven minutes ± 20%. However, inoperative switches are quite difficult to detect. Switches that might fail during a normally "on period" are easy to detect because of customer complaints.

For central controllers and the transmitters not located in the same proximity, redundant or alternate signal paths must be provided. The two circuits must take different paths and should never be together in the same cable. Monitoring of the circuits should be provided alerting operating personnel of any trouble that develops.

4. Ripple Control

In the ripple control system, a coded signal may be injected into the power system at the transmission service delivery point, the bus of the distribution station, or at the distribution delivery point. This ripple signal appears at all points on the system including 120/240 volt circuits in homes and businesses, and conveys switching commands to receivers which in turn control the operation of air conditioners, water heaters, or other appliances.

The term "ripple" refers to the fact that the signal is small, typically one or two percent, compared to the 60 Hz voltage wave; and if the line voltage is viewed on an oscilloscope, the higher frequency control signal is viewed as a small amplitude "ripple" on the line voltage. The ripple control single frequency is between 200 and 1600 Hz.

The ripple control system is comprised of:

- Load measuring transducer;
- Transmission equipment: Central processor, static frequency converter, and coupling circuit;
- Receivers with one, two, three or four independent relays.

Two types of signal injection are available:

- Parallel injection and
- Series injection

Parallel injection is accomplished by coupling the three-phase ripple signal to the three phases of the power system through capacitors similar to the high voltage capacitors used for power factor correction. Series injection employs three large high-voltage current transformers, one in each phase of the load circuit, to inject the signal. Both methods require a switching structure and appropriate disconnect and bypass switches to facilitate maintenance.

The central processor provides the interface between the one ad measuring transducer at the delivery point, the operator, and transmission equipment. The processor signals when a predetermined load level is reached that causes the transmission equipment to inject the control signal into the power system.

The frequency converter receives its power from a three-phase station power transformer bank, usually 480 volts, rectifies it to DC, and as commanded by the central controller, generates an audio-frequency signal in a solid state converter, the power output of which is connected to the coupling and injection circuit.

The power required to be injected depends on several technical considerations. As a rule of thumb for estimating purposes: transmitter power injected is 1-1½% of transmission line voltage. The transmitter does not draw this power continuously, only as commands are transmitted.

The design of ripple control receivers varies between manufacturers and types of coding systems; the basic elements consist of an input filter, a decoding circuit that responds only to the assigned codes, and one or more output relays that provide the control function. The receiver is connected directly across the 120 or 240 volt power line adjacent to the controlled load. Depending on design, from one to four independent control functions can be provided in one receiver. The output relays are bi-stable, requiring one command signal to open the circuit and another to close the circuit. This differs from radio switches which automatically revert to normal operation if a signal is not received for seven minutes.

One single ripple control transmitter can cover a complete distribution network (centralized system). The alternate solution is the decentralized system which calls for separate transmitters at every high voltage to medium voltage substation.

The advantage of the centralized system is the need for only one transmitter at a central location with associated cost reduction. When multiple injection points are provided, the failure of one transmitter will reduce the effectiveness of the load control system.

5. Power Line Carrier (PLC)

Historically, power line carrier (PLC) has been restricted to applications using open-wire, high-voltage primary transmission lines for the purpose of voice communication, supervisory control and/or protective relay systems. Little application was seen on distribution systems due to the large power requirements, cost, and regular maintenance required on both transmitters and receivers. Operating frequencies are in the range of 150 to 500 kHz.

Development of solid state components has reduced the size, power, cost and maintenance requirements. As a result, the equipment has become more attractive for use on lower voltage systems. The signal is generated by a stable solid state oscillator and keyed either on-off or frequency shifted in accordance with a preselected multibit binary pulse code. The resultant carrier may be injected into the power system by parallel or series injection to modulate the power frequency voltage wave.

Injection may be either line-to-neutral or neutral-to-ground via a line-connected coupling capacitor and the necessary protective fuses and isolating switches. A high-frequency current transformer may be used for signal injection if applicable. Injection power requirements are low (normally in the order of a few watts), but rise with a decrease in frequency. Low power requirements encourage the use of this system for two-way communication. Such systems are being used for the purpose of remote meter reading and other remote data retrieval functions, in addition to load control.

The receivers at the customer terminals are provided with input filters for the carrier frequency. Detector-decoders have been designed for the appropriate signal address and operate function. For remote meter reading, the receivers have an "on-demand," retransit capability from integral information storage registers.

Location of the receiver in the customer's building is, typically, at the metering point. This avoids the signal loss due to the customer's wiring and noise generated by end-use devices. The positioning of the receiver (or transponder) at the meter will be necessary if meter information reading is required (present or future).

This will also enable the receiver power supply requirements to be obtained from the unmetered line. Some modification or addition to the building wiring will be required for load control purposes (usually low voltage wiring to an interposing relay).

The factors which influence the cost requirements for a high-frequency power line carrier system may be summarized as follows:

- For practical purposes, the signal transmitted power is largely independent of the system connected or the controlled system load. Line attenuation or the maximum number of addressable receivers per injection point is normally the determining factor.

- Network changes, by virtue of (1) above, have a minimum effect on an installed system. Increasing load densities, if not accompanied by additional metering points, will not significantly change the signal quality. An existing sector may have to be subdivided and an additional injection point installed if the total number of meters increases over the maximum capacity of the existing injection point.

- The use of multiple injection points involves the use of multiple communication channels between the control center and the injection points. This may be in the form of leased or dial telephone lines. On systems which permit several injection points to employ shared lines, this requirement is reduced. Nevertheless, the lines comprise a significant percentage of the operating cost of the system.

6. Hybrid Load Control Systems

Recent development in the load control equipment market has provided for the two techniques of radio and power-line-carrier to be used as an integrated hybrid system. In this system the difficulties that are encountered in sending power-line-carrier signals through the distribution system are bypassed by means of radio, and then multiple power-line-carrier transmitters on the distribution system transmit the signals over the secondary lines to relatively inexpensive receivers which control the appliances.

A central processor and radio base stations are used to broadcast radio signals over a load control radio frequency. These signals are received and decoded by both radio receivers for use by power-line-carrier transmitters which are connected to the secondary of each distribution transformer serving loads to be controlled. The decoded radio signal is converted to a coded power-line-carrier signal which is coupled to the secondary line. The carrier current receivers at the individual occupancies may be connected to control air conditioners, water heaters, dual rate watt-hour meters, etc.

The radio receiver and the power-line-carrier transmitter are mounted on an existing pole at the level of the secondary conductors. The receiver has a self-contained antenna. The unit can be located on the transformer pole or on any secondary line pole. Leads are provided for connection to the distribution system to supply power to the unit and to couple the signal. The power-line-carrier signal travels over the secondary conductors to all points on the distribution transformer secondary.

The power-line-carrier receiver has several configurations: single function control which can be mounted on or inside an air conditioner or on a water heater, and multi-function for use with dual rate metering. An alerting device that plugs into any receptacle is available to notify customers of non-peak, near-peak, and peak load periods. The alerting device is also under control by means of the carrier system.

Because one radio receiver/power-line-carrier transmitter unit is required on each transformer secondary serving loads to be controlled, there must be several customers with controlled loads connected to each installation to make this system price competitive with a radio system, assuming one control function per switch. The break-even point is about four single function receivers connected to each distribution transformer. Use of multiple function receivers also reduces the overall cost per function.

Factors which can influence cost for the hybrid system may be summarized as:

- Joint use of the existing VHF communication facilities and the hybrid load control system can effect substantial savings in procurement, operation and maintenance of the radio portion of the link;

- The hybrid system's major economic justification hinges on the number of controlled end-use loads being fed from the secondary of each low voltage transformer. As each end-use customer being controlled must share the transformer receiver/transmitter cost (the economics are quite sensitive to the number of controlled customers per transformer), each customer is allocated the cost of the carrier current receiver plus the appropriate proportion of the VHF receiver. This sensitivity suggests that the hybrid system is more suited to urban/suburban areas. A combination system approach may be very attractive to the utility serving a mixed urban and rural service area. By applying the hybrid receiver/transmitters to the urban transformers with a sufficient number of controllable loads, and radio receivers directly to the balance of end-use loads to control, the combination system could optimize both the functional utility and cost of the control system;

- Network changes have a minimum effect on an installed system. For all practical purposes, the communication channel is independant of the configuration of the power system. The exception is that portion of the system which utilizes the low voltage transformer secondary connections.

  Location of the power-line-carrier receivers within the customer's building is simple because the signal is available at all power outlets. The receivers may be installed directly at the location of the end-use appliance with only a minimum wiring modification involved.

7. Telephone Load Control Systems

Direct wire control systems have been used for utility and industrial applications.

The presence of the local telephone company's system does provide an equivalent facility which should not be ignored. This network presents an available, reliable and high quality communication channel which enters the vast majority of end-use customers' property. The telephone network can be extended to cover additional locations within the telephone service area at a minimum cost to the utility. Such schemes have characteristics compatible with the general purpose automatic dial telephone system. These systems are available for use as one- or two-way channels for automatic remote meter reading as well as control of end-use customer loads.

In general, these systems share a common feature with other two-way systems: A dependence upon the central control to initiate an information interchange. End-use transponders may independently accumulate data, but cannot transmit this information except in response to an interrogation signal. This places the address capacity at the telephone switching office equipment. It also greatly simplifies the end-use terminal. Message priority is the sole perrogative of the initiating terminal.

For one-way load control use, the instruction is received by the end-use receiver and converted to an "on/off" function for the control circuitry. For a two-way system, in addition to receiving the load control signal, the unit will respond, "upon demand," and transmit to the central control, information fed to it by the meter encoders (or other sensors as applicable). One-way meter reading encoders are only capable of conveying information back to the control centers.

II. LOAD CONTROL SYSTEMS

A. Introduction

This section discusses the salient points of the characteristics for the five basic generic types of communication systems presently available for the direct utility control of customer appliances. These five systems are:

- VHF radio
- Hybrid (radio plus power line carrier)
- Power line carrier - Low frequency injection
- High frequency power line carrier
- Telephony and direct wire

In each of the above systems, the characteristics which may encourage or discourage their use are examined and include the following parameters:

- Operating parameters in the utility system
- Reliability/availability
- Maintainability
- Security
- Viable control philosophies

At the end of this section, two methods of voluntary load control are discussed: Time of day metering and demand metering. These methods may be compared as the reader wishes, with those presented on direct load control. Costs for each system are given in Section V of this bulletin and dollar figures for significant components are quoted for comparison purposes. These figures are purely explanatory and can only be used for budgetary cost estimating. Facilities exist in certain of the five basic systems to incorporate both time of day metering and demand metering. The systems currently able to handle these functions are high frequency power line carrier and telephony.

The communications and control systems described here are of current design and technology. No doubt there will be some design changes and new entries to the field over the next few years. However, once the basic systems are understood by the reader, changes, as they occur, may be readily incorporated into the "repertoire" of knowledge on load control systems. Even at this time there are new systems being introduced which will increase the spectrum of communications and control strategies over those presently available for end use load control, system functions, and remote metering.

The communications and control systems presently in use have inherent design differences that should be recognized. Different communications media and techniques are used with obvious characteristic differences in component equipments. However different these systems are, they each share the same set of common generic requirements as shown in Figure II-1. Each system has: a master control station (central processor) located at the utility's headquarters, the communications path (ripple, radio, power line carrier, etc.) to the load control receiver (shown here adjacent to meter for simplicity purposes), and the load control receiver subsequently connected to the controllable loads. The water-heater and an air conditioner are shown here for purposes of illustration only.

Figure II-2 is a simplified diagramatic overview of a power system.

These two illustrations show there is a sufficiently large set of common parameters in the application of any load control system such that only a few need detailed attention to understand variances in application. These are the composition and structure of the power system, the communications path to the receiver, and the control strategy used by the master station controller.

The balance of this section discusses each of the five generic systems with regard to the parameters inherent in any specific power system. To further facilitate the application of each of the systems to a typical system, idealized layouts of the major equipments and interconnections likely to be found in any average borrower system are shown in illustrations accompanying the discussion in each subsection hereunder. The electric network drawings are subsequently modified for each generic communication system to illustrate the portions of the power system which are used for the communications channel, the point of major interface between the control system and the power system, and the location of major components. This will, in fact, be a modification to Figure II-2 as appropriate.

B. <u>VHF Radio Control</u>

1. <u>General</u>

The basic radio remote control system for load control of end use appliances comprises a one-way radio link from

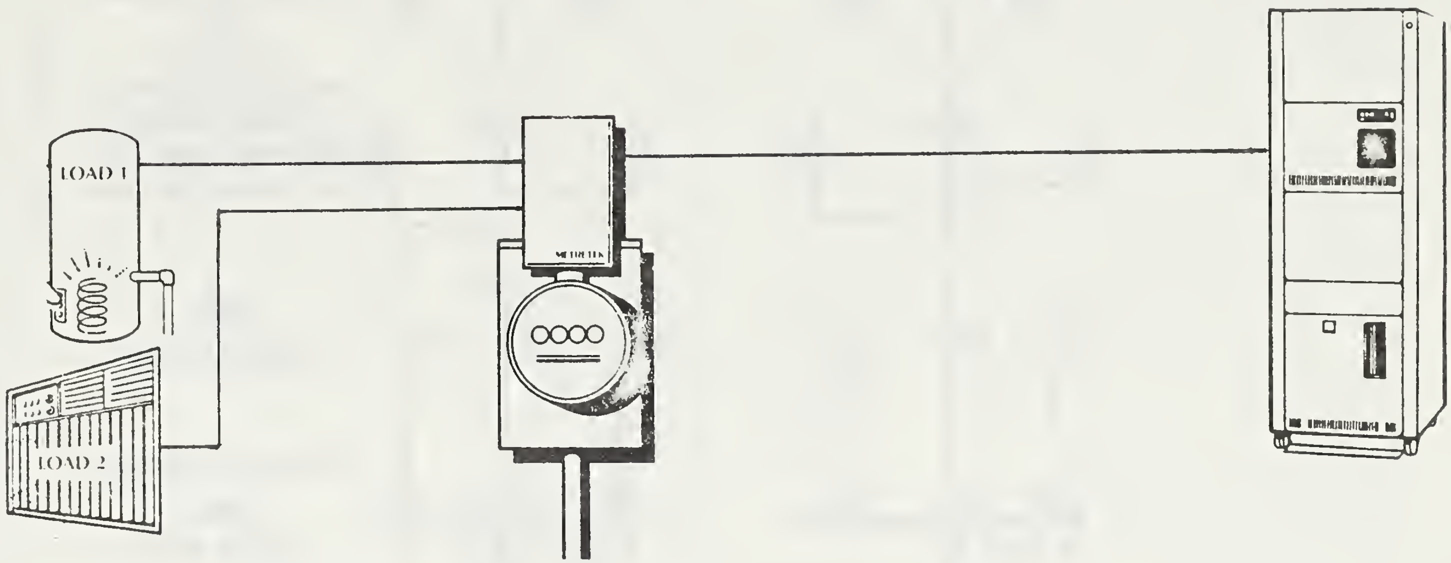

Figure II-1 Basic Control System

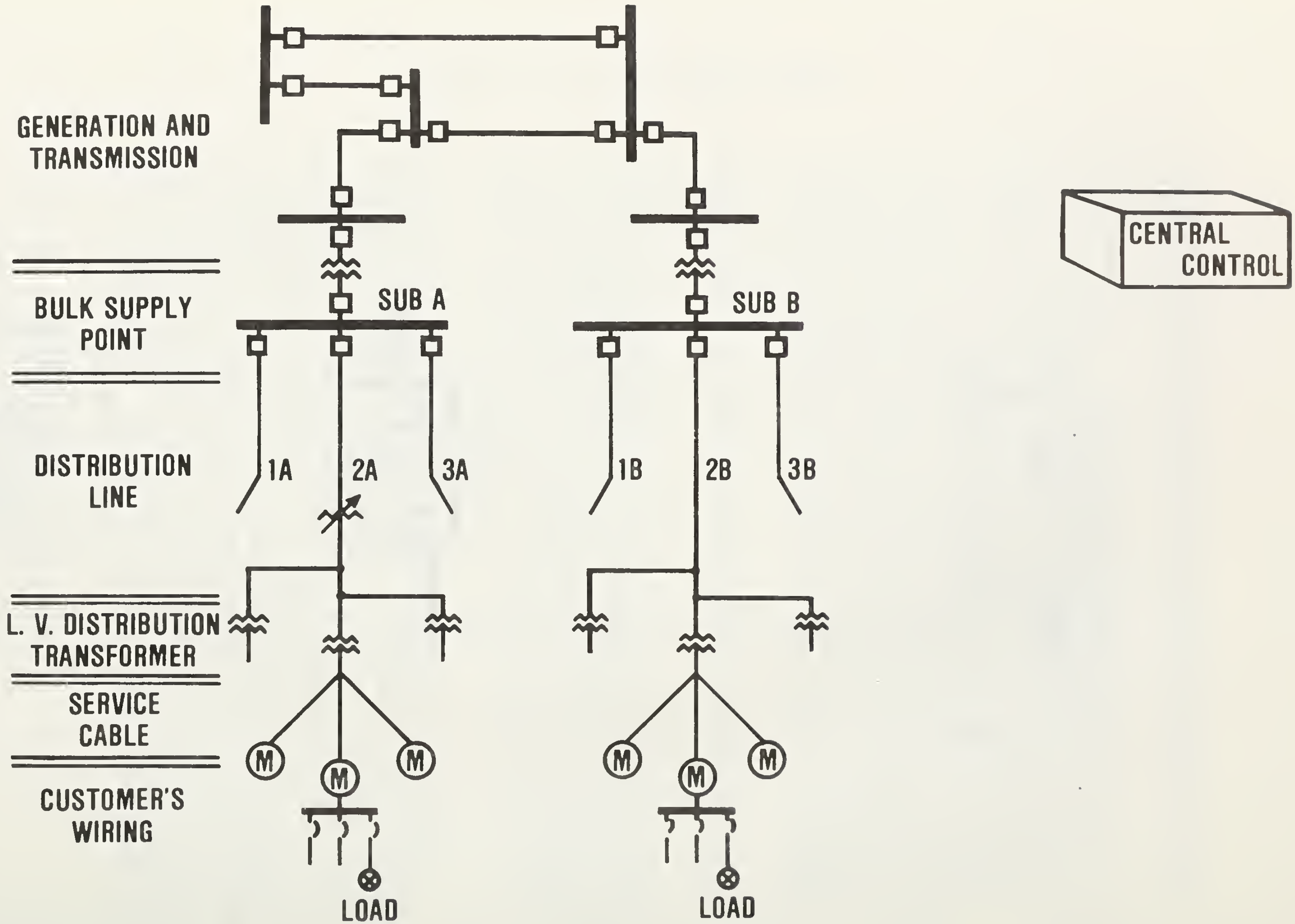

Figure II-2 Power System Overview

area transmitters to locally installed receivers at the consumer's premises. This system has been in use for approximately 10 years in selected areas throughout the United States.

Radio load control systems may utilize a dedicated transmitter or share the use of a transmitter with the utility's existing VHF land mobile radio system. In either event, transmitters operate on Federal Communication Commission controlled frequency bands and are protected against unauthorized interference. Audio tone frequency modulation is used to convey instructions to the remote receivers and either simple audio tone bursts or coded audio tone signals may be used. The signal type is determined by the particular equipment manufacturer and the number of command channels desired. Normally, "off" commands only are transmitted and the receiver will restore the load on the absence of a signal after a preset delay. Prolonged "off" cycles can be obtained by retransmitting the appropriate tone prior to the expiration of this time delay.

Two-way radio control systems are not currently available but development work is proceeding and such systems may be available in the near future.

The application of a radio control system to an idealized distribution system layout is shown in Figure II-3 As no portion of the power system forms part of the communication channel, communication between the central control and the individual receivers is maintained regardless of network switching, abnormal operating routines or arrangement of bulk supply points. Receivers may be located at any point on the distribution network that is within the service area of the transmitter.

There are five basic components of the radio load control system. These are:

- Central control unit
- Communication link to the remote radio transmitters
- Radio transmitter
- Radio receiver
- Control relay

2. System Operation

A central processor automatically or manually chooses

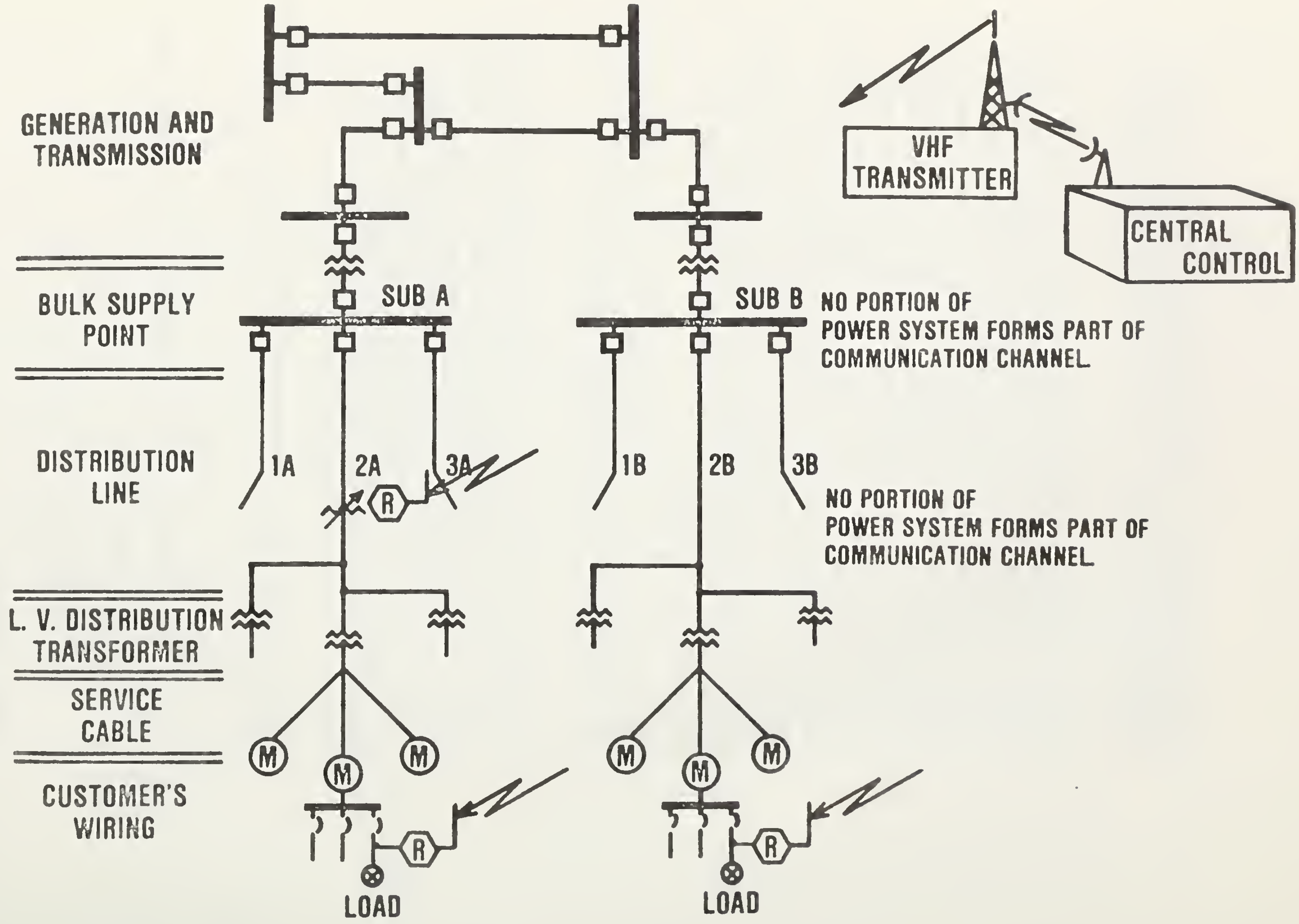

Figure II-3 Application of VHF Radio to Power System the specified groups of loads to be controlled. The control information is distributed to the transmitter stations by telephone or microwave interconnections. The transmitters will operate in pre-selected groups to avoid signal cancellations while broadcasting command signals to radio control switches. The radio control switches installed at each location will operate to disconnect power to the controllable load upon receiving the proper signal. Equal numbers of receivers for each group of audio modulating tones should be installed on consumer premises in a random pattern. Figure II-4 is a system mock diagram.

a. Central Processor

The central processor contains both main and standby equipment that ensures system control in the event of equipment malfunction. The main and standby equipments are identical to each other and an interlocking arrangement is provided which ensures that only one of them at a time may exercise over the system. The processor includes alarm circuitry that provides audio tone alarms.

Each central processor may be divided into two major sections: A load management section and a programmer equipment cabinet.

The load management section contains the necessary operational controls to command the system. From this section the supervisory personnel are able to select a prerecorded program for the control of loads, a secondary tone for the control of voltage regulators, or a load control emergency operation. The panel will also provide supervisory personnel with visual indications of system status.

Each programmer cabinet consists of a digital clock, tape reader, comparison and tone memory circuits, tone generating and coding circuits, output amplifying stages, and a test and alarm panel. The programmer equipment accepts the data output from the load management panel and initiates action to distribute the command information throughout the system in one of three modes: Primary, secondary, and emergency. The progammer also accepts output from time-sharing computers and system generation reqirement meters.

The primary program information is stored on punched tapes and is released and transmitted into the system by the inputs from the load management control panel.

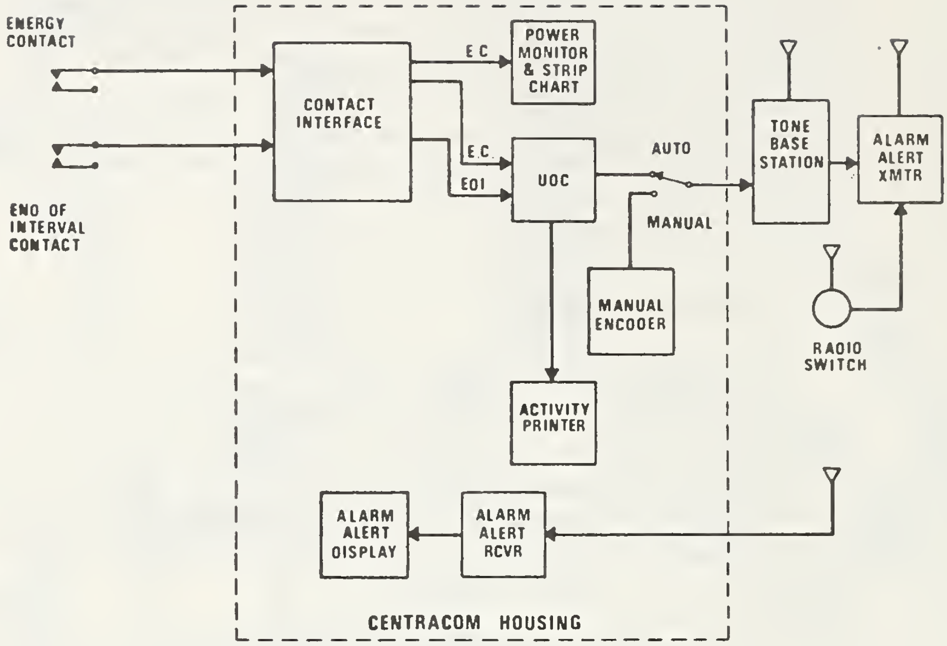

Figure II-4a Remote VHF Radio Control

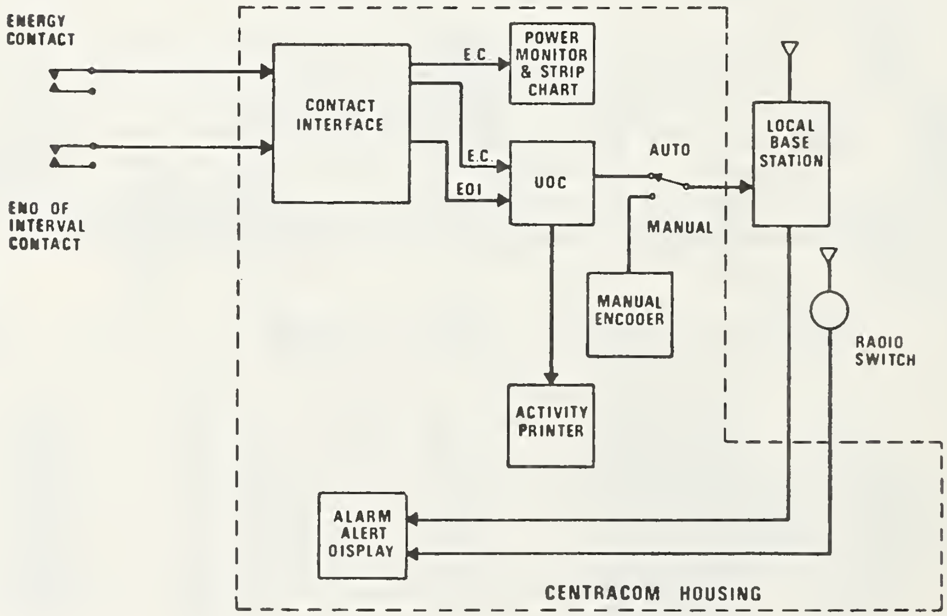

Figure II-4b Local VHF Radio Control

The primary system control tones may be initiated by a program recorded on tape or by the scram control on the load management panel. Programs may be either of two types: time or nontime.

A time-type program is automatically positioned to correspond with the actual time on the digital clock. Nontime programs are initiated without reference to actual time. The program equipment will accommodate up to 100 programs.

An inherent feature in the program equipment is that each of the tones may be rotated automatically to ensure that, if a given program is repeatedly operated, each tone will accumulate the same total off time. As a result, tape programs need not meet the requirement that each tone have an equal off period.

The secondary system consists of five specific tone frequencies and may be activated automatically or from the load management panel. The secondary system is not operated from prerecorded tape programs.

The equipment may be placed into an emergency mode either manually or automatically. An emergency mode may be initiated from system generation requirement meters or manually from the load management panel. The emergency mode exercises complete control over the primary tone system.

The emergency mode causes all transmitters to simultaneously signal each primary audio tone for 220 ms. The purpose of this mode is to achieve a maximum load reduction in minimum time.

b. Communication Channels

The communication network may consist of privately owned telephone cable, microwave voice channels, or leased telephone circuits. The separate channels ensure very high reliability to the transmission system. Tones generated in the programmer directly modulate each base transmitter. It is essential that any noise distortion or frequency translation introduced by the communication network be minimized to ensure proper system operation.

c. Transmitters

The base transmitter stations are used to provide signal strength sufficient to operate radio control switches installed anywhere in the system. Each base station consists of a 300 W output transmitter and controller, and an antenna. Each leg of the communication network terminates in a transmitter controller. The use of cavity hybrid duplexers permits the base transmitters to share the use of many existing two-way VHF radio antenna systems. The 100 dB isolation provided by the duplexer enables the transmission of load management control pulses simultaneously with the reception of VHF mobile signals with a frequency separation of less than 1 MHz.

Base station locations may be selected to provide overlapping areas of coverage. Such saturation may be essential to eliminate many of the weak signal areas caused by reflections and cancellations and to ensure system reliability.

d. Radio Control Switch

The radio control switch or receiver decoder is a dual conversion FM receiver and operates on a frequency of 154.46375 MHz. The receiver decoder is equipped with an internal antenna and a normally closed power relay for water heater applications and a normally opened power relay for voltage regulator applications. An indicator dial and pointer may be attached to the relay to provide visual indication of the number of times the relay is operated. The receiver responds to the 154.46375 MHz frequency modulated by a specific audio frequency. The particular audio frequency to which a given receiver will respond is determined by an electromechanical tuned reed. The audio frequencies used are in the 600 to 800 Hz range. The receiver has a sensitivity of 20 uV per meter for relay operation with internal antenna. One microvolt is measured at input to receiver when patched to 50 ohms. The selectivity of the receiver is 50 dB minimum from carrier reference at plus or minus 30 kHz. The decoder has a selectivity of 15 dB maximum from the carrier reference at plus 10 Hz. When a proper activating signal is sent to the receiver, the relay opens and remains open for seven minutes plus or minus two minutes. The open time is controlled by the time constant of an RC circuit in the receiver. An activating signal duration of 400 ms is required to assure a full length open time.

Figure II-5 is a diagram of a typical radio switch installation for a central air conditioner.

3. <u>Operating Parameters in the Utility's System</u>

The geographical arrangement of the load, i.e., load density or physical dimensions of the distribution system, and the land topography either influences or controls the use of radio as a practical communication medium.

Broken down into the affected components, load density governs the number of receivers located within the transmitter service area, and physical dimensions govern the total number of transmitters required to cover a given area, while the topography controls the range of the transmitter and the effective coverage area.

4. <u>Reliability/Availability</u>

The factors relevant to radio control are (1) the reliability of the communication path and (2) the availability of the equipment to function when required to do so.

Reliability of the communication path is predictable following the installation of the transmitter and completion of the required field strength measurements. Improvements in area coverage may be obtained by arranging for an overlap in the service area of two transmitters at these points. Adjacent transmitters are arranged to be keyed sequentially to prevent mutual interference. Regulatory control by the FCC of the allocated load control or base station frequencies further reduces the possibility of inadvertent transmission interference.

The reliability of the channel can be compromised at infrequent intervals by freak long distance reception of remote stations due to sporadic ionization layers in the upper atmosphere, but the probability of false operation due to precise matching of the correct modulation signal is considered to be small. The band is largely immune from normal day/night variations of the signal path.

Equipment availability has proven to be good, and failure rates less than 2% per year have been reported from various systems.

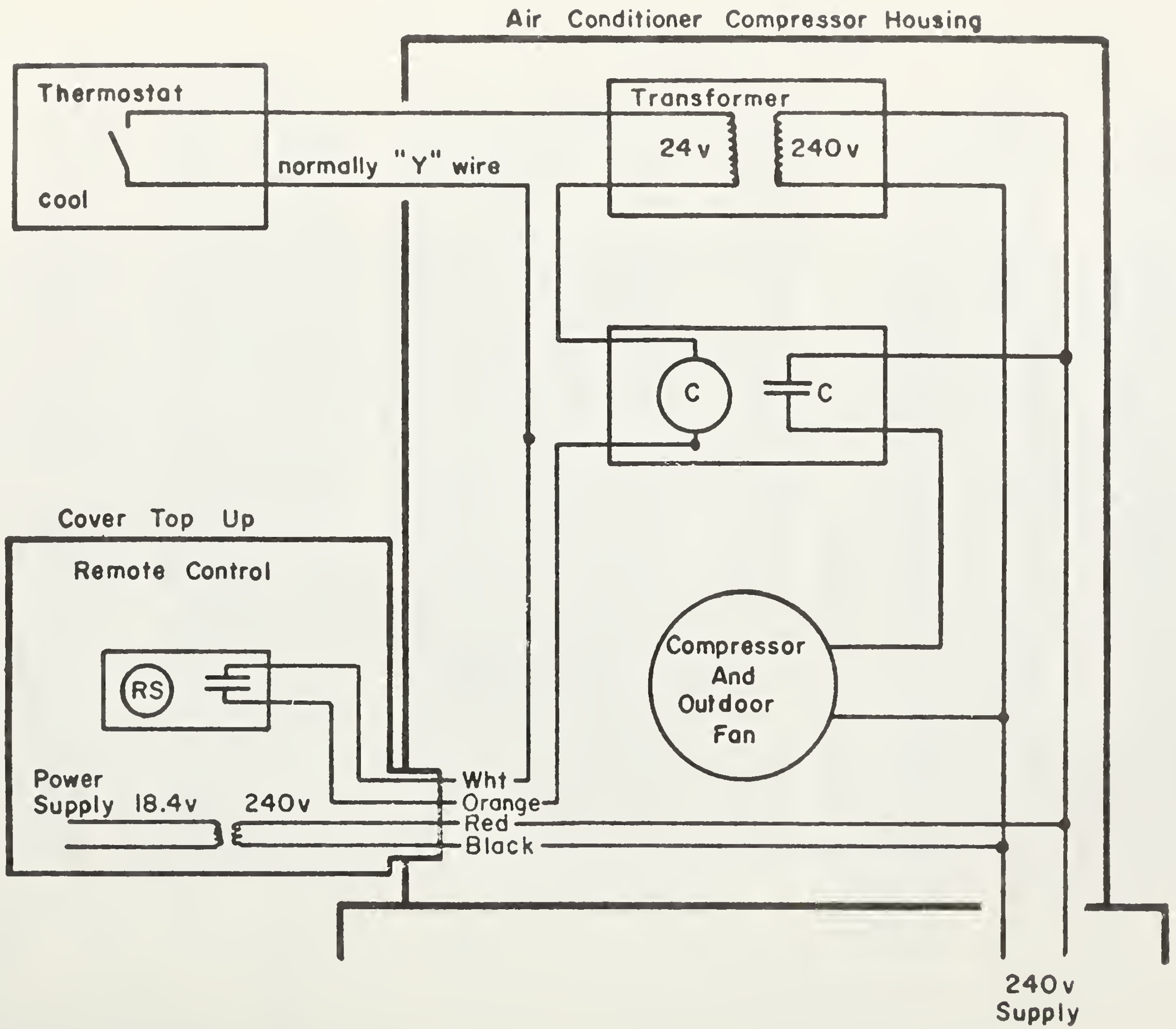

Figure II-5 Radio Switch Installation on Central Air Conditioner

5. Maintainability

Sufficient equipment has been in service for a long enough time to demonstrate that the radio system requires a minimum of maintenance. Such maintenance may be performed by borrower communications technicians working independently of utility operating staff.

Maintenance of the transmitter and antenna system follows the procedures well established for typical, similar power VHF communication base stations. Faulty receivers are normally replaced and returned to a central maintenance shop for diagnosis and repair if it is economical to do so. Typical receiver design life is seventeen years.

Block load monitoring for load reduction for each transmitted signal is considered to be the preferred method controlling the required receiver maintenance, although a form of statistical sampling by means of field tests may augment the monitoring if the number of receivers warrants such a program.

6. Security

Generation of unmodulated RF to block the receiver is a possibility but is unlikely to be a wide-spread occurance and would be easily detectable if such action was intended to affect a significant area.

Attempts to desensitize the receiver by screening the internal antenna would not be successful in the majority of installations due to signal pickup on the power wiring being coupled internally to the receiver input circuit.

Location of the receivers at either the main distribution panel or alternatively, at the end-use appliance position is preferred to location external to the building in order to minimize the risk of vandalism and reduce installation costs. In any location, the possibility exists for tampering with connections to defeat the receiver action.

7. Viable Control Philosophies

Control facilities available with radio control systems are limited in geographical distribution to local control from each of the transmitter sites. The facility to remotely control one or more transmitters via telephone lines or microwave radio makes the system ideal for centralized control. Central control may be extended to remote control points for additional control purposes if this function is required.

It is therefore possible to design a system to be compatible with the requirements for centralized control and maintain the added facility of local transmitter control.

8. Other Related Factors

a. Potential for Two-way Operation

Equipment available at this time is limited to one-way operation for simple load control switching. Development work is already in process on retransmit capabilities from the receivers and this may result in remote meter reading functions in addition to load control in the not too distant future.

b. Number of Controllable Loads

The number of controllable loads from each receiver is dependent upon the specific equipment manufacturer and currently ranges from 1 to 4 circuits.

c. Load Restoration

Restoration of load following the load shedding signal is by means of an integral time delay circuit and does not require an additional transmitted signal. These time delays are deliberately provided with a wide accuracy tolerance to ensure random restoration within one disconnected load group and to prevent simultaneous pickup of large load blocks. The load outage interval may be extended beyond this time interval by retransmitting the control signal prior to the expiration of the time delay.

d. Flexibility

Being entirely unrelated to the distribution system, both on the basis of electric system configuration (as applied to the signal path) and on the number of receivers in a given service area, radio systems are immune from network extensions within the coverage area, load growth or network switching.

Radical changes to the network in the nature of geographical extensions are conveniently accommodated by relocation of an existing transmitter or the installation of additional transmitters.

e. Location of Receivers

Location of receivers in the consumer's building is relatively flexible and simple. With the exception of marginal signal areas and certain types of building construction which result in heavy screening, the receivers may be located at any convenient position to minimize wiring changes. This may be either at the end-use apparatus or at the local distribution panel. Receivers possessing facilities for controlling more than one circuit independently are somewhat less flexible in location.

f. Noise and Signal Attenuation

The principal noise sources to be considered which would affect the performance of radio control systems are generated by electrical appliances and motor vehicle ignition. These noise sources are clearly linked to the type of area to be covered and would be more severe in urban areas. While receivers are largely immune to this style of noise, it may be desirable to improve the signal-to-noise ratio at the receiver by reducing the transmitter coverage area in urban areas to compensate for a reduction in signal strength due to building screening and an increase in noise levels.

C. Hybrid Radio/Power Line Carrier Control

1. General

This system combines the technologies of radio control and high frequency power line carrier control into one integrated system. The strengths and the limitations of each type of system have been utilized for maximum benefit. Equipment available currently is for one-way control of end-use loads with additional facilities for customer alerting devices to warn of impending system peak conditions.

The primary equipment comprises a VHF radio transmitter and a VHF FM radio receiver/high frequency power line carrier transmitter contained within a common enclosure located on the secondary side of a distribution transformer. All customers served by this transformer are contolled from this one unit. Each distribution transformer which supplies customers with controllable loads is provided with a similar receiver/transmitter unit. End-use customers are provided with one or more types of carrier current receivers according to the specific load requirements.

The use of high frequency for power line carrier effectively restricts the range of the injected signal to the low voltage side of the transformer and minimizes the size and rating of the injection equipment. Independent control of adjacent transformer loads is also permissable without interference.

The application of hybrid radio/high frequency power line carrier control to an idealized distribution system layout is shown in Figure II-6. With only the low voltage distribution wiring forming part of the communication channel, the system is for all practical purposes immune to distribution network considerations. The VHF receiver/carrier current retransmitters may be connected to any low voltage transformer secondary circuits which are located within the transmitter service area. Carrier current receivers are located at the controlled equipment in the customer's building.

The seven primary components to the hybrid control system are:

- Message generation unit (Central control processor)
- Communication link to radio transmitter
- VHF radio transmitter
- VHF radio receiver/Power line carrier retransmitter
- Power line carrier receiver
- Control module

2. System Operation

The radio receiver/Carrier current transmitter is the primary unit which differentiates the hybrid load control system from that of the radio control system. A receiver/transmitter is installed on each secondary circuit on which control is to be performed. Up to 24 residences can be served by each receiver/transmitter with up to 7 commands or control functions for each home.

The radio frequency control signals orginate from the message generator unit, centrally located for convenient

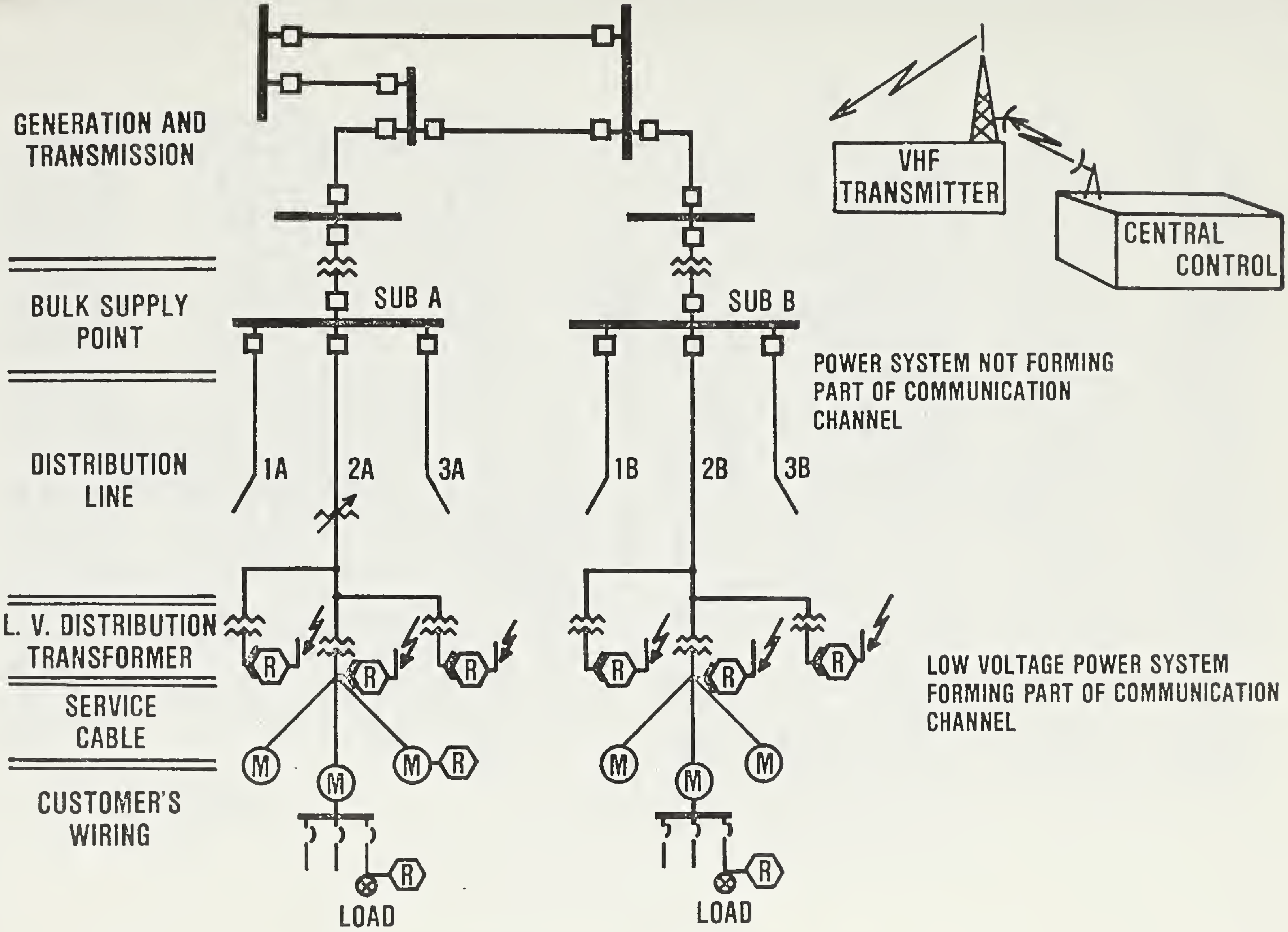

Figure II-6 Application of Hybrid Control to Power System operation. The digital message used allows unique selection of any one of up to 32 receiver groups. Also contained in the message is a command field which indicates which of seven command functions is to be performed.

When a message is sent, the radio receiver/carrier current transmitters assigned the specified address respond. The selected receivers then decode the command field and inject a corresponding frequency modulated power line carrier signal on the secondary circuit.

When a control module recieves its assigned signal, its respective load is disconnected from the secondary circuit and a 7.5 minute (± 20%) fail-safe timer is initiated. If a refresh signal is not received within the fail-safe interval, the control module reconnects the load. If subsequent signals are received within the fail-safe interval, the timer is reinitiated, and operation is extended for an additional fail-safe interval of time.

The VHF base station transmitter used in the hybrid system is virtually the same as that for the radio control system discussed above.

Figure II-7 is a diagrammatic presentation of the hybrid system.

a. <u>Message Generator Unit (MGU)</u>

The MGU is a programmable microprocessor based controller with extensive provisions for automatically controlling direct and indirect load management functions, power factor correction, capacitor switching, voltage regulator control, or any other function where remote switching is required. Manual or automatic operation is permitted selectively for each control group. Up to 20 separate control groups, i.e., groups of water heaters, air conditioners, etc., can be implemented. Each control group can be scheduled as a function of percent load shed, time-of-day, day-of-week, holiday, external sensing, or manual control via console switches for incremental or emergency operations.

The program configuration may be easily changed via a data terminal input. Status monitoring during operation is provided by real time display on the data terminal. An easy to use control allows the operator to vary load cycling during operation.

Remote Switching Using Combined RF/ Power Line Carrier Hybrid or Digital Radio Switch

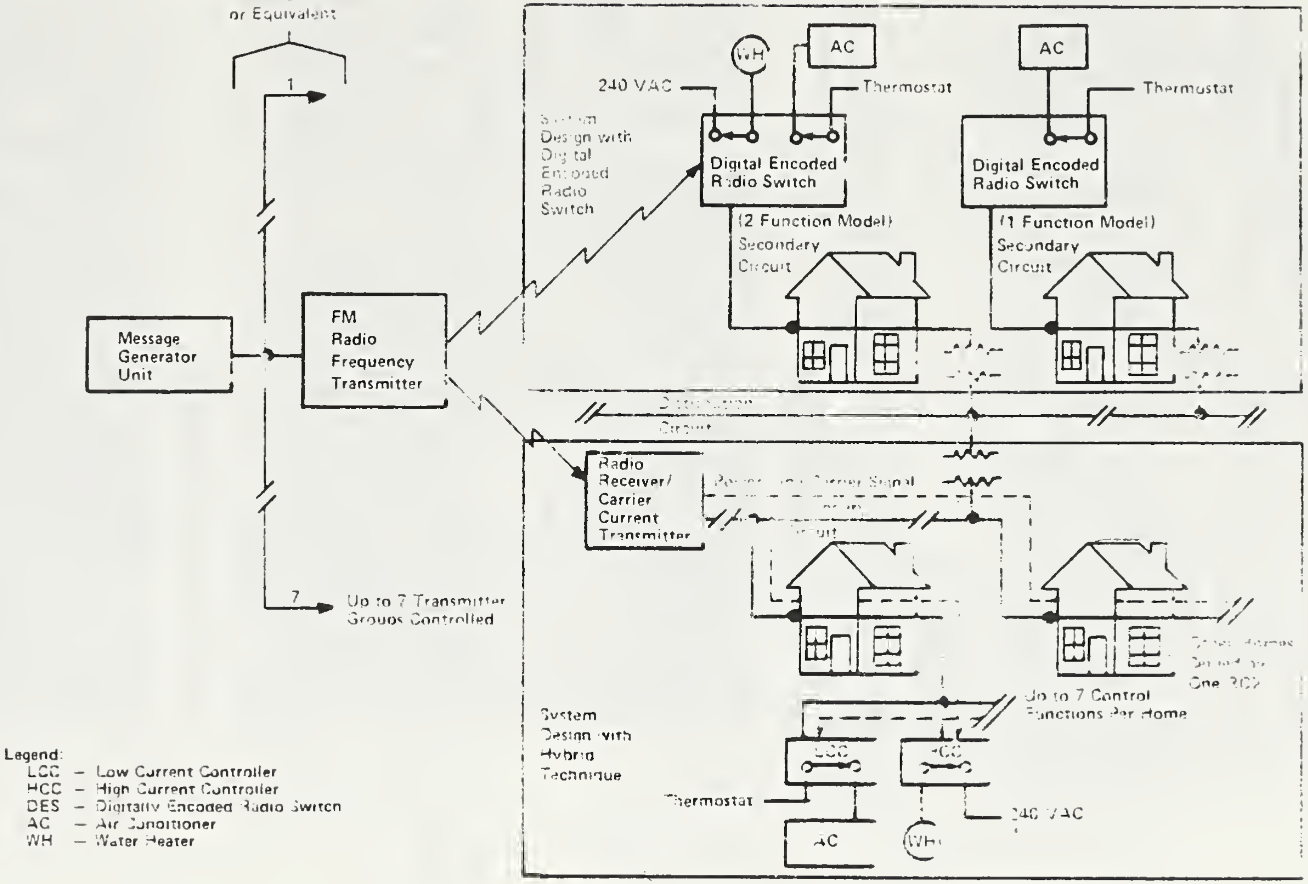

Figure II-7 Hybrid Control System

Real time status reports are operator selectable. Comprehensive information showing the dispositions of each address group in each control group or summary information for all control groups is provided.

b. VHF Radio Receiver/Retransmitter (RCX)

The RCX receives all transmitted radio messages originated by the MGU from the VHF transmitter. If the address field matches the field programmable address assigned to the RCX, a power line carrier signal is generated and injected into the secondary circuit. The power line signal is modulated with a tone representative of the decoded command field received from the message generator unit. Up to seven different functions may be controlled by the RCX on each secondary circuit. The RCX can control any number of control modules on a secondary circuit.

c. Control Modules

Two basic types of control modules are used:

(1) Low Current Controller

This control module is designed for control of low power circuits, such as those found in air conditioners. It can be mounted at any convenient access point to the control circuit. Air conditioners can be controlled in two independent blocks to reduce the burden on secondary transformers. The low current controller also contains a fail-safe provision for reversion to the appliance connected state if a refresh signal is not received within the timeout period. It has a built-in randomized timeout period to diversify appliance reconnect after control periods. An automatic power fail recovery option is available that delays reconnection of appliances to facilitate recovery from power outages.

(2) High Current Controller

The high current controller is designed for water heater load control, or other applications that require interruptions of 30 amp, 240V ac circuits. It can be mounted at the appliance to simplify installation and reduce cost. No control wiring is required in the consumer's home. The unit reverts to the appliance-connected state if a refresh signal is not received within a fail-safe interval. Other features include a built-in randomized time-out period to diversify the time of appliance reconnect after a delayed control period. An automatic power fail recovery option is available for reconnection of appliances to facilitate recovery from power outages.

3. Operating Parameters in the Utility's System

Operating parameters within the utility system for any given network have little influence on the hybrid system. For the radio control portion, only the geographical arrangement of the load, i.e., load density or physical dimensions of the area to be covered, and the land topography, control the design of the required equipment. As the power line carrier portion of the communication path is restricted to the low voltage side of any individual distribution transformer, the system arrangement, its loads or extensions will have minimal effect on any portion of the signal path other than that intimately connected with the small section under modification.

An inherent characteristic of the use of high frequencies for carrier applications is the severe attenuation across inductive devices such as transformers and this factor is used, not as a penalty, but as a means of obtaining isolation between adjacent transformers to permit independent operation.

4. Reliability/Availability

Hardware availability for the radio portion of the system may be correlated with the present performance of typical VHF FM land mobile systems. The power line carrier portion of the channel should not have a lower availability than compatible solid state industrial products using similar circuit techniques. In both instances, failure rates in equipment using solid state devices have been found to be extremely low after the initial burn-in period.

Reliability of the system to transmit, receive and identify a signal is a function of the combined radio and power line carrier systems. Functioning of the radio path is similar to that of a purely radio system described above. Precise reliability figures for the power line carrier portion of the path are at present unknown due to the limited amount of experience available from the available installations. A significant benefit which cannot be overlooked is that with each carrier current system being limited to the low voltage system fed from one distribution transformer, any failure rendering the VHF receiver or carrier injection equipment inoperative will result in a failure to control a very small number of customers.

As with all multibit code systems, there remains the basic requirement that the receiver must detect the complete signal train in order to operate. Due to the wide bandwidth available at the frequencies used, message transmission times are short and the necessity to repeat the command is not as restrictive as with the low injection frequencies used with some other systems.

5. Maintainability

Maintenance for the radio portion of the system would follow normal and existing practices by borrower communications personnel.

The customer's receivers would be handled on a replacement basis with the malfunctioning units returned to a repair facility. Pole mounted VHF receivers would be handled on a similar basis.

Periodic monitoring of signal strength should also be a requirement.

6. Security

The generation of illegal signals either at the radio or carrier current frequencies would be extremely difficult with the signal codes used and would, in effect, be self defeating as such action would only disconnect end-use appliances. Generation of unmodulated RF to block the receiver is a possibility, but would be detectable readily by interference with the voice service.

By-passing the carrier frequency by suitable filters for the purpose of preventing operation would require some knowledge of the system and similar results would be more simply achieved by interference with the power wiring on the output side of the carrier receiver. Such circuit interference would not be detectable without visual inspection of the installation.

7. Viable Control Philosophies

Control facilities available with the hybrid system are limited to those provided at the central control point - both from the standpoint of the location of the code tone generator and the requirement that access to the radio transmitter be coordinated with the voice keying. Operation from one or more satellite transmitter locations is not practicable unless the required tone generator equipment is duplicated at each such location or dial up telephone facilities are provided to permit access to the central controller.

The flexibility does exist for dual control from the G&T and from local distribution provided that additional communication channels are utilized between the two control points, ensuring that the final transmitted signal originates from one common center.

8. Other Factors

a. Number of Controllable Loads

Multiple individual commands are available at each VHF receiver location. Any or all of these commands are available for control functions according to the system requirements, but it must be recognized that these signals will be common to all customers connected to the transformer secondary circuit covered by that VHF receiver. In practice, it is necessary to divide the number of commands between the connected customers in order to avoid destruction of the load diversity on the transformer.

b. Noise

The principal noise source to be considered for the radio portion of the system is generated by electrical appliances and motor vehicle ignition. This noise source is clearly linked to the type of area to be covered and would be more severe in urban areas. While the VHF receivers are largely immune to this type of noise, it may be desirable to improve the signal-to-noise ratio at the receiver by reducing the transmitter coverage area in urban areas to compensate for a reduction in signal strength due to building screening and increase in noise levels.

REA Bulletin 66-5 should be consulted for determination of noise interference on the power line carrier portion of the system.

c. Flexibility

The hybrid system is inherently flexible in application, as the signal path to the VHF receivers is entirely independent of the distribution system configuration and of the number of VHF receivers in a given service area. As such, it is unaffected from network extensions within the coverage area, load growth or network switching. Addition of new distribution transformers will require one additional VHF receiver at each location serving a controllable customer.

Radical changes to the network in the nature of geographical extensions are conveniently accommodated by the relocation of an existing transmitter or the installation of additional transmitters. Such changes would, in all probability, be required for the extension of the voice communication facilities independent of the control system requirements.

d. Controlled Customer Per Transformer

The concept of one VHF receiver transmitting via high frequency carrier injection to all customers connected to a distribution transformer low voltage system renders the system particularly sensitive to cost variations due to system type. As each customer is allocated the cost of the carrier current receiver plus a proportion of the VHF receiver, the proportion, depending upon the number of customers sharing that receiver, becomes an important factor.

Urban systems commonly supplying multiple customers per transformer offer significant cost advantages over rural areas where very low customers per transformer are the rule.

e. Location of Customers' Receivers

Location of receiver relays in the customer's building is relatively flexible and simple. The injected signal is available throughout the wiring system. The relay may be located either at the incoming control panel or at the controlled appliance. Receivers used for time of day metering may be installed as an extension to the plug-in meter base.

f. Location of VHF Receivers

For overhead distribution systems, VHF receivers may be most conveniently located adjacent to or at the transformer pole location. However, for pad mounted or underground transformer vaults, the receiver may be located at any point on the low voltage secondary system where adequate RF signal strength is obtainable. Such points are typically at one of the customer's metering points.

D. Power Line Carrier Control - Low-Frequency Injection

1. General

This system offers one-way communication to control specific end-use appliances. Different methods of signal coding are available which range from simple on-off rhythm keying to multibit binary pulse codes capable of significant intelligence. Regardless of the code format used, all systems employ the following basic techniques. The low frequency signal is in the low audio range, usually less than 1000 Hz. In most applications, the low frequency signal is above the fundamental 60 Hz power frequency. This signal is generated by a low-frequency oscillator and is keyed "on-off" in accordance with the signal code program. The resultant chopped low-frequency carrier is injected into the power system in such a manner that it adds, victorially to the power system waveform, thus modulating the fundamental voltage wave.

Two possible alternatives in the application of low frequency power line carrier control to an idealized distribution system layout are shown in Figures II-8 and II-9. Figure II-8 shows a typical radially connected network with injection taking place at each bulk supply point's medium voltage busbar. Figure II-9 illustrates injection at the high voltage level in order to cover more than one bulk supply point with a single set of injection equipment but indicates the vulnerability of the communication path to switching at the transmission voltage level.

Receivers may be located at any point on the system where a low voltage supply is available. There are five primary components to the low frequency injection system:

- Central control unit
- Communication link to remote injection stations
- Signal injection equipment

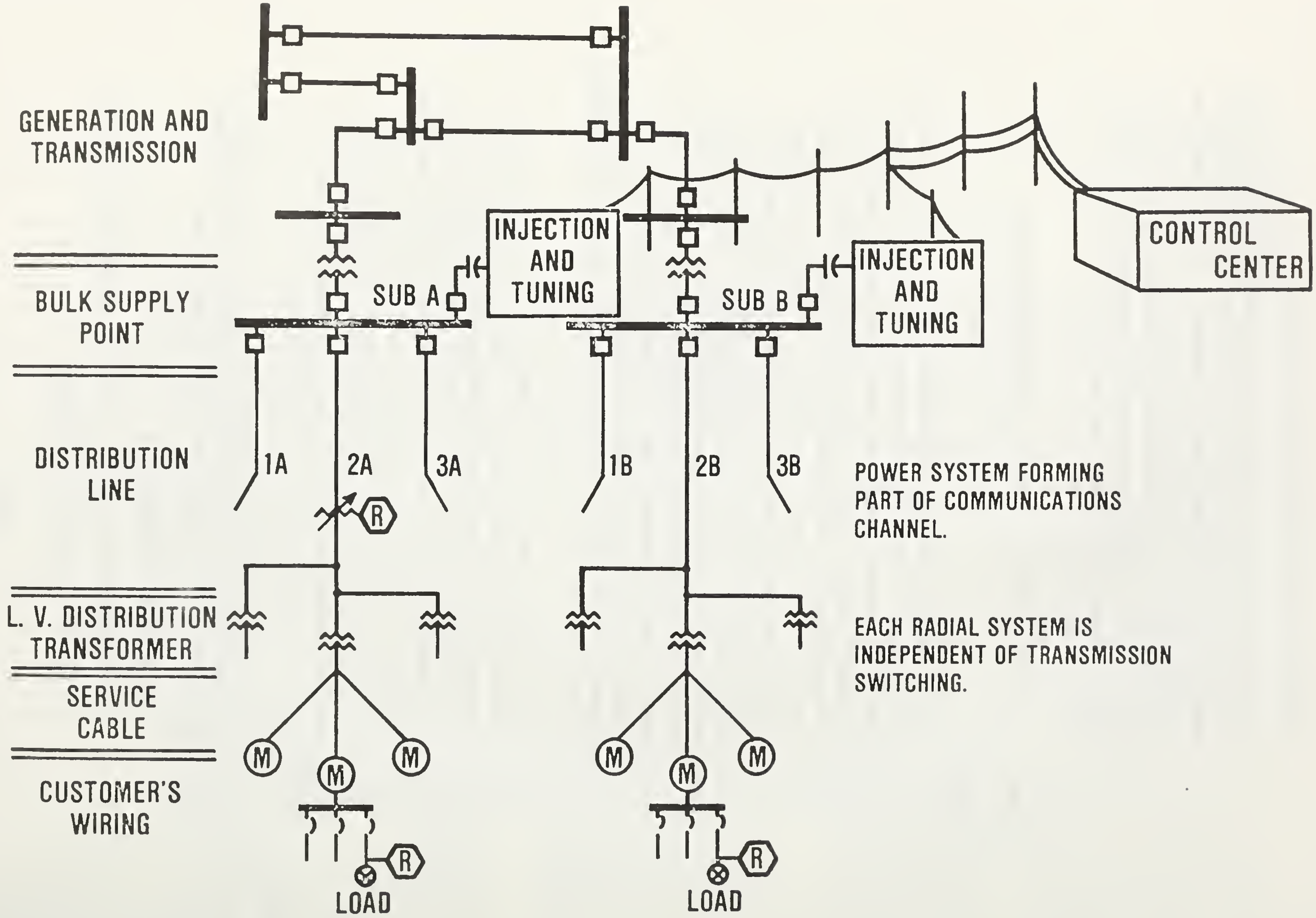

Figure II-8 Application of Low Frequency Power Line Carrier Control to Power System Medium Voltage Level Injection

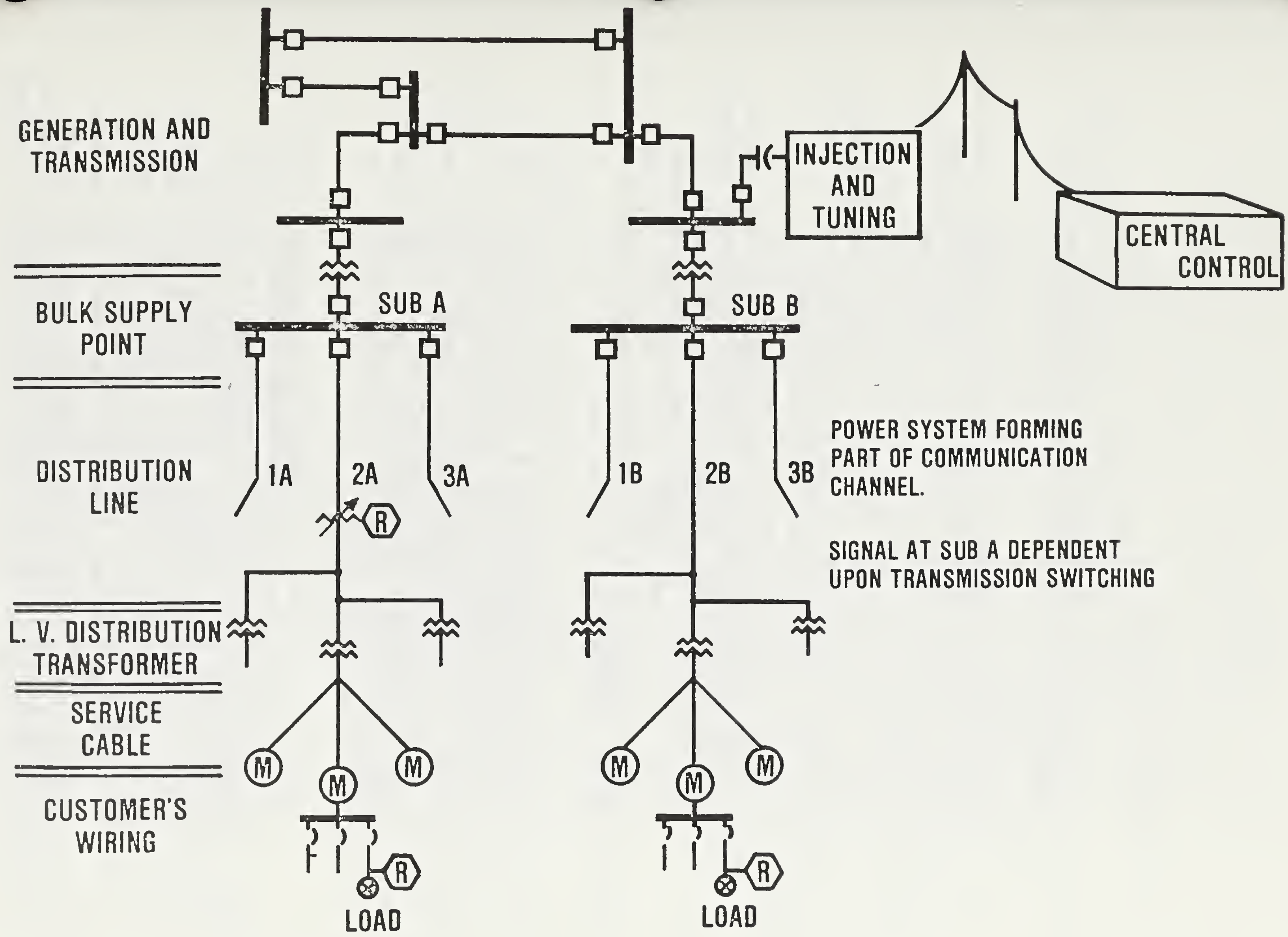

Figure II-9 Application of Low Frequency Power Line Carrier Control to Power System Transmission Voltage Level Injection

- Receiver
- Control relay

2. System Operation

A low frequency injection power line carrier system consists of a central automatic programming unit, one or more injection points and receivers distributed throughout the network.

The central programming unit initiates the control action automatically according to either a predetermined time schedule or to signals from a load control installation.

The injection points consist of a static frequency converter with associated electronic equipment and a coupling filter. Manufacturers of these systems provide for various methods of coupling to the phase conductors.

A tuned coupling filter is used to pass the audio energy into the power network, while isolating the audio generator from the high voltage system. Signals travel through transformers and lines to the low-voltage distribution network, in the same manner as does the power frequency energy, and are therefore available at all consumers' supply terminals.

The audio signals arriving at a receiver are separated from the power frequency by a filter, which also rejects interference from system harmonics and random noise sources. The detected signal is then available for operating a load switch, or a multiple rate meter register, and so controls the conditions of supply to the consumer. The audio power level injected into the network is 0.2% of 0.4% of the supply transformer capability, and transformers of up to 600 MVA can be utilized.

This type of system is essentially a narrow band communication channel, the bandwidth being restricted by the filters required in both the transmitter and receiver. This bandwidth is limited to a few Hertz, so that the transmission of information can take place only relatively slowly. Since it is required to address many different groups of consumers in different sections of the network, the signal is coded to provide several hundred discrete and mutually dependent commands. The code structure used depends on both the control requirements and the design constraints that must be satisfied to produce an economical and dependable decoder for each receiver in order to reject those signals not specifically addressed to it.

3. Operating Parameters in the Utility's System

Significant parameters in the use of low frequency injection may be summarized as follows:

Attentuation of the injected signal by the distribution system components will be lower the more nearly the signal frequency approaches the fundamental power frequency. Generally stated, frequencies below 1000 Hz are sufficiently close to power frequency to permit normal transformer action in power and distribution transformers and injection at the sub-transmission and medium voltage distribution levels is feasible without involving an intolerable reduction in signal strength at the end-use terminals.

A second consideration is signal loss which includes direct losses due to shunt connected loads. The use of a signal frequency close to the power frequency to obtain the benefits of the transmission path characteristics results in a penalty incurred at the consumer's terminal. Each terminal power frequency load also provides a load on the injection signal voltage.

Application of the low-frequency injection system requires a relatively detailed study of the power system to which it will be applied.

System parameters which influence the application include network configuration, normal and abnormal switching arrangements, circuit impedances (methods of construction), location and value of shunt capacitors and series reactors, load type and load distribution (geographical and magnitude). The controlling factor will be the total system load at each point selected for injection as this factor determines the injection signal input KVA.

4. Reliability/Availability

The factors needed to be addressed with respect to reliability and availability are (1) functioning of the equipment when called upon to operate and (2) the propagation of the transmitted signal and its recognition by the receiver. The former may be interpreted as hardware availability for operation and the latter, signal reliability.

Hardware availability has proven to be good over the many years of operating experience with very low failure rates reported. One characteristic of low frequency systems cannot be ignored: These systems, to be economic, must cover relatively large areas and failure of an injection point equipment or component can result in loss of control of substantial blocks of load until the failure is corrected.

Signal reliability is influenced by the type of signal code used, i.e., repetitive rhythm or binary pulse. In the repetitive system, tone bursts and spaces are of equal durations and are repeated in a rhythmic fashion to give a recognizable, periodic time of the injected rhythm. Only relatively few discrete addresses are possible at any one signal frequency. One major advantage is that even if a few of the injected pulses are missed during the transmission period, the receiver will still obtain an identifiable signal. This coding is particularly suitable for systems containing potentially high network noise bursts and where discrete address requirements are minimal.

The binary pulse code utilizes a multibit mark space signal, the mark comprising a short duration tone burst. A basic requirement is that the receiver must detect the complete signal train in order to respond. It may also be necessary to repeat the command more than once, to achieve the same immunity from system noise obtainable with the repetitive system, at a cost of much longer transmission times.

Regardless of the signal code, the low frequency signal is subject to variation in loss due to changing network conditions and periodic retuning is needed to minimize these effects.

5. Maintainability

Overseas experience and the techniques used may not be directly applicable due to the somewhat different economic influences exerted such as more compact systems, labor rates etc.

It is anticipated that for domestic use, receivers and relays would be handled in much the same manner as existing consumer meter practices. Maintenance of the injection equipment would be possible during off-peak periods and would involve periodic inspection, calibration, and cleaning. Periodic monitoring of signal strengths throughout the system may be desirable.

6. Security

Generation of illegal codes and injection into local wiring for the purpose of defeating the relay is difficult for either of the basic signal-coding systems giving good system security. By-passing of the signal for the purpose of preventing operation would require technical knowledge not available to the majority of the population.

Location of the receivers adjacent to the controlled device within the consumer's building minimizes vandalism except that under the direct control of the owner. The possibility exists for tampering with connections to defeat the relay action.

7. Viable Control Philosophies

By virtue of the system, each injection station has the ability to control loads over a relatively large area and as such, the maximum geographically distributed points from which controls may be exercised are located at the individual injection stations if suitable facilities are incorporated into the initial design. The facility to remotely control one or more of these injection stations from a central location makes the system ideal for centralized control.

8. Other Related Factors

a. Speed of Signal Transmission

In order to limit the effects of line noise, the bandwidth allowed by both injection and receiver filter circuits is narrow and with the low signal frequencies used, the effective bandwidth is limited to a few Hertz. Consequently, the speed of transmission of the information signal is slow, commonly in the range of 10 to 30 seconds per message. Depending upon the signal coding utilized, each message may contain one or several independent commands.

b. Number of Controllable Loads

The number of individually controllable loads from each receiver is dependent upon the specific equipment manufacturer and ranges from 1 to 3 circuits. It is not a function of the generic type of system.

c. Restoration of Load

Restoration of load following the load shedding signal may be either as a single block on command or as preselected sequenced increments necessitating several discrete coded signals. Selection of the method of restoration will depend upon the network ability to absorb the cold-load pickup demand, governed by such parameters as voltage drop, equipment rating, and fuse sizing.

d. Location of Receivers

Location of the receiver relays in the consumer's building is relatively flexible and simple. The injected signal is available throughout the wiring system. The relay may be located either at the incoming control panel or at the controlled appliance. Relays possessing facilities for controlling more than one circuit are somewhat less flexible in location and if not installed at the incoming panel, will require some modification to the building wiring.

E. Power Line Carrier Control Using High Frequency Injection

1. General

This system, also referred to as distribution line carrier, developed principally for remote meter-reading, provides facilities for the control of specific end-use appliances. At least three types of equipment are now manufactured. Multibit binary signal codes are generally used and the system is capable of considerable intelligence. Discrete addresses for each receiver installation in addition to block addresses for command functions are available.

Carrier frequencies used for systems to date fall within the range of 5kHz to 100 kHz, a band which studies have shown to contain minimum power system generated noise. Stable solid state oscillators are keyed "on-off," frequency shift or phase shift, in accordance with the preselected signal code. The resulting modulated carrier is injected into the power distribution system conductors. For two-way operation, both the station injection point and the individual consumers' terminals have transmit/receive capability.

The application of a high frequency power line carrier control system to an idealized distribution system layout is demonstrated in Figure II-10. Injection is noramlly at the medium voltage level and although line connected units of low power output are shown, an alternative and perhaps more common higher power substation unit is available with some systems. Injection units may use either individual telephone grade lines to connect to the central control equipment or share party lines, depending upon

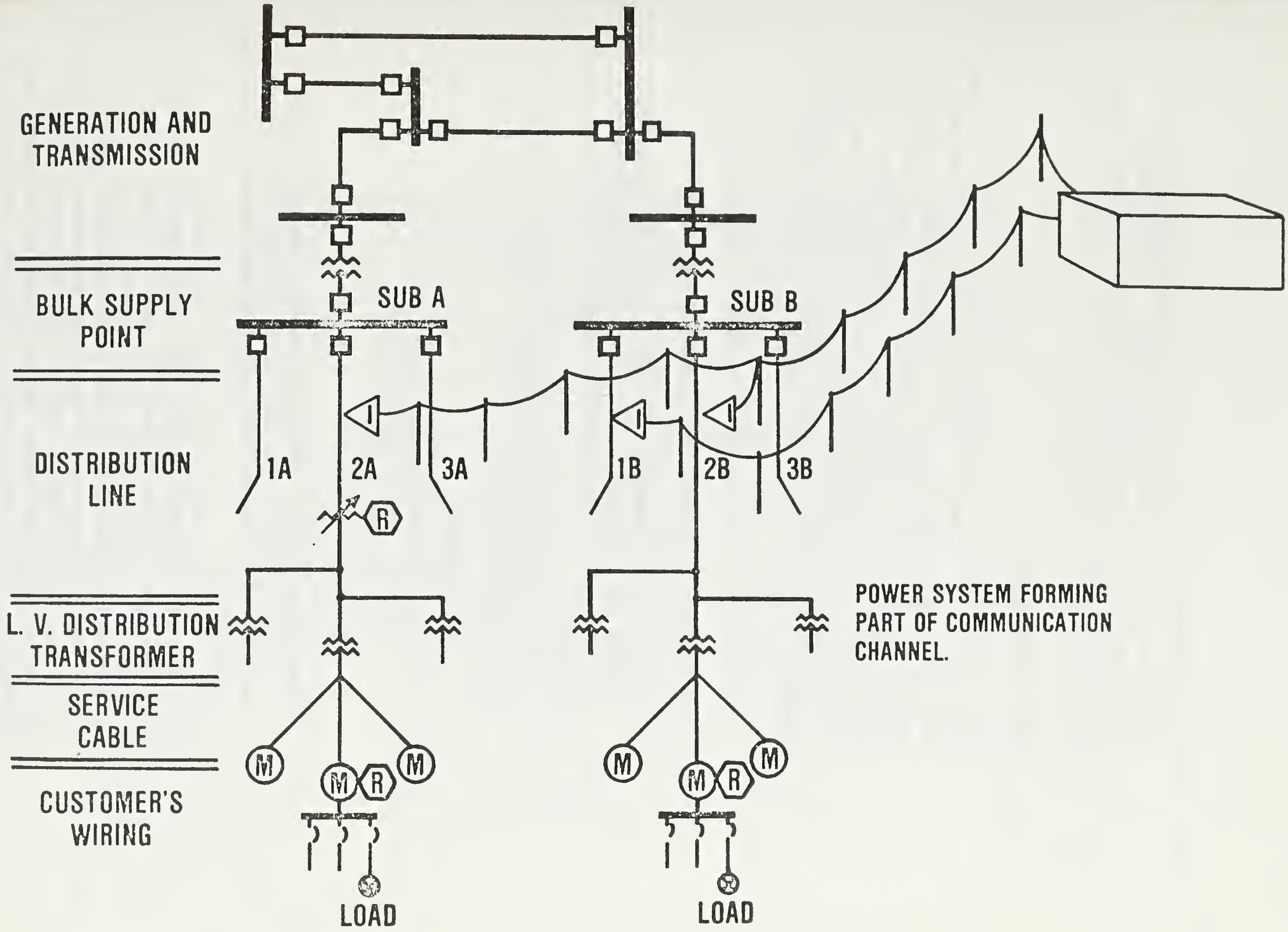

Figure II-10 Application of High Frequency Power Line Carrier Control to Power System equipment type. Receivers may be located at any point on the system where a low voltage supply is available. By virtue of injection being at the medium voltage level, coupling to the power system can usually be via a simple fused disconnect.

2. System Operation

This system typically provides two-way communications and a control link between a central control point and remote locations in an electric utility service area. Operating over the distribution power lines provides a capability to control and monitor a wide variety of distribution system functions, to perform load management, and to accommodate and record revenue metering data. The system is designed for high reliability, flexible operation, with large data capacity, adaptable to a wide variety of applications.

There are four basic types of hardward in the system:

- A centrally located data dispatch computer;
- A substation communications unit at each substation (which may include the accessory substation control and data monitoring unit for substation resident parameters);
- Remote equipment at the customer premises consisting of a combination of:
  - Transponders
  - Auxiliary Switching Units
  - Load Control Receivers
  - Encoding Meters
- Remote equipment located in the distribution system wherever a control or monitoring capability is necessary. These devices are called distribution automation units (DAU).

The interrelationship of the major components in a typical automated load control network is shown in Figure II-11.

The system is controlled by the data dispatch computer (DDC). The DDC consists of a central processor with supporting hardware and software, which communicates with each substation. The DDC issues system commands, acquires network data and monitors system performance. In meter reading application, it receives the revenue data, performs errror checking and stores the data for further processing in a billing computer.

The data dispatch controller communicates via dial-up or leased unconditioned telephone circuits or microwave links with substation communications units (SCUs) located in the distribution system substations. All data passing through this communications link is digital and is transferred between standard modems at a 300 baud rate. The system provides for DDC communication with more than 1000 SCUs.

The SCU recieves, decodes and processes instructions received for the DDC, generates and processes the signals to be sent over the feeder lines to remote terminals (transponders, load control receivers or distribution automation units). In the reverse direction, it listens for, and receives, signals returning over the feeder lines from transponders or distribution automation units (DAUs), demodulates these return signals and processes the data into proper form for transmission back to the DDC.

The signal between the SCU and the remote terminals is a modulated carrier impressed upon the distribution system power lines. The carrier frequency is set at an odd harmonic of 30 Hz at about 6 kHz. This choice of carrier frequency provides for relatively noise-free operation and low attenuation and allows the system to operate directly through distribution transformers without significant signal loss. No transformer bypass or repeater equipment is required. Where pronounced, the shunt effect of distribution system power factor correction capacitors on any communications frequency above one kilohertz is neutralized by use of inductive isolators. The isolators are supplied as part of the system hardware element and are easily installed by utility line crews.

Modulation and demodulation are employed with all internal frequencies derived from the 60 Hz power line frequency.

Data passing from the SCU to remote terminals is transmitted at about 60 bits per second. Data returning from remote terminals to the SCU is usually also at about 60 bits per second. For situations where an acceptable signal is not received from a given transponder, an interrogation strategy programmed into the DDC software automatically switches the transponder to reply at a lower bit rate. This provides increased discrimination against noise, thereby improving the ability to receive messages.

The transponders are remote receiver-transmitters located at

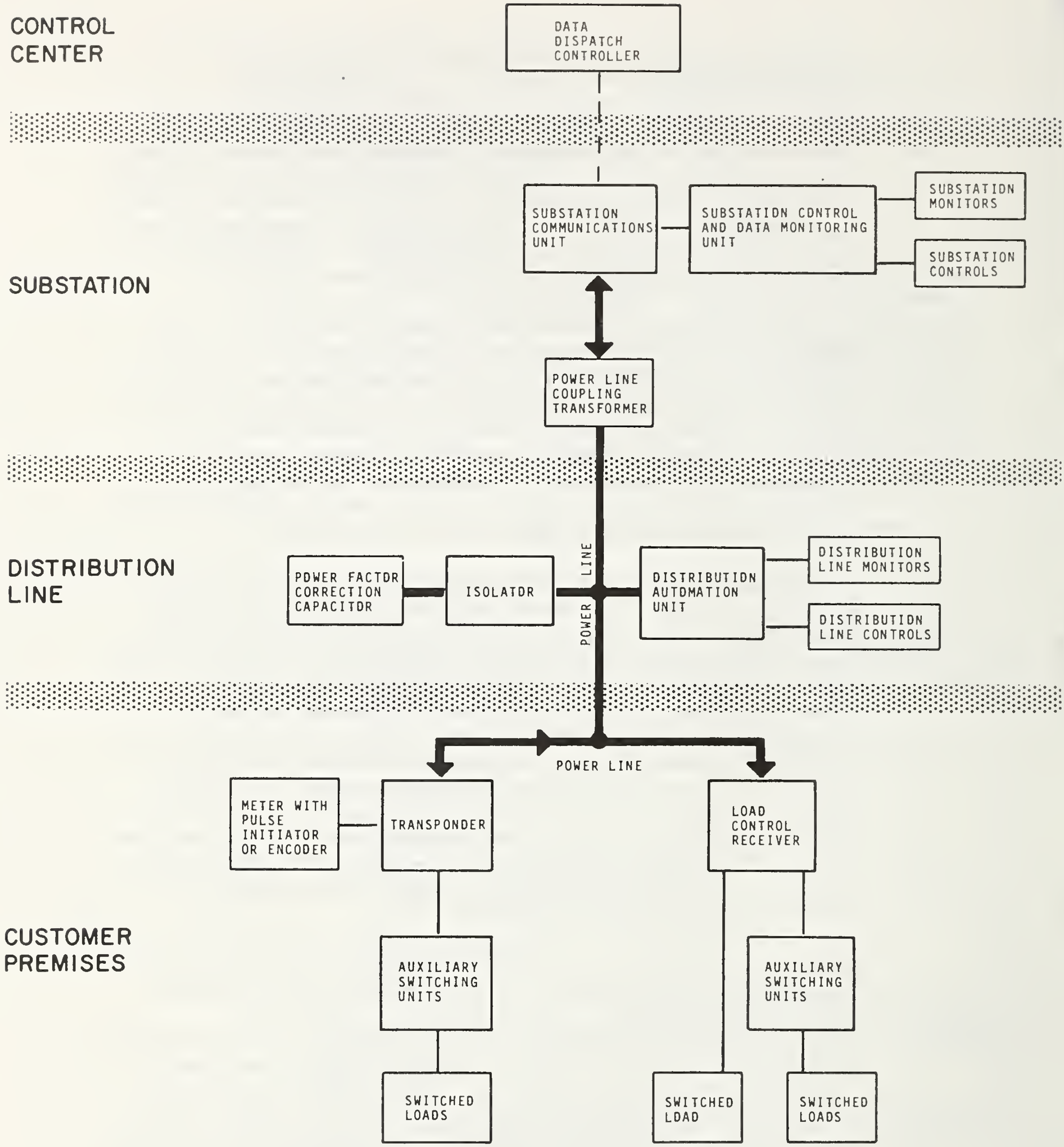

Figure II-11 High Frequency Power Line Carrier Control System each customer site where two-way communication is required. A transponder returns total energy revenue data when used with a pulse initiator meter and also provides multirate and demand metering or load survey data. The transponder may also be equipped with an absolute dial encoder to read conventional watt-hour meters.

The transponder, when used with an auxilliary switching unit, will control the switching of a deferrable load such as a water heater and report back the switch status. One transponder will accommodate up to seven auxilliary switching units.

Two additional hardware elements are also available for use with these types of systems at remote sites where a transponder is not required or appropriate. A distribution automation unit (DAU) will control distribution network switching functions, such as power factor correction capacitor control, switching and transformer tap changing. A DAU can also interface with suitable sensors to return parametric data to the data dispatch controller about distribution system functions such as switch status, distribution equipment temperatures and line voltages.

A load control receiver is available for installation at a remote site to shed a load for a fixed time. This simple unit is analogous to a radio or "ripple" receiver, i.e., it provides no information feedback. It switches one load internally and will control up to six additional loads through auxilliary switching units.

3. Operating Parameters in the Utility's System

Significant parameters in the use of high frequency injection may be summarized as follows:

a. Attenuation of the injected signal by the distribution system components is relatively high due to the high reactance of system series inductance and low reactance of shunt capacitance at these frequencies. The effective range of the signal is somewhat less than equivalent lower frequency systems and injection is usually limited to the medium voltage distribution system. A wide-spread, low-load density medium voltage system may require signal repeaters to achieve adequate signal strength at the remote low voltage end-use terminals.

b. Signal losses are encountered at locations containing shunt connected capacitors but such losses can be controlled by the use of signal traps.

c. A benefit in the use of a signal frequency much higher than the power system frequency is the reduction in the signal loss due to the power frequency load equipment. Sufficient inductance is usually present in the load equipment to severely limit loading of the signal source and this permits the use of low-power injection.

d. Application of the high-frequency injection system requires a minimum of information about the distribution system concerned and will be limited to such factors as network configuration, normal and abnormal switching arrangements and location of power factor correction capacitors.

e. Several factors influence the requirement for a minimum amount of application engineering. Among such factors are:

(1) Each of the systems is predicated upon the use, or facilities for use, of remote meter reading. Discrete sectors of the distribution system report to individual sector control units. Sector control units may either relay messages directly to and from the central control or may process them in order to avoid "bottlenecks" in the information channel where large amounts of data have to be transmitted.

(2) Each sector unit contains the necessary high frequency equipment and forms an injection point. Due to the low transmitted power, such equipment is comparatively small, simple and inexpensive and may be located at a substation or elsewhere on the distribution system as required.

(3) Distribution system impedances at high signal frequencies are unpredictable; thus, empirical determination of injection points is more expedient. If trouble areas are located during tests, it is relatively simple to relocate the injection point or provide repeaters.

(4) The restriction in signal range due to attenuation, plus the use of individual sectors, usually results in injection at the medium or low voltage distribution levels rendering the system insensitive to variations on the high voltage system.

4. Reliability/Availability

Hardware availability should not be less than comparable solid state industrial products using similar circuit techniques. Such products as solid state controls have shown extremely low failure rates after the initial burn-in period. It should be noted that with the use of multiple low power factor injection units, failure of any one piece of equipment will, at worst, affect the receivers controlled by one sector only.

The use of multibit codes contains the basic requirement that the receiver must detect the complete signal train in order to respond. Due to the wider bandwidth available at the high frequency, message transmission times are short and the necessity to repeat a message for reliability purposes is not as restrictive as at low injection frequencies. Used in the remote meter reading mode, the system is largely self-monitoring for signal reliability (a failure to respond will be detected by the central control).

5. Maintainability

It is anticipated that in large scale use, receivers and associated equipment would be handled in much the same manner as existing consumer meter practices; that is, replacement of malfunctioning units, and return to the meter shop for repair. Encoder problems would, in most instances, involve meter replacement.

Routine maintenance of equipment and routine signal strength measurements should be conducted as part of a periodic maintenance program.

6. Security

Security of the system is relatively good. Generation of illegal commands would be difficult. Bypassing the signal for the purpose of preventing operation may be partially prevented by the general practices of obtaining the signal at the line side of the meter, placing the meter inductance between the possible bypass tap and the receiver. In addition, if the system were used for remote meter reading, any such bypass would be readily detected.

Location of the receiver at the metering point does expose the load control circuits to pampering. Wiring between the receiver relay and the end-use apparatus is available to the property owner and may be disconnected without detection during normal operation of the system.

7. Control Philosophies

Control facilities available with the high frequency injection systems are limited to those provided at the central control point. Thus, a geopgraphical distribution of local control is restricted. This limitation is inherent in the currently projected systems using two-way combined remote-metering and control functions. The restriction is solely due to this use. It is in no way a characteristic of the use of high frequency injection.

8. Other Related Factors

a. Speed of Signal Transmission

At the signal frequencies used, the bandwidth is sufficient to allow for moderate speed of transmission resulting in short message transmission times. This factor enables the channel to be available for multiple message commands without excessive delays.

b. Potential for One-Way Operation Only

These systems, as developed, are for two-way communication with facilities for load control as an ancillary function. The use of such systems for one-way control only is possible but would likely be uneconomical as much of the circuitry for the remote meter reading is common to both functions. Some designs incorporate facilities for one-way control initially with the potential for extension to a two-way system at a later date; however, such modifications will be subject to market requirements. There are no technical reasons prohibiting the development of simple, one-way high-frequency systems if demand for such systems continues.

c. Number of Controllable Loads

The number of individually controllable loads from each receiver is dependent upon the specific equipment manufacturer and is not a function of the generic type.

d. Restoration of Load

Restoration of load following a load shedding signal may be either as a single block or as preselected sequenced increments necessitating discrete coded signals. Selection of the method of restoration will depend upon the network ability to absorb the cold-load pickup demand, governed by such parameters as voltage drop, equipment rating, and fuse sizing. The high frequency system is ideally suitable for restoration in multiple, small blocks. Automatic time-out restoration facilities can be provided by specific designs to prevent loss of consumers' loads for prolonged periods in the event of equipment malfunction.

e. Location of Receivers

Use of the receiver unit for retransmitting the local meter reading requires that the unit be installed at the consumer's meter location. Current designs are compatible with the single phase house service meter socket. Thus, connections from the meter location to the end-use appliance must be run as additional wiring. Such wiring is low voltage "thermostat" type cable (control relays are low voltage only). Where higher voltage control is desired, interposing relays must be used.

F. Telephonic and Direct Wire Systems

1. General

Direct wire supervisory control systems for utility and industrial applications have been used for a number of years. While it is uneconomical to install direct wire lines to each and every end-use customer on a given electric distribution system solely for the use of load control, the presence of the local telephone company's system does provide such facility which cannot be ignored. This system presents an available, reliable and high quality communication channel which enters the vast majority of the distribution system's end-use customers property.

Systems available using this form of communications range from simple DC on-off or polarity detectors for distribution system control, to sophisticated high speed signal system for complete system remote control and operation. The majority of existing systems are limited to a few discrete terminals and are in the pilot project/test stage. These systems are those designed for use as one or two-way communication channels for automatic remote meter reading and direct control of end-use customer appliances.

Signals range from tone encoded frequency shift signals to the transmission of discrete digitally encoded signals. Discrete digital addressing provides for the transmission of more intelligence and can address separately more than one customer or a common telephone circuit.

By virtue of the telephone system arrangement, the group addressing of load control receivers is impracticable, but scanning equipment is available which can perform sequential addressing in excess of 10,000 lines per minute/controller/exchange. The effective delay on load control is minimal. Scan rates for meter reading are somewhat lower.

The application of a telephone address control system to an idealized distribution system layout is demonstrated in Figure II-12. As no portion of the power system forms part of the communication channel, communication between the control center and the individual receivers is maintained regardless of network switching or abnormal operating routines. Receivers may be connected at any location serviced by the telephone company without further addition to the telephone distribution system.

There are six functions to a typical telephone type load control system.

- Central control unit
- Data terminal
- Telephone central office selector
- Customer's transponder
- Customer's meter encoder
- Customer's control relay.

Except for the customer located receivers, no additions or modifications are required to the distribution network, all equipment being located at the control center and the telephone company's control office.

2. System Operation

The telephone load control system is depicted in Figure II-13. The SCM system employs a three-level architecture as follows·

- Service Centers - Each operated independently by the utilities and other user organizations;
- Telephone Company Central Office Equipment
    - Process computer
    - Central Office controller
    - Line Scanners
- Remote Units at Customer Premises

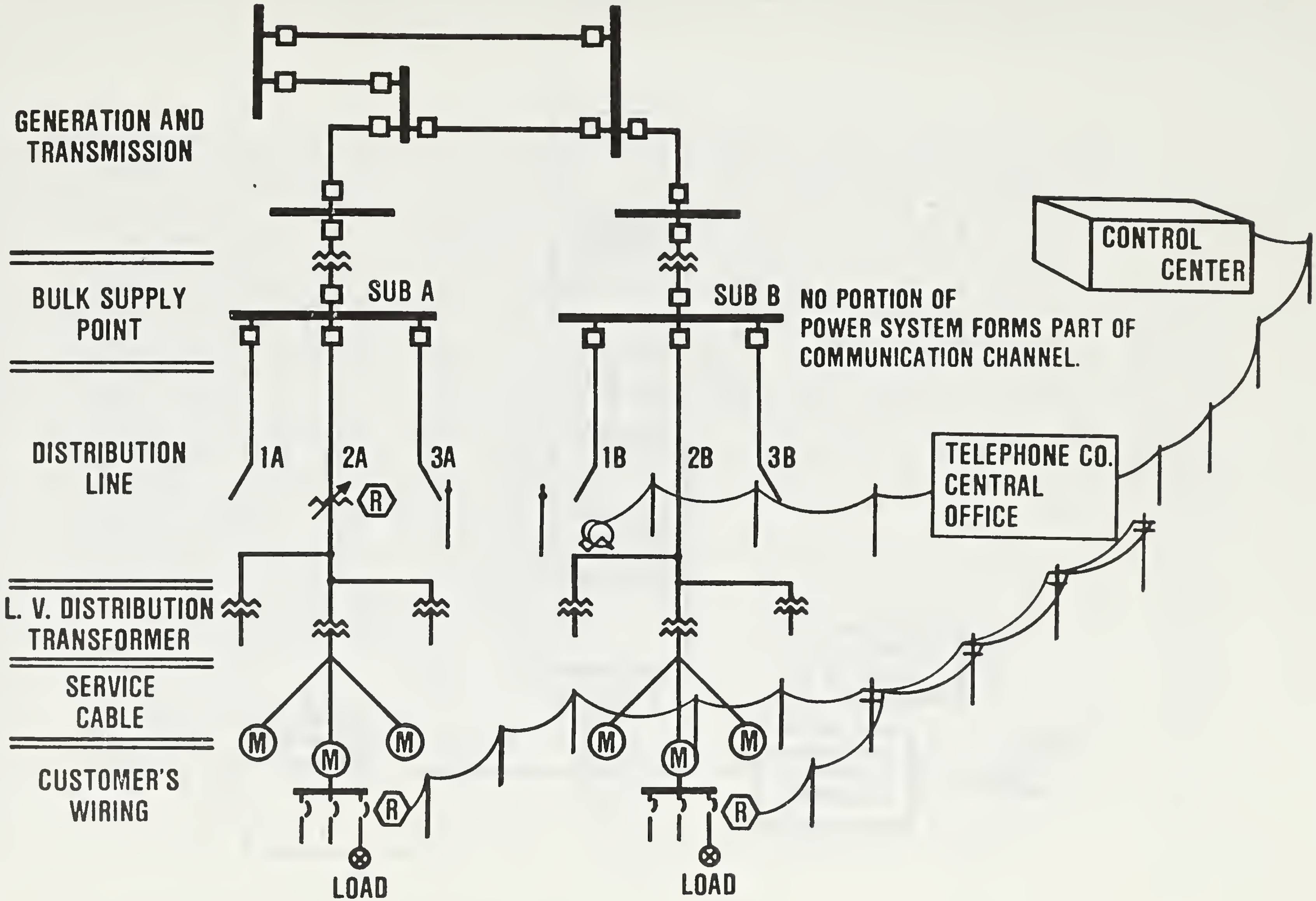

Figure II-12 Application of Telephone Control to Power System

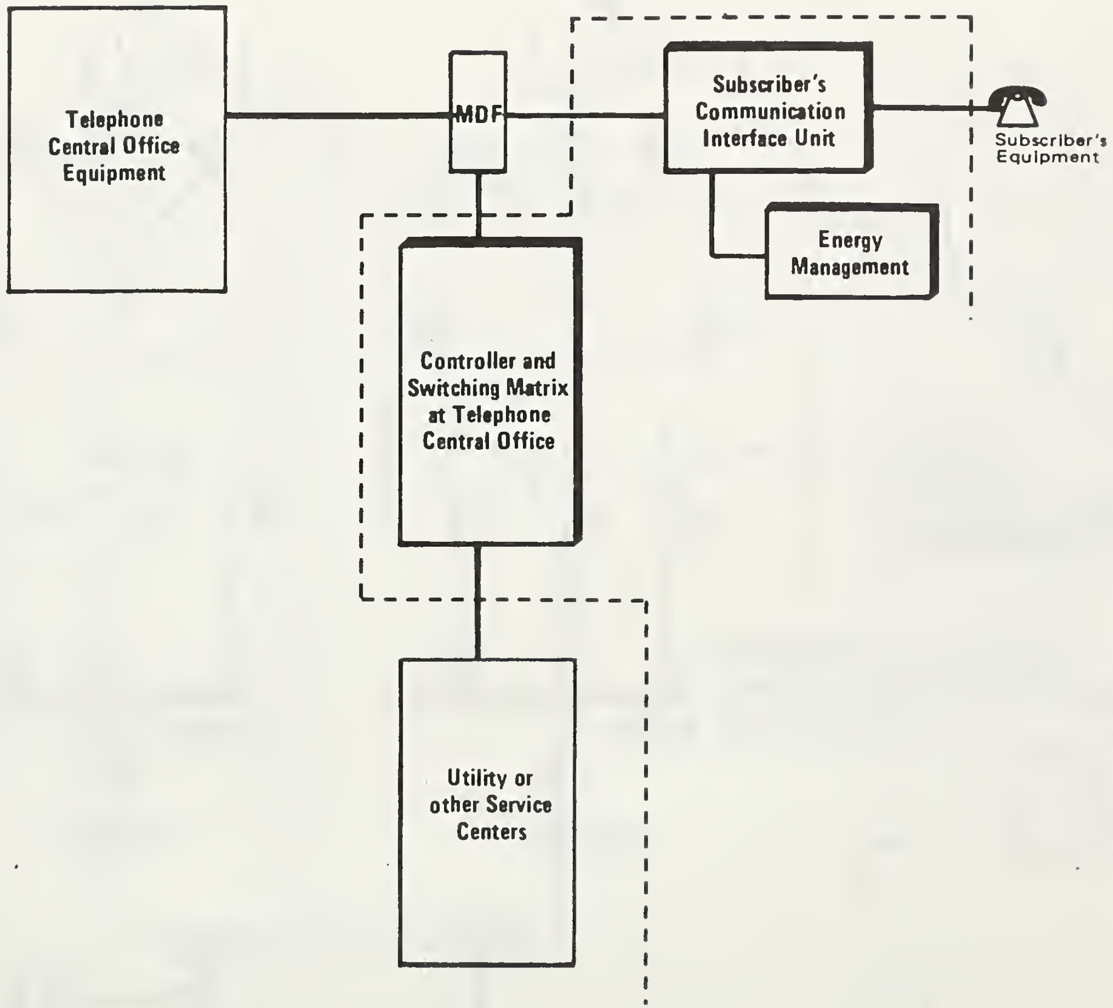

Figure II-13 Telephone Control System

- Subscriber Communications Interface (SCI)
- Energy Management and Metering Module (EMM)
- Alarm Module (ALM)

The central office equipment consists of a modular, expandable, multi-level hierarchy. The configuration is dependent on the number of lines serviced by that central office. The system is entirely solid state, eliminating mechanical relays for telephone line interface. The largest four-level system will accommodate 65,836 remote units. Each central office controller is housed in a single bay of rack mounted equipment with an additional stand-alone computer, sized to application requirements, having peripheral disc and tape drives. Each cable pair from the subscriber's side of the main distribution frame is wired to a central office scanner line card. Each scanner accommodates 256 lines. A maximum of 16 scanners (4096 lines) then interface with a central office controller and a maximum of 16 central office controllers (65,536 lines) interface with the computer.

Scanning occurs in groups of 256 lines. Using this strategy, an entire central office, regardless of size, can be scanned for status or load shed operation in 38 seconds. In a large scale system, all central offices operate in parallel; therefore, each customer location can be accessed in 38 seconds. Acquisition of meter reading data from all remote units connected to a central office can be accomplished in 22 minutes. The system interrogates the remote unit on a cable pair and logs its identification in the data base. If a cable pair swap should occur, the computer will notify the central office of the change in the line pair.

The SCI is a microprocessor controlled device that is connected in series with the incoming telephone line and the subscriber's equipment. The unit contains a command receiver/ decoder and the intelligence to monitor the telephone line and interpret and act on commands from the telephone central office controller. Control channels in the SCI can be activated for remote control of auxiliary equipment such as air conditioner, electric hot water heater or pool pump. Within the unit is contained a data modem for communication with auxiliary modules connected to a common data bus. Upon command from the central office, the proper auxiliary module can be addressed for particular data access.

The data modem provides a general purpose data communications link to the auxiliary modules and equipment connected to a three-state modem bus. Virtually any kind of auxiliary equipment must, however, meet simple interface and protocol requirements for connection to the SCI modem bus. To provide security against unauthorized access to the various modules for tampering and data manipulation, programmable or dynamic access codes may be utilized to access the data stored in the modules.

Control of loads such as air conditioners, electric hot water heaters and pool pumps is implemented by the SCI and the auxiliary load control module. The SCI interfaces directly with the load control module. The load control module provides one control output and one status input for each load to be controlled. The control output from the SCI triggers a timer in the load control module, which opens the circuit to the controlled load for a predetermined time. Once the preset time has elapsed, the load will automatically be restored. This insures fail-safe operation in the event that communications are lost or that the utility load control coordinator becomes involved in other urgent operations and temporarily forgets about the shed load.

Status from the load control module is brought back to a status input channel in the SCI. Monitoring of load status is achieved by supervising an auxiliary contact on the control relay. Upon command from the central office controller, a control output is energized. Relays in the load control modules are magnetically latching so that only a momentary signal is required to perform load shedding.

3. Operating Parameters in the Utility's System

There are no operating parameters in the utility system which influence the use of telephonic controls. Control equipment, end-use hardware and the communication equipment are all independent of the electrical system.

One aspect which does limit the versatility is the existence of customers using electric service who do not have a telephone connection installed. This may be solved by including telephone service charges to these locations when applying such a system and providing such connections during installation. It is unlikely, however, that such locations will have a large electrical demand. Therefore, it is probable that inclusion of these customers in a load control system would not be beneficial.

Access to the telephone line is slightly different for different functions. While signal inputs will not operate the telephone subscriber's bell circuit, meter reading functions require a clear, unused line for transmission. Should a meter reading occur on a busy line, it is normally postponed until a later time. To minimize this re-scan, it is recommended that meter reading be initiated during slack periods.

4. Reliability/Availability

Factors affecting reliability and availability of telephone or direct wire systems, as applied to direct control of small end-use customers, are largely conjecture and are restricted to experience on limited scope projects.

There is, however, no reason to suspect that the overall availability of the control scheme should in any way be inferior to the general service telephone performance and reliability.

5. Maintainability

As a large portion of the system is common with the existing telephone equipment, the bulk of the maintenance responsibility lies with the telephone company staff. The portion which may be under the control of the electric system staff is limited to the meter encoders, the transponder and the central control unit.

It is anticipated that in alrge scale use, meter encoders and transponders would be handled in much the same manner as existing customer meter practice; that is, replacement of malfunctioning units and return to the meter shop for repair.

Routine maintenance of equipment is anticipated to be minimal. This is true particularly where the two-way facilities are employed and the system is self-checking.

6. Security

Security of the system is good. Generation of illegal codes is difficult and this, together with other forms of interferences to the telephone equipment, would require considerable technical knowledge if such acts were not to interfere with normal household telephone use. Wiring between the transponder and the end-use appliance is available for customer interference and the load control function may be defeated without detection during normal operation of the system.

7. Viable Control Philosophies

Control facilities are moderately flexible and permit various interested parties to have access to the system. The facility to remotely contact the telephone office selectors via a phone line permits the design to be compatiable with the requirements of central control from the G and T while maintaining the desires of the distribution facility to have local control over their own area.

8. Other Related Factors

a. Speed of Signal Transmission

The use of high quality voice channel for the transmission path allows an adequate bandwidth for high speed signal transmission. It may be safely assumed that the channel capability will never be the limiting factor in the system.

b. Potential for One-Way Operation

One-way operation implies that the facility is for load control only. Telephone systems can be utilized for one-way operation with a minimum of equipment provided initially for eventual upgrading to two-way operation. Such common equipment may be further reduced if eventual two-way operation is not required.

c. Number of Controllable Loads

The number of individually controllable loads at each addressed location will vary somewhat according to the type of control logic, i.e., direct command or pretimed interval.

d. Control logic

Control logic is influenced by pricing limitations inherent with a telephone interface, limitations which involve a financial liability for each command transmitted.

End-use appliances which contain sufficient storage characteristics to bridge the maximum foreseeable disconnection time may be switched directly for both the "off" and "on" function, thereby restricting the time off to the period of maximum benefit. Appliances which require cycling during the period of control in order to prevent customer discomfort, cannot be controlled in this manner as the multiple commands per control period would involve multiple charges for the use of the communication channel. To reduce costs, such cycled appliances may be provided with a pretimed program which is activated once per day when demand control is required. After such a signal the device reverts to the preset sequence of "off-on" cycles for a fixed elapsed time period or as monitored by outside temperature, as appropriate.

e. Restoration of Load

Selection of the method of load restoration will be dependent upon the network's ability to absorb the cold load pickup demand, governed by such parameters as voltage drop, equipment rating and fuse sizing. End-use appliances switched by direct command may be restored as single blocks or preselected sequenced groups. Those loads using a single "enable" signal coupled with pretimed sequences would rely on the natural diversity of the individual devices to avoid large blocks of concurrent restored load.

f. Location of Receiver

Although the use would suggest locating the equipment transponder adjacent to the meter position, no technical reason exists for this conclusion, the meter encoder being capable of being remote wired to the transponder. With the multipurpose use of the transponder in the reading of up to three meters, control of three loads, etc., the actual location is largely a matter of convenience in consideration of all factors. Connections to controlled end-use appliances are run with "thermostat" type low voltage cable with locally mounted contactors for equipment requiring higher voltage control, i.e., water heaters.

g. Flexibility

The system is inherently flexible in application as the signal channel is completely independent of the electric distribution system configuration. As such, it is immune from network extensions, load growth or network switching.

G. Time of Use and Demand Metering

Voluntary load control is the use of economic incentives and disincentives offered through the electric rate structure to encourage voluntary changes in customer consumption patterns. Under voluntary load control, electric power to all loads is always available (unlike for direct load control) but the rate may vary with time of day or season (time of use rates) and depend on power demand as well as total energy consumed. The goal of voluntary load control is to reduce customer demands during peak periods by shifting the use of appliances and equipments to off-peak periods. The rates used with voluntary load control may also encourage new loads to occur during the off-peak period.

Switching of meter registers is needed to implement time-of-use rates. This may be done through remote communications using the same technologies as direct load control, or it may be done using specially designed meters with built-in timers with mechanisms to maintain or restore the time reference following a power outage. Implementation of demand charge rates requires special meters to record peak demands. The peak demand may depend on the time of occurrence of the peak load. Depending on when the meter is read, the peak demand may be recorded over a day, week, or month.

Many demonstration programs are being planned and conducted by various organizations and electric utilities. New activities and technologies for voluntary load control are being announced regularly. Demonstrations of voluntary load control generally test the communication and control technologies and determine the response of customers to different rate designs. The response of various customer classes in different regions of the United States to changes in rates is not yet well understood and is the subject of much discussion and study.

It is generally accepted that conventional residential rate forms will be displaced by alternative rate structures within the next decade. The greatest impediment to more innovative rates has been the lack of technically-suitable cost-effective metering techniques. It remains only for the utilities, their regulators and customers who now will be unconstrained by technical limitations in hardware to mutually establish the rate designs which suit their needs.

All approaches to alternative rate design involve one or both of the following metering methods:

a. Metering energy use (KWH) as a function of time of day. Typically 2 part (off-peak, on-peak) or 3 part (off-peak, shoulder-peak, on-peak) structures are most common.

b. Metering energy use as function of peak levels of use (KW). Demand metering has traditionally involved establishing peak average demand occurring in any one of a continuous series of demand intervals.

Intervals have typically been 1/4, 1/2, or one hour for the commercial/industrial sector. Demand metering in the residential sector is generally thought to require longer demand intervals, perhaps 2 or 4 hours.

There are several shortcomings to conventional demand metering installations. First, the demand interval is set at the time of installation and is fixed thereafter. Second, peak demand is only of interest during certain parts of the day; for residential customers particularly it is desirable in certain cases to disable the demand metering during low demand periods. Monitoring customer peak demand during utility off-peak hours may not be useful. Third, conventional demand meters operate on a "fixed window" basis in which the successive intervals are framed by fixed boundaries.

Fixed window demand metering has led to the proliferation of a family of demand controllers, some of which do not reduce demand but do reduce revenue because of inherent limitations of traditional demand meters. These demand controllers, in essence, attempt to keep track of demand interval boundaries and to spread a demand peak across a boundary so that the metered peak demand is less than the actual peak demand.

Newer system designs overcome certain limitations of older style demand metering:

- Demand interval may be set at any of five different intervals (15 minute, 30 minute, 60 minute, 120 minute, or 240 minute) and may be changed between two adjacent intervals by remote command.

- The demand metering function may be enabled continuously (as with traditional demand meters) or may be controlled so that the time period in which demand metering occurs is some fraction of a day or some number of days in a week, say Monday through Friday. Thus, it is possible to design a rate featuring time-of-day demand metering. Alternatively, the demand accumulation may be turned on only as system peak, thereby monitoring each customer's demand contribution to system peak. The latter use of the system is known as dynamic demand metering.

- The demand metering function may be furnished with either a "fixed window" interval or a "sliding window" interval. The latter has the advantage that it will observe the peak demand occurring within the selected time interval whenever it occurs. This capability is very important for borrowers which have customers whose demand controllers take advantage of the technical limitation of old style equipment.

III. DEVELOPMENT AND PLANNING CRITERIA

A. General

In advance of conducting an evaluation of the potential of load control for a specific utility, certain objectives should be established. These objectives will set the limits and extent of the study and outline the parameters for the selection of the type of load control systems best suited to perform the required functions.

A determination of the reasons why load control technology is desirable is required as a first priority toward optimizing the selection of the appropriate equipment and communication paths for a utility. If the major purpose is to provide the ability to shed selected loads during periods of emergency, for example, then the rate of speed of the transmission signal and the signal integrity may be more important factors to consider in the selection of the type of equipment than the cost-benefit. If the sole objective desired is that of lowering the demands at peak periods and thus cutting purchased power costs, then a decision may well be made to limit the investigation to the one-way load control systems. In any event, the primary objectives should represent conditions dictating the minimum criterion for acceptability of any system or equipment.

B. The Feasibility Study

The major components of this suggested study plan are structured to provide assistance to the utility management in making a responsible decision concerning load control. The flow chart shown in Figure III-1 pictures the sequence of events required to investigate the feasibility of this technology. The following outline capsulizes the basic segments important to this assessment process.

1. Organizing the Study

A work plan should be developed that will consider the priorities necessary for the timing, manpower availability, and availability of data. A program strategy should be constructed to coordinate the timing and interaction required with the customers of the utility, the regulatory body, the wholesale power supplier or power pool, neighboring utilities, and the general public in the area. The emphasis of this start-up phase of the project will be to set objectives, define work activities, plan strategy, and coordinate the priorities of the necessary work activities.

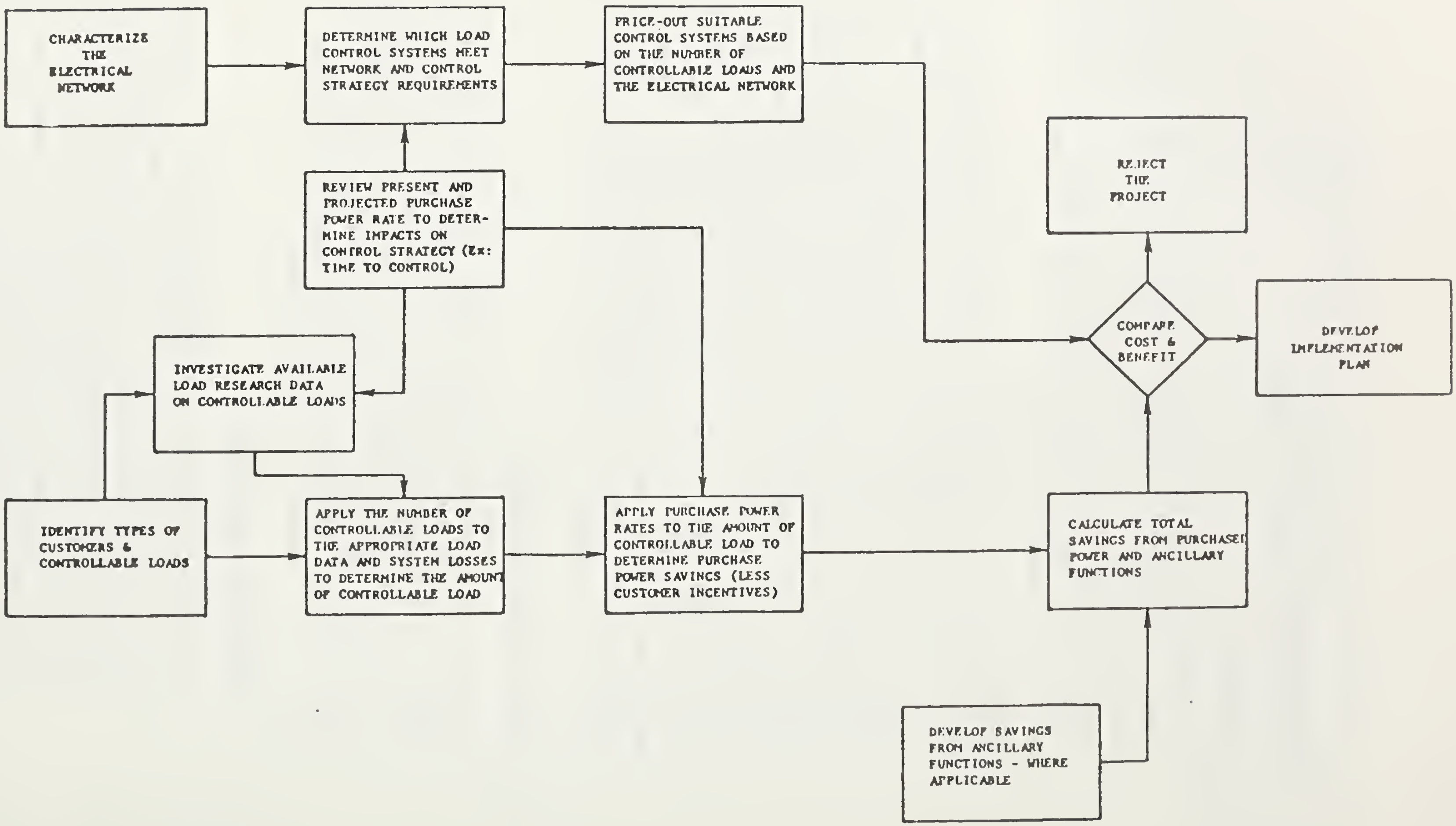

Figure IV-1 Load Control Feasibility Flow Chart

2. Customer and Load Characteristics Survey

It may be necessary to conduct a survey of current customers in order to provide needed information as to the nature, extent, and location of different types of customers with loads having a potential for control. The level of work activity required includes organizing the contents of the questionnaire, structuring the methods for conducting the surveys, and collect and summarizing the results. Because of the unique differences that exist between major classifications of customers, a different approach is suggested for surveying each of the following major categories of customer groups:

a. Residential Customers

If possible, a 100% survey of residential customers needs to be conducted to determine the appliance load saturation, customer density and customer acceptance in the service area.

b. AGRI-Industry

Analyze the various types of agricultural loads and select the types of customers to be surveyed. The utilization of the services of an area agricultural engineer may be necessary to assist in this portion of the survey.

c. Commercial and Other Industry

Analyze the various types of commercial and industrial customers to determine those with characteristics suggesting a control potential. Select interviews with individual customers will be necessary to explore the possibilities of control potential from a commercial or industrial customer.

3. Analyzing and Modeling Load Characteristics

A load analysis should be conducted for the types of end-use customers tied to a distribution system. Where load research data is not available for hourly kw demands of customer groups, it may be necessary to synthesize hourly profiles to characterize the aggregate effect on the system peaking requirements of the utility. Load research data can be utilized as may be available from current tests, utility research, or industry reporting. Regional and climatic influences on specific appliance loads should be analyzed in making the determination of the amount of demand potential available during peak periods. The structure of this phase of the investigation will concentrate on pinpointing the influence of different loads on peak periods.

4. <u>Analyzing and Characterizing Physical Systems</u>

The investigating utility will want to conduct an investigation of the characteristics of the service area and integrated electrical system in order to make a selection of the candidate communication and control systems suitable to provide the functions desired. System characteristics such as type of service area, physical dimension, load density in different areas, interconnection and supply agreements, and the system configuration are important to the selection of the proper type of equipment. The characteristics of the distribution systems (such as primary/ secondary configuration, performance of the VHF communication systems, circuit analysis, line electrical noise limit) are also important considerations to be evaluated. The following is a list of subject components included in this phase of the analysis:

a. Characterization of the Service Area

b. Investigation of Seasonal Characteristics

c. Analysis of the Physical Dimensions and Load Density

d. Analysis of Interconnection and Supply Agreements

e. Analysis of System Configuration

f. Developing the Control Requirements (end-use control and system control applications)

5. <u>Reviewing Planning Considerations</u>

A review of the present plans of the utility will be needed to determine the impact of such plans on the type of communication and control technology specified. It will be necessary to measure the effects of imposing load control on the planning considerations for future periods.

6. Measuring the Effects of Load Management on Existing Rate Structures

An investigation should be made of the effects of applying load management on the wholesale rate structure. An analysis should be made on the implications of restructuring the wholesale rates on the revenue requirements of the distribution utility. Consideration should also be given to evaluating any regulatory constraints that might infringe on the rate design of the supplier in the future.

7. Evaluating the Types of Communication and Control Equipment

An evaluation should be made to examine the various types of communication and control equipment for the purpose of selecting candidate load control systems meeting the unique specifications of an individual electrical system. Coordination of this phase of the investigation with management will be to insure that the analysis is limited to the number and type of systems having the functional applications desired. The work activity involved in this phase of the project will be to examine each of the equipment types to determine the potential load control and system control functions by comparing the requirements dictated by the existing (and planned for) system of the utility. The types of control systems selected as a result of this analysis will then be analyzed to determine the associated costs of each. The costs will be quantified in terms of vendor quotation items, other required investments, and operating and maintenance costs.

8. Developing Cost/Benefit of Selected Candidate System

At this point, a cost/benefit analysis can be conducted, comparing the selected load control systems in terms of the required investments and expenses related, as well as quantifying the associated benefits of each. The results should be structured in the form of a comparative analysis of each system with regard to a rank-ordering in terms of the greatest dollar benefit per dollar of investment required. The format of the cost/benefit analysis will be reviewed with management to insure continuity of purpose with the guidelines of the utility. The cost/benefit analysis should also compare an expected payback potential and/or rate of return for each system selected.

9. Reviewing the Findings of the Study

An investigation of the potential for applying load control technology will result in findings that will need to be compared with the stated objectives of the utility. The related phases of the study, once summarized, should form the basis for that comparison. While the results will be structured with regard to the requirements of the management involved, certain major points will need to be included in any load control decision matrix:

- Do the customer surveys reveal an acceptable tolerance level towards direct utility control of certain of their loads? (Customer education programs may be required to increase the customers' understanding of the intended use of the technology, before load control implementation can begin).

- Is there a sufficient amount of deferrable demand on the system to warrant load control implementation?

- Which of the available communication and control systems satisfy the major objective criteria of the utility?

- Of those, which of the systems are best suited for the specific network configuration and service area of the distribution system (present and future)?

- Do the results of the Cost/Benefit Analyses for the candidate systems remaining demonstrate a substantial benefit over cost? The results should include a Benefit/Cost comparison and expected payback period summary as developed in the casework to follow.

- Of the systems selected, what other ancillary functional benefits may not be reflected in the cost comparison? And what is the incremental cost for the incremental function?

Given the availability of sufficient kW demand from the control of end-use loads at a benefit to the utility, and given the adaptability of communication and control hardware for that purpose, the investigating utility might well consider implementing a load control system. An assessment of the risks involved in load control implementation need to be addressed before any such decision is rendered, however.

Any investment will attract a certain amount of business risk. An investment in a load control system is no different. A very real risk in operating a load control system, particularly for the utility being billed on a coincident basis with the supplier's peak, is the possibility of controlling at the wrong time. Where telemetering arrangements to monitor the supplier's sendout is possible, the risks of improper control will be reduced.

Another concern of load control is the adverse effect that a distribution control scheme may have on the generating utility. The generating utility may not see any benefit from load control in the early years because of the long lead time required to plan for generation additions. As a result, the capacity-related earning base for the wholesale utility is relatively fixed. A lowering of the demands imposed by the distribution utilities in one year will not change the wholesaler's fixed charge requirements. Thus, the effect of lowering demands without lowering fixed charges will be to increase the per kW charge. Any increase in the purchased power rate due to load control may retard the benefits implied in the study.

Certain facilities of the electric distribution system may have to be modified or replaced if load control application is such that the restored load creates a greater kW demand on controlled circuits in an off-peak hour than when initially controlled. Also, while the circuit analyses conducted in the study indicated only nominal effects on isolated circuit nodes, utilities having overloaded circuits or poorly maintained facilities will incur a higher risk.

The uncertainty of the future places a risk on the load control system. The plans of a distribution utility are quite sensitive to those of the supplier. Unexpected system upgrades could force the relocation or replacement of the injection equipment of some of the power line carrier systems.

While the Cost/Benefit analysis has been structured so as to minimize the risks involved, a final element of concern should be recognized in the nature of this procedure. This approach is only as concise as are the inputs to the elements of the cost or benefit side. The relative importance of the suggested Cost/Benefit analysis is then, in demonstrating a benefit over cost by using conservative benefits and liberal costs.

10. Narrative Outline for a Load Control Study

The following is a suggested narrative outline for developing a load control study. The balance of this section is devoted to those sections of the narrative outline for which advice and guidance are readily available. There are sections of the outline for which general advice and guidance cannot be readily given. These sections and data will have to be developed by the borrower for specific system.

NARRATIVE OUTLINE
FOR
LOAD CONTROL STUDY

1.0 Introduction - Should set forth the basic tenets and organization of the study.

1.1 Scope of Study - The purpose, limitations, and goals of the study as they relate to both the load management and load control philosophies either being contemplated or adopted by the electric cooperative. This section may also be used as an executive summary.

1.2 Load Management Concept - Should delineate whether use management, supply management or some combination thereof is being considered. Such elements as price control through rate, voluntary load control by customers, customer storage devices, direct control of customer loads, etc., should be discussed.

1.3 Load Control Concept - Explain which load control system or systems (radio, power line carrier or ripple) is planned and how it meets the control strategies adopted and how the strategy satisfies the particular load concept selected. Provide description of system operation and maintenance. Explain the impact on both the power supplier and customer for the methodology to be used.

1.4 Communications Requirements - Detail any added or new communications equipment that may be necessary in support of load control system to be implemented. Determine requirements for inductive coordination.

1.5 Implementation - Explain steps taken or to be taken in a customer education program, including any surveys or efforts to determine customer acceptance and explanation of benefits to the customers.

1.6 Implementation Schedule - Prepare bar chart showing all the major milestones against a timetable beginning with the study and ending with system cutover for operation.

1.7 Project Costs - List all costs relating to the engineering, acquisition, installation, operation, and maintenance of the proposed system.

2.0 Load Profile Analysis - Provide a map of the transmission system which serves the customers whose loads will be controlled. The load analysis should show the peak demand (time-duration) for summer-winter load patterns, load duration curves plotted against total capacity denoting intermediate levels of peaking capacity, intermediate and base capacity. Daily, monthly, and yearly load factors should be set forth on load profile.

2.1 Analyzing and Modeling Load Characteristics - Conduct load analysis for types of end-use customers served by distribution system. Regional and climatic influences on specific loads should be analyzed. Show duration of loads contributing directly to capital investment or contract/ratchet demand.

2.2 Load Versus Temperature - Prepare graphical analysis showing load variation with temperature for several peak months.

2.3 Characteristic of Existing Loads and Load to be Controlled - Describe system load structure for each category of electrical user--residential, commercial, and industrial. Detail type, extent, and location for those customers with loads having a potential for control. Delineate proportion of customers with controllable loads and hours of control.

2.4 Storage Capabilities of Existing Loads - Provide an analysis of the energy storage capability of loads to be controlled. How long can load be without electricity without causing inconvenience or hardship.

2.5 Shape of Power Pool Load Curve - For those systems using the resources of a power pool it is important to know the member's contribution to the overall power pool load curve and the effect on this curve as a result of the member implementing a load control system. Additionally, there must be coordination between and among members and their respective power suppliers.

2.6 Regional Diversity Affects - Provide data on the inherent regional diversity of the electrical network. Explain effects of the load control system on the diversity characteristics of the network.

2.7 Projected Load Profile - Uncontrolled - Provide an analysis of the future load profile if control is not implemented.

2.8 Anticipated Load Profile - If Controlled - Provide analysis of load profile which results from the control of loads as proposed by the load control program. Explain basis of all data used in developing load curve and any limitations to use of data as it is presented within this report.

3.0 Cost Relationships and Considerations - Provide basis and premises leading to the development of the cost proposals to be stated herein.

3.1 Wholesale Power Cost Savings - State the net effect on wholesale power cost savings using the proposed control strategy. Explain the structure of the wholesale purchase power rate, demand charge of the wholesale rate schedule, kW benefit accruing from control of loads.

3.2 Deferral of Investments - Explain the effect of the load control program on planned or proposed future investments in power production and/or facility expansion to accommodate future power needs.

3.3 Effects of Wholesale Rate Structure on Hours of Control - Explain the effects of the wholesale rate structure using the amount and structure of the demand charge to determine the effective payback period based on the number and particular hours of control. Where different ratchets are used for each season their effects shall be incorporated into this analysis.

3.4 Effect of Load Control on Wholesale Rate Levels - Explain the implications of load control on the wholesale supplier revenue requirements.

3.5 Cost Benefit Analysis - Based upon the load control strategy selected, develop system costs. Various load control systems should be compared in terms of the required investment and the related expenses, as well as quantifying the associated benefits of each. The results should be structured in the form of a comparative analysis of each system with regard to a rank-ordering in terms of the greatest dollar benefit per dollar of investment required. Care should be taken in developing the payback periods, capacity charge savings, operation and maintenance expenses and other costs that may bear upon system implementation. Both costs and benefits should be presented as levelized annual costs and levelized annual benefits to assure conformity in the application analysis.

C. Determining the Customer Load Control Potential

Any benefits to be gained from the application of a load management program by an electric utility must stem from the availability and willingness of end use customers having the types of loads required for a control benefit. In order to recognize this potential, it is necessary to determine which customers have controllable loads and where those loads are located on the distribution system.

In order to provide needed information as to the nature, extent and location of different types of customers with loads having a potential for control, a current assessment is necessary. Appliance and equipment design, saturation in the service area, and customer usage patterns are dynamic and will undoubtedly change over time. If up-to-date customer information is not available, a customer survey may be required. Because of the unique differences that exist between major classifications of customers, a different approach is suggested for surveying each of the following major categories of customer groups.

1. Residential Customers

For best results, a blanket (or 100% sample) survey of residential customers in the service area needs to be conducted to determine the appliance load saturation, customer density on the distribution circuits, and customer acceptance to utility control. For many distribution utilities, a current knowledge of customers is not available. The survey represents an expedient method for gathering the needed information. The investment requirements of load control equipment are too large for most utilities to afford to base their decision on a guess (or possibly a local trade association estimate) as to the potential number of appliances present in the service area.

Most customers will be helpful if they understand why it is important and how it will effect them. A short explanation letter will help to get the utility's point across and insure a larger response.

The survey form should be kept simple and to the point. Too many questions on the form will result in fewer responses. A questionnaire of this type is most effective if the questions can be answered either by multiple choice or in a very few words.

If possible, the survey forms should be in a separate mailing. If stuffed in the envelope along with the bill, the form may be disregarded as just another recipe or pamphlet.

The type of information needed from the customer is:

- The size and type of appliance targeted for load control application

- The location of the customer

- The willingness of the customer to participate in a load control program (Note: Emphasize the nature and frequency of control. The customer will be more likely to volunteer if the utility only plans a minimum of hours of control at very little, if any inconvenience to the customer).

Coordination of the survey with general news release will serve to alert the customers and increase the likelihood of a good response.

If possible, the tabulated results of the survey should allow the customers with controllable loads to be pin-pointed by location on an area map with a distribution system overlay. A good knowledge of the concentration of customers as dispersed throughout the distribution system will be of value in selecting the type of communication path or paths best suited to reach the majority of those customers. In addition, this analysis may suggest an approach to load control that would provide coverage to only that portion of the system having the bulk of the customers with controllable loads and not the entire service area or distribution circuit configuration of the utility.

While an assessment of the attitudes of all residential customers is valuable, particular attention should be given to the receptiveness of those customers with the targeted appliances for load control application. Will these customers give the utility that control? And will they expect an economic incentive in return?

2. Agri-industry

Successful load control application for certain types of crop irrigation has proven beneficial for both the controlling utility and the farmers involved. By working closely with local agricultural engineers, utilities have been able to successfully control irrigation loads by developing water management programs for farmers to optimize crop yield and shift irrigation loads to reduce the demands imposed during peak periods.

In order to assess the potential of irrigation load control, a preliminary site analysis should be made by the agricultural engineer to gain information to determine how much soil moisture depletion would be acceptable during the period of peak water-use without effecting yield requirements. Irrigation system design, system capacity, existing system management, soil type, and type of crop are necessary data inputs for developing a plan for the part-time operation of the irrigation system.

If certain of the irrigation systems surveyed yield the characteristics that would tolerate part-time operation, a program will be necessary to educate the farmer in the ways that load control technology can work to his benefit before implementation can be considered by the utility.

Certainly, for load control application to be successful, both the utility and the irrigator must be satisfied. The irrigator will want some assurances that the watering system operates as/or more efficiently using load control techniques and that crop yields are not decreased or impaired. The utility will need to be satisfied that there is a sufficient presence of irrigation demand coincident with the peaking period of that distribution system.

Other agricultural loads may have the characteristics required to offer an attractive load control application. Heating elements for produce storage bins, stock pond watering, and the like offer a potential for intermittent control because of the natural storage characteristics involved. Cooling fans (in hot summer regions) for produce bins and grain elevators may be equally acceptable for short-period interruptions. Much more definition is needed in identifying agricultural loads with controllable features than is currently available.

In order to recognize the potential applications in agri-industry, personal interviews are recommended for this sector of the customers served by the utility.

3. <u>Commercial and Other Industry</u>

Making a determination of the potential of load control application in commerce and other industry will require an inventory of the types of end-use load requirements of these customers in the service area of the utility.

The results of the study indicate a growing popularity in industry for the application of local logic devices to balance equipment loadings for the purpose of lowering the maximum billing demands of the customer involved. Microprocessor and mini-computer control of refinery processes, assembly-line drill presses, and other operations such as sawmills have been successfully applied for a number of years. As power costs continue to rise, it is expected that more and more industrial customers will explore this alternative for themselves. Unfortunately, the mode of control will be based on the peak loading period of the customer's equipment and not the peak period for the utility serving that customer.

On the other hand, direct utility control of the end-use loads of industrial customers has had good exposure. The sampling of industrial customers interviewed during the course of the study displayed an interest in exploring the possible use of this technology with the utility. Just how successful the application of load control will be in industry remains to be seen. The utility must work closely with the industrial customer to analyze the load characteristics of equipment and processes, the effect of those loads on the utility's peaking requirements, and target potentially controllable loads for further study.

Commercial customers are by far the most sensitive group to consider for load control application. A majority of the customers in this segment are extremely conscious of the comfort requirements of their customers (from shopping centers and malls to office buildings and hospitals). Operating and cost efficiencies are fine as long as they do not interfere with customer convenience or service standards.

As in industry, a few of the major hotel chains and other types of commercial customers have installed local logic devices for load leveling to reduce billing demands.

Particularly because of the reliance on temperature sensitive appliances to satisfy the comfort requirements of their customers, the potential for load control from this group of power users should be explored. Trade associations may be used as a filtering point for educating the businessmen outside of their competitive environment.

As with industry, the utility will need to work closely with the commercial customer to inventory and analyze the equipment and appliances, and develop an acceptable interruption procedure.

D. Recognizing the Potential Loads and Determining Load Characteristics

How much load reduction can be expected from the control of certain appliances and equipment of customers during the peaking periods of the utility? Indeed, for load control application to be cost justified, the answer to this question should indicate a sufficient deferrable kW demand from each type of load being considered. The more knowledge available to the utility on the design and load characteristics of end-use equipment, the greater the confidence level that can be given to an implied kW as a benefit from control.

For the utility conducting ongoing load research testing to record the load profiles of many of the end-use loads of customers served by that system, the quantification of a kW benefit is simplified. Unfortunately, the present costs of a load research metering system may be unaffordable to the smaller, non-generating utility. In those instances where current diversified kW tests results are not available, it is important that any kW deferal expected from control of a particular load not be overstated when calculating the benefits.

1. Residential Appliances

Significant results have been recorded by utilities effecting direct control of selected temperature-sensitive appliances of the residential customers. The contribution of a residential water heater or air conditioner in the form of a deferrable kW demand has enabled many utilities to pursue full implementation plans of load control.

Other household appliances may have the peak-use characteristics that would suggest load control application. Several concerns are worth mentioning that may restrict the susceptibility of such highly visible appliances as washers, dryers, or freezers to an acceptable control logic:

- o The requirements of a working couple for a fixed time of use.
- o The higher diversity present in the collective use of like appliances by other customers in the distribution system yielding a lower deferrable kW demand at any one point in time.
- o Electrical wiring cost per appliance imposed on the utility.
- o Legal implications facing the utility concerning liability in the event of appliance malfunction.
- o Temperature-sensitive appliances, on the other hand, dictate the time and intensity of the peak periods of many utilities.

a. Water Heater

The natural storage characteristic of a water heater makes control by the utility relatively easy to effect with little, if any, inconvenience to the customer.

For most winter-peaking utilities and some summer-peaking utilities, control of an electric water heating load can represent a significant kW benefit. The quantification of a kW per water heater (deferrable at times of the utility's peak) is dependent on a number of factors:

(1) Capacity of the appliance (number of gallons)

(2) Type and size of heating elements

(3) Season of application

(4) Climatic characteristics of the region

(5) Time of day of the peak periods

(6) Saturation of appliance

To assist the utility in estimating a kW demand to apply as a benefit of load control, a section of the Load Research Appendix of this report is devoted to capsulizing the available industry reporting on water heating tests. The range of tests results of the reporting utilities for winter or summer application is quite wide. However, an analysis of the results of two recent water heating tests indicate the following range of average demand per water during evening winter peak hours of 6 - 7 p.m. and summer peak hours of 5 - 9 p.m.:

Winter	-	0.60 to 1.70 kW
Summer	-	0.47 to 1.39 kW

For the purpose of establishing a conservative benchmark for calculating a benefit from controlling water heaters in the absence of test data, the following minimums can be reasonably applied:

Winter	-	0.80 kW
Summer	-	0.60 kW

b. Central Air Conditioners

For summer peaking systems, the influence of air conditioning on the peak of the utility makes it an obvious choice to consider for direct control. Window air conditioning units tend to be smaller in size, greater in the diversity of use, and more portable a load than central units. In addition, electrical wiring problems are possible in cases where a unit is hooked up on an already congested house circuit. Thus, for most applications, optimum benefits can be expected from central air conditioning control.

The major factors to consider in determining a kW benefit from the control of central air conditioning units are as follows:

(1) Individual maximum kW demand per unit (or installed kW if maximum is unknown).

(2) Climatic characteristics of the service area.

(3) Time of day of system peak periods.

(4) Saturation of Appliance.

(5) Length of inhibit period each time controlled.

An analysis should be made of the facility housing the appliance to determine the acceptability for load control application. The condition of the house wiring, air conditioning unit, and building insulation characteristics will determine whether or not the appliance should be considered for direct control.

Again, the Load Research Appendix examines the available load research data concerning central air conditioning tests by utilities. An analysis of findings of recent load research tests and direct load control results indicate an average demand per residential central air conditioner on a hot summer peak loading conditions of over 4 kW can be used.

In order to control central air conditioning units in a manner that will have a minimum discomfort to the customer, the method of control should encompass some form of a shared inhibit cycle. For example, if one-fourth of the units were controlled at any one time, the effect on a 4 kW average demand per central air unit at system time of peak demand would be 1 kW.

c. Central Heating Units

Because of the sensitive nature of protecting the integrity of service for domestic heating loads, more research and testing will be required before adequate demonstration of the merits of space heating control has been effected. The potential kW benefit of control of this type of appliance is greater than that for comfort cooling however.

2. <u>Irrigation</u>

The most successful application of utility control of agricultural loads has been in the control of the irrigation pump. Certain types of irrigation systems (particularly the center-pivot and other sprinkler systems) incorporate watering techniques that, by design, would permit controlled operation. In addition, given an acceptable soil moisture depletion analysis for the soil type and the crop grown, the irrigation system may thus tolerate part-time operation. Significant inroads have been made in refining the technological application of irrigation control and its acceptance by irrigators. Principally in Nebraska, a cooperative effort by the public power district, the Department of Agriculture, and local agricultural engineers have fostered irrigation control strategies for part-time operation at the time of the peak requirements of the utility. As reports on the progress of these efforts indicate, not all irrigation systems, soil conditions, or crop requirements will permit a part-time operation. Flood watering techniques for example, may offer a potential for scheduled operation on a calendar basis that would not allow for interruption of the flooding cycle.

Quantification of the kW demand associated with the deferment of irrigation loads during the peaking periods of the utility requires substantial analysis. There are no guarantees that every utility serving irrigation loads, even sprinkler systems, will find a sufficient presence of deferable demand from irrigation at the time of the peak. In areas where irrigation systems are prevalant, a trend towards increased reliance on new, improved electric irrigation systems may, in itself, mandate a factorial analysis of the implications created by increases in new irrigation loads on the utility system.

3. <u>Commercial and Other Industrial Loads</u>

As was previously discussed in the section dealing with customer surveys, application of load control in commerce and other industry is in its infancy in development. Before the load control potential can be quantified, interruptible equipment and processes need to be characterized by type of business or industry. Sufficient submetering to develop load research on the characteristics of equipment and processes would provide valuable information for considering any potential usefulness for control purposes.

In advance of any such equipment inventory by industry, however, a program plan will need to be developed by the utility, for engaging the cooperation and participation of commercial and industrial customers.

4. <u>Quantifying the Effect of Load Control at Peak</u>

In order to estimate the amount of deferrable load to expect from a system-wide application of load control, a knowledge of the load characteristics for both the targeted load for control and the system is necessary. The principal differences between the demand at the customer and supply levels involve two variables. For one thing, a natural diversity will exist between individual customers and like customers. For another, system losses will be incurred at the various voltage levels in the distribution system. The nature of the average diversified demand of customers using the appliances, or loads, coincident with the peak period of the utility, and the location of those customers on the electric system will then determine the potential demand deferrable.

For the purpose of estimating the total deferrable demand in kVA necessary for any calculation of the dollar benefit attributed to load control, the following components will need to be derived:

- o The total number of appliances or loads that are to be controlled

- o Estimated customer acceptance (an estimate of the percent of the total number of customers having the candidate loads that will participate will be needed in the event that a customer survey is not conducted. No recommendations are supported in this study as to the amount of acceptance expected in any given area, however).

- o Estimated equipment failure rate (In order to allow for the possibility of load control equipment failure, a 2% failure rate was utilized in the caseqork section of this report).

- o The diversified or average kW demand of the end-use load coincident with the time of the system peak (The results of current load testing in the climatic region of the utility should be used if available. Over-reliance on out-of-date, vintage load research data may not compensate for appliance or equipment modifications and efficiencies which will occur over time. Utility consultants, certain large utilities, and collective industry and research groups are involved in ongoing research activities, and represent an excellent data source).

- o System losses.

- o Power factor.

E. Characterizing the Candidate Communication and Control Equipment

1. General

There are differences that exist between the types of equipment systems available for load control. The available systems can be categorized generically in terms of the communication path employed. As reviewed in this section, five separate types of systems will be analized with regard to design differences that are necessary to recognize in the selection process. Choosing the system or systems best suited for a specific utility's application requires a characterization of the present and planned physical system of the utility. The type of service area, the bulk supply arrangements, and distribution system characteristics form parameters that will indicate the limits of application of any one load control system. A review of the system plans of the utility is also important to the selection process. System upgrades, customer shifts, and load growth by area are examples of planning considerations that could limit the application of one or more of the generic types of equipment under consideration. The purpose of this section is to describe the factors that would limit or enhance the choice of one system over another.

The generic types of communication and control systems that will be considered are either presently available or projected to be available in the near term (1-3 years). Unique communication linkups for control purposes necessitate a generic comparison of the systems as might apply in a given situation.

The application of time switches and local logic devices is not addressed, as these are applicable to most systems and do not involve engineering application limitations.

The five generic types of technology available for near-term load control as characterized in this section are:

- o VHF Radio remote control of end-use loads via a 1-way link from area transmitters to locally-installed receivers using F.C.C. controlled frequency bands.

- o Low-Frequency Power Line Carrier (Ripple) 1-way control of end-use loads via a signal in the low audio range (usually less than 1 kH_Z) injected onto the power line as a carrier by modulating the fundamental voltage wave.

- o High-Frequency Power Line Carrier 2-way control and communication systems operating at 5 kH_Z to 100 kH_Z via a modulated carrier injected into the power system.

- o Hybrid Radio/High Frequency Power Line Carrier Systems combine radio transmission to transformer receivers and inject a carrier signal in the 200 kH_Z range over the service cable to control the end-use loads of customers.

- o Telephone and Direct Wire systems for 2-way control and communication with end-use loads utilizing telephone company or dedicated lines as the prime communication path.

The factors to consider in the selection of a load control system are based on the many aspects of the distribution network. Certain points are suggested for guidance but local requirements, operating methods and unique situations may modify the overall picture for any given application.

2. Type of Service Area

The first major aspect to recognize in selecting the type of equipment best suited for a distribution system is the type of service area. The general topography and customer density of the area served by any distribution utility impose parameters that will influence the choice of the available channels for load control. Three general categories of service area distinction need to be recognized: urban and suburban, rural areas having small farms and mixed communities, and rural areas having large farms and scattered population.

a. Urban and Suburban

In most cases, all of the generic types of load control systems categorized will benefit from a high density of controllable loads in urban and suburban areas.

b. Small Farms and Mixed Communities

For the distribution system serving small farms and mixed communities in rural areas, a closer examination of the service area is necessary to characterize customer density. Typically, the type of service area of this type would be categorized by large housing lots, small communities, and a small average number of customers per distribution transformer.

Systems most suitable for this application are radio, high and low frequency power line carrier systems, and telephone.

The high frequency power line carrier suitability is based on the availability of a sufficient number of customers tied to a feeder or substation location. As the high frequency signal has a greater attenuation and a shorter range than the lower frequencies, the high frequency power line carrier system option is highly sensitive to the dispersion of loads on the system. The bi-directional feature of the high frequency power line carrier, if required, may offset a portion of the cost penalties to be recognized in serving this type of service area.

The use of low-frequency power line carrier systems is suitable for this type of service area, but should be analyzed with regard to the number of commands required for load control. Systems operating on the simple rhythm code are likely to be preferable to multi-bit binary code type systems for a distribution utility requiring a small number of commands. Systems using the public telephone network would be suitable for this area application provided the capability exists for signal transmission over any telephone carrier links which may be present and provided the system could handle multiple end-use customers on a party line basis. Telephone systems in design offer a potential for the future. However, certain operating criterions such as signal priority, or the interdependence on multiple telephone companies and systems, must be developed if this type of application is to be considered viable for any local service area.

c. Large Farms and Scattered Population

In rural areas having a presence of large farms and a scattered population, the influence of a very low customer density is even more pronounced. Of the systems using power line carrier frequency injection, only low frequency systems have a range suitable to cover a sufficient number of customers to be effective. The use of a telephone system may have advantages, particularly if coupled with 2-way facilities. Careful coordination should be exercised by the electric utility in those situations where more than one telephone system serves the electric system's operating area. Radio systems in some areas may suffer from economic penalties incurred from having relatively few customers within the range of any one transmitter.

3. Bulk Supply Arrangements

A second major factor to consider in the selection of the type of communication channel concerns the bulk supply arrangements of the distribution utility. The method of feeding a distribution utility could have a significant effect upon the choice of the communication channel. Radio, high frequency power line carrier, telephone, and the hybrid systems are immune from the effects of variation in bulk supply arrangements as they are connected into the system at the distribution voltage level.

Low frequency power line carrier systems are particularly sensitive to this issue. A distribution utility served via one bulk supply point would require only a single injection station to effectively cover the area. (This may also be the case for multiple bulk supply stations if served from a common HV system). And should a HV system be owned by the power supplier, agreement must be reached to permit the injection equipment to inject the control signal into the supplier system. The supplier must also agree to switching limitations to prevent interruption of the communication channel due to system switching.

If an area is fed from more than one wholesale supplier (or where one supplier provides power for a non-common HV system), then the low frequency system will suffer severe economic penalties. This is mainly because of the need for either multiple injection points (one at each supply point), or large capacity injection units sufficient to compensate for the capacity of the wholesale supplier. One additional penalty in the use of the low frequency system is the exposure to network modifications. Substation voltage changes or HV system reinforcement can fundamentally change the system injection requirements.

4. Distribution System Characteristics

The third major aspect deals with those considerations which are engrained in the design and configuration of the distribution system.

5. Number of System Commands Required

The number of system commands required is a function of the number of types of control applications, the number of controlled loads, and the magnitude of each controlled block. For a system requirement to control 1000 water heaters in 15 groups (control blocks) during peak periods, any generic communication and control system would have ample capacity to compensate for the number of command channels required. As long as the estimated number of commands is less than around 25 to 30 channels, then radio and low frequency power line carrier systems with rhythm signals have adequate capacity.

If the number of commands required is greater, the multi-bit, binary code configuration of both low frequency and high frequency power line carrier and telephone systems will be suitable. It is important to evaluate the candidate communications systems command capability in view of future, as well as present, functional activities necessary. From a cost/benefit standpoint, the requirements for an economic payback should be weighed against the requirements for a reserve system capacity in the number of commands permitted in the design of the communication system.

6. Auxiliary Commands and Functions

Auxiliary commands and ancillary functions of the communications and control system should be weighed measuring the desirability versus the affordability of each.

Commands originating at the central control location for purposes (such as call signals for volunteer fire departments or alarming signals for resort area policing) can be added to the system control requirements as may fit the situation. All systems can be adapted for alarming, but only the hybrid system includes this facility at no extra charge other than a small incremental charge for the type of receiver.

Two-way systems possess the capability of extending this auxiliary service to include monitoring, alarming, and remote meter reading. The telephone system design appears to be particularly well suited to this function with high speed scan rates. With the present two-way systems technology, the remote retransmitters can only initiate a signal upon invitation of the control center, no spontaneous transmission is now possible. The requirement for remote meter reading automatically can be successfully applied with a high-frequency power line carrier system or a telephone system in addition to the load control capability. Cost justification may be difficult at present for the distribution utility as will be illustrated in the case work. In cases where a mandate may exist for remote meter reading, however, utilization of these systems offers an attractive method incorporating load control as an auxiliary function.

7. Proportion of Customers with Controllable Loads

The number of customers or loads controlled is an important consideration in this selection process. Should the total number of control customers be small in proportion to the total connected customers of the distribution system, rhythm type low frequency power line carrier, and telephone systems would be the better selections. The use of other systems would incur cost penalties. High frequency power line carrier applications would not be economical with a limited number of customers. Low frequency power line carrier systems having a multi-bit code configuration would be underutilized.

8. Customers Per Transformer Ratio

The customers per transformer ratio is significant to a possible application of the hybrid system. The design of the hybrid system includes a VHF receiver/retransmitter located on the distribution transformer low voltage circuit. The proportion of that receiver/retransmitter cost to be reflected in the cost per end-use receiver point depends on the number of controlled customers per transformer. Optimum application of the hybrid system suggests a customer to transformer ratio of at least 3 to 1. The hybrid system is compatible with the radio VHF end-use receiver system. For some utilities with pockets of customer density and areas of scattered population, it is possible to design a hybrid and radio combination system.

9. Line Electrical Noise

Line electrical noise is an important consideration for all except the telephone communications system. Locations containing significant welding or similar arc-producing equipment subject the network to localized electrical noise. While all systems can compensate for normal system noise, low frequency systems are more exposed to the effects. The multi-bit code low frequency power line carrier system is likely to be the most vunerable to line electrical noise.

10. Performance of VHF Communications

Performance of the VHF communications in the service area is an important factor if hybrid or radio systems are considered. Most distribution utilities use fixed to mobile VHF voice radio systems for day-to-day operations. The radio and hybrid system both use similar equipment. The hybrid system may even use the existing VHF transmitter. Satisfactory operation of either system will be indicated by the operation experience gained from the voice channel. Unsatisfactory mobile operations may indicate a potential signal integrity problem for radio control, particularly if the local area is subject to hilly or mountainous terrain which may screen valleys from radio signals of this frequency type.

11. Physical Dimensions of the Area

The application of radio systems is affected by the physical dimensions of the area to be covered. As the length-to-width ratio of the area increases, radio systems tend to become more costly, particularly where one dimension is significantly less than the transmitter's service area. Such areas, together with areas of an irregular nature, can be covered with specially designed antenna systems.

12. <u>Use of Multiple Load Control Systems</u>

Adoption of one basic communication and control system to a given area does not automatically exclude the use of other systems on portions of the network. The control philosophy used between the system types is not fundamentally different. Such multiple system use may be necessary if isolated pockets are present that the base system cannot cover. Examples of such use would be a small isolated portion of a distribution network fed from a separate bulk supply point or a well-shielded valley in a hybrid system. A second type system could be employed to cover the isolated area, either connected by land line to the central control or alternatively, keyed from a receiver fed by the base scheme.

Also, if the use of combination systems can optimize the economic payback life, the incentive to explore this alternative is pronounced.

At the same time, not all communication channels are compatible for signal transfers between systems. Two-way power line carrier systems, for example, cannot interact with one-way systems for message handling capacities.

13. <u>Distribution System Planning Considerations</u>

A characterization of the existing distribution system and operating environment is not, in itself, sufficient information for selecting the type of equipment systems applicable. It is most important to review the plans of the utility that may effect the future usefulness of a load control system.

The distribution network represents the communication path for the powerline carrier systems. As such, any planned system upgrades that might effect the sizing of injection equipment is integral to the investment requirements of those types of systems.

It is necessary to realize the effects of customer shifts that may occur over time in the service area. Inordinate load or customer shifts from one area to another may require - for powerline carrier systems - the movement of injection facilities, or the consideration of a system with injection potential at a higher voltage level.

Other uncertainties exist in determining the future applicability of any specific load control system.

The effect of bulk supplier planning on distribution expectations is a determinate. The plans of the supplier should be reviewed to gauge the impact of that forecast on the distribution utility. System improvements, relocations, and modifications may effect the placement and sizing of injection equipment. Even so, there are always unforeseen events that will cause the wholesale supplier to change this year's 5-year plan next year.

Changes in the regulatory environment are even more difficult to predict. Rule changes, environment constraints, and new procedures are being proposed all the time. Trends may be useful in developing an idea towards change if only because the legislative mechanism works slowly. No assessment is offered in this report concerning regulation.

Changes in the rate structure could effect the selection of the type of communication and control system to employ. Plans to incorporate time-of-day rate structure, for instance, may change the choice of the system best suited for load control.

F. Load Control Strategy

1. Introduction

The main objective of developing a peak shaving load control strategy is to limit the system peak demand to a level so that the bulk power costs to the non-generating utility are minimized. After the controllable loads are identified, an evaluation must take place to determine the optional method of control. Methods such as cycling of air conditioners and continuous inhibits of water heaters have been discussed previously in Section II only in general terms. Obviously the control strategy links directly with the benefit/cost analysis. The control strategy determines the amount of deferrable load from the available controllable load. Where system load, power supply arrangements and other conditions require control in both the summer and winter, the effective deferrable load per control switch may be reduced. This, in turn, may have a negative impact on the benefit/cost analysis. For example, assume that control is required in both peak seasons with water heaters and central air conditioners controlled in the summer, and water heaters and central space heaters controlled in the winter. The deferrable load is available per water heater all year round and is determined by the diversified demand. However, to obtain the same annual kW of deferrable demand from the central air conditioner (in the summer) and the central space heater (in the winter) twice as many control switches may be required. Thus the deferrable annual load per control switch is effectively reduced. In some cases, this requirement for additional control switches may neutralize the benefits of load control, even where dual function switches are used to minimize cost. Of course as control switches evolve in sophistication, the price of an extra control relay may become insignificant. These considerations not withstanding, a "practical control strategy" would incorporate such factors as flexibility, customer acceptance, and hardware capability as discussed in the following paragraphs.

a. Flexibility - The control strategy should be designed to respond to the differing shapes of load profile curves as the system approaches peak demand levels or predetermined control periods. Quick load shed response to inhibit commands and multi-channel capability are therefore required. The multi-control channel capability would further provide for separate commands for each appliance group and for different appliance types. This would avoid the problem of overloading a distribution transformer if the restore commands to all appliances were all on one channel.

b. Customer Acceptance - Minimum customer discomfort can be achieved only if inhibit commands are distributed equally among the customer groups (channels) and appliance off-time is minimized. This is a critical item to consider in air conditioner control where inhibits over 15 minutes an hour may cause significant temperature rises. The same consideration would apply to the cycling of space heating, for which the off-time may be even more critical because of the higher differential between inside/outside temperatures.

c. Hardware Capability - For a load control system to function properly, real time data collection of system demand is necessary. Load control initiation depends on a reliable estimate of when and how quickly the system load is approaching a control target level. This capability may be possible with an additional real-time monitoring system. (This extra cost has been incorporated in the Case Studies included in Appendix A).

2. Data Requirements

A prerequisite for establishing a load control strategy is the development of a reliable data base. The data base would include: 1) the most current system peak day load profiles for all seasons in which control would be implemented, 2) identification of controllable loads, 3) controlled appliance diversified demand curves for all those periods, and 4) controlled appliance restore demand curves. Since published information in these areas are based on limited studies and can be a function of a specific area, it may be necessary for the utility to generate its own data. As indicated in Section III, diversified demand curves for water heaters vary according to region and season. The small amount of data collected to date on load restoration demand curves necessitates a cautious application in the control strategy.

3. Procedures

a. Establishing Control Target - With the above mentioned data base established, a control target can be developed. To establish priorities in inhibiting controllable loads, the utility must analyze how the different appliance diversity curves interact. The largest interruptible loads should be considered as a base for load shedding. Irrigation loads exhibit this quality. Air conditioning, because of the sheer size of its load qualifies as a base, even though it is most vulnerable to causing customer inconvenience. Water heaters represent the most convenient deferable load, because of their energy storage characteristics, but, in many systems they do not represent the majority of controllable loads. In this latter case, water heater load shedding is used to fine tune the control target when larger controllable loads cannot achieve the amount of load drop desired. In some utilities a relatively flat load curve forces long control times and appliance groups may have to cycle with other appliance groups to avoid customer inconvenience. This type of problem lends itself to a linear programming solution. The objective function would consist of minimizing bulk power costs. This would be balanced against imposed restraints of customer acceptance (appliance off-time) and avoidance of secondary peaks (appliance diversity and restore demand information). In the case studies illustrated in the appendix to this report only one utility had more than one type of appliance controlled. In this case air conditioners, representing the largest loads, were controlled first. Water heaters were later used to provide final load shedding. The result was a rather long control time for air conditioners, but, since no unit was inhibited for more than 15 minutes an hour, there was no assumed customer inconvenience.

The 'tactics' involved in a load control strategy rely on responsiveness. They are developed below for the two principal types of controllable appliances.

If the controllable load has been predetermined to be water heaters only, the straightforward procedure involves multiplying the total number of water heaters by 3 factors: 1) their load diversity at the time of the peaks or control periods, 2) the system loss factor to reflect the load referenced to the bulk, power billing point, and 3) the control switch success rate to account for switch failures. The resultant maximum potential controllable load is then substracted from the system peak demand to obtain the control target related to water heater control.

If the controllable load has been predetermined to be central air conditioners only, a slightly different procedure is necessary. To minimize customer inconvenience, recent tests have shown that only 15 minutes off time is the maximum allowed per central air conditioner in any one hour. Therefore, the maximum potential controllable load, as calculated above for water heaters, must be divided by 4 to account for this restriction. (Further testing might alter this restriction for a specific utility).

For most summer peaking utilities, the maximum diversified demand of central air conditioners is almost 90% of the average air conditioner's connected load (implying that the air conditioning compressors are running almost continuously on the hottest days). Consequently, little diversity of air conditioner demand normally occurs on the summer peak. Maximum diversified demand, during control, is reached approximately after two inhibit cycles and at an earlier time than would occur without control. Maximum diversified demand after a control period could actually be higher than normal demand because of restored demand effects. In any event it is, in many cases, very close to the connected load of all air conditioning at that time.

When central air conditioners are controlled during periods when temperature is below maximum, where insulation standards are high or where thermostat settings may be relatively high, the increased diversity of air conditioning demands will substantially affect the control strategy. Tests conducted by both a midwestern and western utility, for example, show that with a natural diversity of 50% of the air conditioners being on at any one time, very little load was being shed as a result of cycled inhibits. In other words if the inhibit cycle causes a unit to be "off" 25% of the time and "on" 75% of the time, the average demand of the air conditioner will not be affected. The unit will still be allowed to run 50% of the time to satisfy the cooling requirements of the home. The net effect is to shift the "off" period of the unit.

b. The Inhibit and Restore Sequence - With the control target for each load established, the strategy next involves the inhibiting of loads as this level is approached so that it is never exceeded. The controllable load is then divided into a number of groups which is determined by the number of control channels available. As noted previously for air conditioners, the number must be such that approximately 25% can be controlled at any one time. The inhibit and restore sequence necessary to keep the system load below the control target is discussed below for water heaters and air conditioners.

(1) Water Heaters - The system monitor observes the load increasing on a real time basis. At frequent intervals, this value is compared with the control target and the load profile that determined this control target. Based on this load profile's slope, the monitor initiates inhibit commands to a sufficient number of groups to stay below the control target until the time of the next sample. Group demand is a function of water heater diversity at the time of inhibit. It also must be adjusted by the loss factor and switch success rate previously mentioned. Because of the time varying nature of diversified demands, continuous monitoring during the initial inhibit sequence will probably be required. Generally, the initial inhibit sequence, i.e., the removal of all water heater load from the system, is completed within an hour or less.

Total off time will depend on the system load profile. The width and slope of the system peak will determine off time and the initiation of restore. The restore sequence begins as soon as the system load profile decreases sufficiently below the control target. In other words, the difference between the control target value and the actual demand must be at least as great as the first group's restore value. The first group inhibited must be the first group restored to satisfy the minimum off-time objective. The order restore would then follow the order of inhibit. Restore values are calculated as follows: the diversity of each group at the time of inhibit is multiplied by the loss factor, switch success rate, and restore multiplier. The restore multiplier is the ratio of returning load to initial load. These ratios are statistical averages derived from several tests. This data also indicates the manner in which the restore values decay over time to normal values, i.e., the payback period. (See Exhibit III-4). To observe the effects of the first group's restored demand, the initial restore value is added to the load curve with all water heaters off at the time of the restore command. The payback curve is drawn from this point, establishing a revised system load profile. When this revised load profile drops sufficiently below the control target, the next group may be restored. Then in the same manner as before, this payback curve is added to the first payback curve to establish another load profile. This sequence continues until all groups are restored. Note that depending on the slope of the load profile, it may be possible to restore more than one group at a time. Conversely, some time intervals may have to be skipped to allow for adequate load decay.

(2) Central Air Conditioners - For central air conditioners, the inhibit and restore sequences consist of group cycling. Groups can be inhibited only for short intervals (previous tests have used 7-1/2 minutes, no more than twice an hour) to minimize customer discomfort. The inhibit sequence begins when the system monitor projects a load demand above the predetermined control target, as previously explained for water heaters.

Group demand is determined from applicable diversity curves. Once the inhibit sequence is initiated, all groups are cycled in 7-1/2 minute intervals. It may become necessary to cycle two groups at a time as the system load increased rapidly. (Restricted by the fact that no group may have more than two 7-1/2 inhibit periods in any one hour). After two inhibit cycles, it is assumed that each group requires the maximum diversified demand. Therefore, after the second cycle, the resultant load profile is established by adding 3/4 of the maximum diversified demand of the total central air conditioning load (times loss factor and switch success rate) to the load curve with central air conditioners removed. As the revised load profile drops below the control target, central air conditioning load is restored by discontinuing the cycling sequence as soon as possible while still not exceeding the control target. The restore information on central air conditioners shows that payback (the time necessary to satisfy the original thermostat setting) can be anywhere from 3 to 7 hours. This range of payback emphasizes the need for system unique data collection in this area for each utility. The maximum diversified demand extends through the length of the restore period. This means that the load curve after all central air conditioner groups have been restored is determined by adding the maximum diversified demand of the total central air conditioners to the base load curve with central air conditioning removed. This resultant load profile extends through the duration of the restore period.

G. Preparation of Specifications

A load control specification is a translation of ideas, concepts, facts, and requirements. Properly prepared and executed, a specification answers these questions:

- What is needed?
- Who needs it?
- How much is needed?
- Where is it needed?
- What results are expected?

If any of the five questions are not answered by the specification, an ambiguous procurement could result.

The preparation of the load control system specification is the culmination of the planning phase. It is undertaken after the requirements have been developed and the basic concept has evolved into a viable plan. Only after the execution of these tasks, can a procurement specification be written and released to the load control system vendors. The premature preparation or release of the specification will manifest itself at a later date in the form of change orders. These change orders may result in changes in the final contract cost of the procurement, possible alterations to the form, fit, and even the function of the procured system.

A load control specification may be comprised of the following major parts or sections:

Specification Outline for a Load Control System

1.0 Solicitation Instructions and Conditions, and Notice to Offerors

1.1 General

1.2 Sub-Contractor or Material Supplier Requirements

1.3 Bidding Instructions
- 1.3.1 Correspondence
- 1.3.2 Pre-Bid Meeting
- 1.3.3 Inspection of Job Sites
- 1.3.4 Proposals
- 1.3.5 Sealed Price Quotations
- 1.3.6 Pricing Guarantee
- 1.3.7 Price Breakdown

1.4 Information to be Furnished with Proposal

1.5 Preparation of Contract Documents

1.6 Evaluation Factors

2.0 Contract Forms

2.1 REA Form 786

2.2 Contractor's Bond

6.0 Man/Machine Interface Subsystem
- 6.1 Console
- 6.2 Console Configuration
- 6.3 CRT Display Equipment
- 6.4 CRT Monitor
- 6.5 Communications Facility
- 6.6 Logging Devices
- 6.7 Audible Alarms
- 6.8 Packaging
- 6.9 Environment Requirements
- 6.10 Subsystem Expansion Requirements

7.0 Load Control System
- 7.1 General
- 7.2 System Description
- 7.3 Controller
- 7.4 Switches
- 7.5 Load Control Transmitter
- 7.6 Antenna System
- 7.7 Frequency Clearances
- 7.8 Test Equipment
- 7.9 Radio Frequency Field Strength Measurements

8.0 Design Goals
- 8.1 High Availability
- 8.2 Redundancy and Backup Goals
- 8.3 Reliability and Security
- 8.4 State-of-the-Art Design
- 8.5 Man/Machine Interface
- 8.6 Maintainability
- 8.7 Expandability
- 8.8 Life Span

9.0 Facility Considerations
- 9.1 Physical Characteristics
- 9.2 Security
- 9.3 Environmental Characteristics
- 9.4 Power Conditioning
- 9.5 Communications

10.0 Training
- 10.1 General Requirements
- 10.2 Course Material and Related Requirements
- 10.3 Number of Trainees
- 10.4 Training Course Contents

- 10.5 Computer Subsystem Training Courses
- 10.6 Data Acquisition and Control Subsystem Training Courses
- 10.7 Man/Machine Interface Subsystem Training Course
- 10.8 Application Software Training Course

11.0 Spare Parts and Maintenance
- 11.1 Spare Parts
- 11.2 Maintenance Tools and Test Equipment
- 11.3 Maintenance Service

12.0 Documentation and Standards
- 12.1 Documentation
- 12.2 Deliverable Quantities
- 12.3 Review Documentation
- 12.4 Initial Deliverable Documentation
- 12.5 As-Built Deliverable Documentation
- 12.6 Documentation Contents
- 12.7 Standards

13.0 Project Schedule, Installation and Testing
- 13.1 Project Schedule Requirements
- 13.2 Installation Service Requirements
- 13.3 Cabling Responsibilities
- 13.4 Installation Design Details
- 13.5 Inspection Requirements
- 13.6 Test Requirements

14.0 Installation
- 14.1 General
- 14.2 Scope
- 14.3 Planning Requirements
- 14.4 Facility Planning
- 14.5 Standard Installation Practices
- 14.6 Installation Documentation
- 14.7 Equipment Placement
- 14.8 Cabling and Wiring
- 14.9 Circuit Breaker and Panel Wiring
- 14.10 Verification Checklist
- 14.11 General Safety Requirements

15.0 General Considerations

- 15.1 Frequency Allocations
- 15.2 Manpower Requirements
- 15.3 Spares
- 15.4 Environment Control
- 15.5 Equipment Storage and Preinstallation
- 15.6 Lighting
- 15.7 Equipment Placement at Site Facilities
- 15.8 Documentation
- 15.9 Testing and Survey Reports
- 15.10 Provisioning
- 15.11 Technical Manuals
- 15.12 Training
- 15.13 Reliability
- 15.14 Alarm System
- 15.15 Detailed Drawings
- 15.16 Quality Assurance Test and Cutover Plan
- 15.17 As-Built Drawings
- 15.18 System Alignment, Checkout, and Acceptance Testing
- 15.19 Preacceptance Checkout
- 15.20 Reliability Calculations
- 15.21 Maintenance and Maintenance Records

IV. COST METHODOLOGY

A. ONE WAY LOAD CONTROL SYSTEMS

For an individual utility, the mertit of load control hinges upon a favorable balance of potential benefits over inherent costs. Further, the relative merit of alternative types of load control systems is a function of the relationship between their respective benefits and costs. Obviously, if all systems produce the same benefit for the same period of time, the least costly system (considering all elements of current and future cost) is the best economic choice, all other things being equal.

There are a number of economic measures of project merit. Among these, the following will be treated in this discussion:

- o Net Present Value
- o Internal (Economic) Rate of Return
- o Benefit/Cost Ratio
- o Payback Period

Each of the first three methods is dependent upon present worthing procedures. That is, they recognize the time value of money.

Net present value is established as the difference between the respective present worths of project benefits and costs. Some analysts prefer the NPV method of project evaluation because it explicitly defines the magnitude of potential savings or other net benefit. This is particularly useful where project benefits vary appreciably between alternative programs. Since, in the instant case, the principal benefit of load control for a non-generating utility is considered to be the capacity cost savings in purchased power expense, direct load control benefits are the same for any system capable of accomplishing the prerequisite load control. As a consequence, the Benefit/Cost Ratio method serves as a more direct indicator of economic feasibility.

The Internal Economic Rate of Return is defined as that discount rate which produces a net present value of zero, i.e. discounted costs and benefits are equal. An internal rate of return greater than the utility's cost of capital would generally be an indicator of project worthiness. From the non-generating utility's standpoint, this method suffers from the fact that for precise determination, a computer is almost essential since an iterative process is involved.

The Benefit/Cost Ratio on the other hand is a relatively easy test to make, and, particularly where benefits are generally static as between alternative load control systems, is a reliable measure of economic priority.

The suggested methodology which follows relates to the development of the Benefit/Cost Ratio. The Payback Period application will also be treated subsequently.

1. Benefit/Cost Ratio Methodology

It would appear obvious that if the benefits to be derived from a course of action exceed the costs of achieving those benefits, the undertaking is a worthy one, all other things being equal. The Benefit/Cost Ratio is an economic measure based on the ratio of Benefits to Costs; and in its strictest sense, a ratio better than unity is indicative of project worthiness.

On the other hand, relative B/C ratios are not necessarily a realistic criterion for evaluation between alternative projects. For a exaggerated, but legitimate example, an investment of $100,000 to produce a $200,000 benefit may very well be considered to have priority over a $1,000 investment to achieve a $3,000 benefit, even though the B/C ratio of 3:1 in the latter case is greater than the 2:1 ratio produced by the former. The virtues of the Net Present Value approach may be seen from this application.

However, for the evaluation of load control systems, at least for one way systems, the compelling benefit for non-generating utilities is in every case the same-the potential reduction of capacity costs incurred in connection with power purchases. In this specific context, the B/C ratio therefore serves as a valid measure of the relative merit of alternative solutions.

In order to properly compare costs and benefits, they must, of course, be stated on a comparable basis. Load Control Systems represent a sizeable "up front" investment to provide benefits that will hopefully prevail throughout the lifetime of the apparatus installed. Consequently, equalization of timing differences is of primary importance in equating benefits and costs. The Levelized Annual Equivalent basis proposed in this application equalizes these factors.

a. Development of Levelized Annual Costs

(1) Determine Alternative Investment Costs - The criteria for developing total load control system installed costs have been described in Chapter VI of this Report. As indicated, different components make up the alternative systems under review and variances in operating procedures produce differences in costs of installation and similar other factors as well.

(2) Establish Fixed Charge Rate

To express load control system costs in terms of a single initial cost would, from the ratepayer's viewpoint be a misstatement of the fact. For an investor owned utility, that investment becomes a component of Rate Base on which an annual minimum acceptable return is to be earned. The return provides the means to pay annual interest charges on incurred debt, to pay preferred stock dividends if applicable, and to provide a return on common equity at a level sufficient to make the utility's stock an attractive investment for potential new stockholders. These factors together constitute the Cost of Money component of the Fixed Charge Rate.

Before the annual return is realized; the utility may be subject to federal and perhaps state income taxes on the revenues generated to produce such return, and the investment itself must be recovered over the life of the equipment.

For a non-profit municipal or cooperative electric system, the debt vehicle is generally either Municipal Bonds or REA type loans. Since, generally, no stockholder costs are involved, the cost of money relates solely to debt service, and of course, income taxes are not incurred.

In addition to the above annual costs, property taxes may be assessed by local authorities. Insurance or other similar costs may be considered desirable. All of these factors may be most conveniently expressed in a Fixed Charge Rate which when applied to the total investment yields the levelized annual system costs exclusive of operation and maintenance expenses. The Fixed Charge Rate then consists of:

Cost of Capital

Depreciation

Income Taxes

Property Taxes

Property Insurance if applicable

Other Annual Costs if applicable

The Cost of Capital is simply the annual interest rate for current debt vehicles, or, for stock companies, the weighted average current cost of all components of capitalization in a desired mix.

The Cost of Capital thus established may generally be assumed as the minimum acceptable rate of return and consequently, the discount rate to be used in all present worth determinations.

In the context of a Fixed Charge Rate, depreciation is expressed as the annual Sinking Fund factor which when applied to investment cost yields the levelized annual deposit which at a compound interest rate equivalent to the cost of capital will produce an amount equal to the original investment over the service life assumed for the load control system. For even discount rates, this factor may generally be found in compound interest tables. In the case of less common discount rates, the factor may be determined from the following formula:

$$\text{Depreciation Factor} = \frac{i}{(1+i)^n - 1}, \text{ where } i = \text{interest (discount) rate}$$

Together, the Cost of Capital and the Depreciation Factor constitute the Capital Recovery Factor.

Generally, property taxes, property insurance, etc. are already levelized in that they represent fixed annual amounts which may be expressed as a percent of investment. Consequently, this established percentage relationship may be directly incorporated into the Fixed Charge Rate. Where variation in future levels may be reasonably anticipated, annual charges over the life assumed must be present worthed to current levels and converted to annual equivalents by means of an annuity factor.

Where it applies, income tax is the most complex component of the Fixed Charge Rate. Treatment varies by tax source and because of specific options adopted in individual applications. In keeping with the other components of the Fixed Charge Rate, income taxes are expressed as the annual equivalent of the present worth of income tax obligations over the life of the investment. Particularly, because of this complexity, many companies employ a computer program to develop annual fixed charges and a levelized fixed charge rate.

(3) Apply Fixed Charge Rate to Investment Costs

Since the Fixed Charge Rate has been established on a levelized basis, the annual equivalent fixed investment costs for comparative purposes result directly from application of this Rate to Installed Costs as previously determined.

(4) <u>Determine Levelized Annual Equivalent Operation and Maintenance Expenses</u>

In addition, annual operation and maintenance expenses associated with the various systems must be recognized in the total cost stream.

In connection with the economic analysis, it is appropriate to recognize future escalation of O&M expenses as developed at present cost levels. Finally, levelized annual operation and maintenance expenses are represented as the annual equivalent of the present worth of escalated expenses over the life of the investment.

For illustrative purposes, consider this example of constructing levelized annual O&M expenses for one of the generic system types.

	Year	O&M Expense	Present Worth Factor	Present Worth Amount
O&M Expenses As Developed	1	$15,354	.917431	$14,086
Anticipated Expense at 7% Annual Escalation	2	16,429	.841680	13,825
	3	17,579	.772183	13,574
	4	18,810	.708425	13,325
	5	20,127	.649931	13,081
	6	21,535	.596267	12,841
	7	23,043	.547034	12,605
	8	24,656	.501866	12,374
	9	26,382	.460428	12,147
	10	28,229	.422411	11,924
	11	30,204	.387553	11,705
	12	32,319	.355535	11,491
	13	34,581	.326179	11,280
	14	37,002	.299246	11,073
	15	39,592	.274538	10,870
Total				$186,204
Annual Annuity Factor				.124059
Annual Equivalent				$23,100

Both present worth and annuity factors may be determined directly from compound interest tables. In other cases, the following formulae may be applied:

$$\text{Present Worth Factor} = \frac{1}{(1+i)^n}, \text{ where } i = \text{discount rate}, \quad n = \text{year}$$

and:

$$\text{Annunity Factor} = \frac{i}{1-V^n}, \text{ where } i = \text{discount rate}, \quad V^n = \text{present worth factor in final year.}$$

(5) Summarize Levelized Annual Costs

Total costs, for analysis purposes, are the summation of levelized annual fixed costs and operating expenses associated with load control systems.

b. Development of Levelized Annual Benefits

For a non-generating utility, the overwhelming benefit, represented by load control is the potential savings in the capacity cost component of purchased power expense. This is not to imply that other benefits may not accrue, but it would appear that basic justification must reside with this factor. In general, the Benefit/Cost Methodology is predicated on this single potential benefit.

(1) Determine Potential Current Capacity Cost Savings

Having defined appliances to be controlled, the potential diversified demand thereby subject to control and a load control strategy to achieve maximum cost advantage, total controlled load in each month of the year may be determined.

In order to translate the respective control levels into potential capacity charge savings, present or prospective bills for electricity are calculated on a month by month basis both before and after adjustment of billing demands to reflect load control. To the extent that carryover ratchets are imposed, the full impact of load control may be somewhat restricted until the second year of operation, and seasonal demand fluctuations may impose ratchet limitations even thereafter.

Annual net savings representing the difference in calculated billings with and without load control should be reflected for each year throughout the projected life of the load control hardware. Since it appears reasonable to assume that bulk power billing rates will undergo continuing upward adjustments, it is likely that annual net savings will escalte over the forecasted period.

(2) Convert Potential Future Savings to Levelized Annual Equivalents

Once again, in order to express all terms on a comparable basis, future capacity cost savings are converted to levelized annual equivalent amounts through the application of present worthing techniques.

The capacity cost saving in each future year is reduced to its present worth under the discount rate applicable. The cumulative present worth of savings in all years is converted to a levelized annual equivalent amount by means of the annuity factor previously defined.

c. Summarizing Costs and Benefits for Comparative Analysis

Comparative costs and benefits are conventionally measured in terms of a Benefit/Cost Ratio. Since the ratio is developed by dividing project benefits by project costs (expressed throughout this procedure in terms of annual equivalents) a ratio in excess of unity is indicative of a favorable evaluation status, all other things being equal.

A flow diagram tracing each step of the Benefit/Cost Ratio methodology is included in Figure IV-1.

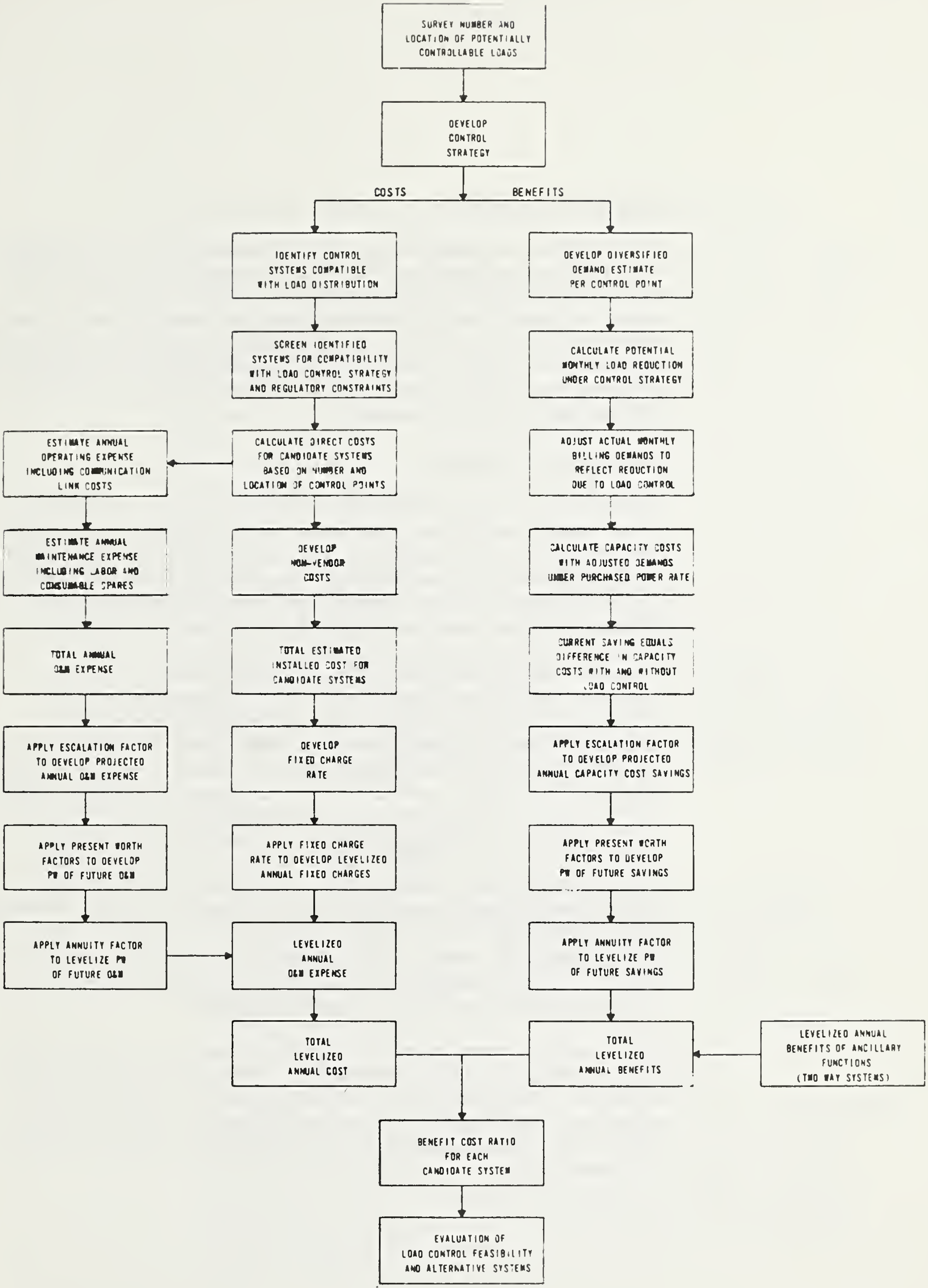

Figure IV-1 Cost/Benefit Analysis Flow Chart

2. Payback Periods

As a further measure of project acceptability, individual payback periods may readily be determined. The Payback Period is defined as the number of years required to recover original investment from net returns before depreciation but after taxes (if applicable). By definition, the payback period is established in that year when cumulative net savings equal or exceed the original installed cost of the system under analysis.

3. Sensitivity Analyses

Inevitably, some assumptions must be made in the course of economic analysis. Although based on the best available information, they may, if in error, bias an investment decision. In order to measure the impact of certain pivotal estimates or assumptions, the analysis results should be redefined in terms of alternate determinants.

In order to measure the impact of varying acceptance rates, control system costs should be segregated into fixed and variable components. The fixed component covers certain central system costs which are inherent in the system and therefore apply at all acceptance levels. On the other hand, certain other costs are directly proportional to the number of installations, and the total cost at any acceptance level is a combination of the fixed cost and the cumulative variable costs for that number of installations. Since capacity cost savings vary directly with the amount of controlled load, benefits are linear from zero to that level established at the 100% acceptance rate. In combination, relative costs and benefits may be determined at any acceptance rate, and critical acceptance levels may be defined.

As a further test of sensitivity, estimated project costs may be adjusted either upward or downward by a fixed percentage. The effect of escalation may be readily determined by restating the analysis without consideration of inflation, particularly that reflected in future capacity cost savings.

B. The Impact of Wholesale Rate Structure On Load Control

In general there is agreement that the most important benefit of load control to the non-generating utility is the savings through a reduction in demand, hence, the costs of wholesale power purchases while the savings to the wholesaler are much more complex. The amount of savings that can be realized will depend, among other things, on the magnitude of the reduced load and on the demand charges built into the wholesale power rate structure, which are subject to periodic changes. Therefore, to evaluate and assess the savings that may be expected from load control programs, it is important to understand the various factors that may affect the wholesale power rate to the non-generating utility. These factors include: (1) the method by which the revenue requirement of the wholesale power supplier is established; (2) the billing determinants used to recover that revenue level; (3) the structure of the rate itself regarding capacity costs and energy costs; (4) the number, size and diversity of non-generating utilities served under that wholesale rate; (5) the timing of wholesale power rate increases relative to the initiation of the load control program; (6) the regulatory jurisdiction under which the load control program's wholesale power rate is established, if any; and (7) the general nature of the relationship between the power supplier and the non-generating utility.

1. Revenue Requirements

Revenue requirements, defined as the cost of providing service at a given voltage level, should be the same for power supplied to a distribution system whether or not that system is owned by the supplying utility. In other words, for a given utility, the "wholesale" rate charged for service provided to another non-generating utility for resale should be equivalent to the power supply costs incorporated in the supplying utility's rates for its own distribution level customers. To obtain the pro rata share or proper amount of fixed charges associated with power supply, the relationship of power supply and costs must be examined. If, as a result of certain peak demands or reliability criteria, increased production and/or transmission costs are incurred by a generation utility, these factors should be considered so that incremental costs are allocated to those purchasers responsible.

Frequently, however, the method actually used to establish the revenue requirements for a wholesale power rate is not totally consistent with the cost factors of the supplying utility. If the wholesale rate is "cost-based", there should be some combination of demands to other allocation factors which are used to set the level of annual revenue requirements from wholesale rates. The factors which determine this overall allocation to wholesale service must be considered in the load control strategy of the non-generating utility.

Load control may not affect the capacity related revenue requirements of the supplying utility. However, such control will result in a reduction of overall revenue derived from the wholesale of electricity and may prompt the supplier to adjust the wholesale rate in order to recover its sunk cost. In such case, the adjustment of wholesale power rate may affect the amount of savings that a non-generating utility can expect from the load control program.

If the rate adjustment is universally applied to all wholesale customers, a possible effect of load control programs is to shift a portion of the supplying utility's costs to its customers not implementing load control. If the non-generating utility's relative share of the supplying utility's total cost is small, certain constraints affecting revenue requirements such as timing, plant size and location, reliability, and other planning criteria may override the effect that the non-generating utility's load control program might otherwise have on planning and total costs. In such cases, wholesale power costs to the non-generating utility may remain unaffected, and the long-term savings from load control program can be realized.

2. Billing Determinants

Normally, after revenue requirements have been determined, the next consideration is revenue recovery using a rate form geared to selected billing determinants. For the non-generating wholesale customer, these determinants are commonly in one of the following forms: monthly maximum demands at individual metering points, the coincident monthly maximum demands of all metering points of the non-generating utility, or even some combination of demands coincident with the supplying utility's peak demands. In addition, a ratchet form may be introduced to establish a minimum monthly demand at some percentage of the highest billing demand established in previous months. This ratchet may be even as high as 100%. The interval of recorded demand, whether 15, 30, or 60 minutes, has little effect on load control strategies currently in use.

3. Demand Charges and Billing Determinants

Quite often in the structure of wholesale power rates, some portion of the total capacity costs are designed to be recoverd in the energy charge. The greater the amount of capacity costs that are included in the capacity charge portion of the rate, the higher the $/Kw and the greater is the savings that may be obtained from each Kw controlled. In any case, that portion of total revenue requirements to be recovered through demand charges is divided by total demand billing determinants to establish the unit price per Kw of the demand. As discussed above, using load control to reduce the billing demands after the rate is established, will, of course, reduce the monthly wholesale power bill. If, as a result of load control, total class demands are less than the billing determinants used to establish unit price, a shortfall will result in meeting the supplying utility's revenue requirements. Consequently, although short term savings may accrue to the non-generating utility implementing load control, such savings may be jeopardized in the next rate filing when per Kw capacity costs are adjusted upward to reflect the decrease in billing determinants. This would generally be the case unless the impact of load control is insignificant with regards to a proportional reduction in the overall wholesale class revenue requirement.

If the non-generating utility with load control is identified as a single wholesale power customer with an individual wholesale power rate the situation indicated above will be even more pronounced. If the load control strategy focuses only upon a reduction in billing units, and the demands and other factors impacting periodic determination of revenue requirements are not affected, savings will only result until the time when that individual rate is again brought under review, all other considerations remaining unchanged. With the revenue requirement unaffected and only the billing units reduced through load control, the per unit capacity charge will be increased and any further savings will be eliminated.

4. Impact of Ratchet Provision

There are additional considerations regarding load control and billing demands. It may be assumed that in order to realize maximum savings when a ratchet is not in effect, demands in all months would have to be controlled (assuming potentially controllable loads exist in each month). However, when a ratchet provision is in effect, control might not be necessary in those months having an otherwise lower billing demand than the minimum billing demand based on the ratchet provision and established even after control is accomplished in peak month(s). Often the ratchet provision is seasonal, and the effect can only be determined after evaluating the specific rate.

5. Metering Points, System Peak, and Distribution Peak

To produce savings through control of specific demands requires that some means be available for anticipating when those demands would reach a "critical" level. This level would be set such that control might produce a savings. Total system load of the non-generating utility is generally, but not always, monitored; control decisions may have to be based on the coincident load of all metering points. In some cases the wholesale rate may be billed on individual metering points, or there may be other reasons for attempting to control on an individual substation basis such as savings in distribution investment. If a control strategy dictates that the individual peaks on all metering points or substations are to be reduced, the problems connected with predicting and controlling loads are multiplied. When maximum or long term savings from a wholesale power rate can only be achieved by controlling demand at the time of the supplying utility's peak, additional metering and cooperation between supplier and non-generating utility may be necessary.

6. Frequency and Timing of Rate Adjustments

As indicated previously, savings may be considerably reduced or even eliminated after a wholesale power rate is restructured. However, with relatively short payback periods, the non-generating utility may recover at least the majority of all load control system costs before the wholesale power rate is again reviewed and restructured. The timing of rate increases or rate reviews is therefore important in the short term perspective of the non-generating utility. Nation-wide, the frequency of rate filings and rate reviews has been increasing in recent years, and it is not uncommon to see wholesale power rate increases filed every few years.

C. Summary - A Procedural Outline

This section serves two purposes. It summarizes the main points of the report and offers insight where clear optimum choices exist. Secondly, this section provides a procedural outline to follow in developing a load control program. Because of the many combinations of user objectives and physical systems possible, the outline cannot be comprehensive enough to serve as a complete reference. It can, however, provide direction and outline the relationship of the necessary basic steps.

In its simplest form the evaluation and the feasibility of introducing a load control system into, as an example, a non-generating utility consists of four major steps:

I. Evaluate the existing (and potential) physical system

II. Identify benefits of load control

III. Identify costs of load control

IV. Select operational system

The last step can be the easiest or hardest depending on the degree of success achieved in the research involved in Steps I, II and III. A key determinant in evaluating the benefits (Step II) may be the ability to forecast future needs.

In the following pages these four major steps are expanded into a procedural outline.

1. System Evaluation

a. Identify the Objective and Scope of a Direct Load Control System

(1) Develop Reasons for Load Control

This will expedite decisions on communication system selection, load control strategy, level of control and economic evaluation. Essential reasons include: a) minimize bulk power demand charges via peak shaving, b) meet the electrical needs of a growing population with fixed capacity available, c) increase distribution system reliability, including emergency load shedding, d) meet the regulations mandated by public utility commissions or large public power pools (if a member).

(2) Establish the Scope of Load Control

Decide whether control should be 1 way or 2 way. (For example, if the objective is unquestionably limited to peak shaving, 1 way should probably be selected). Ancilliary benefits will influence this decision. Decide what level of end users will be controlled (residential, commercial, industrial). Note that these decisions will be preliminary pending investigations in load control strategy and economic analysis. A reiterative process is necessary.

(3) Develop Ancilliary Benefits Desired

Evaluate which ancilliary benefits can be obtained from current hardware and which benefits would dictate another hardware system. Determine the priority. A partial list of ancilliary benefits include:

(a) Automatic Meter Reading

(b) Time-of-Day

(c) Load Research Surveys and Demand Studies

(d) Distribution Automation (switch control, fault location and isolation, feeder redeployment, capacitor switching, voltage regulator switching, feeder monitoring)

(e) Street Light Control

(4) Identify Limitations on the Effectiveness of Load Control

(a) Purchase power agreements - Terms and conditions of the tariff should be analyzed as well as any demand/energy provisions which may effect the control strategy.

(b) Organization - The non-generating utility may be associated with a larger utility group or public power pool which could establish priorities limiting the short term optimum load control for the non-generating utility.

(c) External - Regulation may impose some policies regarding load control, time-of-day rates, etc., relating to the end users or communications system.

(d) Technical - Conduct a preliminary review to recognize any communication hardware limitations.

(e) Physical - Conduct a preliminary review to recognize any limitations imposed by the distribution system.

b. <u>Evaluate Existing Load Curves</u>

System and/or subsystem load profiles and load duration curves are valuable aids in examining the existing load patterns as well as quantifying the effects of direct load control. The objective for load control will define which load curves are of interest. Specifically, when minimizing power supply costs, the nature of the purchased power agreements will indicate the load curves which relate to the power costs. Where billings are set on coincident peak demands, the system profile is used. If non-coincident delivery point peaks set billings, a profile is needed from each duration of the peak period. The profile is in turn used to develop the control strategy.

c. <u>Evaluate Controllable Loads</u>

The quantification of controllable load is directly related to the determination of benefits in the economic analysis. In order to estimate the amount of controllable load several factors need to be developed.

(1) After establishing objectives for load control and examining the appropriate load curves, the number and timing of control periods can be determined.

(2) Controllable appliances need to be estimated for these control periods by:

    (a) Appliance saturation survey

    (b) Existing customer records, such as special rates or service connection application forms

    (c) Billing records where high users may be assumed to have certain appliances.

(3) Develop the controllable load per appliance for each control period from appliance diversified demand curves:

    (a) From "in-house" load research data

    (b) Published data of other utilities

(4) Appliances returned to service after a control period require additional (payback) energy which must be accounted for in the control strategy. Develop energy payback curves for controlled appliances to model the load restoration demand in the control strategy.

    (a) From "in-house" load research data

    (b) Published data of other utilities (Section III-2)

(5) Determine loss factors to reference controllable load from the customer level to the delivery points.

(6) Estimate a switch success rate to account for receiver switch and other equipment malfunctions.

In light of these factors, the following relationship can be used to calculate the controllable load at any control period.

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

Where: C = controllable load
N = number of controlled appliances

D = diversified demand per controlled appliance at the time of the control period
F = switch success rate
L = loss factor

d. Evaluate Physical Transmission and Distribution Systems

(1) Identify the Physical Characteristics of the Service Area

Certain characteristics of a utility service area will exert strong influences on the choice of a load control system. Geographical location will control climatic conditions and be indicative of land topography. The former will affect the possible number of control commands required due to the type of load controlled and control program while mountainous terrain will detract from the effectiveness of radio coverage.

The dimensions of the area and its overall shape will be reflected in the total line route miles to be considered (affecting attenuation for carrier systems) and will generally be related to customer density. This latter consideration is important in determining the proportion of fixed common equipment costs to be allocated to each customer. This density factor is further influenced by the proportion of the total customers with controllable load.

(2) Identify the Electrical Characteristics of the System

Under this category fall the methods of system construction (overhead vs. underground), interconnection and method of supply. Of equal importance to the knowledge of the existing system is an understanding of system reinforcements or extensions which are anticipated to occur within the expected life of the control system.

While the above will determine such features as line attenuation to carrier signals and the normal/abnormal location of a customer feed within the electrical system, the bulk supply arrangement is of primary importance. This factor alone may be responsible for the exclusion of several communication systems from consideration.

In the application of any form of load control communication equipment, whether one way or two way, it is desirable to examine the distribution system for other control functions ancilliary to the load control which may be incorporated economically into the scheme. These may be functions already provided by present controls such as clock controlled capacitor switching or operations desirable but not yet available.

(3) Examine Demand Conditions During Load Restorations

One concern in the widespread remote control of customers load is the destruction of the natural diversity during load restoration periods. A simulation of typical distribution systems to determine localized overload and volt drop conditions during load restoration periods shows that for normally designed modern networks no such overloading of distribution apparatus is to be expected. This modelling technique utilized control strategy requiring load restoration in somewhat larger blocks than would be met with in practice. Areas involving older networks which have not been reinforced over the years to keep pace with the expanding use of electric appliances should however be suspect and examined in more detail.

e. Evaluate Feasible Control Systems

Although many differing control systems are available for the remote direct control of customer's loads, these may, in broad terms, be broken down into five basic generic groups. The salient points of each group are given.

(1) Radio

Direct transmission from a local base station controls individual receivers mounted on the customers apparatus. The location of the controlled appliance must be within the transmitter service area.

This is a relatively simple scheme to apply based on well known equipment technology. It is particularly suitable for areas which have a good operating history of VHF two way land mobile radios. A prime advantage is the complete independence from the power system and operating routines.

The disadvantage becomes apparent in areas having mountainous characteristics and in locations where frequency congestion renders the system prone to interference.

(2) Low Frequency Power Line Carrier

Communication between one or more injection stations and the controlled customer by means of a signal superimposed upon the power line conductors. The signal frequency is below 1000 Hz to maximize the range of the signal.

Of the two signal systems available, rhythm and multibit codes, the rhythm is the least susceptable available.

Disadvantages are that the system is particularly sensitive to network switching and the arrangement of the HV/MV substations. The application to radially connected systems may involve a number of relatively expensive injection stations. Equipment involved in the injection stations is large, requires substantial power supplies and major additions to the power system in the form of fully protected feeder circuits.

(3) High Frequency Power Line Carrier

Communication between injection points and the controlled customer by means of a signal superimposed upon the power line conductors. The signal frequency may range between 5 kHz and 200 kHz, depending upon the equipment type. This is a relatively new application and because of the higher frequency, is capable of more intelligence in the signal code with transmission at a somewhat higher speed than the low frequency system. Both one and two way communication is available.

As the signal frequency is much higher than the power frequency, attenuation effects are more severe and the signal range is less than the low frequency types. The requirement for many injection points to overcome the range defect results in small and relatively low cost units. These units are located on the MV system and are largely immune from power system switching problems.

Because of the larger message handling capabilities, the equipment is relatively complex and requires more elaborate control center equipment than other systems.

(4) Hybrid

A system combining the advantages of both radio and high frequency power line carrier.

The technique is similar to a radio system but with the receivers located on the secondary wiring of the low voltage distribution transformer. The radio receiver retransmits the signal received as a high frequency power line carrier signal to carrier receivers located at all controlled customers appliances fed from the low voltage winding of the transformer.

This system has most of the advantages of a pure radio system in that it is immune to network operation and switching plus the ability to spread the cost of the radio receiver over several controlled customers. Likewise, the same disadvantages of a radio system are common to the hybird scheme.

(5) Telephone and Direct Wire Systems

A relatively modern application using the high quality telephone company system. Very high speed, unique address signal capability is available using the telephone company central station equipment and lines without disturbance to the telephone customer. One way communication in either direction or full two way communication is possible with a minimum of equipment either at the utility end or at the customer location.

The disadvantage at the present time are limited to the legal and political aspects of cooperation between the utility and the telephone company and the area of responsibility of each.

f. Evaluate the Load Control Strategy

Select a load control strategy that maximizes the objective determined. The following procedure develops a load control strategy for peak shaving. Develop a reliable data base to forecast the daily load profiles, controllable load and restore demands of applicable appliances:

(1) Develop the Control Target

Subtract the controllable load (Section III) from the system peak. The load profile may limit the percentage of controllable load that can be utilized. A fat profile, for example, would cause a long control period which may produce adverse customer reaction. The control target level determines the number of days that will need control.

(2) Develop the Priorities of Controllable Loads

Establish which appliances represent the most load and can be most reliably inhibited. Establish which appliances can be used to "fine tune" the load shed. Air conditioner loads, for example, will require cycling of inhibit commands to avoid customer inconvenience. Water heaters can undergo continuous inhibits for several hours. Irrigation loads may have uninterruptible periods. Payback periods of certain appliances may be long to avoid secondary peaks, increasing the probability of customer inconvenience.

(3) Develop Real Time Metering or Monitoring System

Develop an adequate responsiveness to load changes. (A sampling program utilizing selected substations, for example.)

(4) Develop Control Tactics

Divide controllable load into the number of independent/controlled groups, the number of which is limited by ease of operation and hardware capability. Select the members of any one group randomly to avoid political and regional diversity problems. Inhibit and restore loads according to priorities established. Minimize and equally distribute off times to all controlled groups.

(5) Evaluate Limitations Imposed by Contractual Agreements

For example, extend the load control to other seasons if a ratchet clause in a purchase power agreement necessitates.

(6) Develop Level of Control Desired

Determine if a secondary level of control (at a certain substation, for example) would be advantageous. Evaluate what proportion of substation peaks occur of same time as system peak. Unless a particular substation serves a single load, reject this control level if percentage is too low.

2. Benefits

a. Identify Savings or Capacity Changes

(1) Existing Rate

(a) Verify amounts shown on recent year purchased power invoices from supplying utility(ies) by computing bills using existing tariff and monthly billing determinants. Note the effect that the level of capacity charge and the ratchet provision (if applicable) has on the total purchased power bill, since it is through these provisions that savings accure.

(b) For the twelve month period, estimate the change in monthly billing determinants corresponding to the amount of potentially controllable load and load control strategy.

(c) Recompute purchased power bills for the twelve month period using the revised billing determinants. The reduction in purchased power bills represents the annual savings.

Assumptions related to above computations:

- o no growth or attrition of controlled customers is considered
- o existing rate is continued
- o the revised load pattern, as estimated, does not change
- o consequences from load control on power supply or the organizational structure of the non-generating utility are not considered above.

For example, if the non-generating utility is a member of a Generating and Transmission Cooperative, or in any other manner represents a significant part of the load of the supplying utility, it is unlikely that the simplified analysis outlined above would be entirely applicable.

(2) <u>Proposed Rate</u> - After load control is implemented

(a) Review the cost support of the existing rate(s) as filed or available from the power supplier(s) (generating utilities). Determine the methods with which the annual revenue requirements of the non-generating utility are computed (e.g., the capacity allocation factors if appropriate)

(b) Determine the effect on the annual revenue requirements from the load control strategy employed. Estimates or detailed discussion with the supplying utility may be required. The timing of proposed rate adjustments must be considered, as well as the necessity of coordinating the load control program with the supplier and possibly other non-generating utilities who may be related organizationally.

(c) Using the probable rate structure and billing determinants of the proposed rate, calculate the monthly and annual purchased power costs.

(3) <u>Develop Levelized Annual Benefits</u>

(a) Project capacity cost savings due to load control over the life span of control apparatus. An escalation factor recognizing potential future increases in purchased power rates is appropriate for this purpose.

(b) Develop present worth factors for each forecast year. The present worth factor for year n derives from the following formula:

$$PWF = \frac{1}{(1 + i)^n} \quad \text{Where } i = \text{cost of money}$$

(c) Develop the present worth of each future year's capacity cost savings as the product of the savings as projected under (a) above and present worth factor determined under (b).

(d) Accumulate present worths of each forecast year's capacity cost savings.

(e) Convert cumulative present worth to a levelized annual equivalent amount through application of an annuity factor developed from the formula:

$$\text{Factor} = \frac{i}{1 - V^n}, \text{ where } V^n = \text{present worth factor in final year } n$$

b. Ancilliary Benefits

(1) Identify other functions, if any, which may be accomplished in conjunction with load control. Included among these may be:

Capacitor switching

Remote Meter Reading (two way system)

Distribution automation functions

(a) Develop actual or estimated costs of otherwise accomplishing the same function

(b) Escalate costs as appropriate to reflect future costs over the life span of load control apparatus as amended to accomplish ancilliary functions

(c) Develop levelized annual benefits of ancilliary functions by applying procedures outlined under Item 2-a-(13) above to future cost streams representing alternative means of accomplishing the same function.

3. Costs

a. Identify installed costs of technically feasible control systems. Carefully evaluate vendor quotation on prices, as significant additional costs may be required for the purchase of support equipment and installation.

(1) Direct vendor costs - component costs for vendor supplied equipment

(2) Indirect non-vendor costs - includes support equipment, communication links, installation, maintenance, initial tests, and debugging.

b. <u>Identify Operation and Maintenance Expenses:</u>

Operation and maintenance costs will vary somewhat between different equipment types but may be classified broadly as follows.

(1) Central Control and Telemetering - Maintenance/ of telemetering and central control equipment is expected to be minimal with simple one way equipment and will be restricted in the main to periodic cleaning, inspection and recalibration. It must be recognized that the maintenance will increase significantly with the increase in complexity such as will be encountered with fully automated remote meter reading capability.

(2) Signal Source Equipment - This equipment will vary according to the control system and will consist of the following:

Radio	- Radio transmitter
Low Frequency Power Line	
Carrier	- Injection equipment (high power)
High Frequency Power Line	
Carrier	- Injection equipment (low power)
Hybird	- Radio transmitter and VHF receivers
Telephone	- Not applicable

Maintenance for the radio transmitters and low power high frequency power line carrier equipment are expected to be minimal and limited to periodic inspection and calibration checks. It is anticipated that maintenance on line mounted signal injection equipment used in some carrier applications would be at a central location with a field changeout of the defective unit. Maintenance of the low frequency high power injection stations is more expensive and will be comparable with similar size substation equipment.

(3) Communication Links - These links between the central control and signal sources may be radio or leased telephone lines. Maintenance charges for radio systems would be minimal, as referenced above while charges for leased lines would be a fixed monthly charge dependent upon the number and length of line involved.

(4) End Use Receivers - These receivers would be subject to a change out program similar to defective house service meters. A central repair/ recalibration facility may or may not be economic depending upon the volume of units processed. Alternatively, contract repair or factory reconditioning may be considered.

c. Develop Levelized Annual Costs

(1) Express project costs in terms of revenue requirements from ultimate consumers by developing a fixed charge rate incorporating:

(a) Capital Recovery Factor, consisting of:

- The weighted cost of money, expressed as a percent and

- Sinking fund depreciation factor developed from the formula:

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

where i = cost of money and n = the service life of the load control system under analysis.

(b) Property tax rate, if appropriate

(c) Property insurance rate, if applicable

(d) Levelized annual income taxes, if applicable.

(2) Apply Fixed Charge Rate to installed apparatus costs for alternative systems to develop levelized annual fixed costs.

(3) Project operation and maintenace expense over apparatus service life by applying a suitable

escalation factor.

(4) Develop annual equivalent operation and maintenance expenses by applying the present worth and annuity factor technique outlined under Item 2-a-(3) above.

(5) Develop total annual equivalent costs as the summation of levelized fixed costs and levelized operation and maintenance expenses.

4. Selection of Operational System

a. Benefit/Cost Ratio

(1) Identify annual equivalent benefits including levelized capacity cost savings and any ancillary benefits associated with alternative load control systems.

(2) Identify annual equivalent costs for each candidate system as defined above.

(3) Develop Benefit/Cost ratio for each candidate system.

b. Payback Period

(1) Develop net annual benefits as the remainder after subtraction of annual operation and maintenance expenses, property taxes and income taxes if applicable. Note that for this purpose, all benefit and cost streams are on an actual projected basis, i.e., before application of present worthing techniques.

(2) Accumulate net benefits for each year until cumulative net benefits equal or exceed raw cost of load control apparatus.

(3) Determine payback period as elapsed years (or factions thereof) required to recover original costs for the respective systems.

c. Analysis of Results

(1) All other things being equal, the optimal system may be determined as:

(a) That system with the highest ratio (exceeding unity) of project benefits to costs

(b) That system having the shortest payback period

(2) Sensitivity Analyses - Alternative results should be developed based on variations of significant input factors such as:

(a) Customer acceptance rates

(b) Escalation factors

(c) Capital cost variations

(d) Operating expense variations

(3) Project revaluated on basis of alternative conclusions derived as a result of sensitivity analyses.

(4) Consideration should be given to the ability of individual systems to provide for auxiliary functions at some future date if the potential for such applications is reasonably foreseeable.

(5) The ultimate test of project feasibility lies in the application of sound judgment to the tangible results of evaluation analysis and the intangible factors otherwise affecting the potential for load control.

V. LOAD CONTROL SYSTEMS INVESTMENT COSTS

A. General

The various types of equipment available for direct load control are unique for each particular design, however, sufficient similarity exists to permit comparison according to the basic communication methodology. The purpose of this section is to examine each of the generic systems with the utility system and the load control objectives. A detailed engineering study of all the varying equipment types, performance characteristics and options would be an integral part of the engineering phase of the work which would follow the completion of the initital feasibility study and planning document.

In addition to certain differences which are apparent, there are features of the equipment, supporting facilities and methods of installation which are common to all systems discussed herein and are listed in this general section. Such assumptions will apply throughout, unless specifically noted otherwise. Among these assumptions are:

- A central control location for the control processor at the borrower headquarters facility;
- Adequate telemetered quantities should be available at the system control location to permit the monitoring and prediction of peak loads for the system and for such parts of the system that may require particular attention;
- There will be an adequate number of channels to permit communications to be relayed to the extent required. It is also assumed that where necessary, two-way channels will be available. REA Bulletin 66-4 may be consulted for communications system costs to support the proposed load control system. No assumptions are made regarding the use of existing borrower land mobile radio systems for load control purposes, although this may be a possibility which should be examined during any process of detailed design;
- Where several borrowers are involved in a consortium to develop an integrated load control system and individual borrower systems, control is provided as an option, and all signal generation, encoding and message protocol will remain under the jurisdiction of the central control and individual borrower control is limited to a remotely controllable preprogrammed enable sequence. The required telemetering to obtain effective control actions and all such demand measurement and prediction controls are additional

equipment necessary for installation at the central control location. It is assumed that the required current and potential transformer circuits are available at the bulk supply substations for the connection of the telemetering transmitters.

- Installation of receivers, wherever possible, will be at the location of the controlled appliance to prevent the need for rewiring in the customer's location. Where receivers cannot be so located, a transformer operated contactor should be installed at the apparatus location and all wiring to the receiver is of the low voltage type wiring.

- Motors utilized for irrigation or oil well pumping should have a motor starter fitted with a control transformer and a 120 volt operated contactor, suitable for remote operation from a control receiver.

In considering the wide range of sizes and types of communication and control component equipment to categorize, associated costs are difficult to quote in any generalized manner. Some components of a certain system may have become standardized, while other hardware requires "customising." Some vendors provide reasonably firm prices, but others are less firm on price quotes because of either the cost sensitivity of matching the system components to a utility system configuration, or the competitive nature of the load control market.

Load control system hardware costs have been found to be sufficiently stable to provide budgetary quotes on component prices. The demand for these systems will continue to influence the market price. To preserve the usefulness of this section, the major components which make up each generic system type are listed so that the borrower may obtain current vendor quotes on the components required. The components listed correspond to virtually any vendor-proposed system currently available.

The balance of this section is devoted to the development of investment costs for the load control systems discussed in Section II with discrete examples given for two comparative systems. While telephonic costs are discussed, no specific costs are provided at this time due to the uncertainty of application of this type of system by our borrowers.

B. VHF Radio Control

1. General

Table V-1 provides the itemized investment costs for a dedicated VHF radio load control system. It may be that certain of the existing facilities used for land mobile

TABLE V-1

Load Control Investment Costs

Radio System

Item	Cost each per quantity shown 1	2000	4000	8000
	- - - - - - - -	-dollars - - -	- - -	- - -
Radio receiver (switch)	80	75	70	67
VHF Transmitter	8500			
VHF Antenna	600			
VHF Receiver (Monitor)	2900			
Tower-guyed (55 meters)	26000			
Control processor	11000			
Printer	1600			
Bulk supply metering and RTU	2800			
Test equipment	5000			
Engineering	20000			
Program management	10000			
Installation of receivers (each)	20			
Installation of VHF radio	1000			
Installation of metering equipment	1000			
Testing	9600			
Training and documentation	10000			
Spares - 1 year operation				
- Radio receiver switch units	2%)			
- VHF radio equipment	2%)	Percentage of total cost.		
- Metering - RTU equipment	3%)			

(For microwave interconnect and/or leased circuit costs, refer to REA Bulletin 66-4).

maintenance radio may also be used for the load control radio system. Other than the use of the existing VHF radio tower, it is not recommended that either the existing antenna or radio land mobile system be used, shared, or integrated into the proposed load control system for reasons mentioned herein.

Table V-6, Maintenance and Operations costs for the various systems discussed, is to be used as may be appropriate for the system under consideration.

This system provides for adequate radio coverage in the 154MHZ band so as to enable effective radio control of all identified customer appliances. The system utilizes separate VHF base station transmitters dedicated solely for the purpose of radiating load control signals of the audio tone or digital coded types, as may be applicable for the system selected.

In allocating transmitter service areas, guidance may be obtained from the existing land mobile base stations presently in use. Where existing stations are rated at 300 watts, coverage of an average service area radius of 25 miles may be assumed, for estimating purposes, for the FCC limited 300 watt load control transmitter. Wherever possible, joint use of existing facilities may be assumed to economize on tower construction, provision of equipment housing and the availability of power sources.

It may be necessary that all transmitters be remotely controlled from a central control center as only a single frequency is allocated at present for utility load control service of this type and sequential transmitter keying will probably be required to prevent mutual interference.

The use of conventional radio communication techniques and radio control for customer apparatus switching renders this system one of the most predictable and understood methods. The use of a dedicated transmitter ensures a rapid response to any desired command without waiting for other traffic.

The use of multiple transmitters will increase time spent in travel and maintenance at many widely separated sites. This may be reduced by coordination with other preventive maintenance trips to transmitters used for other services.

There appears to be a considerable limitation of frequencies available for load control utility service. At present, only a single frequency is permitted for use with 300 watt transmitter power, the remaining three frequencies in the

154 MHZ band are generally too low in transmitter power to be effective. This has the effect of constraining a multi-transmitter installation to sequential operation and negating some of the advantages for transmitters dedicated to load control. Any given installation is also vulnerable to possible interference from other similar installations While additional frequencies may be made available for specific applications, or alternatively, may ultimately be released for general load control use, the FCC will only consider such petitions on an as needed basis.

Of the two signal codes available, the tone control, with its limited command capacity and single transmitter frequency, is generally employed for applications of relatively elementary control strategy over the area under consideration. Use of the digital code presently available does permit a 32 x 8 command format (32 separately addressable receiver groups and 8 commands per receiver) and careful application of codes to maximize area separation could provide the control strategy versitility necessary. Unwanted switching of customer apparatus in adjacent areas cannot be entirely prevented unless coordinated sequential operation is used.

Some of the problems inherent with local control by individual borrowers may be partially reduced by providing transmitter coverage by cooperative areas - an action which would place each borrower in charge of its own transmitter and allow them to be keyed locally for emergency use.

2. Cost Components

Table V-1 shows costs for the control system described to include vendor costs, costs incurred during installation and costs which recur annually. While vendor costs are principally based on vendor published prices, non-vendor and operating costs are based on estimated values. The use of digital systems would increase the cost per function by approximately $35.00.

Central control of the system assumes control of all available interruptable loads with control initiation from a central headquarters facility. Local control from individual borrower headquarters, in addition to central control, indicates an additional cost of $13.00 per control function. It should be pointed out that the method of control may not be practicable due to limitations in available commands and inter-system signal interference. Additionally, operations and maintenance charges would also increase with individual borrower control. A penalty to be paid for joint use of the existing base station is conditional upon the existing transmitter license; that is, the load control signal must be secondary to the prime purpose of the station. Thus, all load control signals must be delayed until the channel is not required for its normal function (voice communication); a delay device in fact holds load control signals until a clear channel is detected. A mitigating feature which renders this limitation tolerable is that for all but the most busy channels, the delay is not likely to be long. Approximately three hundred milliseconds are required to transmit one address and command and this time is noramlly shorter than that occurring between the changeover in microphone keying during the course of normal conversation. Several of the major cost components shown in Table V-1 are discussed below:

a. Control Processor

The control processor unit cost is a function of the borrower's control philosophy such as the required flexibility in cycling control periods relative to appliances controlled. For a completely automated system, the control processor must have the capability to monitor load conditions throughout the system and initiate a control period at a predetermined load level. Less expensive and manually initiated units are also available primarily for small installations.

b. Radio Transmitters

The maximum rating for radio transmitters allowed by the FCC is 300 watts. These transmitters are similar to those offered for land mobile radio systems.

c. Radio Receiver Switch

The common, single-function audio tone receiver is available from several manufacturers as well as multifunction units. Coded tone receiver, per controlled appliance, is normally required, however, the multifunction receiver can control several appliances per location.

d. Support Equipment

Bulk delivery and/or substation point telemetering is required on a sufficient sample of the total load so as to enable an accurate measurement of system demand. Supply point telemetering is generally the most cost effective.

e. Communications Support Links

These costs are not shown in Table V-1 as they are unique for the specific borrower system under consideration. Detailed cost information for the various communications media available to support the transmission of command and control signals throughout the system is available in REA Bulletin 66-4.

f. Installation and Maintenance

(1) Central Control and Telemetering Installation and Maintenance

The magnitude of the work involved in the installation of the central control equipment will depend upon the complexity of the control to be used. Actual installation costs of the major pieces of equipment should not vary significantly as these will be received as self-contained, free-standing units. Interconnection costs will vary with the amount of external devices, control points, remote alarms, telemetering, etc. Installation of telemetering transmitters at the bulk supply points will vary between the extremes of adding transducers to existing potential and current transformer wiring to the installation of complete metering units (where suitable existing facilities are not available). Maintenance of this equipment is limited to periodic cleaning and inspection.

(2) Transmitter Installation and Maintenance

As the use of VHF two-way, fixed-to-mobile voice communications are now almost universally applied by electrical utilities, installation charges shown here are limited to man-hour charges incurred in placing the transmitter cabinets, wiring power supply and control circuits, erecting the required tower antenna supports, antenna erection and running the antenna coaxial feeder. Experience with similar voice transmitters has shown startup and adjustment requirements to be minimal. The only remaining initial charges are those associated with the FCC licensing application preparation. The maintenance requirements are on the order of one visit per month for cleaning, inspection and possible minor adjustments.

(3) <u>End-use receivers</u>

The receiver switch installation costs will vary with each placement. Locating the switch at the service entrance panel board requires some rewiring. This may require the hiring of contract electricians to meet the minimum standards prescribed by the National Electrical Code. However, where installation is adjacent to the controlled appliance, the use of utility personnel will lower related costs (the NEC requirements still apply). The maintenance of receiver switches is effected in a similar manner to meters. A faulty receiver is generally changed out and replaced with a new unit. Tests are performed on selected components which are easily replaceable if found to be defective, otherwise the unit would be discarded.

g. <u>Testing</u>

This function would comprise initial transmitter setup adjustments, modulation and loading adjustments, and verification that the transmitter is operating within the limits imposed by the FCC station license. Initial tests are required to calibrate the telemetering equipment. A check of the operation of the central control equipment for correct operation codes for each command is also necessary. Where multiple transmitters are utilized, sequential operation should be verified to ensure that no mutual interference is present. These costs would also include factory acceptance testing and customer on-premise testing of a sufficient sample of switch units.

3. <u>Major Factors Influencing Costs</u>

Several major factors will influence the costs for a VHF load control system. Among these are:

- The number of delivery points and metering available;
- The effective coverage area for a radio system is largely determined by the surrounding terrain. The load density within the service area will determine the number of controllable loads and therefore the kW demand per transmitter;

- The need for, or use of, "backup" equipments to improve the overall reliability (power, transmitter, processor, etc.);
- The geographical and electrical system network layout will dictate the number of transmitters;
- The use of existing facilities such as towers and facilities to house the equipments;
- The need for, or availability of, microwave LOS systems or leased circuits as a communications link from the control center to the load control transmitter.
- The complexity of the communications link required between the control point and the transmitter (i.e., the number of transmitters to be controlled and the distance between the control point and the various transmitters;
- The degree of automation in activating the load control system;
- Number of functions per receiver.

C. Hybrid Control

1. General

The use of this system is similar in most considerations to that previously discussed for the radio control system. It is an extension of that system by combining the radio portion with a high frequency, low power, power line carrier channel. The power line carrier range is deliberately restricted to prevent possible receiver interference.

The hybrid technique may be used either as a distinct system or combined effectively with a digital radio control system for maximum utilization. The two are completely compatible. The principle advantage of the hybrid approach is to economize in the use of the more expensive VHF receivers and provide a secondary retransmission of a power line carrier signal from a receiver common to several customers. A less expensive carrier receiver is then all that is required at each appliance location.

Due to the "sharing" of the VHF receiver, this system is particularly sensitive to customer density, or more specifically, controlled customers per distribution transformer. This second factor is due to the effective range of the carrier signal which is limited to the low voltage wiring fed from a distribution transformer. When combined with a digital radio system serving the area considered, the use of hybrid system receivers in higher density locations can result in potential savings.

Many of the same constraints regarding centralized control versus local (individual borrower) control as discussed for VHF radio load control apply. In general, the more dispersed the control, the more costly this system is to implement.

2. Cost Components

Table V-2 itemizes the investment costs for a hybrid load control system.

Central control assumes control of all interruptable loads with the control actions being centrally initialized. Local control involves a substantial increase in costs and is not recommended for this type of system.

Further, the use of a dedicated transmitter is recommended as opposed to the sharing of existing land mobile transmission facilities. However, if the voice traffic on the existing land mobile system is relatively light, then the facilities should be considered for joint use -- assuming the degree of radio coverage is commensurate with the requirements of the load control system.

The various components of cost are discussed below:

a. Central Control Unit

This unit comprises the master controller for tone-code generation and a processor for telemetered bulk supply point information and readout. Costs for the master controller depend upon the facilities required. The processor costs depend on the number of remote telemetering points as well as the degree of automation in issuing system commands.

b. Radio Channel

Compatibility of the control system with a regular VHF two-way voice system permits the use of existing radio facilities for this portion, however, costs shown are for a dedicated transmitter. The widespread use of fixed-to-mobile communications renders the need to provide a separate channel purely for a load control system dependant upon traffic density and security.

c. Radio Receiver, Power Line Carrier Retransmitter

These functions are performed by one device. The units

TABLE V-2

Load Control Investment Costs

Hybrid System: Radio and Power Line Carrier

Item	Cost each per quantity shown			
	1	2000	4000	8000
	- - - - - - - - - -dollars - - - - - -			
End-use receiver	65	60	55	50
VHF receiver/converter	210	194	185	180
VHF transmitter	8500			
VHF antenna	600			
VHF receiver (monitor)	2900			
Tower-guyed (55 meters)	26000			
Control processor	10000			
Bulk supply metering and RTU	2800			
Printer	2000			
Test equipment	7000			
Engineering	20000			
Program management	10000			
Installation of receivers (each)	20			
Installation of VHF radio	1000			
Installation of metering equipment	1000			
Installation of receiver/converter (each)	65			
Testing	10600			
Training and documentation	10000			
Spares - 1 year operation				
- End-use receiver	1%)	Percentage of total cost.		
- Receiver/converter	2%)			
- VHF radio equipment	2%)			
- Metering-RTU equipment	3%)			

may be pole mounted for an overhead distribution system or mounted on a customer's meter base to cover underground systems. One unit will receive a transmitted signal and retransmit to all customers served by the same transformer.

d. Power Line Carrier Receiver, Control Relay

These receivers are suitable for the control of one or more appliances.

e. Support Equipment

Supply point telemetering is required on a sufficient sample of the total load so as to enable an accurate measurement of the system demand.

f. Communication Links

Control points and remote receiver/retransmitter (s) must be interconnected to effect control actions. There are several communication channels which can be adapted to this function. Telephone, microwave, and VHF radio are all possible alternatives.

Existing telephone lines are easily adapted to form this communication link. While direct costs are minimal, the costs of leasing lines may account for a large percentage of the ongoing operating expenses.

Costs for interconnect facilities may be determined from REA Bulletin 66-4.

g. Installation and Maintenance

(1) Central Control and Telemetering Installation and Maintenance

The level of effort involved in the installation of the central control equipment will depend upon the complexity of the control to be used. Actual installation costs of the major pieces of equipment should not vary significantly as these will be received as self-contained, free-standing units. Interconnection costs will vary in relation to the amount of external devices, control points, remote alarms, telemetering, etc. Installation of telemetering transmitters at the bulk supply points will vary between adding transducers to existing potential and current transformer wiring, and the procurement and installation of complete metering units where suitable existing facilities are not available.

Maintenance of this equipment is limited to periodic cleaning and inspection.

(2) Transmitter Installation and Maintenance

VHF two-way fixed-to-mobile voice communications are now almost universal with electric system borrowers. It is assumed that a transmitter site and equipment housing is available for the installation of the load control transmitter and the antenna. Installation charges would be limited to man-hour charges incurred in placing the transmitter cabinets, wiring power supply and control circuits, erecting the required tower antenna coaxial feeder. Experience with similar transmitters has shown startup adjustment requirements to be minimal. The only remaining initial charges are those associated with the FCC licensing application preparation.

Maintenance requirements are on the order of one visit per month for periodic inspection and possible minor adjustments.

(3) End-Use Receivers

Receiver installation costs are low due to the facility for location adjacent to the controlled apparatus. Such installations may be performed by borrower personnel.

Installation of the VHF receivers will involve the use of a service line crew for pole-mounted units.

Maintenance of both end-use and VHF receivers is on a change-out basis, where the malfunctioning unit is replaced if found defective.

h. Testing

Tests would be similar to those for a radio system with respect to the radio transmitter, control, telemetering and field strength measurements.

Verification that the VHF receiver is retransmitting the command over the low voltage transformer secondary wiring is required. A portable, low-power VHF test set is available to test for code injection and check the customer's receiver function. A single test per

VHF receiver should be sufficient unless trouble is encountered.

Costs shown also include factory acceptance testing.

3. Major Factors Influencing Costs

The factors which can influence costs are summarized below:

- Number of delivery points;
- Joint use of existing VHF voice communications system and the load control system can reduce load control system investment costs;
- The need for, or use of, "backup" equipments to improve system reliabilities;
- Number of functions per receiver;
- The number of controlled end-use loads being fed from the secondary of each low voltage transformer. The economics are very sensitive to the load per receiver/retransmitter carrier unit. The hybrid system is more suited to urban/suburban areas;
- Complexity of central processor to initiate load control strategy;
- Electric system network changes have an effect on low voltage transformer secondary connections. Power system faults incapacitate a small portion of the system.

D. Power Line Carrier - Low Frequency

1. General

In using low frequency power line carrier control, costs are influenced greatly by two considerations: system interconnections and the voltage at the point of injection. The use of multiple injection points results in higher costs and complexity while fewer interconnections enable the use of more centrally located equipment. Although such common injection points generally are at the higher Transmission Voltage Levels, the high cost is offset by the maximum use of the large available signal range. To obtain maximum coverage, the lower end of the available audio frequency range is assumed, and paralled injection is used to obtain maximum benefits from the low frequency.

The injection points should be in close proximity to available microwave facilities or lease facilities for direct communication with the central control facilities. Where there are instances to keep within a pooled power system's jurisdiction, injection at the distribution voltage level is the only solution.

Low frequency power line carrier systems provide a multi-address command capability which permit adequate control for the peak load strategies. Sufficient unique address capability is available to permit individual cooperative control of their own loads if this option is desired. Control by individual borrowers is possible by providing each with an "enable" command to interface with the centralized control program and signal generating unit. Such control involves additional communication links to connect the various borrower headquarters to the centralized control.

Injection at the 69 kV levels and above requires large, fully insulated equipment rated for use on the transmission network. This results in comparatively expensive requirements (such as the need to comply with the network insulation coordination, etc.); the equipment must be connected to the station bus and be exposed to the full system short-circuit duty. This requires a fully protected feeder bay comprising the appropriately rated circuit breaker, disconnects, grounding devices, structures, protective relays and controls; all in addition to the basic injection equipment. Equally important is the need to either purchase outdoor equipment or have space available within the substation building to house indoor type units - expensive considerations in either event. Power requirements are large and generally exceed the capacity available for auxiliary power at most substations; thus modification to the house service supply is a likely requirement.

2. Cost Components

Costs are developed in Tables V-3 and V-4 for both multibit and rhythmatic keying. The costs assume central control of all interruptable loads served from a centralized headquarters.

The various cost components are discussed below:

a. Central Control Unit

The central control unit's cost is a function of the utility's control philosophy (i.e., required flexibility in cycling control periods relative to appliance types), and the total number of appliances controlled.

TABLE V-3

Load Control Investment Costs

Ripple System: Rhythm Keying

Item	Cost each per quantity shown			
	1	2000	4000	8000
	- - - - - - - - - - dollars - - - - - -			
End-use receiver	70	63	55	53
Injection equipment*	44000-170000			
Substation switchgear bay	30000 - 90000			
Bus connection and feeder	2500			
Control processor	9800			
Bulk supply metering and RTU	2800			
Printer	1900			
Test equipment	5000			
Engineering	24000			
Program management	12000			
Installation of receivers (each)	20			
Installation of injection equipment	6500-60000			
Installation of metering-RTU	1200			
Testing	11000			
Training and documentation	10000			
Spares - 1 year operation				
- End-use receiver	1%)			
- Injection equipment	10%) Percentage of total cost.			
- Metering-RTU equipment	3%)			

* Price sensitive to line voltage injection level and MVA.

TABLE V-4

Load Control Investment Costs

Ripple System: Multibit Code

Item	Cost each per quantity shown			
	1	2000	4000	8000
	- - - - - - - - - - dollars - - - - - - -			
End-use receiver	90	82	78	74
Injection equipment*	40000-270000			
Substation Switchgear bay	30000-90000			
Bus connection and feeder	2500			
Control processor	15000			
Bulk supply metering and RTU	3000			
Printer	1900			
Test equipment	5000			
Engineering	24000			
Program management	12000			
Installation of receivers (each)	20			
Installation of injection equipment	6500-60000			
Installation of metering-RTU	1200			
Testing	11000			
Training and documentation	10000			
Spares - 1 year operation				
- End use receiver	1%)			
- Injection equipment	10%) Percentage of total cost.			
- Metering-RTU equipment	3%)			

* Price sensitive to line voltage injection level and MVA.

For a completely automated system, the central control unit must have the capability to (1) monitor load conditions throughout the system, and (2) initiate a control period at a predetermined load level. Less expensive and manually initiated units are also available primarily for small installations.

b. Signal Injection Equipment

Costs for injection equipment are a function of the power line voltage at the point of injection. Signal injection at high voltage levels is significantly more costly than signal injection at low voltage levels. Consideration must be given to the number of injection stations as well (high voltage injection requires fewer injection stations versus low voltage injection which requires several injection stations). To summarize cost trade-offs of this function, high voltage injection requires few injection stations at high costs per station versus low voltage injection requiring several injection stations at lower cost per station.

c. Receiver and Control Relay

Both functions are considered jointly as they are performed by a single piece of hardware. There are two distinct types of receiver switches: (1) electro-mechanical, and (2) solid state. Electro-mechanical relays have been standard in overseas installation for three decades. Such production processes have been refined and reflect low costs per unit. Solid state receiver switches are relatively new with higher production costs per unit. Multi-function receivers are available at increased costs.

d. Support Equipment

Supply point telemetering is required on a sufficient sample of the total load so as to enable an accurate measurement of system demand.

Injection equipment - In addition to the electronic portions of the injection station (i.e., tone generators, signal processors etc.), the injection equipment includes the power line coupling components, the isolation transformers, capacitors, tuning inductors, circuit connection devices and protective systems. The two latter devices are not included as part of the purchased load control equipment. According to the voltage at the point of injection, these connection devices may range from a fuse disconnect to a fully protected feeder bay at a major switchyard, comprising the required bus bars, circuit breaker, disconnects, protective relays, etc. Connection from the system to the injection equipment may involve overhead jumpers or, more commonly, insulated cables running from the system connection device location (breaker, fuse) to the location of the injection equipment.

According to the manufacturer's design specification, the injection equipment may be suitable for either indoor or outdoor installation. If the equipment is of the indoor type, building space must be available or constructed. If the outdoor type is required, the associated mounting slabs and support structures will have to be provided.

e. Communication Links

Communications are required between injection points and the control processor. These may be either microwave or leased circuits. REA Bulletin 66-4 may be used to obtain budgetary cost data.

f. Installation and Maintenance

(1) Central Control and Telemetering Installation and Maintenance

The level of effort involved in the installation of the central control equipment will depend upon the complexity of the control to be used. Actual installation costs of the major pieces of equipment should not vary significantly as these will be received as self-contained, free-standing units. Interconnection costs will vary in relation to the amount of external devices, control points, remote alarms, telemetering, etc. Installation of telemetering transmitters at the bulk supply points will vary between the extremes of adding transducers to existing potential and current transformer wiring, and installation of complete metering units where suitable existing facilities are not available.

Maintenance of this equipment is limited to periodic cleaning and inspection. Trouble diagnosis and repair requirements should be infrequent and are expected to be relatively straight forward, with the possible exception of the more complex multi-command coded equipment.

(2) Injection Equipment

This equipment includes the installation of support equipment, the injection equipment and provision of a station auxiliary power supply adequate for the required injected power (in the order of 500 KVA for a 500 MW controlled system). Maintenance charges would be comparable with normal power system maintenance requirements for equivalent size equipment.

(3) End-Use Receivers

Receiver switch installation costs are a function of placement (i.e., at the service entrance panel board or adjacent to the controlled appliance). Installation at the service entrance panel board, mandatory for multi-function receiver switches, requires rewiring of the supply circuit to the end-use appliance. This policy may require the hiring of contract electricians to meet the minimum standards prescribed by the National Electrical Code. Installation adjacent to the controlled appliance may be effected by utility personnel at a lower cost (with the NEC provision being met).

g. Testing

Initial testing comprises checking the operation of the injection equipment and adjusting the tuning inductors for the required signal level with the distribution network in the normal operating configuration. Initial tests are required to calibrate the telemetering equipment and check the central control equipment for correct operation codes for each command.

Signal strength measurements are normally limited to a few sample points on each system fed by an injection point, concentrating on feeder ends or locations downstream from line capacitors or installations of large power factor capacitors. Areas where high, line noise is detected should be examined for adequate signal strength or correction of the noise problem.

Costs for factory acceptance tests are also included in Tables V-3 and V-4.

3. Major Factors Influencing Costs

The major factors to be reviewed during the cost determination are shown below. Among these factors are:

- Number of delivery and injection points;
- Location of central processor;
- The demands placed on the system governs the injection equipment rating. For a given system, the greater the ratio of controlled load to total load, the lower will be the total cost of the system per controlled kW;
- Series injection versus parallel injection;
- Availability of space in substation to house equipment;
- Number of loads per receiver;
- Availability of metering equipment at delivery points or substations;
- Need for or use of "backup" in achieving needed system reliability;
- Sensitivity to network changes affect the required capacity of the injection equipment and tuning. Projected power plans have a significant impact on proposed systems.
- Injection voltage level is probably the most significant cost parameter. The cost requirement per injection point increases significantly at higher system voltages.

E. Power Line Carrier - High Frequency

1. General

This system is currently the only technique on the market today capable of unrestricted two-way operation. A combination of an operating frequency considerably greater than the power frequency fundamental and the volume of messages needed, or capable of being handled, results in a practical application of units of a size suitable for use in an average bulk supply substation. Without exception, this gives an address capability far in excess of the system requirements or of the unit's capability to process in the time available.

One signal injection unit is assumed for each bulk supply substation and most metering points throughout the system. The connection will be to the distribution voltage bus via a fused disconnect to facilitate isolation for cleaning and maintenance. No other primary equipment is required and no application on a split bus substation is anticipated; such substations would require special treatment and a protected tap for each separate bus section.

Communication from the central control to the substation signal injection equipment is required. Of the two possible alternatives for this communication path, it is assumed that the path via the individual headquarters would be the most beneficial. This assumption is based on the following:

- Possible shared use of a communication channel with two or more substation units would reduce the total number of channels required originating at the central control

- The installation is conceived as a load control system capable of upgrading to a two-way remote metering and control facility, either uniformally over the area or in selected areas where such additional features are warranted. In the event of such upgrading, the meter reading, billing and distribution monitoring functions would be required at the Cooperative Headquarters and channels from the headquarters to the substation units would be needed. The assumed communication arrangement facilitates this upgrading.

One additional assumption may be made relative to the receiver installation at the customer terminal. In view of the overall principle of installing all one-way equipment to allow for future upgrading, the receiver may be located at the customer's meter and wired to the controlled appliance by low voltage circuits. A minimum change and customer inconvenience will then be avoided in any conversion to two-way operation.

The primary advantage of the high frequency power line carrier system lies in the greater bandwidth available and the higher speed of transmission of commands which is inherent. A more rapid overall response to a command is to be expected. A secondary, but important advantage to be gained is from the unique address capability available which, in the extreme, permits one command per customer per function. Although this facility would not be used in practice, the versitility available in the development of a control strategy is obvious. This advantage is perhaps greater than appears at first inspection in that the address capacity of each substation unit is significant (up to one million). Although the full capability can never be utilized, a sequence command transmitted to multiple substation units can locate any given receiver (customer) even if that customer is not being fed from the normal source (older systems could only address preprogrammed customers - generally restricted to the normal feeds).

The large address capability also enables significant and selective control of other functions associated with load control (transformer tap control for voltage reductions) or normal distribution actions such as capacitor switching.

Upgrading of the system to two-way operation is possible making available additional functions such as remote meter reading, distribution status reporting and similar facilities where closed loop action configuration is desirable.

While recognizing the versitility and great potential of the system, it is complex requiring special skills for any but the simplest operations and it is expensive. In considering the system capabilities and potential, it must be recognized that the transmission speed, while being superior to all other systems, is still slow by present day standards. The system is limited in transmission speed, and therefore, is basically unable to perform all of the functions of which it is theoretically capable within the time available. To quote it in another way, a unit with a capacity of 1,000,000 addresses in practice could not operate more than a few thousand. Nevertheless, the ability to select a few thousand out of the total capability results in an impressive flexibility of application.

A significant limitation of the high frequency control systems (whether one or two-way) is the fact that all versions are comparatively new and experience is limited to small scale test programs. The ability to transmit commands and, if appropriate, receive return communication via the power line conductors has been proven to be practical. A characteristic of the hardware used for these tests is one of constant change. Each test has used equipment which is custom made for the project and each test has resulted in sufficient modifications such that the subsequent installations bear little relationship to those preceding them. This is the process of development and is necessary, but must also indicate that potential for future similar major changes is great and stability of equipment design is not yet here. It should be recognized that any installation in the foreseeable future will be, to a large extent, experimental and subject to the risk of rapid obsolescence.

In addition to the above, until such time as manufacturing is placed on a production basis, the actual present day costs are considerably in excess of prices often quoted - these prices being based on bulk production costs.

2. Cost Components

The use of high frequency power line carrier load control with its capability of operating as a one-way or two-way system and the potential for upgrading from a one-way to a two-way installation provides a rather unique application to compare with other alternatives. As with the other load control systems, the costs for whole or part systems should also be examined together with differing control philosophies.

It should be noted that per function for a one-way usage is assumed to be one controllable apparatus while for two-way systems, it is interpreted as one meter position which may comprise several individual actions.

Major system units bearing on the overall costs showed in Table V-5 are discussed below:

a. Central Control Unit

The incorporation of meter reading capability into the system places additional requirements of flexibility and capacity on the central control unit. A manual central control unit could not meet such requirements; the alternative is a fully automated unit of significant cost.

b. Sector Signal Injection Equipment

For practical purposes, the power of the transmitted signal is largely independent of the connected or the controlled system load. Line attenuation or the maximum number of addressable receivers per injection point is normally the limiting factor.

Network changes, by virtue of the above, have a minimum effect on an installed system. Increasing load densities, if not accompanied by additional metering points, will not significantly change the signal quality. If the total number of meters increases over

TABLE V-5

Load Control Investment Costs

High Frequency Power Line Carrier

Item	Cost each per quantity shown			
	1	2000	4000	8000
	- - - - - - - - - - -dollars - - - - -			
End-use receiver	115	105	95	90
Load control relay	30	25	25	25
Injection unit	11000			
Connection equipment	500			
Control processor	55000			
Printer	2100			
Bulk supply metering and RTU	2500			
Test equipment	6000			
Engineering	24000			
Program management	12000			
Installation of receiver	10			
Installation of load control relays	18			
Installation of injection units	1200			
Installation of metering - RTU	1300			
Testing	11000			
Training and documentation	10000			
Spares - 1 year operation				
- Receivers	1.5%)	Percentage of total cost.		
- Load control relays	1.0%)			
- Injection unit	10.0%)			
- Metering RTU equipment	3.0%)			

TABLE V-6

Operation and Mainteance Expense

Radio

Maintenance Labor

Transmitter - 0.5 day/month - 2 men
Monitor receiver - 0.5 day/month - 1 man
End-use receivers - 2% of total/year at 1 MH each
Control processor - 1.0 day/month - 1 man
Metering and RTU - 0.5 day/month - 1 man
Consumable spares - Total spare cost X 0.5
Complaints - 10/month at 2 MH each

Hybrid

Maintenance Labor

Transmitter - 0.5 day/month - 2 men
Monitor receiver - 0.5 day/month - 1 man
End-use receivers - 1% of total/year at 1 MH each
Control processor - 1.0 day/month - 1 man
Metering and RTU - 0.5 day/month - 1 man
Consumable spares - Total spare cost X 0.5
Complaints - 10/month at 2 MH each

Ripple - Rhythm

Maintenance Labor

End-use receivers - 1% of total/year at 1 MH each
Injection unit - One at 0.5 day/month - 2 men
Control processor - 1.0 day/month - 1 man
Metering and RTU - 0.5 day/month - 1 man
Consumable spares - Total spare cost X 0.5
Complaints - 10/month at 2 MH each

Ripple - Multibit

Maintenance Labor

Same as Ripple - Rhythm

Power Line Carrier

Maintenance Labor

End-use receivers - 2% of total/year at 1 MH each
Injection unit - 6 MH/year
Control processor - 1.0 day/month - 1 man
Metering and RTU - 0.5 day/month - 1 man
Consumable spares - Total spare cost X 0.5
Complaints - 10/month at 2 MH each

the maximum capacity of the existing injection point, an existing sector may have to be sub-divided and an additional injection point installed.

c. Customer's Receiver, Control Relay, Encoded Message Transmitter

These functions are generally incorporated into a single piece of hardware. Solid state construction is utilized, and is anticipated to keep costs down at full production levels. Each receiver is capable of controlling more than one appliance, however, an additional control relay may be required for each new appliance.

d. Consumer's Meter Reading Encoder

The methods for encoding the consumer's KWH usage vary among vendors; however, the costs per unit are similar because of the competition between vendors.

e. Sector Encoded Message Receiver

This function may be incorporated into a common piece of hardware with the sector signal injection equipment and will reflect similar cost sensitivities.

f. Support Equipment

(1) Supply point telemetering is required on a sufficient sample of the total load so as to enable an accurate measurement of the system demand.

(2) Connection equipment required for each unit is a function of the location of the installation.

g. Communication Links

(1) Sector injection equipment

The use of multiple injection stations involves the use of multiple communication channels between the control center and the injection stations. This may be in the form of either leased telephone lines, or microwave LOS links. On systems which permit several injection points to employ shared lines, this requirement is reduced. While direct costs of such communication links are minimal, associated ongoing costs may account for a significant portion of total operating costs.

(2) Supply Point Telemetering

Generally, the most economic method of interconnection for the telemetering equipment (substation-to-control-center) is by means of leased telephone lines. If two-way meter reading facilities are provided by the control system, then the telemetered bulk supply point quantities may be transmitted over the remote meter reading channel, providing sufficient time is available in the meter reading program for the repetitive interrogations required for this function.

h. Installation and Maintenance

(1) Central Control and Telemetering Installation and Maintenance

Should the high-frequency power line carrier equipment be used for load control purposes only, the installation costs of the central control equipment would vary according to the complexity of the control desired. However, the variance should be in the same order of magnitude as other one-way systems. Such variations would be minimized due to the major pieces of equipment being supplied as self contained units. The difference is due to the variations in the number of interconnections to external devices. If, on the other hand, a full two-way, remote meter reading and control system were involved, the installation costs would rise sharply. These costs would include the remote telemetering cabinets, the computer required for the meter reading program, address capability, retrieval of the meter reading and subsequent processing prior to transfering the information to the approprate billing computer.

Installation costs for the telemetering transmitters at the bulk supply points will vary between adding transducers to existing potential and current transformer wiring to the procurement, and installation of complete metering units.

Maintenance of the equipment is limited mainly to cleaning and periodic inspection. Trouble diagnosis and repair requirements should be infrequent with a one-way control system but significantly increasing in frequency and complexity with the two-way system.

(2) Injection Equipment

Due to the limited range of the high-frequency signal, the majority of applications will result in the injection point being located on the medium voltage system and covering one or at the most, a few feeders from one distribution substation. Two basic injection locations must be considered, at the substation bus bar or on a feeder remote from the substation.

Where the equipment is installed within a distribution substation, space must be provided together with the required system connection equipment (circuit breakers, fuses, etc., as necessary). The installation must be designed in such a manner that the control equipment does not present a hazard to the substation bus. The fault interrupting duty at this location will often dictate the use of protective devices in excess of the rating needed for the injection equipment. However, equipment in this location will frequently service a large number of end-use receivers.

Feeder-mounted equipment generally covers fewer end-use receivers per injection point. This equipment is small and simply installed on an existing line pole. Coupling to the line, with a fuse and surge arrestor, is inexpensive. The existing feeder protection may be used as backup without hazarding an appreciable portion of the power system. The somewhat unpredictable performance of the power system at the signal frequencies is less of a potential problem as the pole location of the injection unit may be easily and inexpensively changed if trouble is encountered. Not all equipment available may be suitable for line installation.

(3) End-Use Receivers

The use of power line carrier permits the receiver to be located at any point in the costomer's system. The signal is present wherever electric service is available. However, the use of the receiver unit for retransmitting the local meter reading requires that the unit be installed at the customer's meter location. Current designs are compatible with the single phase house service meter socket. The units are fitted as an extension of the plug-in meter base. Connections from the meter position to the end-use load location are required in the form of low-voltage "thermostat" wiring. Additional contactors are required where full voltage end-use load is to be controlled. This wiring technique will reduce the total installation costs by minimizing changes to the customer's wiring.

Maintenance for receivers should be handled in a similar manner to the existing house service meters (i.e., a changeout program). Charges would be due to time, transport and the provision of suitable repair facilities. Faulty meter encoders for the two-way system could be changed in the field, if advisable. Injection units installed in substations would be subjected to periodic maintenance. Repair at the location is possible. Pole-mounted units would be replaced by a spare. The faulty unit would be returned to the service facility for repair.

i. Testing

Initial testing comprises initial injection equipment setup. Adjustments would be minimal. Tests are required for each command for one-way systems to verify the correct operation of end-use receivers and spot field measurements would be required at the selected points covered by each injection unit.

Systems with two-way facilities would require extensive initial software verification followed by an individual address signal and reply to ensure correct response and processing. Any receiver failing to respond would require site investigation at the end-use location or the injection unit.

Telemetering calibration would be required on each circuit as provided from the bulk supply points.

Costs for factory acceptance testing are also given in the testing cost item of Table V-5.

3. Major Factors Influencing Costs

The following factors are among the most significant affecting the determination of costs for a high-frequency power-line-carrier control system.

- Line attenuation and/or the maximum number of addressable receivers per injection point is normally the limiting factor;

- Number of delivery and injection points;

- Complexity of central controller;

- Network changes affect load densities;

- Communications costs for multiple injection points;

- The need for, and use of, "backup" equipment to improve system reliability;

- Number of functions per receiver;

- Load density.

F. Telephonic Load Control Systems

1. General

These systems are completely immune to any effects of the operation of the power system. The choice of communication system is limited, in part, by the telephone company line equipment. Should the present experience in trial installations of telephone control systems persist in the future, the predominant cost may be expected to be on a per line interrogation charge. The higher the per call charge, the better the incentives will be to restrict the number of control signals sent.

Non-Vendor costs are largely indeterminate at this time. These non-vendor costs are subject to numerous and significant variables. While the end-use customer installation charges may be on the same order of magnitude as other load control systems, the low capital cost of this system is compensated for by usage charges. No meaningful estimate of the charges can be made at this time because of the variation in charges according to location and the difference in equipment supplied by the telephone company (ranging from the central office selector only to the complete equipment, including the customer's installation), an estimate of the actual charges must be made for each specific location.

Maintenance charges should be for those incurred by a customer's equipment changeout program or return of the faulty units for inspection and repair. Should the telephone company operate the entire system on a lease basis, maintenance charges would be included in the rate charge.

2. Cost Components

The following is a summary of the major cost components in telephonic load control systems:

a. Telephone Office Equipment

This equipment would consist of a central control unit (to act as the interface between the electricity personnel and the telephone system), the central office selector (for originating the calls) and the data terminal (for receiving and storing the transmitted information from the customer's meters and subsequent retransmission to the utility's billing center).

This set of equipment would be the responsibility of the telephone office. Costs are expected to vary from office to office according to the availability of existing suitable equipment. Costs would appear not as direct costs to the system, but as installation tests, a flat fee has been charged similar to the per circuit installation charge levied for the connection of leased circuits.

b. Customer's Installation

This hardware would consist of the meter encoders, transponder and the necessary contactor equipment for full voltage controls.

3. Major Factors Influencing Costs

The factors which determine the costs for telephonic load control systems are somewhat elusive at this time. Among the factors to be considered are:

- Determination of ownership of both office-installed and end-user equipment;

- The co-incidence of telephone and electric service areas;

- The cost of interconnect facilities for the borrower's billing computer;

- Responsibility for insuring initialization of control action;

- Desired system reliability;

- Variations in control strategy between and among different utilities to be implemented on a common control processor;

- Number of delivery points and associated metering costs.

G. Load Control System Cost Examples

Tables V-7 and V-8 illustrate comparative costs between a radio system and a high frequency power-line-carrier system. Before drawing conclusions regarding the economic effectiveness, the planner must consider the attributes offered by each of the systems. By the same analogy, if a particular attribute or advantage is not usable within the load control strategy adopted, then it is an uneconomic surplus whose benefit will not be recovered. In addition, it should be noted that the borrower electric network will often point the way to the most desirable system. Finally, the cost/benefit analysis described earlier should be employed to aid in the final determination.

The estimates for the radio system are based on the following assumptions:

- Four bulk delivery points;

- Central controller and transmitter are located in an existing building remote from the delivery point substation;

- One antenna for joint-use on existing tower with an additional tower being required at a remote transmitting site;

- Watt-hour pulses are available from an existing meter installation;

- Single function per radio switch;

- Semi-automatic initiation of load control system when demand reaches preset level.

The estimates for the high frequency power-line-carrier system are based on the following assumptions:

- Four bulk delivery points;

- Six medium voltage injection points;

- Single function per carrier receiver;

TABLE V-7

Example Load Control Investment Costs

Radio System

Radio receiver switches - 6000 @ $70	$420,000
VHF Transmitter - 2 @ $8500	17,000
VHF Antenna - 2 @ $600	1,200
VHF Monitor receiver	2,900
Tower - guyed - 1, 55 meters	26,000
Control processor	11,000
Printer	1,600
Bulk supply metering RTU - 4 @ $2800	11,200
Test equipment	5,000
Engineering	20,000
Program management	10,000
Installation	
- radio receiver switches @ $20	120,000
- VHF radio	2,000
- metering RTU's	4,000
System testing	9,600
Training and documentation	10,000
Spares - 1 year operation	
- radio receiver switch units	8,400
- VHF radio equipment	422
- metering RTU equipment	336
Total	$680,658

(For microwave interconnect and/or leased circuit costs, refer to REA Bulletin 66-4).

TABLE V-8

Example Load Control Investment Costs

High Frequency Power Line Carrier

End-use receivers - 6000 @ $95	$ 570,000
Load control relays - 6000 @ $25	150,000
Injection units - 6 @ $11,000	66,000
Connection equipment - 5 @ $500	2,500
Control processor	55,000
Printer	2,100
Bulk supply metering RTU - 4 @ $2,500	10,000
Test equipment	6,000
Engineering	24,000
Program management	12,000
Installation	
- receivers @ $10	60,000
- relays @ $18	108,000
- injection units @ $1,200	7,200
- metering RTU's @ $1,300	5,200
Testing	11,000
Training and documentation	10,000
Spares - 1 year operation	
- receivers	8,550
- load control relays	1,500
- injection units	6,600
- metering RTU equipment	300
Total	$1,115,950

(For microwave interconnect and/or leased circuit costs, refer to REA Bulletin 66-4).

- Central controller is located in an existing building remote from delivery point;
- Watt-hour pulses available from an existing meter installation;
- Automatic initialization of load control system when demand reaches a preset level.

VI. GLOSSARY OF TERMS

Availability

The fraction of time that a generating unit is actually capable of service. Operating availability is defined as available hours divided by period hours (AH/PH) expressed in percent.

Base Load

The minimum demand for a given period of time.

Base Load Unit

A generating unit which is normally operated to carry base load and which operates essentially at constant loading.

Capacity

The load for which a generating unit is rated by the operator or manufacturer. Maximum Dependable Capability (MDC) is defined as the dependable main-unit capacity.

Capacity Factor

For a given period of time, the ratio of the total gross generation to the product of the maximum dependable capability and the number of hours in the period (Total Gross Generation/PHxMDC) expressed in percent.

Demand

The rate at which electric energy is delivered to a system, expressed in kilowatts, at a given instant of over a given period of time.

Demand Management

Any method of controlling or selectively altering the rate of consumption of electric energy.

Energy Management

Any method of shifting, reducing or controlling customer energy use.

Forced Outage

The occurrence of component failure or other condition which requires that a generating unit be removed from service immediately or up to, and including, the very next weekend.

Installed Reserve Margin

The difference between the total dependable capability of a system and the peak load during a specified period. Percent reserve is this margin expressed as a percent of the peak load.

Load

The amount of electric power delivered to a given point at a given instant in time.

Load Delivery

The difference between the sum of two or more individual system peak loads and the coincident peak load of the systems.

Load Factor

The ratio of the average load to the peak load for a specified time period.

Load Management

Any method of altering or controlling electrical load shapes.

There are several definitions of load management. Among these are:

- Load Management is the application of measures to influence the customers apparent use of electricity, as seen at the customer's meter, so as to reduce peak demands and improve load factor, consistent with sound economics and acceptable standards of service;

- "Load Management is any deliberate reshaping of a utility's load curve that is achieved by voluntary action by affected customers;"

- "Indirect techniques of Load Management involve creating customer inducements to shift demand away from the system peak, leaving to the customer control over the extent to which at any time his load at system peak is reduced;"

- "Load management equates to load factor improvement and there are two basic methods of improving load factor -- by reducing the peak load or by increasing the average Load;"

- Load Management -- Methods to control load or otherwise adjust load during various hours of the day.

The Department of Energy has used the following definition:

"Load Management is the system's concept of altering the real or apparent use of electricity in order to:

1. Improve system efficiency;
2. Shift fuel dependency from limited to more abundant energy resources;
3. Reduce reserve requirements for generation and transmission capacity; and
4. Improve reliability of service to essential loads."

Further, load management is particularly attractive in terms of its potential for conserving energy and capital in the production and distribution of electric power, for shifting a significant amount of the fuel base from oil and natural gas to coal, nuclear and renewable sources and for stabilizing the cost of electricity.

Off-Peak Load

The load supplied at periods of relatively low system demand, usually specified by the supplier.

Operating Reserve

The amount of capacity which must be available to offset the effect of forced generating outages, provide for errors in the system load estimate and to provide necessary regulating margin to control system frequency.

Peak Load

The maximum demand in a given period of time.

Peaking Unit

A generating unit which is usually operated during high demand periods.

Reliability of Bulk Power Supply System

The assurance against sudden and widespread interruption of electric service.

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