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The Appropriateness of a Load-Management Agreement as the Rate Format for Customer Thermal Storage: Why a Closeout Sale on Off-Peak Electricity Should Be Adopted

MASTER

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THE APPROPRIATENESS OF A LOAD-MANAGEMENT AGREEMENT AS THE RATE FORMAT FOR CUSTOMER THERMAL STORAGE: WHY A CLOSEOUT SALE ON OFF-PEAK ELECTRICITY SHOULD BE ADOPTED

by

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Special Projects Group
Energy and Environmental Systems Division

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ABSTRACT

This report demonstrates why a load management agreement is the best rate format for customer thermal energy storage (TES) from electricity. The first section presents the basic operating and cost characteristics of TES systems as well as potential problems that affect rate setting. Then, the criteria for choosing a rate structure are put forth, and the various rate formats available are analyzed considering the above information. Finally, the means of achieving the maximum social benefits using a load management agreement are explored.

EXECUTIVE SUMMARY

Rate reform and load management are two issues currently being addressed by the electric utility industry. One form of load management is customer thermal energy storage (TES) in which heat is stored during an electric utility's off-peak periods for use during its peak periods. There are two basic residential/commercial space heating TES systems: those using a central unit and those having smaller, dispersed units. At present, only two storage media are commercially available in the U.S., water and ceramic bricks. Ceramic brick TES systems are well-suited to the needs of the utilities.

Dispersed electric storage heaters consist of resistance heating elements interspersed in a stack of bricks surrounded by an insulated box with a fan assembly underneath. Electricity is converted to heat, stored in the ceramic core, and then released either radiantly or by convection using the fan. This keeps room temperature at the desired level. The storage level is controlled by an external temperature sensor. These systems can be fully charged for an entire day's heating in eight hours. At present, there are two American vendors of dispersed units, and they both use equipment made in West Germany.

Dispersed TES units are comparatively expensive. Even when they are firmly established in the market, residential units are expected to cost between $150 and $170 per kW of storage capability (in 1979 dollars). Because they are charged in less time than they discharge, it takes more than 1 kW of TES to equal 1 kW of resistance heating capability. Indeed, for an eight-hour charge time, a dispersed TES installation costs about twice as much as resistance heating.

Unlike the dispersed units, central units may suffer net radiative heat loss. Users, therefore, must be careful to place a central unit where the released heat can be used, such as a basement or utility room. Central units are less expensive than dispersed units unless duct work is required.

TES poses several problems to rate makers. These involve the sizing of the distribution system, the potential for improper sizing of TES units, and the considerable risk inherent in the customer's investment decision. TES systems can burden local distribution systems because they involve placing the entire day's heat load in a small number of hours. The line transformer, which is sized to the customer's peak load, is particularly likely to need upgrading.

The substantial investment that TES requires provides a strong incentive to "undersize" TES units to match the first costs of competing heating systems. Because auxiliary resistance heating units would provide whatever additional heat were needed, undersized TES systems would not necessarily reduce the utility capacity required. Moreover, a reduction in the number of hours that low-cost electricity was available to established TES customers would result in peak shifting as these customers shifted their loads to minimize costs.

The customer perceives TES as an investment involving a degree of risk. Therefore, the best rate is a stable one that maximizes the hours of storage to minimize the needed investment. A rate format should result in the most efficient use of resources. It must meet the following three criteria:[1]

1. Efficiency. The customer should be given the correct signal about the impact of usage on utility costs.
2. Equity. The rate should be fair. The customer should neither be subsidized nor subsidize others, and the rate should be perceived as fair.
3. Adequacy. The rate should provide sufficient revenue to cover costs incurred by the utility.

Failure to meet these criteria is grounds for rejection. Rate stability and understandability are also important.

Conventional rates based on energy consumption offer no incentive for customers to convert to TES, and conventional rates based on demand charges may well shift load to a utility's peak. They are, therefore, quite inefficient and must be rejected.

The time-of-day (TOD) kilowatt-hour-only rate defines seasonal and daily peak periods. The rates during the peak period cover virtually all capacity costs. The rest are charged during the near-peak period, and virtually no capacity costs are charged off-peak. Such a rate is poorly designed for TES. It encourages undersized systems, it fails to protect the distribution system, and it can lead to an oscillating peak period. It is inefficient inadequate, and unfair and is virtually certain to lead to TES customers being subsidized.

Adopting a TOD rate with a peak-period demand charge is in some ways an improvement. Customers are unlikely to undersize storage capacity because even one hour of peak period use is quite expensive. Nevertheless, this rate fails to account for distribution effects; and it is more difficult to administer. A TOD rate with demand charge also fails to protect the distribution system. It can cause both an oscillating peak period and severe consumer problems, and it is more expensive to administer.

A load management agreement resolves all the problems involved in TOD rates. These agreements protect the distribution system by specifying that the utility has the right to reject applications with insufficient storage capability and to inspect installed equipment to prevent improper sizing. In return the utility provides a minimum number of hours of service in any 24-hr period. The customer gets a very low price for his power. The agreement should specify a separate, exclusive meter for this service and provide the customer with a sense of rate stability. Such agreements are currently used in West Germany and Great Britain, and by Central Vermont Power in the United States.

There are, of course, some problems. This is not a standard rate and its exclusiveness could lead to complaints of inequity. However, the situation here is clearly that of a sale. It may be viewed as a capacity overstock that must be moved. Thus the utility has a sale-priced service available, but only at certain localities. When the supply runs out, the sale--at least at that store--is over.

The load management agreement can be used to maximize social benefits. It allows the utility to cut off installations at the optimum level of TES capacity, to offer the maximum number of storage hours to minimize customer costs, and to place the storage load optimally.

1 CHARACTERISTICS OF AVAILABLE SPACE HEATING THERMAL STORAGE TECHNOLOGY

Customer thermal energy storage space heating, with energy provided by electricity (TES), is a proven technology with demonstrated benefits. It is relatively new in the United States, but it was introduced in both Austria and Switzerland just after World War II. Today, both West Germany and the United Kingdom have over 15,000 MWe of TES, and the widespread application of TES has resulted in substantial load flattening and hence a considerable increase in system load factors.[2] This has definitely reduced the need to install capacity.

There are two basic residential/commercial space-heating TES systems: those using a central unit and those having smaller, dispersed units. At present only two storage media, water and ceramic bricks, are commercially available in the U.S. Water systems have a storage capability of relatively short duration, and their interruption capability is shorter than acceptable for many utilities. Ceramic brick units can store a full day's charge in eight hours and therefore are well suited to the needs of U.S. utilities.

There is a third system, Deepheat, which has industrial applications. This system places resistance heating coils 18 in. below the floor of a single-story building. This involves placing a 12-in. sand layer over the coils before laying a 6-in. concrete floor slab. In addition, the building circumference is well-insulated to a 4-ft ground depth. The slab, sand layer, and top 5 ft of earth act as a thermal reservoir. As the ground temperature is 50-55°F about 5 ft below the surface, heat loss is minimal in temperate zones -- perhaps 10% of energy supplied. There is no reason, however, to set rates differently for this application than for others.

1.1 DISPERSED ELECTRIC STORAGE HEATERS

Dispersed electric storage heaters consist of resistance heating elements interspersed in a stack of bricks surrounded by an insulated box with a fan assembly underneath. A cutaway diagram of a commercially available unit is shown in Fig. 1. The unit operates as follows. Electricity is converted to heat and stored in the ceramic core. This charge level is controlled by an external temperature sensor and the setting on the wall thermostat. The unit radiates heat continuously, and the amount of this heat "loss" depends upon the level of charge. The fan is turned on by a relay from the wall thermostat when additional heat is required. This fan draws in room-temperature air at the rear of the unit, circulates it through ducts in the core, and then blows it out into the room. However, before the hot air leaves the unit, it is mixed with room-temperature air in different ratios to guarantee a constant discharge temperature despite changes in the core temperature. Dispersed TES units can maintain room temperature within a very narrow range. Energy losses are essentially zero because the unit's radiant heat emissions serve to warm the surrounding space. There are true losses only when there is a sudden, dramatic, exterior warming and the radiant heat supplied to the space requires opening the windows.

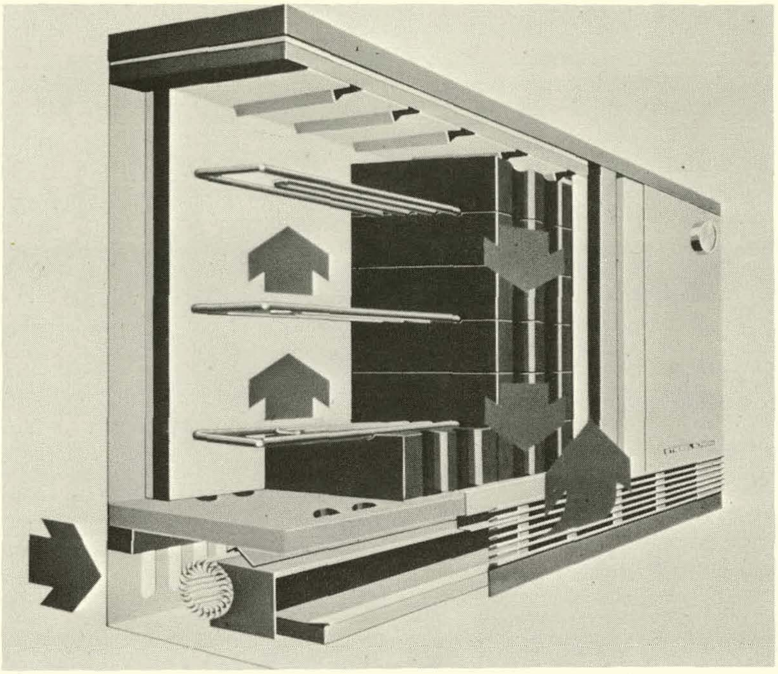

Fig. 1. Cutaway Drawing of Standard Series Model ETS Electric Storage Heater (provided by HB Storage Electric Heating Co., Rutland, Vt.)

The TES units are designed to be fully charged in eight hours. Thus, 1 kW of storage load is associated with 8 kWh of storage capacity. The charge can be controlled so that most of the storage takes place during the early portion of the charge period (forward control) or near the end of the charge period (backward control). This control can be preset. If a utility has a real-time control system, it can use this control to fill its load curve optimally by varying forward and backward control. (See Fig. 2.) Units with longer charging periods can also be designed. This reduces TES capital costs. A unit with a longer charge period can be designed either to spread the storage charging period out equally or for an eight-hour charge with the additional hours used either to maintain space temperature or keep the TES unit fully charged. For example, if a building is designed for a heat requirement of 10 kWh per hour, a 10-hour system could be designed either to store 14 kWh per hour for 10 hours while supplying 10 kWh for heating or to store 17.5 kWh per hour for 8 hours while supplying 10 kWh of heat per hour for 10 hours.

At present there are two U.S. vendors of dispersed units. Control Electric Corporation (CEC) of Burlington, Vermont, uses equipment made in Germany by AEG Telefunken, and HB Electric Storage Heating Company of Rutland, Vermont, uses units made in Germany by Stiebel Eltron. Both vendors anticipate domestic production when the market becomes large enough. Production in the U.S. will reduce both transportation and labor costs, given the high value of the West German mark. Indeed, both vendors already makes controls locally. There is also the likelihood that other domestic manufacturers will enter the market, using European designs. Substantial cost reductions

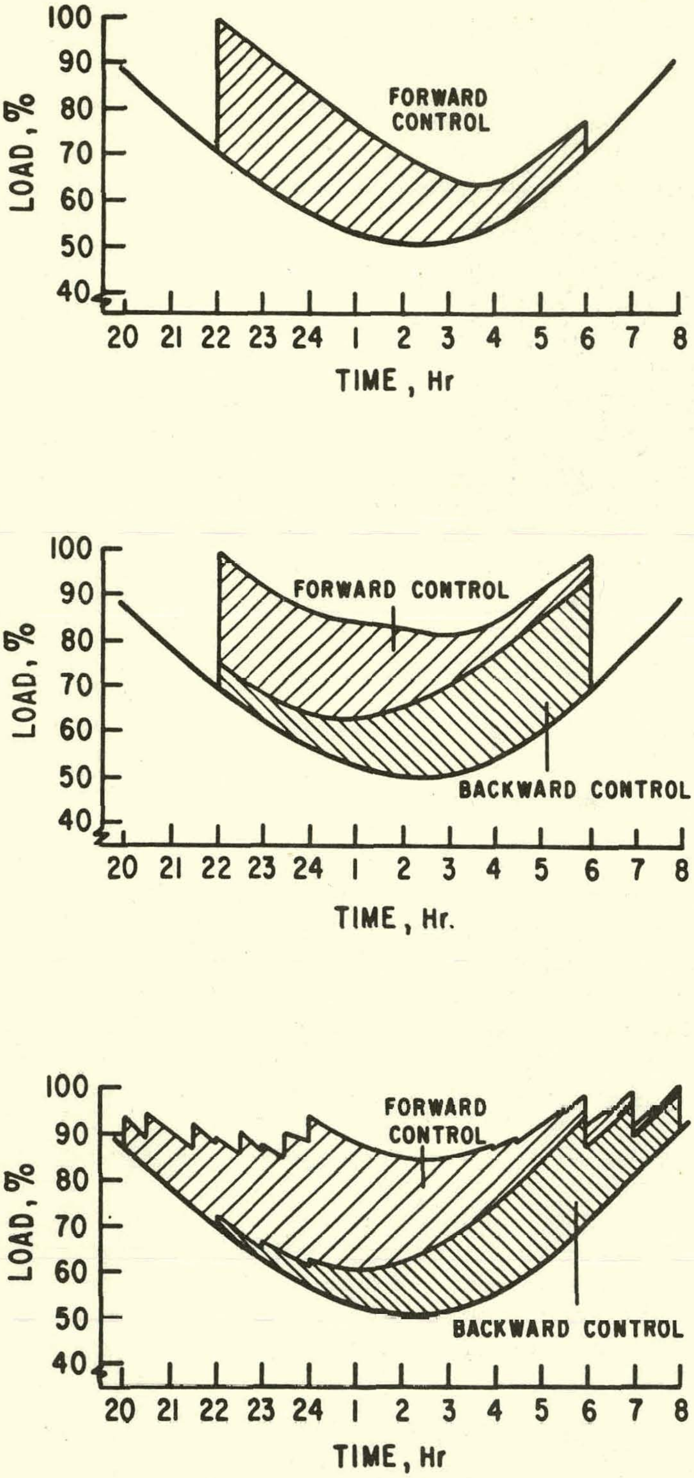

Fig. 2. Ripple Control with Various Combinations of Forward and Backward Control

can therefore be expected. For example, simply transporting bricks from West Germany to Vermont costs about \$4-5/kW of storage load.

Dispersed TES units are comparatively expensive. Table 1 shows recent list prices of both vendors per kilowatt of storage load. The cost of installation must be added to the equipment cost to determine total system cost. Limited experience in Maine and Vermont indicates that the cost of installation per kilowatt of storage falls as the size of the installed system increases. There is also reason to expect these costs to fall as installers become more familiar with the systems.

Limited experience in Maine indicates costs of from \$170 to \$200/kW of electric storage heating for new homes. On a small number of bids for hypothetical new homes in Vermont, costs ranged from \$150 to \$233/kW. Once the units are produced domestically and installers become more familiar with them, the cost of dispersed residential TES space heaters can be expected to fall to between \$150 and \$170/kW (all in mid-1979 dollars) for typical residences installing TES.

Note, however, that one kilowatt of TES capacity is not equal to one kilowatt of resistance capability. On an eight-hour charge, it takes about two kilowatts of storage to equal one kilowatt of resistance heat because the storage units cover the eight-hour off-peak period with resistance units and must also supply the 16 peak hours from storage. Since each storage kilowatt provides eight kilowatt-hours, it takes two kilowatts of storage to meet the same load as one kilowatt of resistance heat capacity. For longer charge times this ratio drops as shown in Table 2.

Table 1. List Prices for Dispersed Electric Storage Heating Units as of June 1, 1979

Size (in kW of load)	List Price $	List Price $/kW
2	310-370	155-185
3	475-418	125-139
4	465-520	116-130
5	510-598	102-120
6	565-716	94-119

Sources: Control Electric Corp., Burlington, Vt.
H.B. Electric Storage Heating Co., Rutland, Vt.

Experience in Maine indicates that 1.25-1.3 kW of resistance heat are typically installed for each kilowatt of home heat loss. By comparison, an average of 2.2 kW of storage heat per kilowatt of heat loss has been installed in Maine. The cost of resistance heating in the Vermont survey averaged about $160/kW of heat loss for a home with about 13 kW of heat loss. Thus, even if storage heat units cost $150/kW, they will be more than twice as expensive--$330 versus $160/kW of heat loss for an eight-hour charge time. A ten-hour charge cuts this difference by only one-third. Clearly, then, dispersed storage units are and will remain substantially more expensive than conventional resistance heating for residential customers.

For commercial customers, costs are considerably lower because installations are likely to be larger--virtually all in the low-cost 5- and 6-kW sizes. The cost of overall controls per kilowatt becomes negligible, and installation costs are likely to be lower due to larger unit sizes and less labor travel time. Thus, the costs for commercial customers might fall to between $110 and $130 per storage kilowatt.[3] This, however, is still considerably above the installed cost of resistance heat.

Table 2. Ratio of Kilowatts of Storage Load to Kilowatts of Heat Loss for Different Charging Times for Dispersed Electric TES

Hours of Charge Time Available	Ratio of Storage Load to Heat Loss
8	2.0
9	1.8
10	1.6
11	1.4
12	1.3

Source: Control Electric Corp., Burlington, Vt.

1.2 CENTRAL STORAGE UNITS

TPI Corporation is currently producing a central storage furnace under license from Creda, a British firm. Only the bricks are imported. These units suffer both radiative heat loss and heat loss in ducts. Users, therefore, must be careful to place them in spaces where the released heat can be used, such as basements or utility rooms. From a full charge, about 15% of the thermal storage is lost through radiation. TPI currently offers units up to 30 kW. The list price, f.o.b. Harrisburg, Pennsylvania, or Johnson City, Tennessee, is $1500 for a 30-kW residential unit and $2000 for a commercial unit.[4] The higher price for the commercial unit provides a cleaner package that is designed to operate like a dispersed unit. The customer's cost includes shipping and dealer markup. At present, smaller units are the same price as the 30-kW size, being basically the same unit with fewer resistors.[4] As the market grows, units of different sizes will be built, and this will make smaller units less expensive.

2 PROBLEMS PRESENTED BY TES

Some of the problems that TES poses to rate makers are the sizing of the distribution system, the potential for improper sizing of TES units, and the considerable risk inherent in the customer's investment decision.

The electric distribution system is in many ways a separate entity from the transmission and generation systems. It must be sized to respond to a possible, short-term, local situation. TES space heat, because it involves placing the entire day's heat load in a small number of hours, can burden local distribution systems. The line transformer and the service secondary, which are sized to the customer's peak load, are particularly likely to need upgrading. The rest of the distribution system should be able to handle some TES, but substantial amounts will also result in increased capacity requirements. For example, one or two large building developments could result in increased requirements for the line transformer, the feeder lines, and even the substation itself. Although the line transformer costs can easily be justified as necessary to attain the savings from TES, no additional advantage is gained if the rest of the distribution system must be expanded -- only added costs. Finally, there is the potential for destabilizing the grid if all the storage units are turned on simultaneously.

Improper treatment of TES for space heating can have a deleterious impact upon the generating system. This may result from undersizing TES installations or because TES has the potential for significant peak shifting. Undersized TES installations are economical for the customer, but changes in the number of hours available for storage, or at least available at attractive prices, can lead to shifts in TES electric usage. Where a large number of TES units have been installed, undersizing can affect the characteristics of the peak period.

The substantial investment required for TES provides a strong incentive to "undersize" installations to match the first costs of competing heating systems. The added heat requirements in undersized systems have to be met by auxiliary resistance heating. On all but the coldest days, this auxiliary is unnecessary, but these are also the days of the system peak. This is illustrated in Figs. 3, 4, and 5. Figure 3 shows a system load curve of Central Maine Power Co. (CMP) on its peak day of the winter of 1978-79. This day normally occurs in January, but, during the winter of 1978-79, it occurred for the first time in February due to unusually severe weather. Figure 4 shows the heating demand on a peak-type day for a home with 11 kW of heat loss and a TES system sized at 2.3 times heat loss with auxiliary resistance heat available. There is an eight-hour charge period. The "extra" capability reflects rounding up of room units. Note that virtually all heating is done at night with the exception of spaces that are too small for storage units, like bathrooms. Also some electricity is needed to run the fans for TES to provide temperature control. Figure 5 shows what happens when the TES installation for the same house is seriously undersized at 1.4 times heat loss. The auxiliary resistance heat comes on at 2:00 p.m., dips down, and then comes on again at a high level at 5:00 p.m. By 7:00 p.m. when the utility system is still nearly at peak, the resistance heat maximum exceeds 12 kW. Of course, this is only a single home, but due to the nature of TES, the diversified load curve will be similar. Thus, undersized systems eliminate much of TES's advantage to the utility by imposing significant demand. However, this is less of a problem if the peak is in the morning.

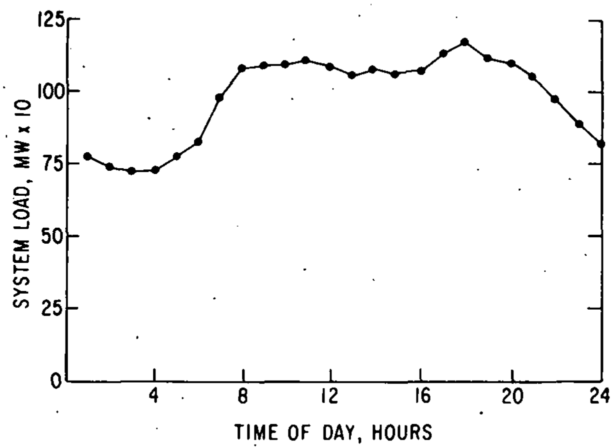

Fig. 3. Central Maine Power Co. January 17, 1979 System Load

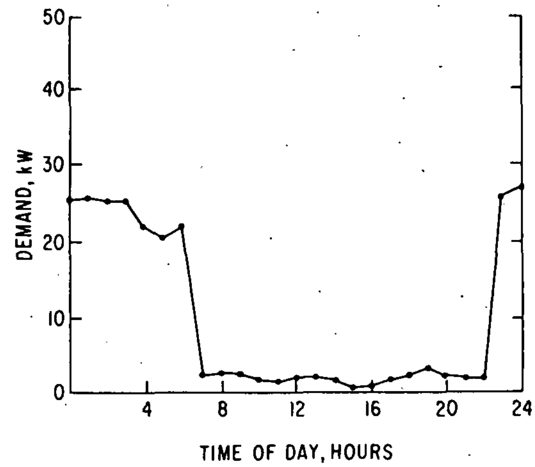

Fig. 4. Simulated Demand Profile on a Typical Peak Day of a Storage Installation Sized at 2.3 Times Heat Loss

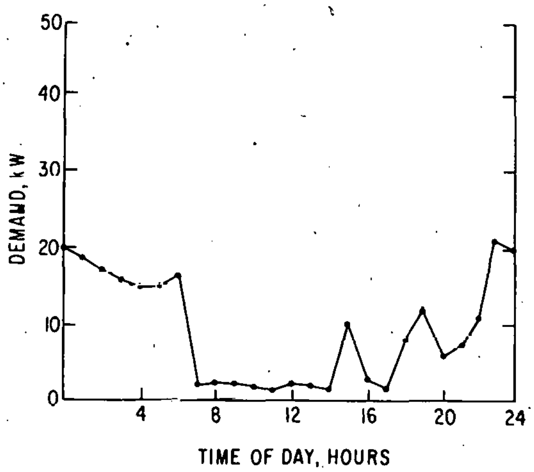

Fig. 5. Simulated Demand Profile on a Typical Peak Day of a Storage Installation Sized at 1.4 Times Heat Loss

The necessity of providing a certain number of hours of charge to maintain customer comfort once a TES system is installed can result in peak shifting. The British nearly had this happen. When storage heaters were first introduced, their system had a three-hour, midday dip in addition to the eight-hour nighttime valley. Consequently, the storage-heater rate and the storage heaters were designed to provide a three-hour, midday boost. This approach made storage heat so attractive to customers that the Central Electric Generating Board (CEGB) and the twelve regional boards had to close off this tariff and introduce the new white-meter tariff, which provided only for an eight-hour, off-peak charge time. However, the original storage tariff was retained for all customers who had already installed TES systems.[5] This was not only a wise political move in terms of customer relations, it was also wise economically in terms of generating costs.

Consider the consequences if the old customers had been forced from an eleven- to an eight-hour off-peak period. On peak days, 27% of energy is consumed on peak and demand is essentially constant. The customer, therefore, attempts to minimize costs by using storage until it runs out. On mild days, no supplemental charge is needed, but on cold days, the charge pattern is that of undersized units, with demand occurring in the afternoon and evening. This causes the midday depression to recur because demand declines at that time and increases during the nighttime peak. Clearly, if the CEGB had not kept existing storage customers on an eight-hour, off-peak charge time with a three-hour midday boost, it would almost certainly have had a higher peak and a shift in demand that restored the midday valley. Even a one-hour change in off-peak period can cause such an effect.*

This also points up two related customer problems -- the risk involved in the TES investment and hence need to minimize that investment. Obviously, if customers do not feel that TES is a good investment, they will not purchase it, and its benefits will not be realized. It behooves the utility, therefore, to offer a rate that is perceived as stable not only to avoid the shifting peak problem but also to encourage TES customers in the first place. Furthermore, the number of hours available should be maximized to reduce the initial investment. Both steps are needed to attain the greatest TES benefits in the least time, and appropriate rates are the only way to do this.

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*Indeed, if the hour shifted occurs in the first hour of the off-peak period, load shifting is guaranteed. Assume a ten-hour off-peak period from 10:00 p.m. to 8:00 a.m. that is changed to 11:00 p.m. to 8:00 a.m. The economically rational storage customer will shift his unit's charge period to commence at 11:00 p.m. to minimize his costs. After all, the first few charging hours account for the bulk of the charge on all but the coldest days, and on relatively warm days, the last hour may require no charge at all. Thus, storage customers would add to the morning part of the off-peak period by shifting load into it and, in abandoning the 10:00 p.m. hour, revert it to an off-peak hour on the basis of current load. If the hour shifted is in the morning, the obverse is true; the customer will charge up as much as possible before then and hope to make it through the day.

3 ANALYSIS OF RATE FORMATS

Storage units are considerably more expensive than conventional resistance heating equipment, yet, they have been extremely successful in Europe. Why? Because electric rates reflect the savings to utilities that occur when customers' loads are shifted off peak. The following analysis examines the types of electric rates available and demonstrates that a load management agreement is clearly preferred for this type of service.

A rate format should result in the most efficient use of resources. Three major criteria are:[1]

1. Efficiency. The customer should be given the correct signal about the impact of usage on utility costs.
2. Equity. The rate should be fair. The customer should neither be subsidized nor subsidize others, and the rate should be perceived as fair.
3. Adequacy. The rate should provide sufficient revenue to cover costs incurred by the utility.

Failure to meet these criteria is grounds for rejection.

Two additional criteria are quite important -- stability and understandability. Stability is very important because of the substantial investment required by TES and the long life of such equipment. If the customer is not assured of sufficient stability to feel that the investment will pay off, then TES will not be installed regardless of its net benefits. Similarly, the customer must understand the rate and how it applies to TES.

3.1 CONVENTIONAL RATES

Clearly, the conventional residential rate, based as it is only on the number of kilowatt-hours consumed, will not provide an incentive to install the more expensive TES equipment.

The time-independent demand charge, which has been common in industrial and commercial rates, can encourage storage. This rate features a charge based on the peak hour (or 30 minutes) of consumption regardless of when it occurs during either the day or the year. Where the individual customer load is peaked, leveling the load shape can produce sufficient savings to justify storage. However, there is no guarantee that this will help the utility. A customer with a winter peak who reduces demand does not save a summer-peaking utility much capacity, though this customer saves considerably on the bill. Now consider winter-peaking utilities, which usually have their peaks between 8:00 and 10:00 a.m. or 5:00 and 7:00 p.m. It is quite conceivable that a commercial establishment will use storage to level load when it is open, say 9:00 a.m. to 5:00 p.m., and fill its store at other times. This could shift the load to precisely the wrong times, that is, 5:00 to 7:00 p.m. or 8:00-9:00 a.m. Thus, this rate is not efficient, fair, or adequate. Furthermore, it does not help with the distribution system. Given the move toward time-of-day rates, it must be rejected as inappropriate to TES due to its potential for placing load on peak, its instability, and its inherent inefficiency.

3.2 TIME-OF-DAY RATES: KILOWATT-HOURS ONLY

There are two basic types of time-of-day (TOD) rates, those based on kilowatt-hour usage only and those incorporating a time-dependent demand charge.

The TOD kilowatt-hours-only rate defines seasonal and daily peak periods. The rates during the peak periods cover virtually all capacity costs. Most of the remaining capacity costs are charged during the near-peak period, and few if any are charged off-peak.

Typically, the peak period lasts from ten to fourteen hours on weekdays. For a winter-peaking utility, there is a substantial price difference per kilowatt-hour between peak and off-peak periods. Rates are designed so that, on the basis of the class load factor, the peak period rate recovers much of the capacity cost as well as the relatively high peak-period energy cost. Thus, if the capacity cost allowable is $22.50/kW at peak, all of which is allocated to peak winter hours defined as 8:00 a.m. to 10:00 p.m., Monday through Friday from December through March (1190 hours), and the average class load factor for that period is 0.588, then 3.5¢ of capacity cost would be allocated to each kilowatt-hour consumed during that period.

This rate applies to all customers and is readily understood because it is similar to long distance telephone rates. The customer sees two very different daily rates and responds accordingly. Unfortunately, however, this rate is poorly designed for TES.

A customer will always try to minimize his total heating cost. Because storage is much more expensive to install than resistance heat, it must be used a certain minimum number of hours per year to make it economically worthwhile. (Probably the vendor will explain this to the customer.) Therefore, the customer will install a mixed system, that is, one that combines resistance elements with TES. This can be seen in Example 1, which shows that for this hypothetical situation a customer would need to use storage capacity at least 500 hours per year to justify its installation.

Example 1: Breakeven Point for Customer Installation of TES Versus Resistance Heat

Incremental capital cost of electric storage unit versus cost per kW of resistance capacity:	$150
Annual cost of capital to customer (after taxes; equivalent to utility fixed charge rate):	15%
Differential (per kWh) between peak and off-peak price:	4.5¢*

$$\text{Breakeven Point} = \frac{\$150/\text{kW} \times 15\%/\text{yr}}{\$0.045/\text{kWh}} = 500 \text{ hours/yr}$$

*Of this, 1¢/kWh is energy.

This system would rely exclusively on storage heat for a substantial part of the heating season. However, as shown earlier in Fig. 4, substantial supplemental resistance heating would be required on the coldest days -- the very days (except weekends and holidays) when the utility system peaks. The resistance heaters would come on just at the system's evening peak and also would add load at very nearly the morning peak. Therefore, this TES arrangement increases the capacity requirements of the utility to a much greater extent than what it pays for on the basis of the relatively few peak hours it demands. Indeed, even the theoretically most-used kilowatt of resistance capacity, 499 hours, would not quite yield enough revenue to cover the capacity costs imposed by it.

Another mixed system would be to install resistance heat as auxiliary heat for spaces, such as second floor rooms, that ordinarily receive sufficient heat from adjoining areas. Here heat would be called upon only when it was needed, but as this would most likely be on the coldest days, once again this system would pay for less capacity than it requires.

It is also highly likely that the TOD TES customer will pay less for energy than the costs imposed. Why? Because customers will front load their installations. The vast bulk of customers will operate their storage systems to recharge quickly because this is the normal mode of operation, i.e. when no other operating pattern is specified, the units operate in this way. Even on a cold, peak-type day, this mode of operation will result in a somewhat higher proportion of electricity consumption in the first few off-peak hours, as can be seen in Fig. 4 and 6. On a less than peak day, the effect is at least as pronounced, as indicated by the collected load data from Vermont shown in Fig. 6. In this case 63% of the eight-hour storage load occurred during the first four hours and 48% during the first three hours of an eight-hour charge period. Other data points illustrate this same expected effect. The storage units also tend to be operated in the same way on weekends. After all, why spend money on a seven-day timer when it saves nothing. If added heat is needed during the day, it is off peak anyway so turning on the input electricity does not matter. When the costs associated with the first two to four hours of the off-peak period are examined, they are found to be considerably above the average for the off-peak. Yet TOD rates do not, typically, weight off-peak period usage differentially. Accordingly, the uncontrolled storage customers will receive a lower than justifiable rate. An example of this was extracted from testimony in a recent rate case.[6] Data from Central Vermont Public Service Company's system for the month of January 1977 were analyzed. Off-peak hours were assumed to be 9:00 p.m. to 7:00 a.m. and all day on weekends. The average cost for these hours was 18 mills. For the first three hours of the off-peak period, 9:00 p.m. to 12:00 midnight, when uncontrolled TES usage is high, the average cost was 21 mills. Thus, there should be a small, but

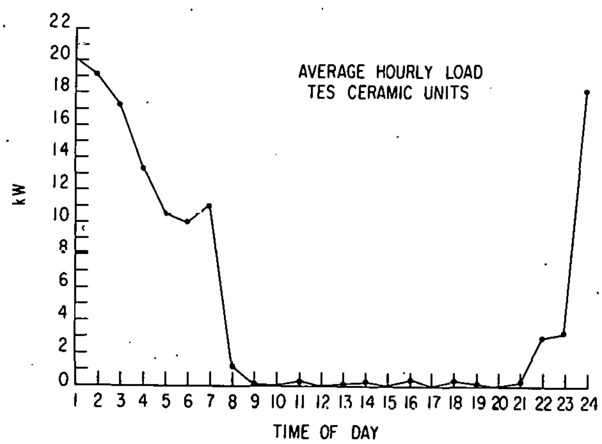

Fig. 6. Average Hourly Load for Nine TES Ceramic Units on Central Vermont Public Services System, Feb. 12, 1979

measurable, gap between energy costs imposed and revenues received when TES is on a TOD rate.

TOD rates understate TES's impact upon the distribution system. Because TES involves meeting all heating load during about one-third of the day, it usually requires a much larger line transformer than is commonly installed. The TOD rate ignores this additional expense and fails to include the possibility of increased requirements upon feeder lines and substations. There is also the distinct possibility that an overload on the distribution system will cause a local service interruption if there is insufficient time to install the needed equipment. Even if there is sufficient capacity, an overload can occur from transients if all systems are switched on simultaneously, as is likely at the start of the off-peak period. Not only are TOD rates inefficient on this basis, they are also unfair in the sense that as load factors rise and price differentials shrink, some customers on "underutilized" substations who should benefit economically from TES would be forestalled by customers on "filled" substations.

As more TES customers came onto the system, their large demand at the beginning of the peak period could result in peak shifting. This would mandate a change in the rate structure with a consequent shortening of the off-peak period. Such a change would lead to a highly unstable situation as TES customers shifted their load in response. Thus the off-peak valley could easily oscillate as TES customers switched back to filling the valley when the off-peak hours were restored and then away when these now "peak" hours were charged at the peak price.

In summary, the kilowatt-hour-TOD charge has high potential for either revenue erosion or cross-customer subsidization because the optimizing of the TES customer's system, the way electricity is demanded, and the impacts of TES on the distribution system result in costs that TES customers do not pay for. At the same time, this rate appears unstable from the customer's viewpoint. Thus the kilowatt-hour-TOD charge suffers serious shortcomings as a rate for TES.

3.3 TIME-OF-DAY RATES WITH DEMAND CHARGES

Adopting a TOD rate with a peak-period demand charge is in some ways an improvement. It lessens the problem of the customer grossly "undersizing" his storage capacity to optimize his system because even one hour of peak period use is quite expensive. Nevertheless, it still fails to account for either the distribution effects of TES or the impact on energy costs.

TOD rates with demand charges have several other disadvantages compared to kilowatt-hour-TOD rates. The costs are considerably higher. At present, dual kilowatt-hour meters cost about $165; adding kilowatt capability raises this to between $225 and $250. In addition, residential customers have historically found demand charges hard to understand. Rochester Gas and Electric, for example, dropped customer demand charges in the late 1960s for this reason.[7] If this type of rate were adopted as the standard, in large part due to TES customers, it could also be argued that they were implicitly placing a large burden on other time-of-use customers in extra metering costs because more expensive meters were required. Furthermore, this rate does not protect the distribution system. However, its most worrisome problem results from dynamic changes in the hours of the peak period over time. The customer who has sized his unit for a ten-hour charge can pay an extremely large penalty if the off-peak period offered by the utility falls to nine hours.

For example, assume a 240-kWh peak day requirement and 10 kW of use each hour. Storage capability is therefore 140 kWh. On the peak day, at least 10 kWh would be required in the peak period, resulting in either a substantial unanticipated charge or the addition of about a 1-kW-per-hour all-day load to maintain the temperature at previous levels. Of course the customer could choose to add more storage or to go without heat. In any case, a substantial unanticipated customer cost would be incurred that would lead to many complaints and the reswitching problem. Furthermore, this demand charge would not necessarily bear any relationship to costs imposed upon the utility by these TES units.

Thus, a TOD rate with demand charge is inappropriate for TES for most of the same reasons that a kilowatt-hour-TOD rate is inappropriate: it does not protect the distribution system from increased expenses; it can cause reswitching and severe consumer problems; it has higher energy costs than the utility charges, and it is more expensive to administer.

4 LOAD MANAGEMENT AGREEMENT

A load management agreement resolves all the problems involved in TOD rates. Load management agreements specify that the utility has the right to reject applications with insufficient storage capability, to reject applications when it has insufficient available capability, to inspect the equipment, to control the charge, and to limit the size of the installation. In return, the utility must provide a minimum number of hours of service in any 24-hour period and charge the customer a very low price for power. The agreement also should specify a separate meter for this service and provide the customer with a sense of rate stability. Such agreements are currently in force on Central Vermont Power's system. They are also used in West Germany and Great Britain.

The ability to reject applications protects the distribution system. It also allows the utility to stop additions if it reaches the optimal load. Combined with the right of inspection, rejection of applications prevents undersizing the thermal store and the consequent subsidy to the TES customer. Controlling the charge provides additional benefits. If the utility controls customer load with a real-time system such as ripple control, the TES load can be placed optimally. Not only can transients be avoided, but the TES units can be charged at times of minimum generating cost. For example, the system's marginal generating cost per kilowatt-hour for Central Vermont Power for the eight daily least-cost hours in October 1977 was 11.1 mills. For a ten-hour off-peak period it was 12.1 mills, and there were three hours "on peak" that month that were part of the least-cost hours.[6] Moreover, control of charging can allow the utility either to lengthen the charge time or add more TES capacity by using some of the near-peak period for charging. To visualize this, assume a utility had a rate with ten off-peak hours and four contiguous near-peak hours. The substantial shifting that would occur if a near-peak hour were the first off-peak hour on a TOD rate would make this into a peak hour. With utility control, however, the charging period can be stretched to twelve hours. One-half of the TES customers could use ten off-peak hours and two near-peak hours. The other half could use the other near-peak hours and the ten hours of the off-peak period. In addition, real-time control provides load shedding in emergencies. A time clock with a carry-over control system, while not providing load shedding, could be set to use backward and forward charge control to pick up most of the generating cost and expanded service hour saving.

This rate has significant advantages for customers. It is readily understood. Because load can be placed optimally, the off-peak rate offered can be lower than the TOD off-peak rate. By providing a long-term guarantee of a rate break, it reduces their risk. Central Vermont Power, for example, makes one-year agreements with automatic renewal unless one party acts to terminate. The rate provides only for fuel adjustment changes. However, it incorrectly equates the fuel adjustment clause, that is, off-peak electricity, with that of standard rates.

The load management agreement protect both parties from capacity costs. Thus the customer is assured of a sufficiently long rate break that is at least equivalent to the rate break enjoyed at the time of purchase. This lower risk makes a lower return acceptable, thereby encouraging additional customers, who will switch from what would otherwise be their best alternative. Because heating service is comparable, the switch is based upon their real costs being lower. Hence, the agreement is not only the best rate format in terms of compliance with rate-setting criteria, but, by reducing customer risk, it increases the social benefit by reducing the cost of heating.

There are of course some problems. Load-management agreements are non-standard rates, and their exclusiveness could lead to complaints of inequity. However, they can be viewed as sales in which capacity overstock must be moved. Thus the utility has a sale-priced service available, but only at certain localities. When the supply runs out, the sale -- at least at that "store" -- is over.* There may be legal problems in some states related to a "contractual" agreement if it is not listed as a general rate. In fact, it should be listed as a general rate for all storage customers, regardless of what they store, provided the utilities' criteria as to sizing, transients, etc., are met. There is precedent for such agreements -- the manifold rates that were formerly used and Central Vermont Power's rate as well as statements such as that by the Public Utility Control Authority of the State of Connecticut: "Interruptible rates and rates applicable to time-controlled appliances should be encouraged as supplements to time-of-day rates."[8] It is clear that many commissions recognize the potential advantages of this approach and the attendant cost savings.

Adding a kilowatt-hour meter does increase the potential for electricity theft. However, this can be eliminated by attaching the control box to the TES breaker box and having meter readers keep a sharp eye for daytime and summer use. If a demand-charge TOD rate is being offered, then the storage meter could also include an on-peak demand register to ensure that customers would not cheat and to eliminate a service call to reseal the control panel whenever the control box needed service. A final problem is that if a management agreement is offered, TES service must be refused under other rates. This could lead to a minor policing problem, though the necessity for large line transformers in most cases will provide the information to prevent such service. A point-by-point comparison of the three rates can be found in Table 3.

In short, because they protect the utility and other customers from subsidizing the TES customer, at least initially, and because they also protect the TES customer from rate instability, a load management agreement is the most economically efficient rate and meets the criteria set forth as the best rate for thermal storage for space heating.

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*The phone company rations its low-cost long distance service in a related fashion via busy signals when the exchange is full.

Table 3. Features of Rates with Respect to Thermal Storage

Impacts	Rate Format: Time-of-Use kWh	Rate Format: Time-of-Use With Demand Charge	Rate Format: Load Management Agreement
Rate Availability	Standard to all customers (of sufficient size).	Standard to all customers (of sufficient size).	Restricted on basis of available capacity.
Customer Cognition	Easily understood.	Has proven hard for residential customers to understand.	Easily understood.
TES Sizing	Leads to undersized TES unit as customer optimizes his system. This places a demand on peak with little offsetting revenue.	Units unlikely to be undersized initially due to high demand charge.	Units sized correctly.
Distribution System	Vulnerable to large number of units on a given substation. This requires added capacity; makes no provision for larger line transformer costs or for transients from simultaneous switching of a large number of units.	Vulnerable to large number of units on a given substation. This requires added capacity, makes no provision for larger line transformer costs, or for transients from simultaneous switching of a large number of units.	Agreement protects distribution system and provides for transformer and transients.
Energy Charge	Off-peak rate less than expected. Cost due to typical charge profile.	Off-peak rate less than expected. Cost due to typical charge profile.	Optimal placement of load reduces cost and rate below that charged off-peak in a TOD rate of comparable length.

Table 3. (Cont'd)

Impacts	Rate Format: Time-of-Use kWh	Time-of-Use With Demand Charge	Load Management Agreement
Shifting Peak	Quite possible; could result in shifting peak as large number of units switch on at start of off-peak period or if hours of off-peak period shortened.	Quite possible; could result in shifting peak as large number of units switch on at start of off-peak period or if hours of off-peak period shortened.	No problem.
Control of Usage	Customer.	Customer.	Utility control allows optimal placement of load, lowering energy cost below that of conventional off-peak period as well as providing load-shedding capability.
Customer Risk	High; changes in rates and particularly hours of off-peak period over time pose real risk if system is designed to minimize cost given initial rate.	Very high due to potential changes in off-peak period.	Low; provides substantial stability of rate break over time.
Problems with Theft	None, incrementally.	None, incrementally.	Possible but small; TES control can be connected to breaker box to force tap into live wires; large summer usage obvious warning signal as is daytime meter running.

5 SETTING LOAD MANAGEMENT AGREEMENT RATES

How should a management agreement be established? In particular, what should be the length of the charge time, the price of electricity, the size of the customer charge, and the capacity cut-off point?

First the utility's benefits and costs from TES must be determined and broken down on a long- and short-term basis. It is beneficial to reduce peaking-unit capacity requirements only if new peaking units are planned or if present peaking units can be sold either permanently or on a unit contract basis. Furthermore, a minimum amount of storage is needed before any real impact upon system costs can occur. Thus, in the first few years, as TES is establishing itself in a customer service territory, its impact upon costs will be minor.

When benefits are positive, the utility's savings are accurately mirrored in the rates charged, that is, if the marginal cost of capacity is $50/kW, and the typical customer is charged $50 for such capacity, setting the load management agreement rate is easy.* The customer pays a charge for off-peak electricity that is equivalent to the average cost of producing and delivering it. In addition, there is a customer charge equal to the cost of metering and increased distribution requirements. Usually marginal costs exceed embedded costs. This means that rates are scaled down from marginal costs. Therefore, the benefits of TES exceed the savings attainable by the customer. In this situation, all other customers pay less than the costs they impose, hence equity demands the same for TES. However, the energy charge should not be changed because this would result in losses on each kilowatt-hour sold. Therefore, the customer charge must be adjusted. This adjustment could be so severe that the charge to a customer in a load management agreement could be less than a standard rate if foregone benefits were high enough. This situation appears to be the case for Central Maine Power Co. Eliminating the customer charge increases benefits from $4 to $5/kW of customer heat loss. This makes eight-hour storage systems marginally viable.

Another mechanism to encourage the use of TES is to allow more hours for charging than a strict off-peak period analysis would show. This considerably reduces the customer's initial investment and particularly the incremental investment. Yet, if done properly, it should not materially affect costs placed upon the system. Why? Because the peak period hours of charge can be varied for different customers and kept off the true peak period. Example 2 and the earlier analysis illustrate how dramatically customer costs can be affected by minor changes in hours of availability.

Example 2

Cost of alternative system (resistance heat) per kW heat loss:	$160
Cost of kW of TES capacity:	$150

*This assumes the unusual situation of marginal costs being equal to embedded costs.

Example 2 (cont'd)

kW requirement for TES with 8 hours charge time per kW of heat loss:	2.2 kW*
With 10 hours of charge time:	1.8 kW*
Costs of TES per kW of heat loss:	
8-hour charge	$330
10-hour charge	$280*
Incremental cost of TES:	
8-hour charge	$170
10-hour charge	$120
Percent reduction in marginal investment with 10-hour charge versus 8 hour charge:	30%

Setting the storage capacity cut-off points involve analysis of the system at all levels. As the applications come in, each distribution line and substation must be analyzed. When its capacity is used, that is, when new installations would be required with TES, then that section of the system should be withdrawn from availability. In effect, the sale at that "store" is over. This withdrawal can be temporary. As conditions change, local capacity can again become available. Optimal daily and annual load duration curves should be developed for the system as a whole. As these are reached, the TES rate should be withdrawn on a system-wide basis until conditions change.

It is clear both that a load management agreement is the appropriate rate for TES and that it offers the flexibility at least partially to correct pricing problems that result from rate regulation. The task facing the electric utility industry, therefore, is to use load management agreements to realize these benefits.

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*Assumes a heat loss safety margin of 0.2 kW of capacity per kW. Costs do not scale linearly; hence the cost savings are proportionally less than the capacity savings.

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APPENDIX

Three-Phase Electric Load Management Agreement

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THREE PHASE ELECTRIC LOAD MANAGEMENT AGREEMENT

Agreement between Central Vermont Public Service Corporation (The Company), and ______________________________ (the Customer), under which the Company will provide Electric Load Management service to be utilized at: ______________________________

Street or Road

______________________________, Vermont ________

Town or Village — Zip Code

____

Account No.

for the following described equipment:

Description of Equipment: ______________________________

____

____

Maximum Connected Load ________ KW.

The Company agrees to provide electric load management for the above described equipment at the above location under the following terms and conditions:

1. Service shall be a nominal 208, 240, or 480 volts, three phase, except that where there is an existing three phase service the voltage will not differ from the existing service, and shall be available only during such hours as the Company may direct, but not less than eight (8) hours during any 24 hour period, except as provided for in the "Load Interruption" section of the Company's Schedule of Electric Rates.

2. Service shall be supplied through a separate meter to such electric equipment as the Company may specifically designate.

3. The Customer shall wire all equipment to a point designated by the Company and provide all required relays and/or equipment control devices necessary to act upon the control signal provided by the Company.

4. Equipment served under the provisions of this agreement shall have control facilities which restrict load (Kw) added by the Customer to equal increments per phase not larger than 6 Kw at intervals of not less than 15 seconds.

5. Capacity of equipment connected to this service (nameplate rating) shall not exceed 500 kilowatts and shall be balanced on each phase.

6. This agreement shall be for an initial period of at least one year from the date of acceptance by the Company and thereafter from year to year, unless terminated by either party on 60 days written notice.

7. The provisions of this agreement may be modified by the Company by giving the Customer notice in writing at least 60 days prior to the proposed change. The Customer shall have the option to terminate this agreement on the effective date of the change instituted by the Company by giving written notice to the Company on or before 30 days from the date of the Company's notice of the proposed change.

8. Billings rendered under the provisions of this agreement shall be subject to the same fuel and/or energy cost adjustment as is applicable to Kwh billings rendered under the rates contained in the Company's regular schedule of electric rates.

9. The Customer must make application to the Company prior to adding additional equipment (Kw) which will receive service under this agreement.

10. The Company reserves the right to reject applications for new or additional service under this agreement at any time or location where insufficient capacity exists to serve the additional load.

11. The violation of any of the provisions of this agreement shall cause the Customer to lose the service, after proper notice, until such time as the violation is corrected.

12. Equipment served under the provisions of this agreement shall not be inductive load and shall not receive service under any of the Company's filed rates at any time during the term of this agreement.

13. The Company shall have the right to inspect equipment served under this agreement at all reasonable times.

14. Service under this agreement is not available to any Customer also receiving service under the provisions of the Company's rates which provide for the delivery of service at a voltage of 2.4 Kv or greater.

15. This agreement is made subject to approval of the Vermont Public Service Board.

16. The monthly rate for service under this agreement is $30.00, plus $0.15 per kilowatt of the highest 15 minute demand established in the current month or in any of the prior 11 months, whichever is greater, plus $0.012 per Kwh.

____
Customer

By ____________________

____
Date

CENTRAL VERMONT PUBLIC SERVICE CORPORATION

By ____________________

____
Date

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