SUMMARY OF DECISION NO. C79-1111, GENERIC RATE PROCEEDING, CASE NO. 5693, ISSUED BY THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO ON JULY 27, 1979

On July 13, 1976, the Colorado Public Utilities Commission initiated a proceeding to consider a number of broad issues relating to electric utility rate structures. All utilities which are regulated by the Commission were made parties to the proceeding. In addition many other divergent interests (including consumer and industry groups) participated in the proceeding. Because the proceeding involved a range of issues and a large number of parties, it was called a "Generic" case. Extensive open hearings were held. On July 27, 1979, the Commission issued Decision No. C79-1111 which deals with a wide range of substantive utility issues. Specifically, the Decision is divided into the following sections:

The findings and conclusions of each of the above-outlined sections are summarized below.

GOALS OF REGULATION

The primary responsibility of regulation is to asssure that rates charged for electricity are the lowest possible commensurate with the provision of adequate service. The Commission indicates that in fulfilling this responsibility the following regulatory goals must be recognized: (1) revenue adequacy; (2) efficiency of operation; (3) conservation of capital and energy; and (4) equity of rates as between classes of customers and among customers within any given class. In recognition of the overriding importance of the above goals, the Commission initiated the generic hearing process. The Commission notes that its ability to meet these goals is limited in terms of its jurisdiction and resources, and states its intention of moving cautiously, in this and subsequent decisions, to assure that the generic goals established are beneficial to the consuming public as well as reasonably susceptible to implementation by the utilities involved.

THE FEDERAL PUBLIC UTILITY REGULATORY POLICY ACT OF 1978

The Commission initiated its generic hearing process on July 13, 1976. After hearings in this proceeding were concluded, the Public Utility Regulatory Policy Act (PURPA) was passed by Congress and signed into law, becoming effective in January of 1979. It is interesting to note that the purposes of Title I of PURPA resemble strikingly this Commission's goals of regulation. Moreover, the ratemaking standards outlined in the Act are virtually identical to the issues considered in the generic proceedings. This section of the Decision spells out the provisions of PURPA and the extent of the Commission's compliance therewith.

RESOURCE MANAGEMENT - POWER POOLING

Resource management is defined as the matching by the utility of its supply of electricity and its customer load at any given time. Efficient resource management is achieved by meeting customer load, by each utility individually or as a member of a group or pool, with the least expensive commitment of capital and energy resources. Achievement of that goal results in minimizing consumers' rates.

In this regard, the Decision describes current operations and planning in Colorado including the present degree of cooperative planning and coordination among Colorado utilities. The Commission outlines certain impediments to further coordination, but concludes that Colorado utilities are not taking full advantage of the opportunities that may be available to achieve the benefits of a more unified approach to resource management. In conclusion, the Commission sets forth the steps it plans to take to encourage Colorado utilities to pursue the benefits of greater coordination.

LOAD MANAGEMENT

Load management is defined as any method of altering or controlling the timing or magnitude of a utility's load. The purpose of load management is the reduction of a utility or system peak, which over time will allow the moderation of capital expenditures for generation and transmission facilities ultimately minimizing rates. Load management can be accomplished directly by the utility or through the action of the customer.

The Commission discusses the limited implementation of load management in Colorado at present, the range of available techniques, and the potential benefits to a utility system and its customers of the implementation of load management in general, and interruptible rates in particular. It is noted that, over the long term, load controls may be a more effective strategy to match customer demands with system needs than time-of-use rates.

Finally, the Commission orders each jurisdictional Colorado electric utility which potentially could benefit therefrom, to develop and file interruptible rates as an option for certain of its high-use customers. The Commission identifies industrial, commercial air conditioning, and irrigation customers as likely candidates for the optional interruptible service. The applicable utilities and specific categories of service for which voluntary, interruptible rates initially are to be developed for each of these utilities are specified in Appendix B to the Decision. The Commission further states its intention of requiring each utility which is part of a winter-peaking system to explore the cost-effectiveness of the implementation of voluntary interruptible rates for its customer classes primarily contributing to that peak.

The criteria to be employed in the design of interruptible rates are described in Appendix C to the Decision.

CO-GENERATION

Co-generation is defined as the production of both heat and electricity from a single plant. The potential benefits of co-generation as well as the technical and institutional barriers to its implementation are identified. The Commission notes that, despite the fact that all utility, industrial, and commercial parties in this proceeding were silent on this topic, it is one which must be considered seriously.

All jurisdictional electric utilities are ordered to survey their territories and submit to the Commission within six months an inventory of all potential sites and joint ventures for co-generation facilities, including a description of any barriers to implementation.

COSTING METHODOLOGY

The topics of costing methodology and rate structure were the primary focus of the generic proceeding. The choice of a costing methodology is the starting point of rate design. The numerous average and marginal costing methodologies considered during the course of the hearing are reviewed and analyzed. The Commission concludes that although a marginal cost analysis is not now appropriate for implementation in Colorado as a basis for determining costs on which rates are to be set, it should be utilized for a more limited purpose.

It is emphasized that the rejection of the marginal cost methodology as a basis for setting rates does not imply that time-of-use rates are inappropriate for Colorado utilities. Time variant rates can be designed based upon an average cost methodology. It is found that the record in this proceeding demonstrates that both the marginal and average costs of providing power vary with time in Colorado. The various average cost methodologies considered during the course of the proceeding are discussed and analyzed. Because of the likely long-run benefit, the Commission orders the selective and cautious implementation of time-of-use rates based upon an average cost methodology where such rates will be cost-effective.

The Commission orders that a presumption exists which favors the implementation of time-of-use rates, and that each utility has the burden of showing that the costs outweigh the benefits of such implementation in its particular case. In order that any adverse shifts in demand may be prevented, the customer response to time-of-day rates will be monitored.

Time-of-day rates initially are ordered for the majority of industrial and large commercial classes of customers. These are customers for whom the requisite metering costs will be minimal, for whom extensive consumer education may be undertaken most effectively, and for which the greatest potential for usage responsiveness exists. Also, the implementation of seasonal rates is ordered for all electric utilities which potentially could benefit from such implementation.

All jurisdictional electric utilities are ordered to file time-of-day rates applicable to their industrial and large commercial customers at the time of their next general rate filing, but not later than six months after the effective date of the Decision. The Commission will then determine their appropriateness on a utility-by-utility basis. All jurisdictional electric utilities listed in Appendix D are ordered to file seasonal rates within the same time frame. A methodology for the calculation of time-of-use rates is set forth in Appendix E, and for seasonal rates in Appendix F.

DECLINING BLOCK RATES

The Commission concludes that the continued use of the declining block rate is counterproductive because it lacks public understanding and acceptability, which are essential factors for any rate design.

A different rate form is proposed for the vast majority of Colorado residential and commercial electric customers. Any rate which is designed to recover the costs of providing service must account for the three causative components of that cost: customer costs, energy costs, and demand costs. The new rate should be designed to recover these cost components through separate charges. Customer costs are now to be recovered from every customer as a flat monthly charge without regard to usage. Energy costs are to be recovered from each customer on a flat per-kilowatt-hour basis. All energy usage will thus be charged on equal and a uniform basis, regardless of usage level or customer class. Finally, the new rate should recover all demand-related costs, including customer-related plant costs, in two or three separate blocks which recognize the decreasing nature of the demand cost. By thus separating the rate into the above categories, it is expected that public understanding of the nature and amount of the costs to be recovered in each category of the rate will be enhanced.

Each jurisdictional utility is ordered to file with the Commission rate schedules for its residential, commercial, and industrial customers in accordance with the new rate design concept at its next general rate filing, or within six months of the effective date of the Decision. It is emphasized that all jurisdictional utilities should be prepared to engage in an educational program to explain fully the operation of the new rate design to all customers.

LIFELINE RATES

A lifeline approach is not adopted in this proceeding. The traditional lifeline rate design prices the initial block of electricity usage (generally defined as a subsistence amount) at a low level. The Commission addresses the various justifications advanced in this proceeding for the adoption of such a rate and sets forth the reasons such justifications have not been persuasive.

For example, it is proposed that a lifeline rate should be adopted because a minimal amount of electricity is required by individuals to maintain a minimum subsistence level. While the Commission recognizes the difficulty faced by low income consumers attempting to pay for ever-increasing electricity bills, it concludes on this record that the rate will not achieve the desired result. Among other difficulties, under a traditional lifeline approach, low usage consumers of electricity rather than low income consumers, are benefited. There is no evidence in this record that low usage consumers will, in fact, be those low income persons most in need of assistance. Adoption of a lifeline rate could thus result in a subsidy flowing from the poor to the affluent. Finally, the Commission notes that a targeted lifeline approach whereby only low income persons receive low rates for low usage previously has been invalidated by the Colorado Supreme Court as preferential and discriminatory.

It is noted that under the requirements of PURPA, the Commission must consider the adoption of lifeline rates every two years. Thus, the Commission will have a continuing opportunity to consider other possible lifeline approaches which are both legal and in the public interest.

ALL-ELECTRIC RATES

The Commission discusses the significant changes in ratemaking policy experienced by all-electric customers in Colorado, culminating in the implementation of the mandatory demand-energy rate for all new residential and commercial all-electric customers in 1975, and the subsequent modification of the mandatory aspect of that policy. It is noted that that modification was based primarily upon the lack of sufficient lead time and appropriate consumer education prior to implementation which would have enabled customers to take full advantage of the new rate.

The demand-energy rate, whereby customers are billed for both their usage and their demand on the utility system, was once again an issue in this proceeding. It is found to be an appropriate rate to implement on a mandatory basis for all new all-electric residential and commercial customers and on an optional basis for existing all-electric and high electric usage customers, so that all customers who can achieve savings under the new rate will be afforded the opportunity to do so.

Each jurisdictional utility providing all-electric service is ordered to file for all new residential and commercial customers, and to offer to existing all-electric and high usage customers, on a voluntary basis, demand-energy rates within six months of the effective date of the Decision to be effective 18 months after filing.

Utilities are directed to make every effort to inform customers as to the operation and potential benefits of these rates in the interim period. Utilities are encouraged, if possible, to provide customers with dual billings during this interim period while charging under the former rate structure, so that consumers will be able to make fully informed judgments.

SOLAR ENERGY AND HEAT STORAGE RATES

Finally, the Commission notes the potential benefits to society of the development of solar technology. The role of utility regulation in this regard should be flexible to accommodate new technology to the extent possible while remaining neutral between competing technologies. This approach will be conducive to the orderly development of nontraditional methods of technology such as solar while not burdening other customers.

The Commission discusses the distinctive usage pattern of solar customers and the appropriateness of present and proposed rate structures to the solar sector. It is noted that an appropriate rate which will recognize the difference in cost to the utility of recharging during peak and off-peak hours can be designed. Such a rate will be applicable both to solar customers and to nonsolar customers with similar heat storage attributes. The appropriate residential and commercial heat storage rate is a simple time-of-day kilowatt-hour usage rate, to be offered on a mandatory basis for all new residential and commercial heat storage customers after sufficient time has elapsed to permit adequate education to consumers.

Thus, each utility is directed to file such rates within six months after the effective date of the Decision, to become effective 18 months thereafter. Existing residential and commercial heat storage customers are to be offered the rates on a voluntary basis. The utilities are expected to engage in an informational program similar to that described in the preceeding section.

APPENDIX E

THE CALCULATION OF TIME-OF-USE RATES

Introduction

The record of this proceeding indicates that costs do vary by time of use, and that benefits will accrue to electric consumers as a consequence of rates based on those cost variations. However, the size of such benefits and the relationship between these costs and benefits is unclear. It is, therefore, proposed that TOU rates be implemented cautiously. To this end, we have ordered the implementation of TOU rates in those instances where costs of implementation are minimal (i.e., appropriate metering exists) and with the requirement that careful records be maintained to permit measurement of resultant savings. By the cautious implementation of TOU rates, the benefits that may accrue therefrom can be measured. In any event, TOU tracks cost and thus is a proper rate form.

In developing a TOU rate, cost data for each costing period is required which often will necessitate a sophisticated study. However, in an effort to place TOU methodology into perspective, we have outlined a relatively simple methodology therefor. In presenting the following discussion we hasten to note that we are presenting an example rather than a mandatory method. We fully recognize that each utility company has unique characteristics which may require variations on or, perhaps the adoption of an entirely different methodology.

In any event, the TOU cost system must meet the following criteria. Any TOU methdology:

1. Must be simple and easy to apply;
2. Must result in rates easily understood by the customer;
3. Must track costs;
4. Must be equitable;
5. Must encourage the conservation of energy;
6. Must encourage the conservation of capital.

These criteria are not necessarily in order of priority, and in some instances, these six criteria may conflict with one another. In such a situation or criteria conflict, an appropriate trade-off may well be required in order to achieve a useful rate structure. If, however, our primary regulatory goals are to save capital and energy resources, then the TOU rates that are designed must provide both an incentive to minimize use at the peak and to conserve energy. Furthermore, the design of TOU rates must take into account time periods and cost variations between those periods. We will now discuss these two last items.

Costing Periods

Utility costs will vary according to the season of the year and the time of day. The seasonal variation occurs because of the nature of the loads placed on the system, and the generating mix required to meet those loads. That is, a summer-peaking system may utilize base load, intermediate and peaking equipment to meet its summer peak, but only use base and intermediate equipment to meet its winter peak. In the case of a winter-peaking system, the reverse could be true. For either winter- or summer-peaking systems, spring and fall might have low costs in that only base load and some intermediate equipment would be necessary to meet fall or spring load. These seasons are also the normal times when routine maintenance is performed. Thus, in terms of methodology, rates could be divided into three or four seasonal blocks in order to track costs. Stelzer proposed seasonal rates for Public Service of Colorado (PSCo) divided into November-February, March-June, July-August, and September-October periods. Such suggested seasonal blocks were based on risk exposure. The March-June and September-October blocks had identical rates. The Commission believes that seasonal rate periods, in order to meet the criteria of simplicity and understandability, should be contiguous and as few as possible given the need to track costs. Assuming that a power system is constructed to meet the system peak, then the peaks of that system should be an indicator of cost differentials. A review of 1976 monthly peak data for PSCo indicates two cycles: one starting in April, reaching an annual peak in July and ending in September or October; the second encompassing the remainder of the year, with a peak in December and a secondary rise in February. The precise nature of that curve will vary from year to year depending upon various factors such as weather. Therefore, in order to derive an average curve, several years such as five to 10 years, should be used to determine the seasonal cycles. For our purposes, we will define May through September as the summer cost cycle; and October through April as the winter cycle. The average cost of meeting load during each of those periods would constitute the costs used as the basis for seasonal rates.

Within the above seasons, costs will vary almost on an hourly basis. Once again, in order to achieve a balance between confusing precision and an understandable, practical rate structure, the costs should be grouped into similar periods, and in this regard, two to three periods should be ample. The Commission is of the belief that a three-period rate would be preferable, in that costs in the peak and intermediate periods should be such as to encourage some movement off the peak while encouraging energy conservation. In any event, the definition of time periods should follow costs.

One way of defining cost periods is on the basis of loss of load probability (LOLP); that is, as Stelzer maintains, defining costs as varying directly with the probability that demand will exceed available capacity. The hour of peak demand is the hour of the greatest exposure to outage, with the other hours bearing a risk of lesser magnitude. Thus, costs can be assigned to each hour in proportion to the degree of risk (LOLP). In applying this system, Stelzer grouped the time periods for PSCo as follows:

1.	November-February	Peak	4 p.m. to 11 p.m.
		Shoulder	6 a.m. to 4 p.m.
		Off Peak	11 p.m. to 6 a.m.
2.	July-August	Peak	9 a.m. to 11 p.m.
		Off Peak	11 p.m. to 9 a.m.
3.	March-June)	Peak	9 a.m. to 11 p.m.
	September-October)	Off Peak	11 p.m. to 9 a.m.

An allied method for defining cost periods is to group hours of similar reserve margins together and thus arrive at the costing periods. The results should be similar to those obtained through the LOLP method.

A somewhat less sophisticated, but acceptable method of determining the groups is by visual examination of appropriate daily load curves. The breakpoints between pricing periods would be those points on the curve indicating the start of a new load cycle. That is, the load pattern of a utility can be regarded as a series of up and down cycles. The task of any method of cost period identification is then to identify where such cycles start and end. For example, inspection of the PSCo pattern for the summer peak day indicates a peak cycle starting at 6 a.m. and proceeding to 10 p.m. with the off peak from 10 p.m. to 6 a.m., and no shoulder period. In this instance, the load curve, exclusive of pumped storage requirements or intertie obligations, was utilized because the rates to be set will apply only to PSCo customers in the latter instance. Pumped storage is an off peak fill-in that distorts the load curve for the above purpose and should be disregarded.

The winter peak day appears to have three cycles; namely, a peak from approximately 3 p.m. to 10 p.m. a shoulder from 6 a.m. to 3 p.m., and an off peak period from 10 p.m. to 6 a.m. In the situation where available capability is less than load at the peak, the intersection of the two curves (capability and load) could be used. For example, in the PSCo summer situation, the peak would be 11 a.m. to 4 p.m., the shoulder 6 a.m. to 11 a.m. and 4 p.m. to 10 p.m., and the off peak 10 p.m. to 6 a.m. This method could not be used for the wintertime periods.

Of the various methods discussed above, the LOLP method has the strongest theoretical support, the closest connection to cost changes, and is most closely allied to existing utility procedures. Therefore, the Commission hereby expresses a preference for such procedure. The other methods are suggested in those circumtances where a utility does not utilize LOLP for its reliability calculations, and does not believe such calculations to be necessary. In such situations, the system load curve should be utilized, rather than that for the class. It is both system peak and energy that we are attempting to minimize, and a class peak off the system peak should not be penalized hereby.

Costs

After cost periods have been determined, the determination of the appropriate costs that apply to those periods must be made. The general rule to accomplish the above task is to assign those costs that apply to each class or customer to the time of use. There are, however, some costs that do not vary by time of use, but rather vary by customer. Examples of such include billing, sales, and administration costs. These costs are not time differentiated and thus should be charged in equal payments per billing period of the year.

Demand and energy charges are time differentiated, however, and these costs should be distributed among the costing periods according to the equipment used to meet the load in each period. That is, off peak costs should reflect the proportionate use of base load equipment plus a proportionate share of transmission and distribution costs including all embedded costs. Shoulder costs should include a proportion of base and cycling equipment, and required transmission-distribution costs. Peaking costs should include the cost of meeting the peak (a proportion of base and intermediate equipment and peaking equipment) including the cost of pumped storage. The full demand and energy charges for pumped storage should be levied against the peak, even though base load equipment operating in the off peak period is utilized. The above is correct because base load pumped storage equipment is used as a means of storing energy to meet the later peak and to follow load variations during the peak hours, and thus such procedure constitutes a peak cost. The proportions of such costs could be based on the relative period demand and energy use.

Rates developed from the above costs would thus be in two parts for each time period, i.e., a single demand rate per kW and a single energy rate per kWh. In addition to the above, there would be a flat monthly customer charge. Table 1 illustrates the format of such. In considering this example, it should be kept in mind that it is not intended as an actual rate, but only as an example of a TOU rate. Due to incomplete data, estimates and shortcuts have been necessary to compute the example.

Table 1 - Time-of-Use Rate Example, General Light & Power

	Cost Item		
Time Period	Customer	Demand	Energy
	($ Per Month)	($ Per kW)	(¢ per kWh)
Summer (May-September)	60.75	-	-
Peak	-	6.42	1.17
Off Peak	-	0.90	0.69
Winter (October-April)	60.75	-	-
Peak	-	4.40	0.83
Shoulder	-	3.30	0.68
Off Peak	-	0.70	0.50

Customer plant costs from a cost of service study were allocated between summer and winter, and were based on the different demand between the two seasons. It was further assumed that the higher the demand, the higher the cost. On peak costs were derived by an allocation based on summer peak; and off peak demand costs were estimated using an elasticity formula with the peak as the base.

Energy costs were computed in a similar manner.

As a consequence, customer billing costs are constant throughout the year, but demand and energy costs vary both by season and by rate period.

APPENDIX F

THE CALCULATION OF SEASONAL RATES

I. Introduction

When power costs vary significantly by season, both the utility and its customers will benefit if rates vary correspondingly. The above is particularly true because no additional metering costs are involved. An example of a general methodology for the design of time-of-use rates has been set forth in Appendix E. That procedure can be simplified greatly, however, when rates vary only by season rather than by time-of-day. This appendix will illustrate an average cost methodology that can be used to design rates that vary on a seasonal basis. Like the methodology outlined in Appendix E, the following procedure is an example only, and is not intended as a prescribed methodology. Each utility company should design rates to match its unique characteristics. It is important, however, that seasonal rates be designed on the basis of the system's load curve and not upon the load curve of any individual member distribution company.

Whatever methodology is used, the same rate design process, as utilized for time-of-use rates, must be used. To reiterate, those five steps are:

1. Selection of the seasonal periods for which seasonal rates will be designed.

2. Functionalization of costs, *i.e.*, the assignment of costs to functions such as production, transmission and distribution.

3. Classification of costs as to whether they are demand related, energy related or customer related.

4. Allocation of costs to the costing periods selected.

5. Allocation of costs to each customer group within the costing periods selected.

Of the five steps required, only the first and fourth require discussion in this appendix. The other steps employ well known methods that have long been used in standard cost-of-service studies.

II. Costing Periods

Methods of selecting costing periods for seasonal rates previously have been described in Appendix E, and need not be repeated. It is sufficient to note that when rates do not vary by time-of-day, the procedure is greatly simplified. Once again, it should be stressed that the costing periods should be related to the annual system load curve and not that of any member utility.

III. Allocation of Costs to Costing Periods

As mentioned in Appendix E, the general rule is to allocate to each costing period those costs which are appropriate to such period. As an example, investment in base load production plant should be allocated to all costing periods in proportion to its relative use in each period. Investment in intermediate or peaking units should be allocated on the basis of their relative use in each costing period. A similar principle should be used for investment in transmission and distribution plant. Expenses such as operations, maintenance, depreciation, and taxes should be allocated to each costing period in the same proportion as their related plant investment is allocated to each costing period.

After costs have been allocated, by the above process, to their appropriate costing period, standard cost-of-service procedures can be applied to allocate these costs among customer classes within each costing period. As an example, if a peak responsibility demand methodology were used, the group contribution to system peak in each costing period would be used to determine the demand allocation factors. Similar considerations would apply to the energy used in each costing period and the number of bills in each costing period. The final result would be a revenue requirement for each customer class in each costing period. This set of revenue requirements would then be reduced to specific rates to be applied to each customer class in each costing period. Rate structures as described in the text of the Decision can be employed.