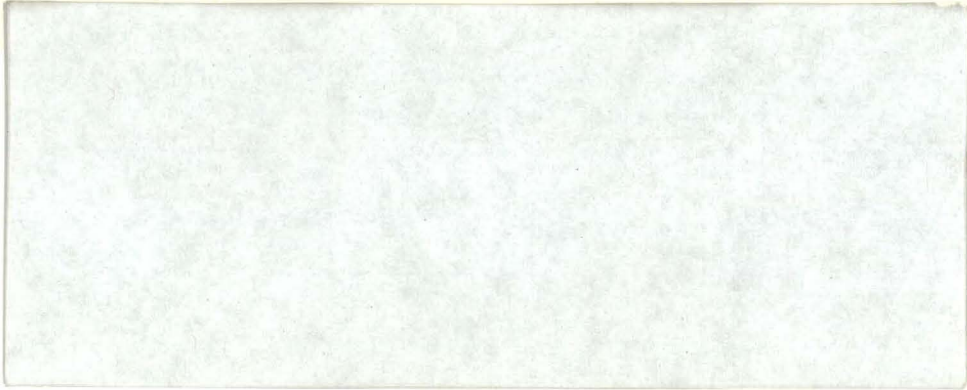


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Technical Memo



ARGONNE NATIONAL LABORATORY
Energy and Environmental Systems Division

prepared for
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ARGONNE NATIONAL LABORATORY
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MASTER

A REVIEW OF THE COMMUNITY
ENERGY PEAK LEVELING PROGRAM (CEPLP)

Prepared by
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Los Angeles, California 90071

for

Energy and Environmental Systems Division
Argonne National Laboratory
Under Contract 31-109-38-5229

March, 1980

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1 EXECUTIVE SUMMARY

A review of the Community Energy Peak Leveling Program (CEPLP), as applied in the Los Angeles and Orange County experiments, indicates that the program is a workable method of reducing demands on a utility system at the time of system peak. The program should not be used as a method of reducing energy consumption. Rather, it should be used in utility systems that need additional capacity at the time of their peak demands. Furthermore, the program is most advantageous when applied to a utility system that faces a rather peaked annual load duration curve.

The value of the capacity "purchased" by a utility under CEPLP approaches the marginal cost of capacity to the utility. In most utility systems, this value equates to the cost per kilowatt of a combustion turbine (currently about \$3.00/kW/mo).

The best form of rate schedule for use under the program is an interruptible rate because of the unwillingness of participants in the program to reduce the level of environmental comfort and other operations below certain minimum levels on a continuing basis. The interruptible rate form allows the program to yield its maximum benefit to the utility with the least amount of disruption of the participant's operations.

CEPLP has several advantages for both the utility and the participants in the program. For the utility, it represents a method of "buying" capacity during system peaks. That capacity can be "purchased" relatively rapidly when compared to the normal lead times required to plan, secure approval of, and build new peaking capacity.

For participants in the program, there are significant economic benefits that take the form of a one-time energy saving during the audit phase of the program, a "payment" (in some form) from the utility involved and, to a lesser degree, a further energy cost-saving through an interruption during the billing period.

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2 THE LOS ANGELES EXPERIMENT

Following the Arab embargo on oil deliveries in late 1973, members of the Central City Association of Los Angeles (CCA), a group of downtown businessmen, met with the management of the Los Angeles Department of Water and Power (DWP) to discuss the reasons for the increasing cost of power supplied by the utility. DWP indicated that, because its system relied heavily on oil-fired capacity, the cost and availability of oil had a significant impact on its charges for electricity. These discussions encouraged certain CCA members to aid DWP in reducing its production costs, with the expectation that any achieved reduction (or part thereof) would be passed on to the consumers. This effort evolved into the Los Angeles Energy Cooperative Demonstration Project, consisting of the May Company (a department store) and the office buildings of United California Bank (UCB), Southern California Gas Company, Occidental Center, and DWP.

Two problem areas began to develop at this early stage. First, the expectation of a reduction in rates was quite high among DWP's four partners in the Project. Recognizing that the level of rates to each class of customer served is the result of highly political decisions made by the Board of Directors of DWP (and the City Council), DWP's management did not share that expectation. It is unclear whether that sentiment was adequately expressed to the other members of the project.

Second, to reduce the need for peak generating capacity, the program, as originally developed, sought to reduce demand by the Project members at the time of peak demands on the overall DWP system. However, DWP did not (and still does not) suffer from a shortage of capacity at peak.

Table 2.1 shows historical and projected peak demands on the DWP system and the resources available to meet those demands in an "energy-short" system; hydroelectric power could be utilized to meet peak demand, but this source would be unavailable at other times of the year. Such a situation would require the use of oil-fired capacity with its resultant higher cost of operation. It is not clear whether this fact was sufficiently explained by DWP or understood by Project members in the early stages of the program's development.

All parties must have a complete understanding of the utility situation if any program of this nature is to be successful. Both of the problem areas discussed above resulted from a lack of understanding of DWP's financial, political and planning situation on the part of the Project's members. Whether that lack of understanding was caused by DWP's failure to present adequately the required explanation or by the Project members' failure to comprehend that explanation is not at issue here.

Engineering Supervision Company (ESCO) of Newport Beach, California, was engaged as a consultant to the group that devised the Community Energy Peak Leveling Program. By mid-1977, the system hardware and software had been developed for CEPLP, and its operation begun. A basic understanding of that operation is necessary.

Table 2.1 Summary of Loads and Resources--Los Angeles Department of Water and Power (1975-1987)^a

Line No.	Actual						Estimated						
	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
	----- (Megawatts) -----												
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
(1) Total Firm Demand	3,737	3,868	3,853	4,157	4,116	4,277	4,379	4,486	4,488	4,618	4,772	4,923	5,077
Resources													
(2) Hydroelectric-Conventional	746	704	704	704	704	704	704	704	704	704	704	704	690
(2) Hydroelectric-Pumped Storage	535	630	630	630	630	630	630	630	630	630	630	630	630
(4) Base Load-Oil and/or Gas	2,915	2,915	2,915	2,871	2,871	2,871	2,871	2,871	2,871	3,331	3,331	3,331	3,331
(5) Base Load-Coal	634	866	866	866	1,071	1,076	1,076	1,006	1,006	936	863	793	1,049
(6) Base Load-Nuclear	0	0	0	0	0	0	0	70	70	140	140	210	210
(7) Peaking-Combustion Turbine	80	80	76	76	76	76	76	76	76	76	76	76	76
(8) Firm Transfers (Purchase)	525	525	525	525	350	360	350	350	350	350	350	350	350
(9) Total Resources	5,435	5,720	5,716	5,618	5,702	5,707	5,707	5,707	5,707	6,167	6,094	6,094	6,336
(10) Margin over Firm Demand Line (9) - Line (1)	1,698	1,852	1,863	1,515	1,586	1,430	1,328	1,221	1,219	1,549	1,322	1,171	1,259
----- (Percent) -----													
(11) Percent Margin Line (10) Line (1)	45.4	47.9	48.4	36.4	38.5	33.4	30.3	27.2	27.2	33.5	27.7	23.8	24.8

^aSource: Common Forecasting Methodology II, Supply Plan for Los Angeles, February, 1979 (Revised), submitted to the California Energy Commission, April 27, 1979 in Docket No. 78-BR-1, Form Number R-1A.

2.1 SYSTEM COMPONENTS

The hardware package for the program consists of a communication terminal at each building and a central computer at ESCO headquarters, all connected by leased telephone lines. Each terminal provides the capability of communication between the individual building and the computer center and collects and transmits the building's demand data to the center. A computer predicts building demand levels every five minutes for 9-10/hour into the future based on historical data and the outside temperature in Los Angeles. If predicted load exceeds a preselected maximum level, a load shedding request is transmitted to the buildings' operators through their terminals. The maximum level at first selected was 3-5% below the network peak of the buildings; this was later extended to 7-10% and finally to 6-12% below the peak.

2.2 SYSTEM OPERATION

The first phase of the program consisted of a building survey and testing analysis. During this analysis, the electrical loads of each building were inventoried to identify their magnitude, timing, and priority in the event of required load shedding. With the help of the buildings' operating personnel, the effects of various activities on the overall quality of the building environment were tested. This was a highly educational experience for most of the operating personnel in that it introduced them to the use of techniques such as fan cycling, temperature fluctuations, higher chilled water temperatures, and rescheduling of certain operations that could be used to reduce their overall power requirements without reducing the operational comfort in their buildings below minimum acceptable levels. Operators were given an equipment priority list to aid them in shedding load, as required, in the operation of the program.

Several participants indicated they felt the major benefit to them from the Project was a one-time reduction in energy usage derived from the energy audit phase. The thoroughness of the audit and the resultant procedures for reducing energy usage led to the adoption of certain of the procedures on a permanent basis.

CEPLP was utilized as described above during August and September, 1977. A review of the results of the program by all parties led to the decision to undertake a one-year test of the program during 1978. During this review, the "energy-short" status of DWP was made clear to the group, and the focus of the program shifted to maximizing energy savings. As a result, the 1978 experiment was conducted as a "rolling demand cap" program wherein the participants' energy usage was reduced across the daily operation period.

Although the magnitude of savings derived from the Project during 1978 may be questionable, it is clear that the Project did succeed in reducing the participants' demands on the DWP system. Energy savings beyond those realized as a result of the energy audit discussed above may not have been substantial. However, regardless of the magnitude of such savings, they represented a decrease in the use of oil-fired generation on the DWP system--a goal of this country's energy policy.

Energy savings under the Project were not larger because: (1) building operators may be willing to reduce the level of environmental comfort and other operations in their buildings below their selected minimum level for a brief period of time on a few days throughout the year, but they are unwilling and/or unable to do so on a continuing basis. Thus, the value of the Project lies in its original intended use, i.e., as a load management or peak-shaving device and not as an energy-saving program.

2.3 RESULTS OF THE LOS ANGELES EXPERIMENT

The record developed during the Project clearly shows that the participants were willing and able to reduce their demands on the DWP system when called upon to do so. The level of effort expended was as high as their initial enthusiasm for the Project. However, the change of focus to energy savings led to the eventual desire to end the Project in 1978. There is a strong probability that had DWP been a "capacity-short" utility and had the Project continued with a peak-shaving focus, it would still be in operation today.

The change of attitude toward the Project among the participants seems to coincide with the announcement by DWP of a time-of-day (TOD) rate for commercial customers in late August, 1978. Only 20% of the 1978 savings under the Program occurred after August.* There could very well have been other, more important reasons for the lesser percentage of savings in the last four months. For example, because a large portion of the savings was related to temperature control equipment, the greatest concentration of savings would be expected to occur in the summer months. Moreover, in late summer, the occupancy rate of one participant's building (UCB) began to increase, thereby requiring greater use of electricity. A change in participant attitude could result only from an apparent lack of communication among the parties.

Simple analysis demonstrates that the new rate form offered more incentive for a reduction in both demand and energy use than did the old rate. (The old and new TOD rates are included in Appendix A.) Data shown in Table 2.2 illustrate that, with one exception, a 10% decrease in either demand or energy consumption by the group under the TOD rate yields a larger reduction in overall billing than did the old rate. (Compare Columns (2) and (7); (4) and (9); or (3) and (8); (5) and (10).) Because two of the three accounts at the Southern California Gas Company do not qualify for the TOD rate, the bill reduction to this participant resulting from a 10% reduction in demand is not as great under the TOD rate as under the old rate.

Discussions with the participants suggest that any lack of incentive may well have been a product of the overall increase in billing level when the new rate was adopted. This can be seen by comparing Columns (1) and (6). It appears that the participants concentrated on the overall increase in their bills instead of on the greater bill reductions possible under the new rate form.

*National Energy Peak Leveling Program, a report by ESCO to the U.S. Department of Energy, February 1979, page I-4.

Table 2.2 Comparison of "Incentives" Under Previous LADWP Rate Form and New TOD Rate

Project Participant	Former A-1 Rate					New TOD Rate				
	Decrease in Bill					Decrease in Bill				
	Normal Usage Bill ----- (Dollars)	10% Demand Reduction	Percent	10% Energy Reduction (Dollars)	Percent	Normal Usage Bill ----- (Dollars)	10% Demand Reduction	Percent	10% Energy Reduction ^a (Dollars)	Percent
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
(1) Occidental Center	\$ 49,731.17	\$ 647.94	1.3%	\$ 1,109.42	2.2%	\$ 55,434.07	\$ 1,489.16	2.7%	\$ 2,488.84	4.5%
(2) LADWP	129,070.34	2,276.00	1.8	3,066.18	2.4	143,611.62	4,140.95	2.9	6,878.62	4.8
(3) Southern California Gas Co.	17,065.35	360.83	2.1	364.81	2.1	18,778.55	235.56	1.3	691.56	3.7
(4) United California Bank	74,493.00	1,870.01	2.5	2,324.79	3.1	84,977.19	3,153.77	3.7	5,215.40	6.1
(5) May Co.	32,705.67	924.39	2.8	784.32	2.4	33,018.66	996.09	3.0	1,715.34	5.2
(6) Project Total	\$303,065.53	\$ 6,079.17	2.0%	\$ 7,649.52	2.5%	\$335,820.09	\$ 10,015.53	3.0%	\$ 16,989.76	5.1%

^a10 percent reduction of peak kilowatt-hours shifted to off-peak.

Source: Data supplied by the Los Angeles Department of Water and Power.

The data in Table 1.2 suggest that the Los Angeles experiment did not end because of the institution of the TOD rate. Rather, an analysis of the details of the Project and interviews with the participants suggest that the Project ended because of the understandable reluctance of the participants to reduce on a continuing basis the level of environmental comfort and other operations in their buildings below certain minimum levels. Because the value of the Project lies in its use as a load-management (or peak-shaving) device and not as an energy-saving program, and because DWP was and is not a capacity-short utility, the program ended in 1978.

3 THE ORANGE COUNTY EXPERIMENT

The experiment under way in Orange County differs significantly from that attempted in Los Angeles. The most important difference between the two experiments is that in Orange County, the entire intent is to shave load at the time of the system peak; the entire experiment is shaped around that intent, and the utility involved is in need of peaking capacity. This difference is the result of the experience gained in Los Angeles which indicated that the CEPLP program is best utilized as a load-shaving or a peak-shaving device.

3.1 SYSTEM COMPONENTS

The program on trial in Orange County is the product of discussions between ESCO personnel, the individual members of the Orange County Energy Cooperative (Co-op) and Southern California Edison Company (Edison). These discussions followed the conclusion of the Los Angeles experiment and were, in part, a result of the success in Los Angeles in using the program for peak-shaving purposes. The Co-op consists of the Pacific Mutual Insurance Company, Fluor Corporation, and the Irvine Company, each occupying an office building, and South Coast Plaza, a shopping center. The test program has been on line since July 1979, and is intended to be of one year's duration. However, should successful results in some shorter time period so warrant, all parties appear willing to move to a permanent program at such time.

3.2 SYSTEM OPERATION

The Orange County test program is fairly simple in its operation. Ten meters at the four locations will be billed on an existing Edison interruptible rate schedule (Rate Schedule Nos. TOU-8 and TOU-8-I, attached as Appendix B). Edison and the participants sought and obtained the approval of the California Public Utilities Commission (CPUC) to undertake the test. Such approval was necessary because:

- (1) Edison will fund the program to an amount not to exceed \$25,000 and will expense the amount against an allowance granted the company in the CPUC's last general rate increase decision.
- (2) Under the terms of the rate schedule at the time of the original application to the CPUC, only customers whose load exceeds 5,000 kW could qualify for such a rate. CPUC approval was required to allow the loads of the four customers to be added together in order to meet this minimum level.*
- (3) For some time, the CPUC has been pursuing new and useful load management strategies. Indeed, under the terms of the Public Utility Regulatory Policies Act of 1978

*Since the institution of the program, the 5,000 kilowatt load level has been reduced to 1,000 kilowatts.

(PURPA), which was passed as part of the National Energy Act, consideration of new load management techniques is established as a federal standard for possible adoption by all state regulatory commissions.

Under the terms of Edison's TOU-8-I rider to its TOU-8 rate schedule, the customer may elect to identify a portion of the load which is specified as firm, and which is referred to as Firm Service.* Each kilowatt of maximum, on-peak demand in excess of the Firm Service level is considered to be interruptible. Thus, a customer may agree to a Firm Service level of 700 kW. Over the course of the year, the monthly maximum demand may vary from, e.g., 800 kW to 1,200 kW. Whenever Edison calls for an interruption, the customer must reduce current load to the agreed Firm Service level of 700 kW. In any month when the customer's maximum demand exceeds 700 kW, the customer will receive a billing credit for such excess demand. For example, in a month when maximum demand is 1,200 kW, the customer will receive a credit based on a 500-kW demand in excess of the Firm Service level. All kilowatts of the billing demand are billed at the \$5.05 rate on the TOU-8 schedule, but the customer receives a credit for those kilowatts of demand in excess of Firm Service level at the rate of \$2.50 or \$3.00/kW depending on the rate option selected under the TOU-8-I schedule. Under the terms of Special Condition 8 of the TOU-8-I rate, charges for excess demand when an interruption is called for range up to \$80/kW and represent a substantial penalty for failure to shed the required amount of load. Co-op members subject to a penalty of this level because it appears to exceed any estimate of the cost to the utility of a failure to meet its peak.

Operating under this rate schedule, the Co-op members are treated, in essence, as a single customer for purposes of meeting the interruptible requirements. The demand credit granted to this group is divided among them monthly, based on the terms of the agreement of the group and each member's performance, or lack thereof, during the month. By early September, several test interruptions had been called for by Edison, and the group was successfully meeting its Firm Service level. In some instances, individual members were not able to reduce their demand to the required level, but other members of the Co-op were able to reduce their demands below their Firm Service level in an amount sufficient to reduce the group total to the required level. Thus, no penalty charges for excess demand were incurred by the group.

As the Co-op agreement presently exists, the individual member who reduced demand below individual Firm Service level (and thereby saved the group from incurring excess demand charges) reaps a reward. This takes the form of an increase in the amount of rebate received at the end of the month, which is based upon the amount of his reduction below the Firm Service level. Thus, there is some incentive to be the "group savior," which appears to have worked well in the Orange County experiment.

As presently operating, the Co-op has several advantages for both the utility and the cooperative members. For the utility, it represents a method of "buying" capacity at the time of system peak. That capacity

*"Firm Service" is defined under Special Condition 1 of the TOU-8-I rate.

can be "purchased" relatively rapidly as compared to the normal lead times required to plan, secure approval of, and build new peaking capacity. However, for this method of "purchase" to be equivalent in the overall planning process of the utility to building peaking capacity, the capacity at the peak must be available--i.e., the utility must be assured that participants will reduce their load to the agreed level. Without that assurance, the value of such an interruptible load to the utility is significantly decreased.

For the Co-op members, the program has some obvious economic benefits. In addition to the rebate on demand charges, each participant receives a direct reduction in the amount of energy charges in any month during which an interruption occurred. Although the magnitude of these savings is not as great as the demand charge rebate, it is a further economic incentive built into the program.* The most important nonmonetary benefit to the participants is that the monetary benefits can be secured without reducing the level of environmental comfort and other operations in their buildings below certain minimum levels on a continuing basis. Such a reduction need only occur on days on which an interruption occurs--an event both the utility and the Co-op participants expect to happen no more than a few times a year.

*One interruption of six hours in a 30-day month would save less than 1 per cent of the kilowatt-hours normally billed in the month for a participant with his interruptible load set at 20 percent of his peak load, assuming he would normally operate at a 30 percent load factor (0.2 kW x 6 hours) (kW x 720 hrs x 0.3) = 0.55%.

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4 DISCUSSION OF THE CEPLP CONCEPT

4.1 UTILITY SETTINGS AND PARAMETERS

The Los Angeles and Orange County experiments confirm that the CEPLP concept is best applied to a utility faced with a rather peaked daily and/or annual load duration curve. Such a setting requires the use of oil-fired peaking capacity which the CEPLP concept would displace, to some degree.

A utility may find itself in one of three conditions regarding its ability to meet its loads.

- (1) It may be in an over-capacity situation and not require any additions to resources.
- (2) It may be in an optimal capacity situation and be striving to maintain that optimality.
- (3) It may be in an under-capacity situation and be seeking to add capacity immediately to meet the peak.

If a utility is in an over-capacity situation, neither it nor the participants will reap any benefits from the CEPLP concept that cannot be gained under properly derived rate structures because the value of capacity to the utility at the margin is zero. Furthermore, the energy savings available to the participants can be captured by them when they reduce consumption during those times when higher per-kilowatt-hour rates reflect the increased cost of oil-fired capacity used during those periods.

When a utility is in an optimal capacity situation, the CEPLP concept is useful because it can help the utility remain in a state of optimality as growth requires new additions to capacity. Increments of CEPLP capacity can be purchased by the utility to maintain its optimum mix of resources.

If the utility is in an under-capacity situation, CEPLP allows the utility to postpone capacity additions. This utility setting is the most favorable to the application of the CEPLP concept.

One word of caution should be offered here. If the utility has begun construction of new capacity into which dollars have been partially spent, it may not be cost-beneficial to push back the in-service date of the added capacity because inflation will increase the cost of any added capacity when it finally comes on line. Thus, from an economic standpoint, it may not be desirable to delay additional capacity because, if the utility can build it now, it can do so at a lower price.

An important benefit of the program is that, wherever used, it should reduce the amount of fuel oil burned by the utility involved. Most often the oil will be distillate fuel burned in a combustion turbine which is the most expensive fuel burned in electrical generating equipment. However, the fuel savings could also consist of other fuels that are in short supply. Thus, the concept could reduce the Nation's reliance on oil to supply its energy needs.

4.2 UTILITY RATE STRUCTURES

Table 4.1 shows the various types of utility rate structures that could be considered for use under the CEPLP concept. Also shown are their applicability to CEPLP and their degree of desirability for use under CEPLP. Desirability is ranked from totally undesirable (-5) to extremely desirable (+5) in the last column shown.

Certain types of rates are clearly unfavorable to the CEPLP concept. Any type of rate structure with a ratchet provision for billing demand charges is unfavorable. A ratchet provision usually requires that demand charges for any month be based on the maximum demand in that month or the highest demand in the previous 12 months, whichever is greater. The program participants would have to reduce their demands to a required minimum level at all times because any increased demand would set their level of billing demand 11 months into the future.

All noninterruptible rate schedules suffer in comparison to those incorporating interruptibility because noninterruptible rates would require reductions in demand level by the participants for long periods to capture any economic benefit. For this reason, their use severely limits the potential for success of the program, as the Los Angeles experience has demonstrated.

A kilowatt-hour rate based on average historic costs is unfavorable because it lacks any credit for reduction in demand by the participants. The only benefits possible to the participants are usage-related and can be captured without CEPLP.

A two-part rate (consisting of both a demand and an energy charge) based on average historic costs is somewhat less unfavorable to the CEPLP concept in that it could allow the participants to reduce the amount of demand charges they would incur. However, the financial benefits to the participants under such a rate schedule probably would be insufficient to warrant incurring the costs associated with the institution of the program.

These observations apply also to the next three rate structures listed on Table 3.1. A time-of-use rate, based on average historic costs, would yield greater potential benefits to the participants than a two-part rate because on-peak demand charges under the time-of-use rate should be higher. A two-part marginal cost-based rate should yield somewhat higher benefits, and a marginal cost-based, time-of-use rate even higher benefits.

An interruptible rate clearly is the best type of rate structure to use in the ESCO program. Unwillingness of participants to reduce the level of environmental comfort and other operations in their buildings on a continuing basis is of great importance here. The interruptible rate form allows the program to yield its maximum benefit to the utility with the least amount of disruption of the participants' operations.

If such a rate form is not available from the utility, institution of such a rate form should be discussed. Indeed, under the terms of PURPA, interruptible rates are established as a federal standard for possible

Table 4.1 Analysis of Applicability of Various Rate Structures to CEPLP Concept

Rate Structure Type ^a	Costing Basis Rate	Applicability Under CEPLP	Degree of Desirability
(1) Straight kilowatt-hour rate (energy charge only)	Average Historic Cost	Unfavorable	-5
(2) Two-part rate (demand and energy charge)	Average Historic Cost	Unfavorable	-3
(3) Time-of-use rate	Average Historic Cost	Unfavorable	-2
(4) Two-part rate (demand and energy charge)	Masrginal Cost	Neutral	0
(5) Time-of-use rate	Marginal Cost	Favorable	2
(6) Interruptible rate with demand charge credit	Average Historic Cost	Favorable	3
(7) Interruptible rate with demand charge credit	Marginal Cost	Favorable	5

^aAny rate structure with a ratchet provision for billing demand is unfavorable for the CEPLP concept. Therefore, each of the listed types are considered as having no ratchet provision.

adoption by publicly owned utilities and state regulatory commissions.* Consideration of that standard must begin no later than November 9, 1980. Thus, the proceedings of the regulatory commission or nonregulated (publicly owned) utility in compliance with PURPA would seem to be a natural vehicle for consideration of the CEPLP at the local level.

Although the interruptible rate used may be based upon either average historical or marginal costs, the latter clearly is more appropriate. A marginal cost-based rate more accurately reflects the economic and operational situation of the utility. The trade-off made by the utility is between CEPLP capacity and new capacity or spinning reserve. An average historic cost value for peaking capacity would not give the participants credit for all of the benefits actually received by the utility.

Any interruptible rate should incorporate a demand charge credit of the type utilized in the Orange County experiment. Such a credit appears to provide a positive incentive to the participants in that it gives them the feeling that they are "getting something" in direct response to their behavior under the program because they are billed for all demand and then receive payment for interrupted demand from the utility. The terms and conditions of the applicable rate schedule should include a requirement that control under any CEPLP program be central in nature and computer-rather than manually oriented. The degree of desirability of the program from the utility standpoint derives from its ability to rapidly and effectively reduce the participants' demands on the system. A manually oriented program loses most of this advantage.

Whatever the rate form is utilized, the contract between utility and the participants under CEPLP must be of a term at least equal to the payback period to recoup the costs of setting up the program. The Los Angeles and Orange County experiments indicate that the period involved should be less than three years, but may vary from case to case depending on the economics of the situation. This protection is needed because the shape of the utility's annual load duration curve may change with time in such a way as to eliminate the need for capacity at the peak. There would then be no reason for the CEPLP to be continued because the value of peaking capacity to the utility would be zero. The contract must ensure the participants that they will at least recoup their costs of participation in the program.

Each participant in CEPLP will derive the benefit of the one-time energy savings which resulted from the energy audit phase of the Los Angeles experiment. Although the level of that benefit is difficult to quantify before the program begins, such savings could reduce the length of the pay-back period for the cost of participation.

The length of contract proposed also makes the program more attractive to the utility involved. If the utility were to build peaking capacity instead of "purchasing" it from the participants, it would lock itself into

*Title I, Subtitle B, Section 111(d) (5) of PURPA states: "Each electric utility shall offer each industrial and commercial electric consumer an interruptible rate which reflects the cost of providing interruptible service to the class of which such consumer is a member."

owning that capacity and incurring at least the fixed cost of that capacity for the life of the asset (about 25 yr for a combustion turbine). An additional benefit to the utility derives from the fact that a CEPLP capacity "purchase" need not be as permanent as building new capacity.

Concerning type of rate structure, in the case of a utility that is chronically in an over-capacity situation, the CEPLP concept does not make sense to the utility only; therefore, the rate structure discussion above has no application. Because capacity at the peak is valueless to the utility, the concept loses its applicability under any rate structure.

4.3 COOPERATIVE ARRANGEMENTS AND BENEFIT DISTRIBUTION

The experience gained in the two experiments discussed here indicates that the CEPLP concept is cost-beneficial when utilized as a peak-shaving device. However, it will not work equally well for all utilities across the country and will work most effectively under certain rate structures. Its applicability can be tested using the following analysis.

- First, the utility system involved must have a need for generating capacity at the time of the system peak. The Los Angeles experiment has demonstrated the inapplicability of the concept to an "energy-short" system. Furthermore, the concept is best applied to a utility system facing a rather peaked annual load duration curve. The expected number of interruptions in any year would be reduced for such a system which in turn represents a substantial benefit to the participants.

- Second, the utility must be willing and able to treat capacity "purchased" under the program at the margin. The value of the capacity to the utility is approximately equal to the cost of new alternate peaking capacity. Such costs may vary from utility to utility, but they probably would not exceed the cost of a new combustion turbine and a small amount of transmission capacity. For purposes of rough analysis, this value could be set at about \$3.00/kW/mo, based on a capital investment of \$200/kW and a levelized annual charge rate of 18%. That benefit to the participants would have to be balanced against the cost of the CEPLP hardware and software estimated as \$250,000 in investment and \$75,000 in annual operating costs.

- Third, although other rate forms might be used under this concept, an interruptible rate clearly is the best form of utility rate structure to use in such a program. The primary consideration here is the unwillingness of participants to reduce the level of environmental comfort and other operations in their buildings below a minimum acceptable level on a continuing basis. The interruptible rate form allows the program to yield its maximum benefit to the utility with the least amount of disruption of the participants' operations.

If a given situation under consideration meets these three tests, there is a high probability that CEPLP will benefit both the utility involved and the participants in the program. However, in developing a local program, other areas need to be addressed to maximize its usefulness.

The size of the group of participants is an important consideration because one of the major benefits to the utility and the participants of group participation, as opposed to individual participation, is the "insurance" that the group arrangement offers them. If one member of the group is unable to reduce demand at any given time to a required level, another member may well be able further to reduce demand in the amount required. Group participation thus increases the likelihood that the required level will be reached. This cooperation is important to the utility involved for planning purposes and to the participants because it enables potential benefits to be captured while lessening the potential for hardship circumstances in the event load cannot be sufficiently reduced.

Thus, the larger the group of participants, the more likely the success of the program, but the group should not be so large as to cause difficulty in control. In this regard, group size would seem to be limited only by the capabilities of the computer equipment utilized. The agreement among the participants as to how any economic benefits derived from CEPLP are to be distributed is best left to discussion among the participants in each unique set of circumstances. As a minimum, such an agreement should set forth:

- (1) the responsibilities of each party as to load reduction,
- (2) a mechanism for allocating benefits assuming all members meet their required load level, and
- (3) a method of allocation in the event that one or more members do not perform adequately and one or more other members act as "group savior(s)."

Beyond these basic needs, the agreement might deal with any penalty provisions such as can be assessed under the Edison TOU-8-I rate by enforcing the penalty within the group when one or more members reduce their loads beyond their required level and save the group from being penalized by the utility. For example, assume a cooperative program consisted of several members who agree to a total firm service level of 50-MW. Suppose that at the time the utility calls for interruption to the 50-MW level, participant A is unable to reduce demand to the required level and that participant B makes up the difference. Without help from B, the group would incur a penalty charge for excess demand which A would have to pay. By agreement, the group might arrange that A pay B the penalty amount which would have been assessed by the utility, or some percentage thereof.

Such an agreement adds to the incentive to become a "group savior" (and thereby adds to the utility's assurance that the "purchased" capacity will be available). However, this could become a disincentive to participation by a member who feared incurring the penalty charges. This example demonstrates the need to let the participants set the terms for distribution of benefits in the manner best suited to the situation.

All parties to the arrangement must clearly understand the situation of the others in setting such terms. It might seem unfair to a utility

to "pay" the participants the value of new peaking capacity when, in fact, the kilowatts purchased are coming from existing capacity; however, that is the cost the utility would incur, without the help of the participants in the program. Similarly, although a large penalty for failure to perform as required might seem unfair to the participants, any such failure causes the utility to incur emergency costs of covering its peak demand. Thus, any tailoring of the program that adds to the assurance that the group will perform as required reduces the need for a penalty in the utility's eyes. In short, to the utility, performance is critical; to the participants, incentive is critical. The agreement reached must balance those needs for the program to work.

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APPENDIX A

**Electric Rate Ordinance -- Department of
Water and Power -- City of Los Angeles**

LOS ANGELES DEPARTMENT OF WATER AND POWER

SCHEDULE A-1
GENERAL SERVICE

APPLICABILITY

For all general service, including lighting and power, which may be delivered through the same service at one standard character in compliance with the Character of Service Rule.

This schedule is applicable to any service for which no special schedule is available.

CHARACTER OF SERVICE

Alternating current at a regulated frequency of 60 cycles.

Single phase - 120 or 240 volts, 2 wire or
120/240 volts, 3 wire.

Three phase - 240 or 480 volts, 3 wire.
- 2400, 4150, 4800, or 34,500 volts, 3 wire may be available at the Department's option for special loads and locations.
- 120/208 or 277/480 volts, 4 wire may be available at the Department's option for special loads and locations.

TERRITORY

City of Los Angeles and the Counties of Inyo and Mono.

MONTHLY RATE

Service Charge - Single phase _____ \$2.01
- Three phase _____ \$3.36

plus
\$0.25 per kilowatt of Billing Demand in excess of 20 kw.

Energy Charge - 3.88 cents per kwh for the first 1,000 kwh
2.97 cents per kwh for the next 2,000 kwh
2.33 cents per kwh for the next 4,200 kwh*
1.24 cents per kwh for the next 9,200 kwh*
0.69 cents per kwh for each additional kwh

* add 110 kwh for each kw of Billing Demand in excess of 20 but not exceeding 300 kw, plus 80 kwh for each kw of Billing Demand in excess of 300 kw.

Minimum Charge - The Service Charge plus \$1.20 per kilowatt of Billing Demand in excess of 20 kilowatts.

ADJUSTMENT FOR FUEL COSTS

The Energy Charge of the foregoing Monthly Rate is subject to adjustment on a kilowatt-hour basis for variation of fuel costs, as described in the General Provisions.

BILLING DEMAND

The Customer's Maximum Demand shall be measured monthly when a load test indicates a demand greater than 20 kilowatts. Billing Demand shall then be the higher of the Maximum Demand for the month or the highest Maximum Demand occurring in the preceding eleven months.

MAXIMUM DEMAND

Maximum Demand shall be the average kilowatt load to the nearest one-tenth kilowatt during the fifteen-minute period of greatest use during the month as indicated or recorded by Department's meter.

In cases where demand is intermittent or subject to violent fluctuations, the Department may establish the Maximum Demand on the basis of measurement over a shorter interval of time or the kilovolt-amperes of transformer capacity required to serve customer's load.

ADJUSTMENT FOR HIGH VOLTAGE SERVICE

Applicability - A discount shall be applicable to billings under this rate when service is delivered at a subtransmission or higher voltage.

Discount - The amount calculated by application of the foregoing rate, exclusive of any other adjustments, shall be subject to a 5% discount.

Substation Equipment on Customer's Side of Point of Delivery - All equipment or structures necessary for the utilization of service delivered by the Department at high voltages shall be located on the customer's side of the point of delivery and shall be owned and maintained by the customer.

Metering - Metering of energy and demand shall be provided by the Department at the primary side of transformers or, at the Department's option, on the secondary side of transformers and compensated by instruments or loss calculations to the delivery voltage, as provided in the Metering Rule.

Note: All charges under this schedule were increased 13.8 percent by Ordinance No. 147,770 effective December 9, 1975 and an additional 12.5 percent by Ordinance No. 150,356 effective December 23, 1977. Charges in effect after the 1977 increase are shown on the next page.

ELECTRIC RATES

fixed by the
DEPARTMENT OF WATER AND POWER
CITY OF LOS ANGELES
in the
CITY OF LOS ANGELES
Effective on Electric Service Rendered
On and After
December 10, 1978

Ordinance No. 151,685

D. SCHEDULE A-3 - LARGE GENERAL SERVICE

1. Applicability

Applicable to general service, including lighting and power, which may be delivered through the same service in compliance with the Character of Service Rule.

2. Territory

City of Los Angeles.

3. Monthly Rates

a. Rate A

		Rates in Effect	
		from 12-10-78 to 11-30-79	on and after 12-1-79

(1) Service Availability Charge	\$10.00	\$10.00
(2) Capacity Charge - per kw	\$0.25	\$0.25
(3) Demand Charge - per kw	\$5.89	\$5.89
(4) Energy Charge - per kwh	\$0.00437	\$0.00664
(5) Minimum Charge (both periods)	\$6,600.00 or \$1.00 per kw*, whichever is greater	

b. Rate B

(1) Service Availability Charge	\$10.00	\$10.00
(2) Capacity Charge - per kw	\$0.25	\$0.25
(3) Energy Charge - per kwh	\$0.01458	\$0.01690
(4) Minimum Charge (both periods)	\$6,600.00 or \$1.00 per kw*, whichever is greater	

c. Rate C

(1) Service Availability Charge	\$10.00	\$10.00
(2) Capacity Charge - per kw	\$0.25	\$0.25
(3) Energy Charge - per kwh		
On-Peak Period	\$0.03831	\$0.04063
Off-Peak Period	\$0.00432	\$0.00664
(4) Minimum Charge (both periods)	\$6,600.00 or \$1.00 per kw*, whichever is greater	

* Kw as determined for application of the Capacity Charge under Special Conditions below.

d. Energy Cost Adjustment

The Energy Charge of the above rates is subject to adjustment on a kilowatt-hour basis for variation of energy costs, as described in the General Provisions.

4. Special Conditions

a. Billing

The bill under Rate A shall be the sum of the Service Availability Charge, the Capacity Charge, the Demand Charge and the Energy Charge (including the Energy Cost Adjustment) — or the Minimum Charge, whichever is greater.

The bill under Rates B and C shall be the sum of the Service Availability Charge, the Capacity Charge and the Energy Charge (including the Energy Cost Adjustment) — or the Minimum Charge, whichever is greater.

b. Capacity Charge

The Capacity Charge shall be based on the highest Maximum Demand recorded in the last 12 months.

c. Demand Charge

The Demand Charge shall be based on the Maximum Demand during the month.

d. Maximum Demand

The Maximum Demand shall be the average kilowatt load to the nearest one-tenth kilowatt during the fifteen-minute period of greatest use during the month as indicated or recorded by the Department's meter.

In cases where demand is intermittent or subject to violent fluctuations, the Department may establish the Maximum Demand on the basis of measurement over a shorter interval of time or the kilovolt-amperes of transformer capacity required to serve customer's load.

e. Optional Rates

The Department will install a "time-of-use" meter and the customer shall then be billed under Rate C. Until such meter is installed, the customer may choose to receive service under Rate A or Rate B; however, such choice may not be changed at intervals of less than 12 months.

f. On-Peak Period

The On-Peak Period shall be from 11 a.m. to 7 p.m. Pacific Standard Time daily except Saturday and Sunday. The Off-Peak Period shall be all other hours, including all day Saturday and Sunday.

g. High Voltage Service Adjustment

(1) **Applicability** - A discount shall be applicable to billings under this rate when service is delivered at a subtransmission or higher voltage.

(2) **Discount** - The Capacity Charge plus 2% of the Energy Charge including Energy Cost Adjustment.

(3) **Substation Equipment on Customer's Side of Point of Delivery** - All equipment or structures necessary for the utilization of service delivered by the Department at high voltages shall be located on the customer's side of the point of delivery and shall be owned and maintained by the customer.

(4) **Metering** - Metering of energy and demand shall be provided by the Department at the primary side of transformers or, at the Department's option, on the secondary side of transformers and compensated by instruments or loss calculations to the delivery voltage, as provided in the Metering Rule.

h. Applicability of Rules and Regulations

Application of this Schedule is subject to General Rules and Regulations adopted by the Board of Water and Power Commissioners.

APPENDIX B

Schedule No. TOU 8, California Edison Company

SOUTHERN CALIFORNIA EDISON COMPANY
2244 Walnut Grove Avenue
Rosemead, California 91770

Revised Cal. P.U.C. Sheet No. 5147-E

Cancelling Revised Cal. P.U.C. Sheet No. 5020-E

Schedule No. TOU-8

GENERAL SERVICE — LARGE

APPLICABILITY

Applicable to three-phase general service, including lighting and power, supplied directly from lines of transmission voltage, or where for the Company's operating convenience service is supplied from lines of distribution voltage.

This schedule is applicable for all customers of record on August 23, 1977, served on Schedule No. A-8 and thereafter is applicable to all customers whose monthly maximum demand exceeds 5,000 kW for any three months during the preceding 12 months. Any customer whose monthly maximum demand has fallen below 4,500 kW for 12 consecutive months may elect to take service on any other applicable schedule.

TERRITORY

Within the entire territory served, excluding Santa Catalina Island.

RATES

	Per Meter Per Month
Customer Charge:.....	\$1,075.00
Demand Charge (to be added to Customer Charge):	
All kW of on-peak billing demand, per kW.....	\$ 5.05
Plus all kW of mid-peak billing demand, per kW.....	0.65
Plus all kW of off-peak billing demand, per kW.....	No Charge
Energy Charge (to be added to Demand Charge):	
All on-peak kWh, per kWh.....	0.530¢
Plus all mid-peak kWh, per kWh.....	0.380¢
Plus all off-peak kWh, per kWh.....	0.230¢

Minimum Charge:

The monthly minimum charge shall be the sum of the monthly Customer and Demand Charges. The monthly Demand Charge shall be not less than the charge for 25% of the maximum on-peak demand established during the preceding 11 months.

Daily time periods will be based on Pacific Standard Time and are defined as follows:

- On-peak:** 12:00 noon to 6:00 p.m. summer weekdays except holidays
5:00 p.m. to 10:00 p.m. winter weekdays except holidays
- Mid-peak:** 8:00 a.m. to 12:00 noon and 6:00 p.m. to 10:00 p.m. summer weekdays except holidays
8:00 a.m. to 5:00 p.m. winter weekdays except holidays
- Off-peak:** All other hours.

Off-peak holidays are New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas.

For initial implementation of this schedule by the Company, winter shall consist of the billing periods for the six regularly scheduled monthly billings beginning with the first regularly scheduled billing ending after November 14, 1977. Thereafter, regularly scheduled monthly billings shall include six summer billing periods followed by six winter billing periods. In no event will winter include scheduled billing periods ending after May 31 of any year.

(Continued)

(To be inserted by utility)

Issued by

(To be inserted by Cal. P.U.C.)

Advice Letter No. 478-E

Edward A. Myers, Jr.

Date Filed December 27, 1978

Name

Decision No. 89711, 89783

Effective January 1, 1979

Vice President

Resolution No.

SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Rosemead, California 91770

Revised Cal. P.U.C. Sheet No. 5148-E

Cancelling Revised Cal. P.U.C. Sheet No. 5050-E

Schedule No. TOU-8

GENERAL SERVICE — LARGE

(Continued)

SPECIAL CONDITIONS

1. **Voltage:** Service will be supplied at one standard voltage.
2. **Maximum Demand:** Maximum demands shall be established for the daily on-peak, mid-peak, and off-peak periods. The maximum demand for each period shall be the measured maximum average kilowatt input indicated or recorded by instruments to be supplied by the Company, during any 15-minute metered interval, but not less than the diversified resistance welder load computed in accordance with the section designated Welder Service in Rule No. 2. Where the demand is intermittent or subject to violent fluctuations, a 5-minute interval may be used.
3. **Billing Demand:** Separate billing demands for the on-peak, mid-peak, and off-peak daily time periods shall be established for each monthly billing period. The billing demand for each daily time period shall be the maximum demand for that daily time period occurring during the respective monthly billing period.
4. **Voltage Discount:** The charges before adjustments will be reduced by 1% for service delivered and metered at a nominal voltage of 33,000 volts, and by 2% for service delivered and metered at a nominal voltage of 66,000 volts or over.
5. **Power Factor Adjustment:** The charges will be adjusted each month for reactive demand. The charges will be increased by 20 cents per kilovar of maximum reactive demand imposed on the Company in excess of 20% of the maximum number of kilowatts.
The maximum reactive demand shall be the highest measured maximum average kilovar demand indicated or recorded by metering to be supplied by the Company during any 15-minute metered interval in the month. The kilovars shall be determined to the nearest unit. A device will be installed on each kilovar meter to prevent reverse operation of the meter.
6. **Temporary Discontinuance of Service:** Where the use of energy is seasonal or intermittent, no adjustments will be made for a temporary discontinuance of service. Any customer prior to resuming service within twelve months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.
7. **Contracts:** An initial three-year facilities contract may be required where applicant requires new or added serving capacity exceeding 2,000 kVA.
8. **Energy Cost Adjustment:** The rates above are subject to adjustment as provided for in Part G of the Preliminary Statement. The applicable energy cost adjustment billing factors and fuel collection balance adjustment billing factor set forth therein will be applied to all kWh billed under this schedule.
9. **Tax Change Adjustment:** The rates above are subject to adjustment as provided for in Part I of the Preliminary Statement. The applicable tax change adjustment billing factors set forth therein will be applied to kWh billed under this schedule.
10. **Conservation Load Management Adjustment:** The rates above are subject to adjustment as provided for in Part J of the Preliminary Statement. The applicable conservation load management adjustment billing factors set forth therein will be applied to kWh billed under this schedule.

(To be inserted by utility)

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Name

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Vice President

Resolution No.

SOUTHERN CALIFORNIA EDISON COMPANY
 2244 Walnut Grove Avenue
 Rosemead, California 91770

Revised Cal. P.U.C. Sheet No. 5149-E
 Cancelling Original Cal. P.U.C. Sheet No. 4869-E

Schedule No. TOU-8-1

GENERAL SERVICE—LARGE—INTERRUPTIBLE

APPLICABILITY

Applicable to customers served under Schedule No. TOU-8, General Service—Large, and is available only under contract. New customers will not be served under this schedule if the total interruptible load of all customers on this schedule exceeds 300 megawatts.

RATES

\$ Per kW
 Per Month

RATE A

Applicable where the customer elects to provide only Company-controlled Interruptible Load.

The net billing determined under Schedule No. TOU-8 will be reduced as follows:

For each kW of the maximum on-peak demand
 in excess of Firm Service..... 3.00

RATE B

Applicable where the customer elects to provide only Customer-controlled Interruptible Load.

The net billing determined under Schedule No. TOU-8 will be reduced as follows:

For each kW of the maximum on-peak demand
 in excess of Firm Service..... 2.50

RATE C

Applicable where the customer elects to provide both Company-controlled Interruptible Load and Customer-controlled Interruptible Load.

The net billing determined under Schedule No. TOU-8 will be modified as follows:

1. The Billing Demand may not be less than the sum of Firm Service and the Company-controlled Interruptible Load.
2. The net billing determined under Schedule No. TOU-8 will be reduced as follows:

For each kW of Company-controlled Interruptible Load..... 3.00

For each kW of the maximum on-peak demand less the sum of the Firm Service and the Company-controlled Interruptible Load..... 2.50

If the maximum on-peak demand is less than the sum of the Firm Service and the Company-controlled Interruptible Load, the reduction in billing will be limited to the maximum demand minus the Firm Service times \$3.00 per kilowatt.

SPECIAL CONDITIONS

1. **Firm Service:** Firm Service is the maximum demand which the Company is expected to supply during periods when the Company has called for interruptible load to be disconnected from the Company's lines. Firm Service shall be specified by the customer. Increases in Firm Service may be made no more often than once per year and then only when the customer has made a bona fide addition of load. Such changes in Firm Service are subject to the approval of the Company.

(Continued)

(To be inserted by utility)

Issued by

(To be inserted by Cal. P.U.C.)

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Edward A. Myers, Jr.
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Vice President
 Title

Resolution No.

SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Rosemead, California 91770

Revised Cal. P.U.C. Sheet No. 5150-E

Cancelling Original Cal. P.U.C. Sheet No. 4870-E

Schedule No. TOU-8-I

GENERAL SERVICE—LARGE—INTERRUPTIBLE

(Continued)

SPECIAL CONDITIONS (Continued)

2. Company-controlled Interruptible Load: Such interruptible load is that increment of the customer's maximum demand, occurring during any Period of Interruption that is in excess of the customer's Firm Service requirements, and which the customer agrees shall be disconnected from the Company's lines upon notice by the Company. Such interruptible load shall be specified by the customer, and initial load and subsequent changes shall be approved by the Company.

3. Customer-controlled Interruptible Load: Such interruptible load is that increment of the customer's maximum demand, occurring during any Period of Interruption that is in excess of the customer's Firm Service requirements, and which the customer agrees shall be disconnected by the customer from the Company's lines upon notice by the Company. Such interruptible load shall be specified by the customer, and initial load and subsequent changes shall be approved by the Company.

4. Notice of Interruption: The Company will give the customer not less than ten minutes notice before interruption of the Company-controlled Interruptible Load and will give the customer not less than 30 minutes notice before interruption of the Customer-controlled Interruptible Load is to be required. The Company will notify the customer at the end of the Period of Interruption under this schedule.

5. Period of Interruption: Any Period of Interruption under this schedule will occur during the on-peak and mid-peak periods specified in Schedule No. TOU-8 when, in the Company's sole judgment, the next-to-last available major combustion turbine generator otherwise would be required to be operated.

6. Ownership and Control of Facilities: Communication, metering, and interrupting facilities, as specified by the Company, will be installed, owned, and maintained in accordance with Company specifications at customer's expense, including such facilities not located on the customer's property. Such facilities will be under operational control of the Company without intervention by the customer unless otherwise specified by the Company.

Such communications and interrupting facilities may include, but will not be limited to, the following:

- a. Necessary facilities between the customer and the Company to provide notice of interruption by signal.
- b. Equipment to permit remote and automatic disconnection by the Company.

Where feasible, and upon written request of the customer, the Company will, at the sole expense of the customer, provide data which can be utilized by the customer's load control equipment.

7. Excess Demand: The Maximum Demand occurring during each Period of Interruption during any billing period which is in excess of Firm Service shall be considered Excess Demand.

8. Charges for Excess Demand: During the first billing period in which interruption is called for, Excess Demand will be multiplied by \$3.00 per kilowatt under Rates A and C, by \$2.50 per kilowatt under Rate B, and the product added to the customer's billing. Thereafter, any Excess Demand will be charged on the following schedule:

After the first billing period in which interruption is called for, for the first Period of Interruption during which the customer incurs an Excess Demand, such Excess Demand is to be multiplied by \$20.00 per kilowatt and the product added to the customer's billing. For the second Period of Interruption during which the customer incurs an Excess Demand, regardless of the billing period, such Excess Demand is to be multiplied by \$40.00 per kilowatt and the product added to the customer's billing. For the third and all subsequent Periods of Interruption during which the customer incurs an Excess Demand, regardless of the billing period, such Excess Demand is to be multiplied by \$30.00 per kilowatt and the product added to the customer's billing.

The progressively increasing charge will recycle to \$20.00 per kilowatt after three regular billing periods in which interruptions are called for if no Excess Demand is recorded.

9. Contracts: A contract is required for service under this schedule. During the initial year of service the customer may terminate service under this schedule upon not less than 30 days written notice to the Company. After the initial year not less than five years notice to modify or terminate service under this schedule will be required. A customer may not obtain interruptible service within three years following termination of interruptible service under this schedule.

(To be inserted by utility)

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