(Decision No. C79-1111)

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF COLORADO

IN THE MATTER OF THE GENERIC HEARINGS CONCERNING THE RATE STRUCTURE OF ALL ELECTRIC UTILITIES OPERATING UNDER THE JURISDICTION OF THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO.	CASE NO. 5693 DECISION OF THE COMMISSION

July 27, 1979

Appearances:

Tucker K. Trautman, Esq., Denver, Colorado,
Special Counsel to the Commission;
Eugene C. Cavaliere, Esq.,
Assistant Attorney General, and
John E. Archibold, Esq., Denver, Colorado,
Assistant Solicitor General
for the Commission;

Donald W. Glaves, Esq.,
Chicago, Illinois, and
Petersen & Fonda by
Harry S. Petersen, Esq.,
Pueblo, Colorado, for
Central Telephone & Utilities Corporation;

Kelly, Stansfield & O'Donnell by
Donald D. Cawelti, Esq., Denver, Colorado, for
Home Light and Power Company;

Kelly, Stansfield, & O'Donnell by
James R. McCotter, Esq., and
Bryant O'Donnell, Esq., Denver, Colorado, for
Public Service Company of Colorado;

Horn, Anderson and Johnson by
Gregory L. Johnson, Esq.,
Colorado Springs, Colorado, for
City of Colorado Springs
Department of Public Utilities;

Gorsuch, Kirgis, Campbell, Walker & Grover by
William H. McEwan, Esq., and
Clinton P. Swift, Esq., Denver, Colorado, for
Colorado Association of Municipal Utilities,
Town of Estes Park Electric Department,
City of Fort Morgan, City of Fountain,
City of Glenwood Springs Electric System,
City of Gunnison, Town of Holly, City of Lamar,
Las Animas Municipal Light and Power Company, and
City of Longmont Electric Department;

John J. Conway, Esq.,
Denver, Colorado, for
Colorado Rural Electric Association,
Delta-Montrose Electric Association,
Grand Valley Rural Power Lines, Inc.,
Gunnison County Electric Association, Inc.,
Highline Electric Association,
Holy Cross Electric Association, Inc.,
La Plata Electric Association, Inc.,
Moon Lake Electric Association, Inc.,
Morgan County Rural Electric Association,
Rural Electric Company,
Sangre de Cristo Electric Association, Inc.,
Springer Electric Cooperative, Inc.,
Tri-County Electric Cooperative, Inc.,
Tri-State Generation
& Transmission Association, Inc.,
Wheatland Electric Cooperative, Inc.,
White River Electric Association, Inc.,
Yampa Valley Electric Association, Inc., and
Y-W Electric Association, Inc.;

R. Gregory Haller, Esq.,
Howard S. Bjelland, Esq., and
Girts Krumins, Esq.,
Montrose, Colorado, for
Colorado-Ute Electric Association, Inc.;

Richard L. Banta, Jr., Esq.,
Englewood, Colorado, for
The Intermountain Rural Electric Association;

Baxter W. Arnold, Esq.,
Sterling, Colorado, for
Highline Electric Association,
K. C. Electric Association,
Y-W Electric Association, Inc., and
Morgan County Rural Electric Association;

Robert T. James, Esq.,
Colorado Springs, Colorado, for
Mountain View Electric Association, Inc.;

Price and Cross by
Warren H. Price, Esq.,
Loveland, Colorado, for
Poudre Valley Rural Electric Association, Inc.;

Gordon H. Rowe, Jr., Esq.,
Monte Vista, Colorado, for
San Luis Valley Rural Electric Cooperative, Inc.;

Robert P. Rush, Esq.,
Salida, Colorado, for
Southeast Colorado Power Association and
Sangre de Cristo Electric Association, Inc.;

Walker Miller, Esq.,
Greeley, Colorado, for
Union Rural Electric Association, Inc.;

Bryan Blakely, Esq.,
  Fort Collins, Colorado, for
  Platte River Power Authority;

Rothgerber, Appel and Powers by
Judith C. McNerny, Esq.,
Frederick L. Coldwell, Esq., and
James M. Lyons, Esq.,
  Denver, Colorado, for
  Home Builders Association of Metropolitan Denver;

John P. Thompson, Esq.,
  Denver, Colorado,
Stephen Chesnoff, Esq.,
  New York, New York, and
Lynn J. Ellins, Esq.,
  Denver, Colorado, for
  J. C. Penney Company, Inc.;

Holland and Hart by
Jeffrey C. Pond, Esq.,
  Denver, Colorado, and
Thaddeus M. Sims, Esq.,
  Kansas City, Missouri, for
  Russell Stover Candies, Inc.;

Andrea Valasquez,
  Thornton, Colorado, of
  The Very Concerned Citizens of Adams County;

Holland and Hart by
John Flemming Kelley, Esq.,
Jeffrey C. Pond, Esq.,
Craig Blockwick, Esq., and
B. Lynn Winmill, Esq., Denver, Colorado, for
  Colorado Association of Commerce and Industry;

Gorsuch, Kirgis, Campbell, Walker & Grover by
Leonard M. Campbell, Esq., and
Clinton P. Swift, Esq.,
  Denver, Colorado, for
  Climax Molybdenum Company, a
  Division of AMAX, Inc.;

Bruce C. Driver, Esq.,
  Washington, D.C., for
  United States Department of Energy;

Welborn, Dufford, Cook & Brown by
David W. Furgason, Esq., and
Richard L. Fanyo, Esq.,
  Denver, Colorado, for
  CF&I Steel Corporation;

Bradley, Campbell & Carney by
Douglas S. Rouse, Esq.,
  Golden, Colorado, for
  Adolph Coors Company;

Philip Mause, Esq.,
  Washington, D.C.,
Laurence Edelman, Esq., and
Craig S. Barnes, Esq.,
  Denver, Colorado, for
  Environmental Defense Fund, Inc.;

McNees, Wallace & Nurick by
Henry R. MacNicholas, Esq.,
  Harrisburg, Pennsylvania, for
  Airco, Inc.;

D. Bruce Coles, Esq.,
  Denver, Colorado, for
  Mountain Plains Congress of
   Senior Organizations and
  Colorado Utilities Taskforce;

James K. Tarpey, Esq.,
  Denver, Colorado, for
  Phillips Control Corp.;

Elbridge Burnham, Denver, Colorado, _pro se_;

Richard Wood, Esq.,
  Denver, Colorado, for
  District Attorneys of First, Second,
   Seventeenth and Twentieth Judicial
   Districts, State of Colorado;

Ronald L. Lehr, Esq., and
Barry Satlow, Esq.,
  Denver, Colorado, for
  Office of Energy Conservation,
  State of Colorado.

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BY THE COMMISSION:

I.

HISTORY OF PROCEEDINGS

A.

DECISION NO. 89068

Case No. 5693 was commenced by this Commission on July 13, 1976, by the issuance of Commission Decision No. 89068. By Decision No. 89068 this Commission determined to embark upon electic utility generic hearings. The circumstances prompting the Commission to embark upon such generic hearings in Case No. 5693 were set forth in the first paragraph of page 1, Decision No. 89068, to wit:

> During the past several years, state and federal regulatory commissions have been considering nontraditional pricing and costing methodologies as factors in determining rate structure. They have been impelled to do this by considerations of economic efficiency, concerns about the environment, a newly awakened awareness of the desirability and necessity for energy conservation, and a recognition of the capital shortages with which electric utilities recently have been confronted. In view of these concerns, it has become increasingly evident that a commission which fails to take action in this area is, in fact, taking action by indirection; that is, it is putting its stamp of approval on an existing rate structure which may, in the long run, be detrimental to individual consumers and to the public at large.

After discussing why the Commission had selected the vehicle of a generic hearing to accomplish the above goals, the Commission stated that the purpose of the hearing would be to "explore pricing and costing alternatives within the context of the specific cost and load characteristics of electric utilities operating under the jurisdiction of this

Commission." The scope of the hearings was stated by the Commission to be:

> The generic hearings, as hereinafter ordered, will be devoted to an investigation of the full range of alternatives in the complex area of rate design. The purpose of such hearings will be to explore the theory and practical application of the various pricing and costing techniques, using the data currently available and becoming available during the course of the hearing. The generic hearings will include, but will not be limited to, considerations of the following topic areas: In regard to the marginal cost analysis, it will be necessary to consider methodologies estimating cost components, relevant periods, customer groupings, et cetera. With respect to time-of-use pricing, the feasibility of application through time-of-day metering, interruptible service, load management techniques, and so forth must be considered. An associated area to be explored is that of available metering technology, as well as new technology being developed, with special emphasis on the comparative costs and benefits of particular metering technologies. The utilities should be prepared to supply load data which has been and is presently being collected so that a determination can be made of information gaps which must be filled so as to determine consumer use patterns and appropriate cost assignments. In addition, some attention should be given to the measurement of demand elasticities and the extent to which these should be reflected in the rates. The above is intended to indicate particular areas of interest and not to limit the proceedings. (Decision No. 89068, p. 3)

Because of the complexity of the issues to be considered in generic Case No. 5693 and the possible ramifications thereof, all electric utilities in Colorado operating under the jurisdiction of the Commission were named Respondents in the proceeding. In addition, the Commission ordered that any person, firm or corporation desiring to intervene as a party in Case No. 5693 would be required to file for leave to intervene therein on or before September 13, 1976. The

Commission further provided in Decision No. 89068 that subsequent to the September 13, 1976, deadline for intervention, the Commission would issue a decision setting forth (1) a service list containing the names of all parties to the proceeding and (2) a proposed agenda which would govern Case No. 5693.

B.

PARTIES

As stated above, Commission Decision No. 89068 named as Respondents in Case No. 5693 all electric utilities operating in the State of Colorado which were subject to the jurisdiction of the Commission on the date Decision No. 89068 was entered. Electric utilities operating in the State of Colorado which are subject to the jurisdiction of this Commission are generally of three types: investor-owned electric utilities, certificated municipal electric utilities (with respect to service outside the corporate limits of the municipalities), and rural electric associations. The electric utility parties set forth in Decision No. 89068 were as follows:

1. Investor-Owned Electric Utilities

Central Telephone & Utilities Corporation

Home Light and Power Company

Public Service Company of Colorado

2. Certificated Municipal Electric Utilities (as to Service Outside Corporate Municipal Boundaries)

City of Colorado Springs
Department of Public Utilities

Town of Estes Park
Electric Department

City of Fort Morgan

City of Fountain

City of Glenwood Springs
Electric System

City of Gunnison

Town of Holly

City of Lamar

Las Animas Municipal Light and Power Company

City of Longmont
Electric Department

City of Loveland
Light & Power Department

Platte River Power Authority

3. Rural Electric Associations

Carbon Power and Light, Inc.

Colorado-Ute Electric Association, Inc.

Delta-Montrose Electric Association

Empire Electric Association, Inc.

Grand Valley Rural Power Lines, Inc.

Gunnison County Electric Association, Inc.

Highline Electric Association

Holy Cross Electric Association, Inc.

The Intermountain Rural Electric Association

K. C. Electric Association

Kit Carson Electric Cooperative, Inc.

La Plata Electric Association, Inc.

Moon Lake Electric Association, Inc.

Morgan County Rural Electric Association

Mountain Parks Electric, Inc.

Mountain View Electric Association, Inc.

Poudre Valley Rural Electric Association, Inc.

Rural Electric Company

San Isabel Electric Association, Inc.

San Luis Valley Rural Elective Cooperative, Inc.

San Miguel Power Association, Inc.

Sangre de Cristo Electric Association, Inc.

Southeast Colorado Power Association

Springer Electric Cooperative, Inc.

Tri-County Electric Cooperative, Inc.

Tri-State Generation & Transmission Association, Inc.

Union Rural Electric Association, Inc.

Wheatland Electric Cooperative, Inc.

White River Electric Association, Inc.

Yampa Valley Electric Association, Inc.

Y-W Electric Association, Inc.

Commission Decision No. 89068 further provided that any person, firm or corporation desiring to intervene in Case No. 5693 as a party would be permitted to intervene upon the filing of an appropriate pleading on or before September 13, 1976. By subsequent decisions of the Commission (89105, 89177, 89240, 89267, 89350, 89366, 89390, 89552 and 90279), the additional following parties were granted leave to intervene in Case No. 5693:

4. Intervening Parties

Colorado Municipal League

Home Builders Association of Metropolitan Denver

J. C. Penney Company, Inc.

Russell Stover Candies, Inc.

The Very Concerned Citizens of Adams County

Colorado Association of Commerce and Industry

Advocates for Conservation of Energy (ACE)

Climax Molybdenum Company, a Division of AMAX, Inc.

The Gates Rubber Company

Environmental Action of Colorado

Federal Energy Administration (FEA)

CF&I Steel Corporation

Platte Valley Action Center

Adolph Coors Company

Environmental Defense Fund, Inc.

Airco, Inc.

Mountain Plains Congress of Senior Organizations

Colorado Utilities Taskforce

Weld County Council on Aging

Pikes Peak Gray Panthers

Colorado Rural Electric Association

Colorado Association of Municipal Utilities (CAMU)

Senior Citizens for Fair Utility Rates of Pueblo County

San Luis Valley Regional Council on Aging

El Centro Communidad de Lafayette

East Central Community Action Program

Elbridge Burnham, pro se

Betty P. Mahaffy, pre se

J. A. Mahaffy, pro se

Jonathon Mahaffy, pro se

Phillips Control Corp.

Johns-Manville Corporation

Colorado Open Space Council Committee
on Utility Rate Reform

Plessey Chatsworth

American Science & Engineering, Inc.

Energy Conservation Supporting Services
Colorado Department of Education

Colorado Common Cause

City and County of Denver

District Attorneys for the First, Second,
Seventeenth and Twentieth Judicial Districts,
State of Colorado

Office of Energy Conservation, State of Colorado

On March 9, 1977, Respondents Carbon Power & Light, Inc.; Rural Electric Company, Inc.; Tri-County Electric Cooperative, Inc.; Kit Carson Electric Cooperative, Inc.; Springer Electric Cooperative, Inc.; Wheatland Electric Cooperative, Inc.; and Moon Lake Electric Association, Inc., filed a petition with this Commission. By such petition these Respondents requested an order of this Commission excluding them from participation in Case No. 5693. As grounds for the petition, the named Respondents urged that each was and is an out-of-state electric company serving but few customers in the State of Colorado. By Decision No. 90331, dated March 15, 1977, the Commission granted the petition of said Respondents.

On April 25, 1977, Intervenors Betty P. Mahaffy, J. A. Mahaffy, and Jonathon Mahaffy filed a letter with the Commission requesting permission to withdraw as intervenors in Case No. 5693. The request was approved.

C.

AGENDA

On October 19, 1976, the Commission entered Decision No. 89530 which set forth a proposed agenda for the conduct of the proceedings in Case No. 5693. Decision No. 89530 provided for the conduct of Case No. 5693 in three stages: Stage I would consist of preliminary proceedings; Stage II would consist of theoretical principles and costing methodologies; and Stage III would involve rate structure implementation. Stages I, II and III, respectively, were described by the Commission in Decision No. 89530 in part as follows:

Stage I - Preliminary Proceedings

1. Each party who desires to do so shall file a statement of position which shall include the following:

a. Suggested changes, if any, in proposed agenda including suggested time periods and the reasons therefor;

b. A summary of the party's preliminary position with respect to each issue, if known;

c. A statement of the nature and extent of the party's participation in each stage of the proceedings and the utility category in which it fits for purposes of Stage III. In this regard each party should set forth a list of its witnesses and a brief summary of their testimony. (For purposes of Stage II and Stage III testimony, reference may be made to written testimony presented before other regulatory bodies which the party may wish to adopt.)

d. A statement of the data, studies or information which the party believes is relevant and necessary to resolve issues presented, e.g., elasticity studies, data on load characteristics, etc., indicating the existence and availability of such information or the methodology which should be used to obtain it and the cost, if known. The party should concentrate on issues relevant to the stages and utility categories in which it is interested. (With respect to Stages II and III, relevant and necessary data and the utility's ability to gather certain data or perform studies may vary by utility category.)

2. The Commission will issue a revised agenda.

3. A pre-hearing conference will be held for the purpose of resolving problems with the revised agenda and discussing other procedural matters, including hearing dates and data collection.

4. The Commission, if necessary, will order the gathering and circulation of data or information or the conducting of studies by various parties based upon an analysis of their respective statements of position.

Stage II - Theoretical Principles and Costing Methodologies

Stage II deals with the theoretical principles and costing methodologies which may be used to design electric rate structures. In Stage II the Commission will examine alternative costing methodologies and alternative pricing methodologies. Because there is an abundance of literature and an extensive written dialogue within the regulatory community concerning this theoretical area, the Commission anticipates that Stage II may be handled without the necessity of oral hearings. In lieu thereof, each party who desires to do so may file written testimony of its witnesses or file copies of written testimony by persons presented in other similar proceedings which the party desires to adopt as its own. In response thereto, other parties may file comments or rebuttal either through counsel or the written testimony of witnesses.

Stage III - Rate Structure Implementation

In Stage III the Commission will examine the feasibility of implementing rate structures based upon various principles and costing methodologies developed in Stage II. In other words, it will be necessary for the Commission to determine whether its assumptions with respect to the theoretical principles and costing and pricing methodologies are realistic. The Commission must also determine whether the benefits of implementation outweigh the costs. Due to the fact that the electric utilities operating under the jurisdiction of this Commission are not homogeneous, the issues in Stage III should be considered within the context of the data base and specific load characteristics of the electric utilities operating within the State of Colorado. In order to do this, the Commission proposes that the utilities be grouped, to the extent possible, for purposes of data collection, studies and hearings on the merits, into the following categories:

(1) Investor-owned utilities;

(2) Municipal systems including municipal power authorities;

(3) Generation and transmission REAs;

(4) Winter-peaking distribution REAs;

(5) Summer-peaking distribution REAs.

Each electric utility which is a party to this proceeding should designate its appropriate utility category.

The Commission also established by Decision No. 89530 a proposed procedure for the filing of written testimony and cross-examination thereof. The Commission also provided in Decision No. 89530 for the holding of a prehearing conference to be held on January 19, 1977.

Subsequent to the entry of Decision No. 89530, and in accordance therewith, statements of position regarding Stage I of the proceeding were filed by the following parties:

On November 18, 1976, by

J. C. Penney Company, Inc.

On November 19, 1976, by

The Intermountain Rural Electric Association

Union Rural Electric Association, Inc.

Colorado-Ute Electric Association, Inc.

Empire Electric Association, Inc.

On November 22, 1976, by

City of Colorado Springs Department of Public Utilities

Highline Electric Association

Y-W Electric Association, Inc.

K. C. Electric Association

Central Telephone & Utilities Corporation

Weld County Council on Aging

Adolph Coors Company

Sangre de Cristo Electric Association, Inc.

Platte River Power Authority

Town of Estes Park Electric Department

City and County of Denver

Climax Molybdenum Company, a Division of AMAX, Inc.

Poudre Valley Rural Electric Association, Inc.

City of Lamar

Environmental Defense Fund, Inc.

Home Builders Association of Metropolitan Denver

Public Service Company of Colorado

Federal Energy Administration
(United States Department of Energy)

Colorado Association of Commerce and Industry

Colorado Association of Municipal Utilities

Home Light and Power Company

CF&I Steel Corporation

The Gates Rubber Company

On November 23, 1976, by

White River Electric Association, Inc.

On November 24, 1976, by

Mountain View Electric Association, Inc.

Pikes Peak Gray Panthers

The Very Concerned Citizens of Adams County

Morgan County Rural Electric Association

San Isabel Electric Association

On November 26, 1976, by

Colorado Open Space Council

Gunnison County Electric Association, Inc.

Mountain Plains Congress of Senior Organizations

City of Gunnison

Senior Citizens of Lafayette

After reviewing the statements of position filed by the above parties, the Commission, on January 14, 1977, entered Decision No. 90017, whereby a revised agenda was established for Case No. 5693. In the revised agenda, the Commission provided dates for the filing of documents and data by utility parties, dates for information requests by parties, dates for filing of direct testimony and dates for cross-examination of direct testimony and for public witness testimony.

On January 19, 1977, the Commission held a prehearing conference for the purposes of receiving suggestions or objections concerning the following: revised agenda, hearing dates, and the collection of data. The prehearing conference was attended by a large number of parties, and a substantial number of suggestions and objections were then presented regarding the revised agenda, hearing dates, and collection of data. A substantial number of questions were also raised.

On April 13, 1977, the Commission, after considering the suggestions and objections made, together with the questions posed by the parties at the prehearing conference, entered Decision No. 90503, which was responsive to the foregoing. By Decision No. 90503 the Commission issued a second revised agenda which incorporated many of the suggestions made by the parties at the prehearing conference. By the second revised agenda, the Commission provided for the filing, by utility parties, of certain documents and data for calendar years 1974, 1975 and 1976, as fully described in paragraph No. 16 of the Statement in said Decision No. 90503. Such documents and data were required to be filed with this Commission on or before June 1, 1977. Paragraph No. 16 of Decision 90503 states:

On or before May 2, 1977, each electric utility party subject to the jurisdiction of the Commission, except any utility named in Decision No. 90331, shall file with the Commission the original and 17 copies of a Notice of Information Available, and shall serve a copy thereof upon each party of record in this proceeding. The Notice of Information Available shall list in separately numbered paragraphs the title to all documents that the utility has available containing the following information for the calendar years 1974, 1975 and 1976:

A. Load factors and load patterns on both a system-wide basis and for each customer rate class;

B. Cost-of-service studies for each customer rate class;

C. Elasticity studies;

D. Marginal cost studies;

E. System data reflecting supply and demand for electric service by customer rate class;

F. Power pool data;

G. Annual daily peaks for summer months and winter months for the years listed above, including load duration curves, percentage of forced outage, scheduled maintenance and reserve margins by hour for the annual peak days involved.

With respect to the information in subparagraphs A through G, above, which the utility does not have in its possession on May 2, 1977, or has been unable to obtain by said date, the utility shall include in the Notice of Information Available a statement as to the approximate cost and time that would be necessary for the utility party to obtain such information. The utility party may also include in this statement any written argument as to why it should or should not incur the costs necessary to acquire the information.

The Notice of Information Available shall also list in separately numbered paragraphs the title to all documents that the utility has available containing the following information:

H. Load management devices and systems both self-contained and under utility control;

I. Energy storage systems of all forms including, but not restricted to, those associated with solar systems;

J. Metering devices and systems including remote meter reading systems, systems providing automatic billing, and systems providing displays for information feedback to customers.

In the second revised agenda, the Commission provided for the filing of written direct testimony by witnesses for utility parties on or before August 5, 1977, by witnesses for nonutility parties on or before September 9, 1977, and by witnesses for the Staff of the Commission on or before October 14, 1977. Rebuttal testimony was ordered to be filed on or before November 11, 1977. The Commission provided in paragraph No. 23 of Decision No. 90503 that each party wishing to cross-examine any witness, filing written direct testimony or written rebuttal testimony, was to file with the Commission on or before November 25, 1977, a Designation of Intent to Cross-Examine. Such designation was to list, by name, those witnesses that the party's attorney intended to cross-examine and the approximate amount of time anticipated for such cross-examination. The purpose of such designation was to give the Commission an indication of the amount of time that should be reserved for cross-examination. The Commission further provided in said decision for hearing dates for the cross-examination of utility witnesses, nonutility witnesses and Staff witnesses. (However, due to the amount of time requested by the parties in their respective Designations of Intent to Cross-Examine, the dates for cross-examination were later vacated and additional dates were provided.)

Pursuant to the provisions of paragraph Nos. 16 and 17 of Decision No. 90503, voluminous data and documents were filed by the following utilities:

On May 27, 1977 by

Mountain View Electric Association, Inc.

On May 31, 1977, by

Empire Electric Association, Inc.,

San Luis Valley Rural Electric Cooperative, Inc.,

Tri-State Generation and Transmission Association, Inc.

Southern Colorado Power division of Central Telephone & Utilities Corporation,

Home Light and Power Company

On June 1, 1977, by

Public Service Company of Colorado

Colorado-Ute Electric Association, Inc.

City of Colorado Springs Department of Public Utilities

Southeast Colorado Power Association

Municipal Electric Systems Group (Estes Park, Fort Morgan, Fountain, Glenwood Springs, Las Animas, Longmont and Lamar)

Y-W Electric Association, Inc.

Poudre Valley Rural Electric Association, Inc.

Union Rural Electric Association, Inc.

Highline Electric Association

Grand Valley Rural Power Lines, Inc.

Holy Cross Electric Association, Inc.

Yampa Valley Electric Association, Inc.

K. C. Electric Association

On June 2, 1977, by

Sangre de Cristo Electric Association, Inc.

Platte River Power Authority

On June 9, 1977, by

San Miguel Power Association, Inc.

On June 10, 1977, by

Morgan County Rural Electric Association

White River Electric Association, Inc.

On June 29, 1977, by

Public Service Company of Colorado
(additional data and documents)

On July 8, 1977, by

Colorado-Ute Electric Association, Inc.
(additional data and documents)

San Isabel Electric Association, Inc.

On August 9, 1977, by

Public Service Company of Colorado
(additional data and documents)

On August 15, 1977, by

Southeast Colorado Power Association

Pursuant to the provisions of paragraph No. 19 of Decision No. 90503, written direct testimony of the following-named witnesses (and supporting exhibits) were filed on behalf of the following utility parties:

J. H. Ranniger, Joe D. Heckendorn, J. K. Fuller, Donald Athen, Irwin M. Stelzer, and Jules Joskow,
for Public Service Company of Colorado;

Keith R. Cardey,
for Southern Colorado Power division of Central Telephone & Utilities Corporation;

Robert L. Dekker,

for Town of Estes Park Light and Power Department;

Glenn W. Calvert (two volumes),

for City of Fort Morgan Electric Department and for Colorado Association of Municipal Utilities;

Gerald B. Trotter,

for City of Longmont Electirc Department;

Ralph Barbee,

for Las Animas Municipal Light and Power Department;

Frank J. Bustamento,

for City of Fountain Public Utilities;

Gary L. West,

for City of Gunnison;

L. A. Blotiauex,

for City of Glenwood Springs Electric System;

Bill D. Carnahan,

for City of Lamar Utilities Board;

Larry R. Day and Frederick A. Kuhlemeier,

for Colorado-Ute Electric Association, Inc.;

Russell E. Dunn, Melvin C. Rich, Walter M. Schirra, Donald A. Murry, Stanley R. Lewandowski, Jr., and Carl N. Stover, Jr.,

for The Intermountain Rural Electric Association;

Leon L. Wick,

for Poudre Valley Rural Electric Association, Inc.;

Robert R. Goldenstein,

for K. C. Electric Association,
Y-W Electric Association, Inc., and
Highline Electric Association;

Gerald E. Hager and Richard L. Arnold,

for Union Rural Electric Association, Inc.;

Richard L. Arnold, Lawrence A. Crowley, Everett C. Johnson, Delbert L. Hardy, Dick Wilkerson, Stanley R. Lewandowski, Jr., Samuel M. Sampson, and Carl N.

Stover, Jr., for Colorado Rural Electric Association;

James Lim and Louis W. Tempel,

for Climax Molybdenum Company,
a Division of AMAX, Inc.;

Jann W. Carpenter,

for CF&I Steel Corporation;

Joseph M. Cleary,

for Airco, Inc.;

Charles W. King,

for J. C. Penney Company, Inc.;

Elvin C. Phillips,

for Phillips Control Corp.;

Alan Chalfant, Mark Drazen and Morris Brubaker,

for Colorado Association of Commerce and Industry;

Eugene Coyle,

for Colorado Utilities Taskforce and Mountain Plains Congress of Senior Organizations;

William J. Gillen and Ernst R. Habicht, Jr.,

for Environmental Defense Fund;

Craig R. Johnson,

for United States Department of Energy;

Whitfield A. Russell, George J. Parkins and Barbara B. Murray,

for the Staff of the Colorado Public Utilities Commission.

Pursuant to the provisions of paragraph No. 22 of Decision No. 90503, certain parties filed rebuttal testimony as provided for in said paragraph:

J. H. Ranniger, J. D. Heckendorn, Thomas J. Boardman, and J. K. Fuller,

for Public Service Company of Colorado;

Gerald D. Hager and Richard L. Arnold,

for Union Rural Electric Association, Inc.;

Richard L. Arnold, Dick Easton, Delbert L. Hardy, Alan F. Ingram, Donald A. Murry, Samuel P. Sampson, Donald E. Smith and Carl N. Stover, Jr.,

for Colorado Rural Electric Association;

Jann W. Carpenter,

for CF&I Steel Corporation;

Mark Drazen,

for Colorado Association of Commerce and Industry;

Eugene Coyle,

for Colorado Utilities Taskforce and Mountain Plains Congress of Senior Organizations;

Buie Seawell,

for Colorado Office of Energy Conservation;

Craig R. Johnson,

for United States Department of Energy;

Whitfield A. Russell,

for the Staff of the Colorado Public Utilities Commission.

On December 8, 1977, Dr. Barbara B. Murray, who had filed written direct testimony on behalf of the Staff of the Colorado Public Utilities Commission, filed a letter with the Commission requesting leave to withdraw as an economic consultant to the Staff of the Commission. On December 13, 1977, by Decision No. 91805, the Commission granted leave to the Staff of the Commission to withdraw the testimony of Dr. Murray, and ordered that Dr. Murray's testimony be stricken from the record in Case No. 5693.

On December 20, 1977, the Staff of the Commission filed a motion with the Commission for leave to submit additional testimony on behalf of the Staff. Said motion requested that the Commission permit the Staff to file on or before January 6, 1978, the testimony of Dr. Thomas K. Standish. On December 22, 1977, by Decision No. 91860, said motion of the Staff of the Commission for leave to file the written direct testimony of Dr. Thomas K. Standish was granted by the Commission.

On December 30, 1977, written direct testimony of Dr. Thomas K. Standish was filed by the Staff of the Commission.

As provided by paragraph No. 23 of Decision No. 90503, the parties to Case No. 5693 filed Designations of Intent to Cross-Examine 44 of the witnesses who had filed either written direct testimony or written rebuttal testimony.

On December 2, 1977, the Commission entered Decision No. 91758 in which it set forth a witness schedule. Therein the names and the date or dates on which each witness was required to be made available for cross-examination were established.

On December 13, 1977, the Commission entered Decision No. 91804 modifying the schedule for cross-examination of witnesses contained in Decision No. 91758.

On December 7, 1977, starting at 10 a.m., 2 p.m., and 7 p.m., the Commmission heard oral testimony from 46 witnesses from the general public.

As provided in paragraph Nos. 26 and 27 of Decision No. 90503, the Commission conducted oral hearings on the following dates for the purpose of taking the cross-examination of witnesses who had filed written direct testimony and/or written rebuttal testimony: December 8, 9, 14, and 15, 1977; January 18, 19, 20, 25, and 26, 1978; February 1, 2, 3, 8, and 9, 1978; March 8, 9, 15, 16, 22, and 23, 1978; April 5, 6, 19, and 20, 1978; and May 10, 1978.

At the conclusion of the oral hearing on May 10, 1978, the Commission provided that any party so desiring could file a statement of position herein on or before October 2, 1978, and a reply to any filed statement of position on or before November 17, 1978. The Commission reserved December 15, 1978, for oral argument, if so requested by the parties.

On May 25, 1978, the Commission entered Decision No. C78-717 in which it reiterated the dates previously specified for the filing of statements of position and replies, and for oral argument, and further admitted into evidence all written direct testimony and supporting exhibits that had not been made the subject of a <u>Designation of Intent to Cross-Examine</u> by any party to Case No. 5693.

Opening statements of position were filed on the following dates by the following parties:

On October 2, 1978, by

J. C. Penney Company, Inc.

Public Service Company of Colorado

City of Colorado Springs Department of Public Utilities

United States Department of Energy

Home Builders Association of Metropolitan Denver

Climax Molybdenum Company, a Division of AMAX, Inc.

Colorado Office of Energy Conservation

Colorado Association of Municipal Utilities (representing the Utility Board of the City of Lamar, Town of Estes Park, City of Fort Morgan, City of Fountain, City of Longmont Electric Department, City of Gunnison, Town of Holly, Las Animas Light and Power, and City of Glenwood Springs Electric System)

The Intermountain Rural Electric Association

Colorado Association of Commerce and Industry

CF&I Steel Corporation

Mountain Plains Congress of Senior Organizations

Colorado Utilities Taskforce

Colorado-Ute Electric Association, Inc.

Colorado Rural Electric Association

On October 5, 1978, by

Environmental Defense Fund

On October 6, 1978, by

Southern Colorado Power division of Central Telephone & Utilities Corporation (Southern Colorado Power)

As provided by the Commission on the last day of oral hearing and by Decision No. C78-717, replies to statements of position were filed on the following dates by the following parties:

On November 16, 1978, by

Colorado Office of Energy Conservation

On November 17, 1978, by

Public Service Company of Colorado
Colorado Rural Electric Association
Colorado Association of Commerce and Industry
Mountain Plains Congress of Senior Organizations
Colorado Utilities Taskforce
CF&I Steel Corporation
Colorado Association of Municipal Utilities
Climax Molybdenum Company, a Division of AMAX, Inc.

On November 22, 1978, by

Environmental Defense Fund

On November 30, 1978, by

Home Builders Association of Metropolitan Denver

The date of December 15, 1978, had been reserved for oral argument with respect to each party's filed statement of position, if deemed necessary by the Commission. The Commission declined to order such oral argument and therefore no hearing was conducted on December 15, 1978.

On November 28, 1978, Intervenor J. C. Penney Company, Inc., filed a letter with the Commission. Such letter indicated that J. C. Penney Company, Inc., was in receipt of the Colorado Office of Energy Conservation's Reply Statement of Position. Said Reply Statement of Position addressed, among other issues, the impact of what is popularly known as the National Energy Act, and specifically the Public Utility Regulatory Policy Act (PURPA), on this Commission's deliberations in Case No. 5693. Intervenor J. C. Penney Company, Inc., in said letter, stated that in the event the Commission desired to take into consideration the impact of the National Energy Act, each party should be given an opportunity to state its position with respect to the impact of the National Energy Act upon the Commission's deliberations in Case No. 5693. In response to said letter, the Commission entered Decision No. C78-1578, on November 28, 1978, in which it ordered that all parties would be permitted to file, on an optional basis, on or before December 20, 1978, statements of position with respect to the impact of the National Energy Act and, in particular, the Public Utility Regulatory Policy Act of 1978 (Public Law 95-617 (November 9, 1978), 92 Stat. 3117, 16 U.S.C. 2601, et seq.).

Pursuant to the Commission's Order in Decision No. C78-1578, several parties filed statements of position concerning the impact of the National Energy Act upon the Commission's deliberations in Case No. 5693:

On December 20, 1978, statements were filed by:

Colorado Rural Electric Association
CF&I Steel Corporation
Colorado Association of Commerce and Industry
Climax Molybdenum Company, a Division of AMAX, Inc.
Environmental Defense Fund

and on December 21, 1978, by:

J. C. Penney Company, Inc.

II.

DISCUSSION, FINDINGS OF FACT AND CONCLUSIONS ON FINDINGS OF FACT

A.

GOALS OF REGULATION

Regulation of public utilities has become increasingly complicated. However, the economic theory utilized to justify such regulation is direct and simple. In the text-book model of the competitive ideal, transactions among numerous atomistic private entities, devoid of market power, result in the correct setting of prices and the most efficient allocation of resources. By contrast, electric public utilities are natural monopolies and as such are not subjected to the forces of competition. Thus, regulation of public utilities is justified as a substitute for competition. From the above point in the analysis of public utility regulation, the simplicity ends.

A mere description of the electric utility industry in Colorado graphically demonstrates the enormity of this Commission's regulatory task. Presently, there are 64 electric utilities in this state: three investor-owned utilities; 30 municipal electric utilities; two generation and transmission rural electric associations (G&Ts); and 29 distribution REAs.[1] The above-enumerated electric utilities serve approximately 1,024,426 customers in Colorado and provided in excess of 20,774,800,000 kilowatt-hours (kWhs) of

[1] There are also federal power systems which operate in Colorado which were not participants in this generic case; accordingly, their absence made it infeasible to address the full range of issues in this proceeding.

electricity to such customers in 1977. Having total sales of $506 million for the year 1977, the Colorado electric utility industry is one of the largest economic enterprises in the state. However, simply recognizing the enormous size of the electric utility industry fails fully to indicate the importance and impact of the electric industry upon our society.

The critical importance of electrical energy to our society, comprised of industrial, commercial, agricultural, and residential sectors, needs little elaboration. Historically, public utilities, because of their protected and natural monopoly status, have been given the responsibility of meeting the demands of their customers, no matter how large or at what time those demands occur. Perhaps as best stated by the Supreme Court of Colorado in Englewood v. Denver, 123 Colo. 290, 300, 229 P.2d 667 (1951), "The nature of the service is such that all members of the public have an enforceable right to demand it." In short, public utilities, unlike other businesses, cannot refuse new business; they legally are obligated to serve the public at large.

In Colorado, business expansion has been substantial. Over the last five years, the demand for electric energy statewide (measured in kWs) has grown at a 5.1 percent compounded annual rate. This growth is attributable to both the demand of new customers and increased usage by existent customers. For example, over the last five years, the number of new customers has grown at a 4.6 percent compounded annual rate. It is of interest that the rural areas of our state, whose growth rate has been historically less than that of the urban areas, now have an annual compounded growth rate in new customers of

8.1 percent. And finally, notwithstanding the conservation ethic, the energy usage level (measured in kWhs) of all customers over the last five years has increased at a 1.7 percent annual compounded rate. Although some forecasters predict a moderation of these recent growth trends, such predicted moderation has been questioned in light of Colorado's potentially massive energy development and its large concomitant requirement for electricity. In any event, there is no doubt that the Colorado electric power industry, now and for the foreseeable future, will experience significant growth.

While growth in demand for electric service traditionally has been considered a favorable development, such optimism has been tempered in recent years as the costs of capital and natural resources necessary for the production of electricity have reached historically high levels. The consumers of electricity recently have felt the financial effects of this continued growth in demand and cost acceleration. For example, a residential customer with an average usage (500 kWh) has experienced an increase in rates of 39.5 percent over the last five years. It can be anticipated that rate increases will continue in the foreseeable future.

The electric utility industry is characterized by capital intensity. For example, of every dollar paid by the consumer for electricity, approximately 70 cents is attributable to the cost of capital and 30 cents is attributable to fuel and other operating costs. The production of electricity has always required large investments of capital for construction of power plants. However, construction costs in general, as well as the costs of environmental protections,[2] required for power plants and transmission facilities have increased dramatically in recent years. Public utilities, in order to finance these accelerating construction costs, must, of necessity, resort to the capital markets. Many factors, including the high rate of inflation, have caused investors to demand increasingly higher returns in recent years, which ultimately are reflected in the utilities' costs of capital.

In addition to capital, a major ingredient in the production of electricity is fuel. While Colorado is fortunate in that it has some hydrogeneration available, the bulk of Colorado's electricity is produced by the use of coal, natural gas, and fuel oil. Although Colorado utilities, because of their primary reliance upon coal, have escaped the severe price increases experienced by Eastern utilities, which rely principally on foreign oil, increases in coal prices in recent years have exceeded the general inflation rate and may continue to do so for the foreseeable future. While only a relatively small percentage of electricity is generated in Colorado by natural gas and oil, the prices of those fuels also have increased substantially. For example, federal deregulation efforts which culminated in the Natural Gas Policy Act of 1978 have resulted, on average, in a 25 percent increase per year in the price of natural gas. It also should be recognized that the actions of the Organization of Petroleum Exporting Countries (OPEC)

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[2] In constructing generating and transmission facilities, utilities now must comply with numerous federal environmental statutes including the Clean Air Amendments of 1977; the Federal Resource, Conservation and Recovery Act; the Federal Toxic Substances Act; the Clean Water Act of 1977; the Federal Endangered Species Act of 1973; the Federal Wild and Scenic Rivers Act; the Federal Surface Mining Control and Reclamation Act of 1977; and the Federal Wilderness Act of 1964.

have increased the financial burden on the consumer by substantial increases in the price of oil. In short, the costs of the two most important resources relied upon by electric utilities for the generation of electricity, i.e., capital and fuel, have now reached historic highs. These costs, in all probability, will continue to exceed the general inflation rate in the United States. Increased costs of capital and fuel inevitably translate into increased utility bills for Colorado consumers.

Increases in demand for electricity and the upward spiral of costs to meet that demand do not relieve Colorado utilities of the responsiblity of providing adequate and reliable service. At the moment, the reliability situation is critical. For example, on July 25, 1978, between 3 p.m. and 4 p.m., Public Service Company of Colorado experienced its peak demand of 2,492 megawatts (MW). Public Service Company was able to serve only 2,427 MW or 97.4 percent of that demand from its own resources because of generating plant outages. Fortunately, Public Service Company, at the time of said peak demand, had available purchased power of 100 MW, plus 24 MW available from power pool reserves, which enabled it to serve its peak load with a reserve margin of 59 MW or 2.3 percent. Colorado-Ute Electric Association, Inc. (Colorado-Ute), experienced its winter peak of 433.7 MW at 7 p.m. on January 2, 1979. Colorado-Ute could only supply 368.1 MW or 84.9 percent of its imposed load from capacity available to it. Additional capacity of 98.4 MW made available to Colorado-Ute through power pool reserves and interchange provided a total available capacity of 466.5 MW resulting in a reserve margin of 32.8 MW or 7 percent. Such reserve margins are significantly below those deemed sufficient to assure adequate reliability. Without concerted conservation efforts, reliability can be improved only with continued construction of power generating facilities and other arrangements to obtain power, such as pooling interchanges or purchases.

The high levels of capital costs, the increasing cost of fuel, and the diminution of power reserve margins, coupled with significant consumer resistance to higher rates, poses an increasingly difficult dilemma for utility regulation in Colorado. This Commission's primary responsibility is to assure that rates charged to consumers for electricity are the lowest possible, commensurate with the provision of adequate service. While the above proposition is easily stated, its attainment is not readily assured. To enable a utility to provide continued adequate service, it is necessary for the Commission to authorize increased rates from time to time. On the other hand, should the Commission set rates at a level below a utility's costs, including those costs of raising necessary capital, eventual deterioration of utility service becomes inevitable. It should thus be understood, as the United States Supreme Court has stated in Federal Power Commission v. Hope Natural Gas, 320 U.S. 591, 603 (1944), "the ratemaking process . . . involves a balancing of the investor and the consumer interest."

In fulfilling its ratemaking responsibilities, this Commission must be cognizant of a number of regulatory goals among which are: (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. The foregoing collateral goals of ratemaking and utility regulation deserve further comment.

Revenue adequacy requires that utility rates be established at a level which will allow each utility to recover its prudently incurred operating costs and its cost of capital. Until recent years, the determination of the adequate revenue requirement of a utility was the focus of regulatory concern. Thus, regulation historically concerned itself with the overall level of a utility's earnings. The design of rate structures to generate the required revenues was left to the discretion of the utility's management. Similarly, the choice of services to be offered the consuming public and the technology to be utilized in the provision of such services were also left to utility management. Accordingly, commission regulation traditionally did not "second guess" management decisions with regard to rate design, services offered, or technology.

Currently, many regulatory commissions have assumed a more aggressive role in rate design (sometimes called "spread-of-the-rates"), service, and technological issues. Nevertheless, the obligation to offer a utility the opportunity to obtain overall earnings sufficient to recover prudently incurred operating costs and the cost of capital remains a primary area of regulatory responsibility.

In the instance of an investor-owned utility, the cost of capital includes not only debt service on bonds, but, in addition, a sufficient return upon the utility's equity to allow it to continue to raise the capital necessary to provide utility service. The regulatory goal of adequate utility revenue partakes of constitutional due process dimensions, which have been described cogently by the United States Supreme Court in the case of _Bluefield Waterworks & Improvement Co. v. Public Service Commission_, 262 U.S. 679 (1923). In _Bluefield_, the United States

Supreme Court indicated that unless a regulatory commission grants a utility a fair rate of return, not only will the affected utility and its customers suffer because of service inadequacies, but the investors in the utility will suffer a confiscatory taking of their property in violation of the Fourteenth Amendment to the Constitution.

The increasing cost of and demand for electricity make the goals of efficiency and conservation critically important. However, these goals must be put in proper perspective. Initially, the primary responsibility of assuring that a utility is efficiently run is the responsibility of management. The Supreme Court of Colorado has indicated that utility management must be allowed the opportunity to exercise reasonable business judgment and discretion in the operation of the utility, and that the role of regulation is to monitor the exercise of that discretion in order to assure that no abuse occurs. Mountain States Telephone & Telegraph Co. v. Public Utilities Commission, 182 Colo. 269, 513 P.2d 721 (1973). In other words, although this Commission cannot assume the primary role of utility management, this is not to say that this Commission is without authority to encourage, through rates or otherwise, the most efficient operation possible. Thus, simply to set rates which will cover all costs begs the fundamental question -- that of the reasonableness and prudence of costs. The primary question which must be addressed by this Commission is whether or not the management of any given utility has done everything in its power to assure that all costs, upon which its rates are based, are, in fact, as low as possible. Accordingly, this Commission will continue to review managerial decisions and will take appropriate remedial action, where warranted.

While conservation has become a more visible concern in recent years, it always has been an implicit goal of regulation. Conservation, if conceived as the wise use, rather than nonuse, of resources, is merely a subcategory of efficiency. If management is operating a utility as efficiently as possible, it is then minimizing the use of resources and thus "conserving" resources. Regulation must be concerned both with the conservation of capital and of energy. Given the significant increase in the cost of capital and of energy, it is readily understandable why conservation has become increasingly important.

Fundamental fairness has long been a goal of regulation. After it has been determined that the level of utility revenues allowed is adequate, but no more than adequate, that the utility costs passed along to the ratepayer are commensurate with efficient utility operation, and that capital and energy costs have thus been controlled to the extent possible, it then is necessary to spread the payment of those revenues among the customers of the utility. Quite simply, fundamental fairness dictates that customers similarly situated be treated in similar fashion. Costs, types of service, and the characteristics thereof, historically have been the prime considerations for determining whether customers are similarly situated; however, other noncost factors also have been utilized in making such determination. A recent Colorado Supreme Court decision makes it clear that residential gas customers may not be treated differently merely because of disparities in income. Mountain States Legal Foundation v. Public Utilities Commission, ___ Colo. ___, 590 P.2d 495 (1979). However, the Mountain States decision has in no way eliminated fundamental fairness as a goal of regulation.

(Colorado Constitution, Article XXV). By virtue of its interstate operations, Tri-State Generation & Transmission Association, Inc. (Tri-State), which is a generation and transmission REA serving 10 member distribution companies in Colorado, has been considered beyond the jurisdiction of this Commission. The Federal Energy Regulatory Commission (FERC), rather than this Commission, has jurisdiction over the provision of wholesale power as, for example, the direct sales on a wholesale basis of Public Service Company power to various retail electric utilities. Several municipal utilities purchase power from a quasi-governmental association, over which this Commission has not exerted jurisdiction. And finally, most of the distribution REAs receive a portion of electric power from the federal government's Western Area Power Administration (WAPA), over which the Commission does not have jurisdiction. Thus, while the scope of many regulatory problems facing this Commission is wide, this Commission's ability to address those problems is limited.

Three years ago this Commission commenced Case No. 5693 in order to study a variety of electric utility regulatory issues. In order to fully explore all presented issues and to allow a full response thereon from all electric utilities; industrial, commercial and residential customers; environmental and consumer groups; and the U.S. Department of Energy, and to provide an opportunity for all to study and consider these issues carefully, this Commission decided to consider these issues outside of the limiting confines of usual ratemaking proceedings. In this generic proceeding, the Commission has considered such topics as: efficiency and coordination of resource management by and among utilities, load management

Rates must be spread among customers, and such task should be accomplished, utilizing cost, service, and all other relevant economic and social customer characteristics, in as equitable a fashion as possible.

Recognition of the foregoing goals of regulation does not ensure their automatic attainment. Under the best of circumstances, no more can be realistically expected than a continuous, and approximate, attainment of such goals. A more rapid and constant movement in the desired direction of attaining regulatory goals by the Commmission is hampered in two respects.

First, state commissions (including the Colorado Commission) historically have not had a full complement of financial and personnel resources to accomplish their assigned tasks. It is evident that, given the complexity of current regulatory issues and the size and attendant resources of the electric industry, any attempt by a truncated commission conscientiously to regulate will be hurt seriously by a diminished technical and technological capability. To the extent that commission resources are lacking, regulatory analysis and monitoring necessarily suffers.

Second, as is further explained below, many of the issues involving utilities require a unified approach. However, this Commission does not have unlimited jurisdiction over all public utilities operating in the State of Colorado, nor does this Commission have jurisdiction over many other utility entities whose decisions affect Colorado consumers. As a result of constitutional limitation, this Commission has jurisdiction over municipally owned utilities only to the extent of service provided outside of the municipal boundaries alternatives for utilities and their customers, various average and marginal costing methodologies, diurnal and seasonal time-of-use rates and other rate structures, including declining block, lifeline, all-electric, and special solar rates. The Commission, having embarked upon this massive task and having considered all the attendant issues related thereto, has concluded that the vast majority of the issues as presented in this proceeding can be analyzed and resolved only on a coordinated basis. Inasmuch as this Commission has neither the jurisdiction nor the resources fully to effectuate a coordinated analysis and resolution of the issues, the Commission realizes that it is necessary to undertake the new role of encouraging nonjurisdictional utilities and governmental entities (not subject to the jurisdiction of this Commission, but which affect Colorado utility operations) to give serious consideration to the policy which the Commission will establish for those utilities subject to its jurisdiction. The course established by this Decision will be effective only with the cooperation of jurisdictional utilities, nonjurisdictional utilities and governmental entities. Finally, it should be emphasized that while the Commission has explored in depth some very significant and far-reaching issues regarding electric utility regulation, it intends, by this Decision, and by subsequent decisions, to move carefully. It is our intention to ensure that the generic goals established herein both are beneficial to the consuming public and are reasonably susceptible to implementation by the various utilities involved.

B.

PUBLIC UTILITY REGULATORY POLICY ACT OF 1978

Subsequent to the close of the record in this proceeding, Congress passed and the President signed into law the Public Utility Regulatory Policy Act of 1978, Public Law 95-617; 92 Stat. 3117; 16 U.C.S. 2601, et seq. (PURPA). In general, Title I of PURPA requires state regulatory bodies such as this Commission and nonregulated utilities to hold evidentiary hearings to "consider" and "make a determination" whether certain rate standards set forth in PURPA are "appropriate" to be implemented in the state and to adopt certain other policy standards if required by state law.

Before outlining the provisions of PURPA and discussing this Commission's compliance therewith, a few preliminary comments are appropriate. First, as will be discussed below, the purposes of Title I of PURPA bear a striking resemblance to this Commission's goals of regulation as discussed above. Moreover, the ratemaking standards outlined in PURPA are virtually identical to the issues considered in this proceeding. The identity of issues will facilitate this Commission's compliance with the Act. However, the Commission is concerned that PURPA and the regulations promulgated thereunder by the Federal Energy Regulatory Commission (FERC) not result in unnecessary and burdensome regulation of Colorado utilities and imposition of additional regulatory and administrative burdens upon this Commission. Ultimately, any such additional costs and burdens are reflected in rates to consumers. Specifically, this is a problem with reference to information required to be filed by utilities pursuant to §133 of PURPA, which problem will be discussed below. An additional concern is that PURPA fails to require consideration and determination of the appropriateness of the federal standards by electric utility wholesalers, who sell power for purposes of resale. The exclusion of wholesale utilities from the coverage of PURPA necessarily frustrates the achievement of its purposes, as explained more fully hereinafter.

1. Relevant Provisions of PURPA

Section 101 of the Act sets forth its purposes. They are as follows:

> 1) To encourage conservation of energy supplied by electric utilities;
>
> 2) To encourage the optimization of the efficiency of use of facilities and resources by electric utilities; and
>
> 3) To encourage equitable rates to electric consumers.

The Conference Report of the Committee on H.R. 4018 makes clear that the above purposes are not listed in order of priority and should be considered independently (p. 69). Further, the Report indicates that it is not necessary that all of the three purposes be achieved in order to determine that commission action complies with the spirit and intent of the Act. It is only necessary that commission action accomplish any of the purposes to be achieved therein, and that the others not negatively be affected for such a finding to be made (p. 69).

Pursuant to §111(a) of PURPA, this Commission is required to "consider" certain ratemaking standards, outlined below, and "make a determination concerning whether or not it is appropriate to implement such standard to carry out the purposes of this title." It is noted in that section that nothing prohibits this Commission from making a determination "that it is not appropriate to implement any such standard, pursuant to its authority under otherwise applicable State law."

Section 111(d) of PURPA sets forth the following ratemaking standards, which must be considered by the Commission:

1) Cost of service -- the rates for each class of service must be designed, to the maximum extent practicable, to reflect the cost of providing service to such class as determined under §115(a).

2) Declining block rates -- the energy component of a rate for any class of service may not decrease as consumption increases unless the utility demonstrates that those energy costs in fact decrease as consumption increases.

3) Time-of-day rates -- the rates for each class of service shall be on a time-of-day basis which reflects the cost of providing service at different times of day unless such rates are not cost-effective for that class, as determined under §115(b).

4) Seasonal rates -- rates charged by an electric utility for the provision of service to each class of consumer shall be on a seasonal basis which reflects the costs of providing such service to each class of consumer at different seasons to the extent that costs vary seasonally for the utility.

5) Interruptible rates -- 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.

6) Load management techniques -- each electric utility shall offer to its electric consumers such load management techniques as the commission has determined will a) be practicable and cost-effective, as determined under §115(c), b) be reliable, and c) provide useful energy or capacity management advantages to the electric utility.[3]

Within two years after the enactment of PURPA, this Commission is required to begin consideration of the six rate standards as set forth in §111(d). A Commission decision that any and all such standards are or are not "appropriate" to carry out the purposes of Title I must be made within three years after enactment of PURPA; that is, by November 9, 1981. Section 113(b) requires that commission consideration be made after public notice and hearing, and that the determination of the appropriateness of those standards be made in writing, based upon findings included in such determination and upon the evidence presented at the hearing, and be available to the public.

Fortunately, PURPA provides in §124, that proceedings commenced by a regulatory agency prior to the date of the enactment of PURPA shall be treated as complying therewith "if such proceedings and actions substantially conform" to the requirements of the Act. Section 124 of PURPA provides that any proceeding commenced before the date

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[3] PURPA sets forth a second set of policy standards which appears in §113 as follows:

1) master metering;
2) automatic adjustment clauses;
3) information to consumer;
4) procedures for termination of electric service; and
5) advertising.

These subjects are not at issue in this proceeding and thus will not be dealt with herein.

of enactment of the Act, but not completed before such date, shall comply with the requirements of the Act, "to the maximum extent practicable, with respect to so much of such proceeding or action as takes place after such date."

Section 114 of PURPA, which deals with lifeline rates, provides that PURPA does not prohibit this Commission from approving a rate for the essential needs of residential electric consumers, which rate would be lower than the cost of providing such service. Essential needs, pursuant to the Act, would be defined by the commission. It is provided further in §114 of PURPA that if any electric utility subject to the commission's regulation does not have a lifeline rate in effect two years after the date of enactment of the Act, the commission shall then determine, after an evidentiary hearing, whether such a rate should be established by the commission for implementation by the utility.

Section 133 of PURPA requires that each electric utility "shall periodically gather information" pursuant to rules promulgated by FERC as the utility determines necessary "to allow determination of costs associated with providing electric service." Section 133 also requires that the gathered information be separated, to the maximum extent practicable, into the following categories: customer costs, demand costs, and energy costs. Further, it is required by §133 that the following information be filed with FERC:

1) The costs of serving each electric consumer class by consumption, voltage served, time of use, and other appropriate factors;

2) Daily kW demand load curves, for all classes combined and by class, representative of daily and seasonal differences in demand;

3) Annual capital, operating, and maintenance costs for transmission and distribution services and for each type of generating unit;

4) Costs of purchased power, including representative daily and seasonal differences.

FERC must promulgate rules within 180 days from the enactment of PURPA and may establish exemptions from the information-gathering requirements thereof, if such is not likely to further the purposes of §133. While the purposes of §133 are not entirely clear, the Conference Report indicates that the information as gathered by each utility is intended to facilitate the "consideration and determination" process (p. 86). Finally, §133 requires the affected utilities to file such gathered information with FERC and state regulatory commissions, and make the same available to the public within two years of enactment of PURPA, and every two years thereafter.

2. Compliance With PURPA

In light of the extensive public participation as well as the extensive analysis and testing of the relevant issues herein, this Commission has made every effort in this proceeding (including the Decision herein) to comply with the provisions of PURPA so as to avoid unnecessary duplication of effort in the future. Specifically, as mentioned above, §124 of PURPA makes it clear that this proceeding, even though commenced prior to the date of enactment of PURPA, can be utilized to satisfy the requirements of "considering" and "determining" whether it is appropriate to implement the federal rate standards in Colorado, and thus comply with the purposes of the Act. As the Statement in this Decision indicates, this Commission provided widespread notice of its intention to study the issues as specified in this proceeding, and further provided an opportunity for a broad range of parties with diverse interests to intervene and provide input into the consideration of such issues. In addition, this Commission required all electric utilities in the State of Colorado to file all information necessary for the consideration of these issues. Such information was made available to all parties in the proceeding and to the public at large. At the time of enactment of PURPA, this Commission had completed its hearings, closed the record, and received statements of position from the parties. It is the belief of this Commission that proceedings in this Case No. 5693 "substantially" have conformed to the requirements of the Act. Once PURPA became law, this Commission offered all parties the opportunity to file supplementary statements of position regarding PURPA's requirements and its applicability to this proceeding. And finally, this Decision fully complies with both the procedural requirements of PURPA §111(b) and is reviewable in court in compliance with PURPA §123.

Moreover, all of the rate standards set forth in PURPA §111(d) were specifically made issues in this proceeding and have been thoroughly "considered" as required by §111(a). The Conference Report makes it clear that the type of proceedings envisioned by PURPA may include those of a generic nature, even though the rate standards must be considered on a utility-by-utility basis (p. 72). Thus, as will become clear in the discussion of the substantive issues in this Decision, this Commission has herein made the PURPA required rate standards determinations on a utility-by-utility basis, when possible. In those instances where insufficient information was available regarding specific utilities, the Commission has withheld final determination until a later date or until the utility's next rate proceeding.

3. Federal Cooperation

This Commission has made substantial progress toward full compliance with regard to consideration of and determinations concerning the §111(d) PURPA rate standards in Case No. 5693. As part of this proceeding, we have further requested that the Respondent utilities perform certain additional studies, using prescribed methodologies, and provide further information to this Commission, in order to implement this Decision. As always, we have proceeded with caution, and we have carefully considered the burden that any requirement of this Decision will place upon the affected utilities and ultimately upon the ratepaying public.

In light of the substantial information gathered and filed by the Respondent utilities herein, this Commission is concerned that the FERC rules and regulations, established pursuant to §133 of PURPA, which required Colorado utilities to gather and file such information, will be duplicative and may serve no substantial useful purpose. To preclude an increase in consumers' rates as a result of unnecessary regulation, this Commission urges FERC to consider exemption of Colorado utilities from the information requirements of PURPA §133, to the extent that the Decision and utility information filed herein renders the submission of such information duplicative or unnecessary.

C.

RESOURCE MANAGEMENT -- POWER POOLING

Resource management can be defined simply as the matching by the utility of its supply of electricity to its customer load at any given time. This matching occurs, of course, in the short run on a minute-to-minute basis and in the long run over the planning cycle. Resource management can be handled individually by each utility, or by several utilities grouping or pooling their electrical supplies. The goal of efficient resource management is to meet the customer load at any given time with the least expensive commitment of capital and energy resources.

Resource management has always been an integral part of the utility industry and has been a primary responsibility of utility management. While this Commission does not intend to preempt management's primary role with regard to resource management, this issue is of paramount importance, particularly in respect to plant expansion and the level of electric rates in Colorado. Therefore, the role of management in regard to resource utilization should be monitored closely by this Commission. The record in this proceeding indicates that Colorado utilities are not taking full advantage of the potential and to that extent are not realizing the substantial benefits that may be achieved through a more unified and coordinated utility approach to resource management.

The potential benefits to be derived by a coordinated resource approach are easily described. From a short-run operational point of view, an individual utility, if operating in isolation, or without coordination with other utilities, can rely upon only its existing and available generating facilities. As the load of such a solitary utility rises during the day, the utility employs its available generating units in increasing order of running costs, proceeding from base load units to intermediate units and finally to peaking units. At any given point in time, the utility attempts to meet the next increment of demand with its available generating unit having the lowest incremental operating cost.

To the extent that a utility may obtain power not only from its own generating units but also from the resources of another utility, savings can usually be achieved. For example, a utility which is capable of meeting its load from its resources only can be placed in the circumstance where at a given time it is necessary to commit an oil-fired combustion turbine generating facility which has a very high operational cost. However, at the same time another utility may not be experiencing outages or peak demands and would therefore have generating capacity and energy available at a much lower cost.[4] In essence, a greater number of generating units and a greater diversity of loads within a unified and coordinated system produces an optimal use of resources with consequent lower costs than would lesser aggregations of loads and resources operated in isolation. Interconnection alone does not assure that savings will occur; the further step of integrating operations also must be taken.

From a long-term planning point of view, such coordination can also result in savings both to the utilities and their customers. Substantial benefits

[4] If the two utilities in this hypothetical example were jointly planning the daily commitment of their generating units, the likelihood of their relying upon one another and thus saving operation costs would be enhanced.

(attributable to economies of scale and avoidance of unnecessary redundancy) can be derived from building fewer but larger generating and transmission facilities. Such coordinated resources can be connected by high-capacity transmission facilities and can achieve the requisite level of reliability with lower reserve margins than would be required by uncoordinated or isolated resources. The construction of large generating and transmission facilities is more feasible where utilities jointly participate in the financing and construction thereof. By the same token, small utilities find it difficult, if not impossible, to finance such a large single project alone. Moreover, the decision as to the type (i.e., base load, intermediate or peaking) and location of generating facilities, should be made on a unified basis so as to achieve the greatest benefit for the total system. Also, transmission facilities should be sized and built, not only to serve a particular utility, but also to promote interconnection and coordinated operations among all utilities of the region. Such coordinated long-term planning cannot only reduce the per-unit capital expenditures of all utilities involved, but it can also help a total system achieve operational efficiency and improve reliability.

1. Current Operations and Planning

a. Colorado Systems[5]

Retail electric service in Colorado is furnished by 62 electric utilities comprised of three investor-owned power companies, 29 distribution rural electric associations, and 30 municipally owned electric utilities. Colorado wholesale power is supplied to the above-described distribution systems by five utilities: Western Area Power Administration (WAPA), Public Service Company of Colorado (Public Service Company), Colorado-Ute Electric Association, Inc. (Colorado-Ute), Tri-State Generation & Transmission, Inc. (Tri-State), and Platte River Power Authority (Platte River).

The 1977 Colorado electric load was 20,774,800 megawatt-hours with an estimated diversified summer peak demand of 3,781.3 megawatts. In order to serve this 1977 load, the below utilities had available capacity[6] as follows:

[5] This information is compiled from the Commission's Staff report, Colorado Electric 1977-1987 Supply Survey, which is a part of the Commission's records and of which official administrative notice is hereby taken. That report is attached as Appendix A.

[6] Adjusted for summer operating conditions.

UTILITY	MW
Public Service Company	2,440
Southern Colorado Power	106
Colorado-Ute	312
Tri-State	498
City of Colorado Springs	368
Platte River	151
All Other Municipals	131
TOTAL	4,006

The total Colorado electric generating capability is comprised of: 71 percent steam, 14 percent internal combustion turbines, 11 percent conventional hydro and 4 percent pump storage hydro. The steam, internal combustion, and combustion turbine units which are fossil fueled were fired 82.9 percent by coal, 15.6 percent by natural gas, and 1.5 percent by oil.

By the end of 1987, Colorado utilities now plan to nearly double available generating capacity. Such will be accomplished by adding 3,820 MW, comprised of 3,290 MW steam (fossil), 200 MW pump storage hydro and 330 MW steam (nuclear).[7] Thus, by the end of 1987, Colorado utilities will have a total available generating capability of 7,826 MW; with 77 percent of such capacity steam (fossil), 7 percent internal combustion turbines, 8 percent conventional hydro, 4 percent pump storage hydro, and 4 percent steam (nuclear).

[7] The nuclear facility listed is, of course, Public Service's Fort St. Vrain station which was not in service at the time of the Colorado Electric 1977-1987 Supply Survey.

Mention should also be made of the advantage to Colorado utilities of the availability of hydro and pump hydro storage capacity. If hydro storage capacity is available to Colorado utilities as a peaking resource,[8] it can be coordinated with thermal units so as to maximize the effective capacity of both types of units. Further, a pumped storage hydro unit, such as the Cabin Creek facility operated by Public Service Company, allows this system both to pump water during off-peak hours with then available thermal units, and at peak hours to generate electricity by releasing the stored water. Such resources are extremely helpful in minimizing the cost of electricity to the consumer but, as discussed below, they should be managed on a more systematic and coordinated basis.

b. Power Pools

The above-described Colorado power systems do not operate in isolation. There are presently two power pools in Colorado: the Inland Power Pool (IPP) and the Colorado Power Pool (CPP). The membership of IPP includes Public Service Company, Colorado-Ute, Platte River, Salt River Project, Tri-State, the City of Colorado Springs Department of Public Utilities, and WAPA. The membership of CPP includes Public Service Company, Southern Colorado Power, the City of Colorado Springs Department of Public Utilities, and the City of Lamar. In general, the purpose of IPP and CPP is to share the reserves and resources of the entire pool. By such sharing, the reserve requirements of each pool member is minimized. One of the major advantages of

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[8] Currently, WAPA imposes restrictions on its hydro capacity which prevent its full utilization as a peaking resource. See Discussion in Part III-B-1, infra.

power pooling is that each pool member, in an emergency, may draw upon the power reserves of other pool members when it cannot meet its demand with its own resources. For example, should one member experience an unscheduled outage of a generating facility, such utility may then draw upon the power reserves of other pool member utilities. An additional benefit of power pooling is that members of the pool coordinate the scheduled maintenance of generating units. However, in Colorado maintenance scheduling is not done with a view toward minimizing cost but is done primarily to assure that minimum levels of spinning reserves are maintained.

The advantages of such power pooling arrangements are evident. However, it is the view of the Commission that more coordination, cooperation, and power pooling among Colorado utilities could be and should be undertaken. Presently, no central clearinghouse exists to control and monitor daily unit commitment and economic dispatch of generating units throughout the service areas of pool members. In fact, Colorado has three separate control areas; namely, one operated by Public Service Company, one operated by WAPA's Missouri River Basin (MRB) and one operated by WAPA's Colorado River Storage Project (CRSP). Thus, the coordination of the hydro resources of WAPA with the thermal resources of Public Service Company and other pool members can generate economies which are beyond the relative capacities of each pool member. However, the lack of a consolidated control center[9] precludes the full

[9] The Commission realizes that an impediment to establishment of one consolidated control center is the reluctance of one or more utilities to delegate effective control of their own generating units, which the establishment of a consolidated control center would entail.

realization of all the potential benefits of power pooling on an on-going basis. In other words, the record herein makes it clear that operational coordination among power pool members does not occur on a real-time, automated basis which would be directed toward minimizing production costs for the region.

c. Bilateral Arrangements

In addition to the power pooling agreements mentioned above, Colorado utilities are governed by numerous bilateral interconnection agreements. These agreements permit the contracting utilities to interconnect their transmission systems with the transmission systems of other suppliers. Such arrangements result in more reliable service to the utility customers. Moreover, any such interconnection agreement provides a vehicle for reciprocal wheeling arrangements whereby each utility may deliver power to loads of another utility. This represents another instance wherein construction of duplicate transmission lines is avoided, with consequent savings. For example, WAPA, Public Service Company, and Southern Colorado Power wheel power to Colorado-Ute loads, and Colorado-Ute, in turn, wheels power to the loads of those same power suppliers.

Interconnected system operation permits a participating utility to purchase, sell, and exchange power and energy with other power suppliers when necessary. Such transactions may occur through an outright sale of capacity and energy, or may involve a simple exchange whereby one utility provides energy to another utility at a given time and recalls energy at a mutually agreeable time. For example, Colorado-Ute has received power and energy from

WAPA during periods when Colorado-Ute's Hayden units have been forced or scheduled out of service. This "loaned" power and energy is then returned to WAPA by Colorado-Ute during periods when excess thermal capacity is available on the Colorado-Ute system. Public Service Company and WAPA have a similar agreement.

Notwithstanding the foregoing, it is clear that Colorado utilities have not taken advantage, to the extent possible, of the many available opportunities for coordination which such bilateral agreements can provide. Moreover, if such currently existing bilateral agreements were multilateral in nature, rather than bilateral, the possibilities for benefiting Colorado's consumers would be enhanced. In short, the more resources that can be utilized in a coordinated and cooperative manner to supply a given Colorado load, the more efficient and effective will be the match between power supply and power demand.[10]

d. Long-Term Planning

Most power planning generally is accomplished by each individual utility anticipating its own future load requirement. However, some planning coordination is evident among Colorado utilities. For example, the Western Systems Coordinating Council (WSCC), which is an association of electric utilities in the western part of the United States, provides a mechanism for voluntary planning among utilities.

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[10] In highly integrated pools, coordination of all the resources occurs as if those resources were owned by one utility company, and no pool participant knows or is concerned whether it is buying or selling at any given moment. Reconciliation of transactions is made after-the-fact, in accordance with contract formulae which assure that each participant's position is maintained at a level which it would have maintained without such contract. New England Power Pool provides one such example.

While WSCC has initiated and coordinated many innovative projects, such innovation principally has involved West Coast utilities rather than Rocky Mountain Power Area (RMPA) utilities. Finally, there are numerous *ad hoc* arrangements and negotiations among various Colorado utilities concerning the planning of power in and around the RMPA.[11]

However, the record in this proceeding evidences the absence of a formal and unified approach to long-term power planning in Colorado. Other regions of the nation no longer rely upon *ad hoc*, bilateral planning arrangements, such as those which generally govern utilities in Colorado. Instead, many other regions in the country have adopted a variety of multilateral or pooling arrangements. Pooling in other regions has served as a continuing mechanism for identifying problems, expedition of the negotiation of problems and affording all affected utilities access to the planning of, and participation in, new bulk power resources. In short, it is only by coordinated planning, which looks to the whole Colorado power picture, that the expansion of Colorado's bulk power supplies can proceed in a fashion calculated to meet consumer need. Also, only by such planning can the state's utilities be expected to provide electrical service to Colorado customers at the lowest possible rates.

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[11] The difficulty is that projects are sized, designed and constructed by one or a few utilities which then market their excess after such planning is completed. This leads to obvious suboptimality. See Chapter 10 of the *National Power Grid Study* for a further discussion of the need for more coordinated planning in Colorado.

2. Problems of Further Coordination

a. Operations

Achieving the optimal power operational characteristics which are the outgrowth of coordination will not be accomplished free of problems. The first, and perhaps foremost problem, is that Colorado's utilities view their respective systems as largely self-contained and self-sufficient. This self-contained and self-sufficient outlook dates from the time when the resources necessary to supply electricity were inexpensive, and the concomitant need for power coordination and cooperation among utilities was not pressing. Furthermore, the Colorado public/private power disputes which occurred in the 1950s and 1960s also contributed to the compartmentalized attitude of Colorado's bulk power suppliers. Even though the conditions which previously led to this self-contained outlook on the part of Colorado's utilities no longer exists, the contractual framework which evolved from these earlier conditions still remains. For example, Tri-State (as do all other firm power customers of WAPA) purchases power from WAPA at rates of delivery which are proportional to Tri-State's total demand ("load pattern service"), whereas deliveries in a peaking mode would be more valuable to Tri-State now and in the future. However, CRSP insists upon load pattern service so that it may close its hydro units from time to time and thus purchase thermal energy during Tri-State's off-peak periods. Both the above-mentioned off-peak purchases and maintenance, performed by CRSP and the utilities served by CRSP are not expressly planned to coincide with the availability of less costly thermal energy. Accordingly, any savings realized through existing coordination arrangements are random and less than what could be realized by consolidation of existing control areas. The consolidation of control areas, to be most cost effective, should operate and manage the control area's resources on a "one-system" basis.

More appropriately, CRSP should be utilized to serve a specified level of customer loads (energy and capacity). This goal could well be achieved by an agreement among the parties that CRSP would serve such a customer level and that CRSP's generation would be dispatched by a consolidated control center in a way that maximizes its value to the region as a whole. Currently, CRSP first accommodates the needs of its customer utilities and then provides power to noncustomer utilties. Such a result means that each nonfederal system now attempts to optimize the use of its resources on a bilateral basis. The Commission finds that such approach foregoes the synergism which the Commission expects and desires to result from a comprehensive, multilateral arrangement.

Colorado and the Rocky Mountain region have geographic characteristics which may present obstacles to further coordination among utilities. In this regard, the rugged and mountainous terrain of Colorado creates problems for construction of transmission facilities.[12] Apparently, fewer rights-of-way are now available through the mountain passes, which makes interconnection beyond that now existing more expensive. However, we find that presently existing transmission facilities within Colorado are adequate for most, if not all, coordinated operations. A major obstacle to full power coordination among utilities in the region is

[12] The Colorado terrain requires that the limited rights-of-way across the Rockies be planned and designed to accommodate reasonably the needs of all the state's utilities and not merely the needs of the proponents of new transmission.

the lack of transmission facilities continuing across state lines, primarily to the north and south. We further recognize that the great distances between load centers in Colorado and the other regions of the West makes interconnection and coordination difficult but still not impossible. While Colorado utilities, of course, must be concerned about the reliability of their respective systems, the distance and terrain problems perhaps can be alleviated by more extensive agreements for joint construction, displacement, and wheeling.

The current power pools are dominated by one very large supplier -- Public Service Company of Colorado. This situation results in a potential disparity between the power pooling benefits achievable by the customers of the large utility (Public Service Company) and those achievable by the customers of the smaller utilities. Small systems, relatively, will benefit more operationally from coordination than large systems will benefit. However, the incremental cost of cooperation to large systems is relatively small and to small systems is relatively great. This situation can be ameliorated by coordination agreements which will "split-the-savings" (not necessarily on a 50-50 basis) and thus recognize the above cost and benefit differences. Furthermore, such coordination agreements should include non-Colorado utilities, so that Colorado utilities can look beyond the borders of Colorado for similar load and size power pool participants. Such "multi-state" power pools would provide benefits to all parties involved. With development of adequate transmission ties, prime candidates for inclusion in a "multi-state" pool would be Public Service Company of New Mexico, the Arizona Public Service Company, as well as utilities in California and the Pacific Northwest.

As previously discussed, the benefits of coordination increase as more parties participate.[13] A significant impediment to increased coordination of Colorado's utilities is that there are numerous parties, not subject to regulation by this Commission, whose cooperation is crucial to the achievement of operational efficiencies which may be achieved through coordination. For example, as the description of the Colorado power system demonstrates, WAPA is one of the prime suppliers of electricity in Colorado. Furthermore, WAPA has one of the most flexible types of power generation facilities, namely, hydro. WAPA's operations are not subject to the jurisdiction of this Commission. Tri-State is another major transmission utility in Colorado which, because of its interstate operations, heretofore has not been considered subject to the jurisdiction of this Commission. Platte River has also been considered beyond Commission jurisdiction because of its municipal ownership. A non-Colorado utility that might participate beneficially in any pooling arrangement is beyond the jurisdiction of this Commission. Thus, this Commission has no authority to require coordination by utilities not subject to our jurisdiction, but can only seek to persuade such nonjurisdictional utilities of the benefits of coordination with those utilities which are subject to our jurisdiction.

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[13] A corresponding drawback, we are informed, is that the pace of negotiations slackens as more parties participate. Accordingly, in order to be workable, pools should avoid legal mechanisms which may require something more than majority agreement of the pool members so as to preclude deadlocks.

b. Planning

Planning, as well as operations, presents problems. Apparently, municipal utilities have experienced obstacles in constructing and operating facilities outside of their service territories. Because municipally owned systems are nontaxable, authorities in other jurisdictions are often hesitant to grant required construction permits. The above circumstances make prospective joint venture participants reluctant to include municipalities as joint venturers, in that inclusion of such may well precipitate costly and time-consuming legal disputes.

There is also concern that Colorado, either through the executive branch, or through this Commission, will not permit a non-Colorado-based utility to own more than 50 percent of a Colorado project, unless the out-of-state utility submits to Colorado regulation. Such a parochial stance could not only result in an adverse impact upon coordinated planning and participation by non-Colorado utilities, but might result in retaliatory measures by other states. Accordingly, this Commission hereby states that it intends to avoid any actions which will encumber coordinated planning for bulk power resources by Colorado and non-Colorado utilities.

3. Required Action

While the record in this proceeding by no means provides an adequate basis for this Commission to order all jurisdictional electric utilities immediately to implement a fully coordinated planning and operational power scheme, the record does provide sufficient evidence for the Commission to order certain preliminary steps. The record is clear that there is now no centralized and automated operational coordination among Colorado utilities, nor is there formal coordinated planning for new bulk power resources. As indicated above, a number of possible constraints now exist which may well hamper the achievement of planning and operational coordination; however, the Commission does not believe that these constraints are insurmountable. In fact, utilities in other states, faced with similar problems, have overcome them and have achieved significant savings for their consumers.

In order to determine whether the benefits to be derived from a system of coordinated planning and operations among utilities in this region outweigh the costs, it will be necessary to perform a production cost study. In essence, such a study should assume consolidated planning and operations among Colorado utilities, as well as certain other utilities in the region, in order to determine whether savings can be achieved by such utility coordination. Any projected savings should be compared with the derived costs of achieving coordination, i.e., the costs of increasing transmission ties and additional control centers, staffing, communications, and all associated costs.

Performance of such a study will be expensive and should not be undertaken by a single utility. Rather, the costs of this study should be assumed by all parties that stand to benefit. Parties to the study would include: Colorado jurisdictional electric utilities, Tri-State, Platte River, WAPA, and other non-Colorado utilities that may be likely candidates for coordination, either in terms of planning or operations. In order to facilitate the participation of such parties, this Commission will arrange an informal meeting of all the appropriate parties, and therein discuss the parameters of the study and the role of all parties therein. We believe that the voluntary approach is the first step in the proper direction. If such voluntary cooperation is achieved, it will not be necessary for the Commission to then mandate such a study by those utilities subject to its jurisdiction.[14]

As the results of the power production study become known, the Commission will implement procedural changes in its regulation of jurisdictional utilities. Such changes will be designed to encourage, to the maximum extent possible, coordinated planning and operations among all jurisdictional utilities. For example, as part of any quarterly fuel cost adjustment or purchased power adjustment hearings before this Commission, the applicable utility will be required to demonstrate that the unit commitment and economic dispatch decisions, embodied within the fuel mix utilized and firm purchases made, were coordinated with other utilities to the maximum extent possible. Further, in future application proceedings for a certificate of public convenience and necessity, and application proceedings for approval of the issuance of securities, the utility applicant will have the burden of demonstrating that the generation or transmission facility proposed, or for which financing is being sought, has been planned in coordination with other Colorado utilities and meets the needs of the Colorado system as a whole. The purpose of such regulatory

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[14] It should be noted that Section 205(b) of PURPA requires FERC, in consultation with the reliability councils, the Secretary of the Department of Energy and the electric utility industry to study the benefits of pooling arrangements and report its results to the President and Congress within 18 months of the enactment of the Act. The proposed Colorado study will provide specific answers to the problems of implementation in this region, but should also be timely and useful for purposes of the broader federal study.

modifications, which will be implemented six months from the effective date of this Decision, is to encourage Colorado jurisdictional utilities to pursue the benefits of coordinated planning and operations.

Finally, to the extent that cooperation from the jurisdictional utilities, as well as cooperation from those outside interests necessary to achieve a unified approach on the matters is not forthcoming, the Commission will attempt to secure implementation of the needed changes through appropriate legislation or other regulatory modes. Involuntary alternatives, of course, will not provide the flexibility that a negotiated and cooperative approach will and, accordingly, should be viewed as a less desirable approach.

D.

LOAD MANAGEMENT

Having discussed the power supply question in the previous section dealing with resource management, it is appropriate to discuss the issue of power demand and first deal with load management. Load management is any method of altering or controlling a utility's timing or magnitude of its customer load. The purpose of load management is directly to reduce a given utility's system peak which over time will allow the utility to reduce its capital expenditures for generating and transmission facilities. As discussed below, load management can be effectuated directly by the utility, without customer involvement, or load management can be left to the discretion of the customers of the utility.

The most valuable type of load management to the utility is that which allows it to interrupt consumer service without notice, without limit of duration or repetition, and at the sole discretion of the utility. The availability of a high number of separate interruptions of long duration are desirable attributes for a utility system under emergency conditions, particularly where the revenue lost by interruption is less than the utility's cost of purchasing emergency power to provide such service. By contrast, load management (or interruptibility) which is fully within the control of the customer is of much less value to the utility system. In such circumstances, the utility assumes the risk that the mechanism (or customer thought processes) for curtailing demand will not be effective when such curtailment is most required, i.e., during peak demand time periods.

From the point of view of the consumer, load management which is within the sole control and discretion of the utility imposes severe restraints upon the consumer's freedom to determine when and if he will use power. The most desirable method of implementing load management is for the utility in question to offer the consumer an alternative rate schedule which provides the utility with the option of curtailing or interrupting service at its sole discretion. Such a rate appropriately would be priced below an alternate rate for similar service without interruption. Should the consumer have the inclination, or the available technology to take advantge of the favorable rate, the consumer could do so. However, if, for whatever reason, the consumer desired firm power, that option, at a higher price would be available.

The theory behind the above approach is that economics, as well as developing load management technology, would induce more and more customers to select interruptible rates. As more utility customers select interruptible rates, the utility would then be in a position, by the "flip of a switch," to reduce load during peak periods, rather than firing its peaking generating units or puchasing expensive outside power. Furthermore, by implementing such load management techniques the affected utility would not be vitally concerned regarding the question of peak shifting. By implementing interruptible power rates, power demand will be reduced absolutely during the peak, with little of such peak demand being shifted to off-peak time periods.

The technology required for the above approach to load management is both direct and is now in widespread use elsewhere. Any utility can control the entire load of any customer, or of any particular energy-consuming device of that customer, by the use of several techniques such as: radio signals, high-frequency impulses carried over power lines, low-frequency ripple signals transmitted over the power lines, or pulses transmitted by means of an independent communication channel. If determined to be cost-effective, the cost of the installation of such devices should be borne by all the implementing utility's ratepayers, in that interruption capability of a utility benefits the utility system as a whole, rather than merely the customers that select such service.

Over the long term, load management controls may be a more effective means of controlling demand than time-of-use rates. Since demand can be affected by unpredictable weather, load management controls can be more flexibly used to match the demands of consumers with system needs than inflexible, established time-of-use rates. Also, load management may be more cost-effective than time-of-use rates, in that such rates do not require the installation of storage devices or other equipment necessary to respond to time-of-use rates by consumers. Further, interruptible rates eliminate the need for the utility to determine the costs of service during different times of use. In addition, load management has relative certainty as to the magnitude of shift from peak to off-peak demand, as contrasted with time-of-use rates which are uncertain. Load management provides the opportunity for an absolute reduction on peak without any significant shift of such demand to other time periods, whereas time-of-use rates appear to shift peak demand to other time periods. Finally, the affected utility is aware of its inventory of interruptible customers and such inventory is available at any given time. Thus, such utility can utilize load management techniques at any given time in order to maintain a particular level of reliability with less generating capacity, by selectively reducing levels of service to particular customers at specific times.[15]

1. Requirements of PURPA

As mentioned above, load management is the subject of one of the federal standards established by PURPA. Section 111(d)(6) of PURPA provides that each electric utility shall offer to its electric consumers such load management techniques as the appropriate state regulatory authority has determined will: (1) be practicable and cost-

[15] In other words, load management techniques, or interruptible service may be considered as the equivalent of a preplanned series of rotating blackouts.

effective, as determined under §115(c) of PURPA, (2) be reliable, and (3) provide useful energy or capacity management advantages to the utility. Section 115(c) further provides that a load management technique shall be determined by the state regulatory authority to be cost-effective if: (1) such technique is likely to reduce maximum kilowatt demand on the electric utility, and (2) the long-run cost savings to the utility of such reductions are likely to exceed the long-run cost to the utility associated with implementation of such technique. Finally, PURPA, in §111(d)(5) requires each electric utility to offer to each industrial and commercial customer an interruptible rate which reflects the cost of providing that service to such class of customers.[16]

As set forth in the general discussion on load management above, there are significant utility benefits to be derived from the implementation of load management in general and interruptible rates in particular. Having fully considered the load management and interruptible rates standards herein, the Commission determines, as set forth below, that it is appropriate to implement both such standards, and in such manner carry out the purposes of PURPA as well as our own goals of regulation. As the following discussion will indicate, at the present time, the Commission finds that interruptible rates, as a load management technique, will likely be the most cost-effective of the various load management techniques. However, that is not to say that by favoring interruptible rates, the Commission rejects other load management devices or

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[16] Even though interruptible rates are considered a separate standard from load management in PURPA, we consider the former a subcategory of the latter.

techniques. Rather, the Commission believes that with regard to the area of interruptible rates, as well as with other load management areas, implementation should be deliberate but cautious and thus those load management techniques having the highest cost-effectiveness should be first implemented.

2. Interruptible Rates

Despite the potential for significant savings that can be achieved by the implementation of interruptible rates, the use of interruptible rates by utilities in Colorado has been insignificant. For example, Public Service Company has a so-called "curtailable" rate with CF&I Steel Corporation. Said rate is denominated "curtailable" by the parties because it is something less ambitious than a true interruptible rate. The referenced curtailable rate allows Public Service Company to curtail service to CF&I for up to 600 hours per year. History has shown that the actual curtailment of CF&I's power, on a yearly basis, has been substantially less than the 600 maximum allowable hours. The record in this proceeding does not indicate that any other utility, supplying an industrial or large commercial customer, has offered or negotiated an interruptible rate, or promoted such as potentially beneficial both to the system and the customer. The only other significant Colorado movement, established herein, toward interruptible rates involves the efforts of some distribution REAs to grapple with the increasing summertime peak caused by irrigation customers. For example, at the time that Y-W Electric Association, Inc. (Y-W), filed its testimony herein, it was in the process of installing utility control shutoffs for electric service to 49 irrigation wells. It was further established that Y-W offers well owners received a reduced interruptible rate to induce them to utilize interruptible service. One-seventh of the load imposed by the referenced 49 wells will be subject to shutoff by Y-W each day. As Y-W's demand reaches peak levels, the interruptible wells will be shut off on schedule until the peak demand ends. The above method of load management saves no energy (because the same amount of pumping must be done in any event), but it does allow the requisite level of pumping to be accomplished without increasing system peak demand. However, with the two noted exceptions, Colorado utilities have not encouraged the use of interruptible rates to any great extent.[17]

There are several prime areas with regard to interruptible rates which this Commission believes should be pursued by the utilities subject to our jurisdiction. Industrial customers provide several advantages and opportunities for the implementation of interruptible rates. The loads of industrial customers typically are very large and have grown rapidly in recent years. Thus, industrial customers provide a significant potential benefit of peak shaving to the utility. Most utilities have few or a limited number of industrial customers, thus any required incremental investment in control and metering equipment needed to implement interruptible rates is economically feasible. Moreover, most industrial customers are sophisticated and often can design their operations to accept interruption on a limited basis. Also, the evidence

[17] The Commission is mindful of Public Service Company's pumped storage hydroplant and WAPA's planned addition to the Mount Elbert pumped storage hydroplant, each of which creates benefits similar to an off-peak interruptible load.

in this proceeding demonstrates that the industrial load makes a significant contribution to the yearly and daily peaks of several Colorado utilities.

Commercial air conditioning is a likely candidate for interruption. Many summer peaking Colorado utilities have a number of large commercial loads occasioned by air conditioning. The utility with the ability to interrupt such loads can realize significant benefits. Although there are usually more large commercial customers than industrial customers, the number of commercial customers is sufficiently limited that the installation of control technology should not be an undue expense when compared with anticipated benefits. Present technology now available will allow phased interruption by utilities without significant interference with commercial customers' summertime power needs. The utility would have the option of interrupting only a portion of its interruptible commercial customers for, say, 15 minutes of the hour, interrupting another portion for another 15 minutes, etc. The evidence in this proceeding demonstrates that summertime peaking utilities typically have a large commercial air conditioning load at the time of the system peak. For example, Public Service Company, which is a summer-peaking utility, experiences its peak in the late afternoon, which indicates a commercial air conditioning load of some consequence.

Irrigation customers of many summer-peaking utilities have become an increasing proportion of the summertime peak. As with industrial and commercial customers, irrigation customers have significant loads during a utility's peak hours. As implementation of the irrigation interruptible rate by Y-W demonstrates, an irrigation customer can take advantage of an interruptible rate by managing his load. If the rate is made attractive enough, irrigators may install storage facilities so that they may obtain the same amount of water over a given period of time. Similar to the situation involving commercial air conditioning, the utility could establish an interruptible rate whereby the interruption would not cause a significant impact upon the customer. For example, Y-W employs a phased "interruption" of its irrigation customers. The Commission believes that interruptible rates should be explored fully by those utilities having heavy irrigation loads.

Winter-peaking utilities, such as Colorado-Ute, should explore the cost-effectiveness of interruptible rates for the customer classes primarily contributing to that peak. For example, residential and commercial space heating as well as water heating are likely candidates for interruptible rates for a winter-peaking utility. However, the record in this proceeding is not sufficient to order implementation of such rates for customers of winter-peaking utilities without further study. Thus, the Commission expects the utilities in winter-peaking systems to study the customer classes contributing to winter peak and the types of service which will be most appropriate for interruption.

However, the record does demonstrate potential benefits to many Colorado utilities from the immediate implementation of voluntary interruptible rates for industrial loads, commercial air conditioning loads, or irrigation loads of any consequence. Accordingly, the Commission will require each utility listed in Appendix B to develop interruptible rates for its industrial, commercial or irrigation customers, as indicated, based upon rate design criteria set forth in Appendix C, and file said rates in its next general rate proceeding, but not later than six months after the effective date of this Decision. In such filing, the affected utilities also may submit evidence which, in their opinion, would document their conclusion that the implementation of such voluntary interruptible rate would be inappropriate. Appendix B also contains a list of utilities for which the Commission finds that interruptible rates for designated classes are not appropriate and the reasons for that finding.

E.

CO-GENERATION

Co-generation refers to the production of both heat and electricity from a single plant. The process of generating electricity is generally inefficient in that approximately one-third of the heat utilized for production results in net electric power for other use while the best input of the remaining two-thirds is lost. Proponents of co-generation urge that use of this "lost heat" for beneficial purposes would materially solve the environmental problems created by heat rejection, would contribute to conservation efforts, and would yield substantial general benefits. Also, the production of process steam[18] alone is less efficient than steam production in combination with steam for use in generation of electricty.

Superficially, the above position, with respect to co-generation, appears reasonable. However, substantial technical problems in terms of plant location, design construct of plants, the pressure at which process steam is

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[18] Process steam is defined as "steam produced for heating, drying or as an ingredient in any industrial process." Process steam is typically produced and used at much lower pressure (400 psi) than steam produced for use in turbines (1000 psi).

to be used, the level and structure of backup cost, and the price a co-generator will receive for any excess energy that will be sold to a utility all suggest that major difficulties to the implementation of co-generation can be anticipated. There are also other difficulties which appear to be institutional. For example, many who might otherwise pursue co-generation alternatives are uncertain as to the extent to which their regulatory involvement with this Commission and FERC would increase. The passage of PURPA and the promulgation of FERC's regulations concerning co-generation, discussed below, should dispel much of this uncertainty.

Although co-generation is not a new concept, it now seems to be receiving renewed attention. In 1950, co-generated electricity accounted for 17 percent of the U.S. total. In 1974, however, co-generation supplied only 4 percent.[19] During this earlier period, the benefits of co-generation largely were ignored primarily because of the declining costs of electricity. With increasing electricity costs, a growing public concern regarding energy conservation and the environment, and the uncertainties with regard to the supply of natural gas and oil as boiler fuels, the benefits of co-generation appropriately are being re-examined.

1. Federal Requirements

Section 210(a) of PURPA requires FERC to develop rules by which utilities shall carry out their newly created obligation to offer to sell power to, and buy power from,

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[19] Kirschben, J. Dicken, "The Co-generation Movement is Picking Up Some Steam," National Journal, January 15, 1977, p. 103.

qualifying co-generation facilities. Sales by the co-generator are limited to sales at wholesale for resale, except insofar as state law permits co-generators to make retail sales. Section 210(b) of PURPA requires FERC, in developing its rules, to ensure that the rates for utility sales to qualified co-generators be just and reasonable to other utility customers, in the public interest and nondiscriminatory to small power producers or co-generators. The above requirements are expressly interpreted in the Conference Report at page 97 thereof. It is indicated that such requirements are not intended to subject the small power producer or co-generator to the type of examination which typically is given electric utility rate applications in determining what is the just and reasonable rate to be received for electric power. In defense of higher than normal profits which a co-generator or small power producer may experience by virtue of its dealings with a utility, the conferees noted: (1) the co-generator operates in a competitive market and is unable to raise prices on the products which it primarily manufactures, and (2) Congress' intention to encourage co-generation. However, a safeguard is provided to utilities in that a ceiling is established on the price a utility <u>must</u>, if ordered, pay for the power it buys from the small power producer or co-generator. This ceiling provision only limits the price which a utility <u>must</u> pay for power and does not preclude arrangements in which a utility pays more for other benefits. For example, a utility may pay more than the ceiling price in recognition of the fact that the purchased energy is accompanied by or creates usable and dependable capacity. Hydro capacity available in Colorado makes this a possibility.

PURPA provides that FERC must consult with state commissions and prescribe rules to encourage co-generation. State commissions must implement FERC co-generation rules within one year of their adoption. However, co-generation is not one of the federal standards that must be considered by state regulatory commissions pursuant to §111(d) of PURPA.

2. Record in this Proceeding

All the utilities in this proceeding were silent on the question of co-generation, as were industrial and commercial parties. Yet the Commission believes this subject must be given serious consideration, in that Colorado may have numerous potential opportunities for developing co-generation facilities, both public and private. Accordingly, the Commission will order all of its jurisdictional electric utilities to survey their service territories and, within six months of the effective date of this Decision, submit to this Commission an inventory of all potential sites and joint ventures for co-generating facilities, including a description of any economic, legal or engineering barriers to the joint development of such facilities. Presumably, FERC will have adopted its co-generation rules prior to the time that the Colorado utilities' co-generation reports are due at the Commission. Thereafter, the Commission should be in a better position to ascertain the potential benefits, if any, of co-generation.

F.

COSTING METHODOLOGY

The topics of costing methodology and rate design were the primary focus of this proceeding. Nevertheless, the distinctions drawn in these proceedings by the parties between costing and pricing concepts at times became indistinct. Thus, certain preliminary clarification is necessary.

It is important to stress that the pricing methodology selected to recover costs, i.e., the specific rate form, is independent of the costing methodology selected to arrive at the cost components to be recovered by the rates. In this area of pricing, some of the parties inadvertently interchanged costing and pricing concepts. There are four costing methodologies that might be employed:

1) fully distributed historical costs;

2) fully distributed costs for a projected period;

3) short-run marginal costs; and

4) long-run marginal costs.

No matter which costing methodology is selected, the costing process will consist of five steps:

1) The selection of the rating periods, i.e., which periods of time will be considered peak periods, shoulder peak periods, or off-peak periods. These periods may be daily, seasonal, or both.

2) The functionalization of costs, i.e., the various categories of expense and plant investment must be associated with the functions of production, transmission, and distribution.

3) The classification of costs, i.e., after plant investment and expense are functionalized, they must also be classified as to whether they are demand related, energy related, or customer related.

4) The allocation of investment and expenses to the various rating periods.

5) The allocaton of investment and expenses to the various classes of customers within each rating period.

When rates are not designed to vary with time, steps 1 and 4 can be omitted. The methodology which remains after omitting steps 1 and 4 is that which long has been employed in making standard cost-of-service studies. In any event, whether rates are to vary with time of use or not, the end result of the foregoing process will be the determination of demand related, energy related, and customer related costs, of whatever type, to each customer class in each rating period. The costing process is the starting point of all proper rate design irrespective of the particular costing methodology selected. Once demand, energy, and customer related cost components have been determined for each customer class for each rating period, a suitable pricing methodology or rate form can be structured to recover these cost components. This means, for instance, that a rate can be designed on the basis of marginal cost for each rating period. Although the components of the rate will vary with the rating period, it will retain the same structure. In similar fashion, although marginal cost pricing has been equated by some with time-of-use pricing, it is quite possible to base time-of-use pricing upon average rather than upon marginal costs. To avoid confusion, the Commission separately will review and analyze the question of costing methodology and the question of the design of rates to recover those costs.

1. Requirements Of PURPA

Section 111(d)(1) of PURPA establishes cost-reflective rates for each class of customer as a federal standard to be considered. Section 115(a) provides that costs shall be "determined on the basis of methods prescribed by the state and regulatory authority." However, Section 115(a) provides:

> Such methods shall to the maximum extent practicable --
> (1) permit identification of differences in cost incurrence, for each such class of electric customers, attributable to daily and seasonal time of use of service and
> (2) permit identification of differences in cost-incurrence attributable to differences in customer demand, and energy components of cost. In prescribing such methods, such State and regulatory authority or nonregulated electric utility shall take into account the extent to which total costs to an electric utility are likely to change if --
> (A) additional capacity is added to meet peak demand relative to base demand; and,
> (B) additional kilowatt hours of electric energy are delivered to electric customers.

Although earlier drafts of the proposed PURPA legislation indicated a definite preference for marginal cost methodology, PURPA, as finally enacted, does not require utilization of marginal cost methodology. The plain language of §115 states that the cost methods selected are those prescribed by the state regulatory authority. Moreover, the Conference Report makes clear that the choice of the phrase "taken into account" in Section 115(a)(2) was selected so as not to imply a preference for any specific costing methodology. Further, the Report states that the state regulatory authority has the discretion and authority consistent with state law to select the appropriate costing methodology or methodologies. Finally, the conferees indicate that the matters specified in paragraphs A and B of subsection 2 are factors to be taken into consideration in determining costs of service, particularly with respect to time of day, interruptible, and seasonal rates.

This Commission, then, has the discretion to determine the appropriate costing methodology, whether marginal or average, upon which to base rates. Further, in determining the proper costing methodology, as discussed hereinafter, the Commission has analyzed fully the considerations set forth in paragraphs A and B of Subsection 2 of §115 of PURPA.

2. Average Cost

Traditionally, rates have been based upon historical average costs. For example, a utility will establish an actual test year for determining revenue requirements and utilize the historical costs for purposes of functionalizing and allocating the costs to various classes of customers for purposes of establishing rates. In that fashion, both the revenue requirements and the rates ultimately determined are based upon the average costs for the historical test year.[20] Those who favor the use of fully allocated average costs as the basis for determining rates cite the following in support of their position:

1) Such costs are generally compatible with the period of time upon which the revenue requirements are determined;

2) The time period upon which costs are determined is well defined thereby preventing a great deal of estimation and guesswork;

3) The use of average costs recognizes the heavy influence on overall revenue requirements imposed by the already existing costs;

4) By using a proper allocation procedure applied to these costs, recognition can be given to the fact that off-peak loads do in fact have a significant demand related cost responsibilility;

5) The use of a proper allocation procedure applied to average costs can recognize variances in load factors and thereby cost responsibility;

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[20] It should be noted, however, that even if revenue requirements are based on a projected test year, or a combination historical and projected test year, average costs for those periods in like manner can be used for setting rates providing a similar match.

6) The use of average costs precisely tracks revenue requirements as determined by the Commission and therefore requires no adjustment in order to hold revenues at the allowed level; and

7) Average costs accurately reflect utility operating characteristics and customer load requirements as they are known to exist.

It is also stressed that both regulatory commissions and regulated utilities are more familiar with average costs distributed on a fully allocated basis than with any other costing methodology.

3. Marginal Cost

By contrast, marginal cost methodologies are by no means as familiar in the utility industry. The concept of marginal cost, however, is familiar to the economist. Marginal cost is defined as the change in cost by virtue of the production of one unit more or less of a product such as electricity. The rationale for the use of a marginal cost methodology is that the essential economic question is how to make the best use of our limited resources. In other words, since the production of one more item of a product will result in the sacrificed production of an alternative product, cost is a measure of the alternatives that must be foregone in order to produce something (i.e., opportunity cost). Consumers buy commodities, whether tangible goods or products such as energy, on the basis of price, on the one hand, and preferences. Price, however, in order to be a proper guide, must reflect opportunity cost if the consumer is to receive the correct signal, and thus judge whether the satisfaction derived from the consumption of one product is worth the sacrifice in foregoing consumption of another. Economic theory maintains that marginal cost provides the correct price signal because it reflects the cost of resources necessary to supply one unit more or less of a product. A price below marginal cost will result in consumption of more of the product than is economically optimal; a price in excess of marginal cost, of less.

Thus, from the viewpoint of orthodox economics, the purpose of marginal cost pricing is to charge the correct price, not to encourage conservation of capital and energy, although many argue that such corollary benefits naturally will follow. There is no question that marginal cost pricing is the <u>logically correct</u> way to price in terms of economic efficiency, if the assumptions of the theory are correct. The controversy centers around whether the assumptions are realistic and valid and whether that theory has practical application to the electric utility industry.

A significant problem which has been identified in the application of a marginal cost methodology to the electric utility sector is that of the "problem of second best." The "second best" problem is the question of whether the optimal allocation of resources is achieved if only one sector of the economy is utilizing marginal cost pricing while other sectors price above or below marginal cost. Other sectors would price above or below marginal cost if they are characterized by imperfect competition or are subject to institutional or governmental restraints. Accordingly, such prices would give the consumer an incorrect price signal resulting in misallocation of resources. For example, if electricity were to be priced on a marginal cost basis, and oil were priced on the basis of average cost, energy users who were thus receiving an improper price signal might shift to oil during periods of increasing electricity costs, when marginal costs were rising faster than average costs, and act in a contrary manner during a time of decreasing costs.

Dr. Irwin Stelzer, President of National Economic Research Associates (NERA), maintains that "second best" is not a problem in a competitive economy, inasmuch as, in a competitive economy, goods and services tend to be priced at marginal cost. While Dr. Stelzer's proposition is incontrovertible, it does not speak to the question of whether our economy, and more specifically the energy sector of the economy, is, in fact, competitive. Dr. Stelzer contends that the economy is competitive in sufficient degree that any deviations from competition will not affect the final outcome. For example, Stelzer did not believe that natural gas needed to be considered for purposes of his marginal cost argument because its scarcity limits its use as an alternative to electricity. However, in our view, scarcity does not accurately describe the current natural gas situation.[21] Moreover, by virtue of the gas pricing system recently approved by the Congress, it appears that gas will continue to be sold at less than marginal cost in most sectors of the economy largely by reason of its continued "vintage" pricing. The pricing system adopted by

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21 The reduction in demand resulting from conservation efforts and regulatory restrictions on new industrial customers, coupled with increased natural gas discoveries, has dramatically changed the gas situation. Footage drilled for gas between 1970 and 1977 rose from 23 million feet to 60 million feet while reserve additions climbed from the recent low of 6.8 Tcf in 1973 to 11.8 Tcf in 1977. Production appears to have leveled off at 19 Tcf. (The Oil and Gas Journal, "U.S. Gas Supply/Demand Seen Nearing Balance," Sept. 25, 1977, pp. 57-62).

Congress utilizes incremental pricing only in the industrial sector.

According to Stelzer, oil is priced above its true marginal cost, but the OPEC price constitutes the marginal cost for the U.S. economy even though it is a cartel price. This occurs because the cartel price is the price of the marginal barrel for the United States. Again, Stelzer's view, while imaginative, does not present the entire picture. There is no question that domestic oil prices, presently regulated on a vintage basis, do not reflect marginal cost. In fact, if Stelzer's view that imported oil reflects the marginal cost to the U.S. is correct, the price of domestic oil, which makes up a significant portion of the market, is clearly below marginal cost. The price of oil can then be viewed as "average" through the vehicle of various regulatory schemes, such as import tickets, small refinery programs, and other techniques. In any event, the prices paid for oil reflect a combination of foreign monopoly prices and domestic regulated prices, and as such cannot be said to approximate marginal cost.

Thus, the "problem of the second best" does exist. With regard at least to the oil and gas portions of the energy sector, prices do not appear to reflect marginal cost. Therefore, even if the theory is accepted as valid, it follows from the very premise of the theory that the pricing of electricty to reflect marginal cost could tend further to distort the allocation of resources.

The so-called "revenue gap" problem in regard to the use of a marginal cost analysis was also discussed at great length during these proceedings. Under the current regulatory system, when the revenue requirement of a utility is established and distributed among customer classes on the basis of average costs, the total revenues collected through the rates should provide the rate of return allowed by the Commission. However, the use of average costs to determine revenue requirements and use of marginal costs upon which to base rates will almost always result in over or under recovery of revenues by the utility. That is, when marginal costs are higher than average costs, as they are said to be currently, the utility will receive revenues in excess of the fair and just rate of return established by the regulatory body, thereby creating the so-called revenue gap.

The solution proposed to this problem by Stelzer is to determine rates based on marginal cost, and then proportionally to reduce those rates below the marginal cost in each class by the amount of the revenue overage. It also is proposed that one method of effectuating this reduction is through the use of the so-called "inverse elasticity rule" which purportedly minimizes distortion of allocation and consumption patterns. Inverse elasticity requires that the rate be set at marginal cost in those portions of the electric market in which demand is responsive to price (i.e., elastic), in order to provide the proper price signal. In those portions of the market in which demand tends to be unresponsive (i.e., inelastic), rates should be raised or lowered above or below marginal cost as necessary in order to maintain the total revenues collected at the proper level. In accordance with the inverse elasticity rule, it would be expected that the residential customer, who tends to be least able to vary demand as a result of price, particularly in the short-term, generally would experience more moderate rate increases than customers evidencing greater price elasticities of demand at a time of increasing costs. Dr. Eugene Coyle, who testified on behalf of Mountain Plains Congress of Senior Organizations, maintained that low-use customers in the residential class should be the beneficiaries of the above-described reduction and that high-use customers should be charged the long-run incremental cost (LRIC), which is a variant of marginal cost.

In attempting to solve the revenue gap problem, marginal cost advocates depart from their theory. Despite the argument that such departure is slight and the resulting misallocations minimal, the question remains whether or not many of the benefits of marginal cost are lost in the adjustment. To solve the "revenue gap" problem, the utilities must be capable of establishing with some precision, the relevant customers' price elasticities of demand. We do not believe the "state-of-the-art" has reached that point of precision.

4. Marginal Cost Methodologies

Aside from the problems of second best and revenue allocation, there is considerable controversy over how to compute marginal cost. To merely identify computation of marginal cost as an additional problem does not imply an absence of controversy over the proper methodology to compute average cost; however, established methodologies carry a presumption of validity while new methodologies must earn such status. There were two marginal cost methods of calculation presented in this case: one based on LRIC and one based on the use of loss-of-load probabilities (LOLP).

In addition, the EBASCO[22] method was incorporated as part of the Electric Power Research Insitute (EPRI) study in the record of this proceeding.

a. The LRIC Method

The LRIC method was introduced in this matter by Dr. Eugene Coyle who distinguished it from a pure marginal cost approach. Dr. Coyle defined LRIC as the cost of building and operating new power plants some five years in the future, whereas marginal cost is the cost of one more or less (infinitesimal) unit of output. It is generally recognized that there are difficulties involved in measuring the cost of a single unit of electricity. This is particularly true since an electric plant is built in discrete "chunks." As a result, LRIC is generally regarded as a variant of long-run marginal cost. Dr. Coyle subsequently agreed, however, that LRIC is similar to long-run marginal cost, but stated that its use would result in the peaking customer paying the same for electricity as a consumer with a high load factor, all despite possible differences in costs therefor. Dr. Coyle's system deals solely with usage, i.e., kWh and not with demand, i.e., kW. For purposes of our consideration, LRIC should be considered as a marginal cost method. Finally, Dr. Coyle's LRIC theory will be discussed in its applied form under the lifeline rate section of this Decision where it is more appropriately considered.

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[22] EBASCO stands for Electric Bond and Share Company, the previously existing holding company of utilities for which EBASCO was the consulting group.

b. The NERA Method

The second marginal cost methodology was presented by NERA. That methodology is based largely on the use of loss of load probabilities (LOLP), which is an operating measure of the risk of not being able to meet customer load at any given time.

The NERA method calls for the computation of marginal demand costs of generation, transmission and distribution as well as marginal running costs. The marginal demand costs for generation, over which there was the greatest controversy, was considered to be the cost of the last unit used by the planner to meet demand. In the instance of Public Service Company, the proposed last unit was the Valmont turbine, planned to come on line in 1979. Transmission investment was assigned in part to the generation function and the remainder to a system function.[23] Distribution was computed by subtracting customer related expenses from estimated distribution expenditures during the 1977-1981 period. The result was divided by incremental demand on the distribution system at each voltage level. Generation and transmission costs were then allocated to pricing periods based on LOLP. All of the above was premised on the assumption that LOLP properly reflects the cost of adding capacity to serve incremental load. Such presumption was made because LOLP varies, in a given time period, with the risk of load exceeding generating capacity. Distribution cost is also allocated by

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[23] The component of marginal transmission investment related to generation (not combustion turbine additions) constituted 74/188th of the marginal transmission cost. A second component of transmission was based upon total projected expenditures in 1979-1981 period less those associated with generation.

LOLP based on the risk of load exceeding distribution capacity. The distribution cost is computed as the inverse of the distribution capacity margin (capability of a sample of transformer banks or feeders minus the monthly maximum loadings).

As with most marginal cost methodologies, the NERA approach is not without problems. Initially, LOLP is very complicated. Moreover, the NERA approach relies, to a large extent, on long-term projections of how the system will meet its peak demands five years in the future. Of necessity, LOLP requires a great deal of estimation, and thus uncertainty is inherent. For example, in the marginal cost study performed by NERA for this proceeding the demand costs (as mentioned) were computed based upon the costs of the Valmont turbine due to come on line in 1979. However, between the time of the drafting of the testimony and the cross-examination of the NERA witnesses, the system planners for Public Service Company had eliminated the Valmont turbine as an addition to plant. This demonstrates the hazards of attempting to base a costing methodology on the planners' present estimation of a system's future needs.

Moreover, the NERA methodology focuses on the tradeoff that the planner <u>should</u> make in terms of the last unit put on line to meet peak load rather than how the planner <u>actually</u> meets that peak load. For example, with respect to Public Service Company, testimony indicated that because of the startup delays of turbines, the Public Service Company peak is served by a combination of turbine capacity and the pumped hydro-capacity of the Cabin Creek facilities. Irrespective of this operational reality, Dr. Leo Mahoney of NERA testified that the cost of Cabin Creek would not be considered since it was not the "last unit on the line." And yet the choice in this analysis between a low running cost pump storage and/or a high running cost combustion turbine makes a significant difference to the final cost outcome. Further, it is noted that allocation of a generating resource, such as a combustion turbine, to a single pricing period will not accurately reflect the numerous functions served by that type of generating capacity during all pricing periods.

In addition, there is some problem with the use of LOLP as a tool to allocate demand cost. It is clear that when LOLP is low, i.e., when the risk is low, reserve margins are high and to the contrary when LOLP is high. However, the relationship between reserve margins and LOLP is not a straight-line relationship. For example, a given change in reserve margin will result in a larger change in LOLP when reserve margin is low (on peak) than when it is high (off peak). Thus, the addition of a generating unit which increases the reserve margin will cause a greater reduction in LOLP for on-peak users than for off-peak users. This is true even though the peak customers are relatively more responsible than off-peak customers for the need for additional plant. Thus, the use of LOLP to allocate demand results in peak users being placed in a preferential position subsequent to the plant addition vis-a-vis the nonpeak users. Dr. Stelzer claims that the above effect is mitigated in the long run. However, the Commission clearly must be concerned with the equity of rates in the short run. Moreover, LOLP traditionally has been used to measure operational risks but not the costs of reducing that risk. Similarly, LOLP is affected by forced outage rates, unit sizes relative to load, system load duration curves, maintenance schedules, interties, and the mix and number of generating units. Many of the above factors can be controlled or manipulated by the utility, thereby distorting the allocations of demand costs between customers. For all of the above reasons, the Commission concludes that the NERA approach unduly complicates an already complicated subject. Furthermore, there is no assurance that the NERA approach will lead to stable rates or logical and reasonable results. Indeed, there is evidence in this record that the NERA method will promote the opposite.

c. <u>The EBASCO Method</u>

The final marginal cost methodology before the Commission in this proceeding is the EBASCO method which is discussed in the EPRI study made a part of this record. The EBASCO method is considered by EBASCO to be a marginal cost method, but EBASCO defines its approach as the average cost of serving new energy requirements in the long run. Costs for EBASCO purposes are defined as LRIC and the long-run fixed costs are treated as new costs rather than additional costs to an existing system. EBASCO uses three costing periods: the base, the intermediate, and the peak. The latter period is defined as peak hours of the peak months. The intermediate period is defined as the peak hours of the secondary season (<u>e.g.</u>, winter-peaking on a summer-peaking system). The base period is defined generally as the off-peak hours. Costs are allocated to time periods as follows: peaking units to the peak; intermediate units, one-half to peak, one-half to secondary season; base units, one-third to each period. The class allocations are accomplished by using the coincident peak method for peaking and intermediate costs, and the average demand of hours in the base period or the average and excess demand method for cost allocation in the base period.

The Commission concludes that there is an insufficient basis in this record upon which to judge the merits of the EBASCO methodology.

In the judgment of this Commission, marginal cost analysis as a basis for determining costs upon which rates are established is not now appropriate for implementation in Colorado for numerous reasons. There now exists substantial uncertainty in light of both current price distortions in the energy sector of the economy, and the question of the actual competitive nature of the U.S. economy as a whole, as to whether the implementation of marginal costing may result in a further distortion of the price signal to consumers. Moreover, the revenue gap problem, inherent in any marginal cost methodology, when revenue requirements continue to be determined on an average cost basis, injects an additional lack of precision into the costing process and may result in so great a divergence from the theory that the application of such theory could be problematical. It should also be noted that the means of implementing marginal cost-based rates which have been used in other jurisdictions, and as proposed by the proponents of said theory in this proceeding, would serve further to compound this imprecision.[24] Further, the only comprehensive marginal cost analysis which was presented to this Commission (by NERA) is very complicated, relies upon uncertain projections, and uses LOLP which is a technically questionable method for the allocation of demand costs. The above factors must be given consideration by this Commission in light of the burdens that implementation of such a methodology would place upon the affected utilities, particularly those with limited staff resources, as well as the burdens placed upon the Staff of this Commission, to monitor such implementation. The Commission also is concerend that basing rates upon a marginal cost analysis would result in a de facto abrogation of this Commission's rate-setting function. And finally, such a costing methodology, as a basis for setting rates, does not meet satisfactorily the tests of simplicity and familiarity to utility consumers. Notwithstanding the foregoing, the Commission does favor the utilization of marginal costing for a limited purpose, as more fully explained below.

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24 For example, the New York Public Service Commission, in its well-known LILCo decision implementing marginal cost-based rates, departs from a strict application of marginal costing principles, not only by conforming rates to the aggregate revenue requirement of each class, but also by reducing the ratio of demand charges between peak and intermediate demand from the 18: to 20:1 which the company's marginal cost study revealed, and even from the 8:1 ratio which the company proposed, to 4:1 at least in part so as to moderate the abruptness of rate change for customers (State of New York Public Service Commission, Opinion No. 76-26, Case 26887 - Long Island Lighting Company - Electric Rates - SC2-MRP, Opinion and Order Requiring the Establishment of Time-of-Day Rates for Large Commercial and Industrial Customers, Issued: December 16, 1976, page 37). Moreover, in the instant proceeding, Jules Joskow, Executive Vice President of NERA, advocates a move in the direction of time-of-use rates which "would not, and should not, fully reflect differences in current marginal costs." (Exhibit T, pp. 18 and 19)

5. Average Cost Methodologies

While there are approximately 30 methods for allocating demand costs, these methods can be assigned into three major groups; namely, the coincident peak methods, noncoincident peak methods, and combination load diversity factor methods. The latter is generally used in Colorado and will be discussed in greater detail below. In addition to the allocation of demand costs, energy costs normally are allocated upon the basis of the number of kWh sold. Customer costs usually are allocated on the basis of the number of customers per class. Further, a portion of the costs of the distribution system also is allocated to customer costs by using methods such as the minimum intercept costs of facilities or the minimum size of facilities. The above cost allocations tend to have much less impact on the results than demand allocations. As a consequence, average cost methodologies focus most attention upon demand allocations.

a. Coincident Peak Method

A coincident peak is the sum of the demand of two or more individual customer groups occurring in the same time interval. The use of coincident peak (peak responsibility method) for the allocation of demand costs is premised on the assumption that the capacity requirement of the system is determined by the peak load alone, thus the peak responsibility method requires that those who contribute to the system peak will pay accordingly. Coincident peak method, in some respects, resembles a marginal cost analysis in that it assigns demand costs to peak users. Those who oppose the use of a coincident peak method state that it tends to distribute diversity benefits inequitably, does not recognize off-peak demand responsibility, and is too sensitive to shifts in system peak. In the latter case, a shift in the system peak would have a drastic impact on the cost of service for the various customer groups, thus leading to sudden fluctuations in rates.

The most common variant of the coincident peak method used for allocating cost is contribution to the annual system peak. Many utilities, however, have more than one significant peak in the course of a year, such as a summer and winter peak. As a consequence, methods have been developed to reflect this circumstance. For example, costs are sometimes allocated in proportion to the customers' coincident demand at the time of two or more system monthly peaks.[25] In other situations, the minimum monthly peak or the maximum monthly peak could be utilized as an allocation mechanism. There are, of course, many variations on this theme.

b. Noncoincident Peak Method

The noncoincident peak costing method, by contrast with the coincident peak method, is the sum of the maximum demand of two or more individual customer groups, irrespective of time of occurrence. By the noncoincident peak allocation system, demand costs are allocated to each customer group based upon the individual group peak, regardless of the relationship of such peak to the system peak. The noncoincident demand method assumes that each group, if served independently, would require sufficient

[25] FERC requires allocation of demand costs based upon the 12 coincidental monthly peaks.

facilities to meet the maximum demand of that particular group. Therefore, each group is allocated demand costs on the basis of its maximum demand, irrespective of the relation of that peak to the time of the system peak. The noncoincident method tends to allocate diversity benefits without regard to the individual group's contribution to the system peak. On the other hand, the noncoincident method may produce a cost distribution which is unrelated to bulk power supply costs, and may be inequitable to off-peak customers who cause better utilization of utility facilities and thus generate lower unit costs. The noncoincident peak methods are resorted to in cases where the available metering or load research data are insufficient to permit use of coincident peak methods. Noncoincident peak methods are regarded generally as less accurate and less equitable than coincident peak methods.

c. Average and Excess Demand Method

As noted above, the average and excess demand method is the major allocation system used in Colorado. Demand costs are divided into maximum and average demand components. Average demand components are then allocated to customer groups on the basis of average demand, while maximum demand costs are allocated to groups based on some form of peak responsibility. Two variations of the method exist: the load factor excess demand which is sometimes known as average and excess demand method (AED) and the load factor diversity factor method (LFDF). The major difference between AED and LFDF is in the factor used to compute the average demand component of each. The factor used in the LFDF method is composed of a combination of both load and diversity factors, while the AED method assumes a linear relationship between the customer class peak and the load factor, and thus tends to allocate less of the diversity benefits to the high load factor customer groups and more to the low load factor groups. Proponents of AED believe it to be equitable because high load factor groups contribute less in terms of diversity benefits than low load factor groups. The AED method is suitable for use in a system where considerable diversity exists and the benefits from this diversity assume greater importance than others. Mr. Ranniger noted that the AED method was preferred by Public Service Company because it recognizes maximum system demand, customer class demand, and annual customer class load factor. As a consequence of the above, he claimed that AED is compatible with the levelized demand, high load factor character of Public Service Company. Mr. Ranniger further maintained that high load factor customers make greater use of facilities than low load factor customers and should pay accordingly. And finally, Mr. Ranniger prefers the AED method because of its recognition of off-peak demand responsibility.

Dr. Eugene Coyle, on the other hand, testified that the AED method favors larger customers over residential customers. It is clear that the AED method places a greater burden on a customer class whose ratio of peak demand to average demand is greater than that ratio for the system as a whole. The above results in a greater burden upon the residential customer, but it is the larger volume customer who places a greater demand on the system at the peak. The residential customer class tends to have a sharp peak (low load factor) and is penalized accordingly. Although Dr. Coyle was unable definitively to state that such situation is true in Colorado because the class load curves were unavailable for this proceeding, he believed that such is generally true. Further, Dr. Coyle noted that the Public Service Company peak data penalized the residential class because residential metering encompasses 15-minute intervals while special contract service customers are metered in 30-minute intervals, and special primary power customers in 60-minute intervals. The longer the interval, the greater the opportunity to offset brief periods of high demand by lower demand. Thus, it can be observed that the different intervals used by Public Service Company tilts the results in favor of those with longer intervals. Finally, a bias against the residential customer through the use of the AED method is introduced in that the method as applied by Public Service Company uses the arithmetic mean in the computation of the class maximum demand. Use of the arithmetic mean tilts the results in the direction of a few large values, whereas the use of a median would avoid this problem.

d. Appropriate Average Costing Allocation System

Even though this Commission has stated its policy of basing rates on average costs, rather than marginal costs, it does not believe it appropriate, in a generic proceeding such as this, to dictate the appropriate allocation procedure. As the above discussion demonstrates, the appropriate procedure will depend, to a large extent, upon the operational and load characteristics of a given utility. In general, this Commission believes that the coincident peak method is likely to be more appropriate for systems having little diversity among its customers, whereas the AED method may be more appropriate for those systems with greater diversity among customer loads. As to the question of whether the coincident peak or the AED method is the appropriate vehicle to give proper recognition to the demand of off-peak loads, we are now withholding judgment. The Commission does believe, however, that the noncoincident peak method is likely to have little application and usefulness in Colorado. And finally, the Commission agrees that Dr. Coyle's criticisms concerning the variation in the intervals used for peak determinations and the use of an arithmetic mean for class maximum demand calculations are well taken and should be corrected by Public Service Company at the earliest possible time.

The Commission will expect each jurisdictional utility in its next rate case to come forward with evidence justifying the use of its proposed allocation system. The Commission can scrutinize carefully the operational and load characteristics of each individual utility and make an appropriate determination as to the proper allocation formula to be utilized.

6. Time-Of-Use Pricing

The Commission, for the above stated reasons, does not believe that it is appropriate to base rates on marginal costs; however, by virtue of said determination, we do not intend to suggest that time-of-use rates also are rejected. As explained previously, it is quite possible to design rates which vary by time but are based on average, rather than marginal, costs.

While the Commission believes that the utilization of a marginal cost analysis upon which to base rates is impractical, it does believe that such an analysis is useful for purposes of deciding <u>whether</u> to implement time-of-use rates. Thus, if the marginal or incremental costs of serving peak demand are greater than those for serving off-peak demand, rates should reflect such differential even though they do not track precisely those marginal costs because of the practical problems of application noted above. Marginal costs, with their forward-looking orientation and their disregard of sunk costs, are the appropriate costs to be considered for purposes of making this fundamental decision. However, the purpose of using marginal cost analysis in this limited manner is not to optimize the allocation of resources, in that rates will not be based on marginal costs, but to give the customer a signal that peak usage costs more to supply than off-peak usage. Thus, the customer will be encouraged to shift from peak or reduce peak usage, thereby resulting in conservation of capital and perhaps energy.

As a general proposition, rates, to the extent possible, should track the cost of providing service. Without regard to whether marginal costs vary by time of use, a variation of average costs by time of use dictate that rates track that variation as closely as possible. Not only will such rates place the cost burden on those that cause the burden, but they also will encourage, over time, consumers to shift from peak or reduce peak usage which will minimize the need for future plant. Even if peak shifting by consumers should not occur as the consequence of rates that accurately track cost, at minimum those responsible for the cost burden, i.e., the peak users, will bear an appropriately greater cost.

The record in this proceeding amply demonstrates that the marginal (as well as average) costs for serving peak load are greater than those for serving such loads during nonpeak periods. With respect to marginal costs, as previously mentioned, NERA performed a marginal cost study of the Public Service Company system. Despite the many practical problems of using that methodology to set rates, the Commission does find the study very helpful in determining whether time-of-use rates should be pursued in Colorado. Also, Colorado-Ute performed a marginal cost study on its system. Both of those studies clearly indicate that the marginal cost of serving peak usage is substantially greater than the cost of serving off-peak usage.

Further, upon examination of the evidence in this record concerning the variation of average cost by time of use, the conclusion is the same. For example, notwithstanding Mr. Ranniger's testimony that Public Service Company's costs do not vary by time of day, the record herein indicates an opposite conclusion when the Cabin Creek facility costs properly are allocated to the peak period. The conclusion that Public Service Company's costs vary by time of day is supported by a review of how a utility typically meets its peak and off-peak loads. It is an operational fact that incremental energy costs are appreciably higher for peak than for off-peak periods. Moreover, the evolution of electric utility systems tends to reinforce the divergence between peak and off-peak costs in that older and less efficient base load units are assigned to the peak and intermediate functions, with newly accquired and more efficient units being applied to base load. Colorado utilities typify the described evolution. Public Service Company, Colorado-Ute, and Colorado Springs each has converted the use of old steam units from base load service to seasonal or intermediate service. Energy costs of natural gas and oil, typically used in peaking turbines, are appreciably higher than the energy costs of coal, which is typically used in base load units. The heat rates of internal combustion turbines are poor compared to heat rates of steam turbines fueled by coal; thus, the internal combustion turbine operating costs are higher.

Accordingly, the Commission concludes that the record herein has established a prima facie case which favors time-of-use rates for Colorado. However, the mere fact that this record demonstrates that marginal and average costs of providing power vary with time does not, on its face, dictate wholesale implementation of time-of-use rates in Colorado. The Commission must and will evaluate, on a case-by-case basis, the costs of implementation of such rates against the likely benefits to be derived therefrom.

a. Requirements of PURPA

As previously mentioned, §111(d) of PURPA includes, inter alia, federal standards requiring consideration of time-of-day and seasonal rates. Specifically, with regard to time-of-day rates, Section 111(d) of PURPA requires that the rates charged by any electric utility to each class of customer shall reflect the cost of providing service to such class at different times of the day, unless such time differentiated rates are not cost effective with respect to such class, as determined under §115(b) of PURPA. Section 115(b) provides that such rates shall be determined to be cost effective with respect to each such class if "the long-run benefits of such rate to the electric utility and its electric customers in the class concerned are likely to exceed the metering costs and other costs associated with the use of such rates."

With regard to seasonal rates, §111(d) of PURPA requires that: "The rates charged by an electric utility for providing electric service to each class of electric consumers shall be on a seasonal basis which reflects the cost of providing service to such class of consumers at different seasons of the year to the extent that such costs vary seasonally for such utility." This PURPA standard concerning seasonal rates does not contain any qualification in respect to cost-effectiveness because implementation does not involve costs of new metering equipment or other expenses at the customers' end of the line. The Conference Report makes it clear that the state regulatory authority may disregard insignificant seasonal variations in the cost of providing electric service (p. 74).

b. Costs of Implementation

Perhaps the issue most extensively discussed in this proceeding, in conjunction with the question of implementation of time-of-use pricing, is the effect that such implementation would have upon the operating characteristics of Colorado utilities, more specifically upon utility load curves and load factors which frequently were characterized as "favorable." Since the primary purpose of implementing time-of-use rates in Colorado is to give customers an appropriate price signal of the variations in costs that occur by time, so as to encourage the shift from peak or reduction of peak usage, it is important to estimate the magnitude of that shift and the potential effect that it will have upon a utility's operations. Obviously, if the implementation of time-of-use rates will cause an insignificant peak shift, or no shift at all (customer demand being inelastic), then it may not be worthwhile to implement time-of-use rates. Also, if consumers will react to rate differentials (customer demand being elastic) but the shift in demand will require the utility to install more generating capacity than would be installed without such rates, clearly the implementation of time-of-use rates would be counterproductive. In the above circumstance, the marginalist would suggest that the described considerations are irrelevant provided that the customer is being charged the "right" price. However, this Commission must be assured that the consuming public is likely to be as favorably served subsequent to a change in rate design than before such change.

(1) Time-of-Day Rates

Mr. Ranniger of Public Service Company presented extensive testimony on the subject of time-of-day rates. Essentially, Mr. Ranniger contended that as a result of the historical utilization of appropriate rate design, climatological conditions existing in the company's service territory, past promotional activities which have assisted in shaping the load curve of Public Service Company and past and present system design, the Public Service Company generating capability closely matches the company's system load. Furthermore, Mr. Ranniger concluded that the match was "optimal." According to the testimony of Mr. Ranniger, there thus is little, if any, available capacity within the Public Service Company system to absorb any shift in customer load from peak to off peak. It follows that, given this current favorable match, a significant shift to off-peak periods, in the short run, could increase the risk of curtailment of service to customers and impair the company's ability regularly to maintain its generating facilities.

Further, in the long run, such a shift could result in the need for additional base load capacity to serve that off-peak load, which capacity might not be needed without such time-of-use rates.

Mr. Ranniger supported these contentions with an extensive analysis consisting of 550 sets of daily load curves showing various system parameters and operating characteristics for a 24-hour period over an 18-month interval (Exhibit 5). In essence, the above analysis compares, for each day, the available generating capability (i.e., gross capability less necessary seasonal restrictions on various generating units, maintenance, equipment limitations, fuel limitations, and pumping requirements at the Cabin Creek pump storage plant) and the total load obligation of Public Service Company, including its reserve requirement. According to the testimony of Mr. Ranniger, the analysis shows that there is no one hour of any 24 hours of any day when the company consistently, month after month, or even within seasonal periods of time, experiences excess capacity. From the above analysis, Mr. Ranniger then concludes that there is a near optimum match between the company's existing facilities and the load experienced on the system. Colorado-Ute, through its witness Larry Day, presented similar conclusions but had not performed such a comprehensive study.

While the Commission believes that the above considerations raised by Mr. Ranniger and Mr. Day are of extreme importance, the record of this proceeding does not demonstrate the optimal match perceived by Mr. Ranniger and Mr. Day. First, merely because the existing generating capability of Public Service Company, or any other utility, currently matches its load characteristics, does not necessarily lead to the conclusion that such will be true in the future. It should be recognized that one of the purposes of implementing time-of-day rates is to reflect more accurately the costs of service, but an additional important purpose thereof is to encourage a shift in demand in order to delay or minimize future additions of generating plant. The fact that the Public Service Company system has a high annual or daily load factor does not necessarily indicate that this favorable situation will continue as new loads are added to the system. To the extent that Public Service Company, and other utilities, develop an expanded power pool arrangement in the near future, as previously discussed, the operational characteristics of said various utilities may be modified. For example, Mr. Ranniger by his analysis discounted the available generating capability for Public Service Company's reserve margin, rather than the lesser margin which will be required should the proposed power pools become effective. With the current domination in terms of size, by Public Service Company of existent power pools in which it participates, the maintenance of a large reserve margin as a standard by Public Service Company is prudent. However, were Public Service Company to participate in a power pool with comparably sized utilities with less critical reserve margins, the reserve sharing capabilities of the pool would result in greater power availability for Public Service Company. In other words, Mr. Ranniger's study of the existing match between Public Service Company's generating capability and system load is helpful. However, it is not dispositive of the question of what will be the long-run operational characteristics of the company. Even within the framework of Mr. Ranniger's analysis, his conclusion that the current match is "optimal" is an overstatement. Indeed, the near match between the loads and resources to which Mr. Ranniger testified is a result of the unduly low margins Public Service Company has experienced in recent years.

A review of Mr. Ranniger's analysis presented in Exhibit 5 demonstrates that while Public Service Company has clear variations from excess capacity to deficiency in capacity, there is a definite relationship between the existence of excess capacity and system off-peak hours and the existence of insufficient capacity and peak hours. Moreover, assuming that Exhibit 5 establishes a good match between Public Service Company's supply and demand, that match alone does not indicate that the Public Service Company's system serves its customers at the lowest possible cost. For example, Public Service Company meets peak demand with Cabin Creek pumped hydro, which is less expensive than meeting those demands with an oil-fired turbine generating unit. However, should those peak demands be shifted to off-peak hours and be thus met with base loaded generation facilities, such a procedure would be less expensive than Cabin Creek hydro.[26] Finally, the operational flexibility of Cabin Creek, i.e., its ability to switch from pumping to generating mode in a matter of minutes, would allow Public Service Company to meet any short-run inadequacies of capacity that might occur during off-peak hours when daily generating maintenance is performed. Thus, the interruptibility of the Cabin Creek pumped storage resource enables Public Service Company to absorb off-peak demand to

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[26] Mr. Fuller of Public Service Company testified that Cabin Creek requires 1.9 kWhs of pumping energy for each kWh it later generates. To the extent that a kWh can be served off peak instead of on peak, the need for additional pumped storage capability, and its associated energy losses, are avoided.

a greater extent than would be indicated from a cursory examination of Exhibit J.

The effect on the electric utilities' operational characteristics caused by implementation of time-of-day rates depends, of course, on the scope and timing of implementation, the rate differentials set between time periods, and the customers' reaction thereto. There was much discussion in this proceeding concerning the likely magnitude of shift of customer loads which would occur from implementation of time-of-day rates. From the proponents' point of view such shift would benefit the system and from the opponents' point of view would be a detriment to the system. The questions of size and system benefit of shift both are of importance in evaluating whether to implement time-of-day pricing, but said issues may be impossible to answer definitively absent the implementation of such rates.

We note in this regard that Public Service Company witness Mr. Fuller presented the results of a substantial study. This study demonstrated the long-term impact of shifting the energy associated with the top 15 percent of Public Service Company's annual peak demand to off-peak demand, upon Public Service Company's reliability and revenue requirement. Mr. Fuller's study was not expressly offered as representing the likely result of implementating time-of-day rates, and there was criticism of magnitude of shift that was assumed in the study.

The Commission believes that the study sponsored by Mr. Fuller was useful but is limited in several respects. First, the results of the study are inconclusive because of the obvious sensitivity of the results to changes in assumed load shifts. The sensitivity was not fully investigated by Mr. Fuller or any of the other parties in this proceeding.

Second, without regard to the sensitivity of the results to the underlying assumptions, Mr. Fuller's conclusions from the study were postulated from the point of view of Public Service Company alone, rather than the Rocky Mountain region or Colorado as a whole. This restrictive view certainly influenced Mr. Fuller's conclusion that the Public Service Company system could not benefit from the assumed shifts. For example, Mr. Fuller viewed the various circumstances of which the study was composed from the perspective of whether the reliability of Public Service Company was compromised, instead of the overall reliability of all of the power pool members. Further, the study contained no analysis of whether purchased power was available during the years when the LOLP was above acceptable levels. Finally, the relative accuracy of Mr. Fuller's study would be affected by both the company's plant generating additions and the time when these additions came "on line." Many of the wide swings of LOLP could be minimized, and thus the results of the study changed, by the promotion of staggered construction of installed generating capacity facilitated by joint planning among all utilities in the region, a theme to which the Commission intends to return.

Evidence was also presented by NERA concerning the elasticities of demand of electric customers by time of day. NERA constructed two econometric models of customer behavior. The models measure the response of customers to changes in electricity rates and make available to the Commission and its Staff an analytical tool against which various alternative assumptions with regard to elasticity and the sensitivity of the company's load pattern might be tested. Much of the empirical data available, however, is based upon Federal Energy Administration (FEA, now

Department of Energy) demonstration projects throughout the country and the European experience with time-of-use rates. There are admitted difficulties in interpreting the European experience within a U.S. or Colorado context. It is generally recognized that the FEA demonstration projects provide little useful information as to the likely shift of customer demand with time-varying rates, in that all but one were conducted on a voluntary basis and all contained some defects.[27] Thus, such projects were only composed of customers who were willing to shift and thought that they could achieve savings thereby. The above circumstances would, of course, tend towards a nonrepresentative selection of customers and a consequent skewing of the results. Department of Energy (DOE) witness Mr. Johnson, in attempting to rebut the study performed by Mr. Fuller, relied heavily upon the FEA Arizona elasticity estimates. In addition to the voluntary aspects of that demonstration project, Arizona, of course, varies from Colorado in climate, customer mix, and customer load characteristics. Recognizing these limitations, Mr. Johnson presented two alternatives to the Arizona figures, one assuming greater, and the other less, elasticity. In light of the above-mentioned defects, which tend to undermine the reliability of all of the FEA demonstration projects, and the enumerable differences between Colorado and the systems studied in other states, the Commission does not find the FEA elasticity data presented in this proceeding to be convincing.

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27 In some cases the study groups were small or the study period too short. In others, participation payments were made or metering problems were experienced.

Notwithstanding the fact that the present record has not, and probably could not have, indicated a clear result of using time-of-day rates, future use of such is not thereby precluded. Given the number of variables in any time-of-day rate study and the effects of such variables on the results thereof, as well as the vast differences between Colorado operational characteristics and those in other utility systems, the Commission believes that any study of customer responsiveness to time-of-day rates cannot predict with reasonable accuracy the precise magnitude of consumer shifts before implementation of those rates. We do believe, however, that the information that has been presented in this proceeding does indicate that there is some elasticity, or customer responsiveness, to changes in utility rates. On this basis, the Commission is reasonably certain that the implementation of time-of-day rates will likely result in positive benefits to the system. With the cautious implementation of time-of-day rates, the Commission can then monitor and review the responses of Colorado customers to time-of-day price differentials. Further, if necessary, the Commission can then modify those differentials to prevent any adverse shifts in customer demands. A cautious approach should not only solve the problem of the lack of precise elasticity data, but also should accommodate the concerns of Mr. Ranniger and Mr. Day that implementation thereof will distort the current match between generating capability and customer load.

The other significant costs that must be considered before a decision can be made regarding the implementation of time-of-day rates are the costs of requisite metering required to take advantage of such rates. Based upon this record, the Commission concludes that across-the-board implementation of time-of-day rates for all Colorado utilities is not feasible at this time, given the size of the necessary investment in metering. Implementation of time-of-day rates for the residential class and the vast majority of commercial customers, who have meters that measure usage only at the present stage of metering technology, would not be cost effective. The record in this proceeding indicates that a time-varying kWh meter, at present, costs between $45 and $80 depending upon whether it measures two or three periods. This compares with the standard single-phase kWh meter typically used for residential installations which costs approximately $20. These prices, while exclusive of the added costs of installation and maintenance, are also exclusive of the likely unit cost reductions that customarily result from volume manufacture.

However, for the vast majority of industrial and large commercial customers, metering costs are not an impediment to the implementation of time-of-use rates. Many of the customers in such classes already have meters which are suitable for measuring usage by time of day. Any additional investment required for customers without appropriate meters would be minimal, when compared with the potential benefits that could be realized from implementation of time-of-day rates for these classes of consumers.

We are convinced of the necessity of moving cautiously with any plan of implementation of time-of-day rates, so as to monitor both the customer reaction and the effect upon the utility system. Numerous characteristics of the industrial and large commercial classes (in addition to low metering costs) justify implementation of time-of-day rates for those groups of customers. The implementation of time-of-day rates will require extensive consumer education, which most efficiently can be undertaken initially with a relatively small group of informed, knowledgeable consumers such as industrial and large commercial customers. Moreover, in that this Decision instigates the first phase of the implementation of time-of-day rates, the choice of large-use customers therefore is appropriate in that there is a greater potential for usage responsiveness by such consumers, thereby benefiting the entire utility system. Further, the large consumption of energy by industrial and large commercial customers offers them both the opportunity and the inducement to take effective action, even at some initial cost, to shift their load off peak. In essence, implementation of time-of-day rates for industrial and large commercial customers increases the likelihood of achieving the benefits to be derived by time-of-day pricing at the lowest possible cost.

As might be well expected, some industrial and large commercial customers have opposed the implementation of time-of-day rates as to their classes. The spectre was first raised of commercial and industrial customers fleeing the State of Colorado to avoid being charged on such a basis. This argument reduces to the proposition that customers concerned with rate continuity, if confronted with new, uncertain (and perhaps higher) rates, might consider relocating to a state with a more traditional rate structure. It is also contended that new industry may avoid locating in Colorado as a result of the implementation of such rates. We find the above arguments unpersuasive. If time-of-day pricing is adopted gradually, and is accompanied by adequate customer education, customer expectations need not be pessimistic. Let it be recalled that the above arguments were used to justify federal minimum standards regarding the setting of electric utility rates. It was maintained that individual states would not initiate time-of-day pricing out of concern that such would cause local industry to relocate to other sections of the country. Furthermore, as a result of the PURPA deadlines and requirements, Colorado will not be the only state considering and implementing such new rate forms. Many states have commenced such consideration. Thus, commercial and industrial customers may be unable to avoid time-of-day rates even should they be so inclined. Also, the power costs of few, if any, businesses comprise such a large proportion of total costs so as significantly to influence location decisions. Finally, there is the likelihood that many commercial and industrial customers will find time-of-day rates salutary rather than disadvantageous.

It should be emphasized that the selective implementation of time-of-day rates will not change the revenue requirements allocated to commercial and industrial classes as a whole. Cost-of-service studies will continue to be determinative of the revenue needed to be recovered from industrial, commercial, residential, and other customer classes. Subsequent to such allocation being made, however, the revenues attributable to industrial and large commercial classes will be recovered through time-of-day rates, while the revenues to be recovered from other consumer groups will be recovered by other rate structures. Thus, industrial and large commercial classes as a whole will not be prejudiced by the implementation of time-of-day rates.

Disregarding the above, many of the industrial and large commerical customers have argued that their operations preclude the shifting of demand from peak to off-peak periods. Such customers conclude that implementation of time-of-day rates for them will result in their being penalized. There is no question that customers who are able to manage their load and who can thus shift load from peak to off-peak will be benefited more than those without such flexibility. The evidence in this record indicates that industrial and large commercial customers, in general, are the customers most likely to be able to design, implement, and finance load management techniques which will permit them to be benefited from time-of-day rates. Commercial customers have argued that by the nature of retail operations, they must use electricity throughout the business hours, thereby precluding any realistic ability to shift use to off-peak hours. However, commercial customers with the implementation of time-of-day rates will have an additional price incentive to which they can continue to respond in all future purchases of appliances which utilize electricity. In addition, there are now load management techniques available to facilitate the shaving of peak usage through phased operations rather than through a complete shift of that usage to off-peak periods.

Similarly, some industrial customers have contended that the continuous nature of their operations precludes taking advantage of time-of-day rates. However, for continuous users the higher on-peak time-of-day rates will be offset by lower off-peak rates. Also, future additions and operations can be designed to minimize the impact of time-of-day rates. Moreover, even though the Respondent utilities may see a short-term increase in rates, they will realize, in the long run, the benefits to the class as a whole since, with each succeeding rate case, the improved load factor of the class will be reflected in the amount of revenue requirements assigned to that class.

And finally, and perhaps most important, the Commission intends to implement such time-of-day rates cautiously. As this Decision makes clear, the differential to be set initially will be modest so as to avoid any large swings of customer demand from peak to off peak and thus minimize the financial impact upon those customers for whom usage shifts are impossible. However, the differential will be established so that customers with some ability to shift their demand may take advantage of the rate, and thus the class as a whole will benefit in the long run.

(2) Seasonal Rates

The question of the cost-effectiveness of implementing seasonal rates, as compared with time-of-day rates, is much simpler. Implementation of seasonal rates does not impose any additional metering costs. Essentially, utilities could institute such rates immediately merely by the filing of appropriate tariffs. The salient questions in regard to the effects of implementation of such rates concern their impact upon the utilities' operation and the appropriate winter-summer load differential to which they are to be applied. The purpose, of course, of implementation of seasonal rates is to shave the cost burden of the annual seasonal peak. Such rates, unlike time-of-day rates, will not cause any significant shift in usage from one time period to another but rather should encourage an absolute reduction in annual peak usage. Thus, much of the argument raised in these proceedings which focused on the effects of a shift in usage caused by time-of-day rates, upon utility operations, are not applicable to seasonal rates. In short, basic utility operations should proceed in much the same manner before and after implementation of seasonal rates, except that less capacity will be required to serve the peak season. Such is, of course, the precise result intended.

In light of the fact that there are virtually no costs of implementing seasonal rates, the appropriateness of such rates for any given utility must be judged solely in terms of the seasonal load characteristics of that utility. Quite obviously, a utility with an insignificant seasonal differential would realize little benefit from such rates. Furthermore, the minimum seasonal differential required for effective application of seasonal rates may vary by utility, depending upon the size of that utility. Generally, the Commission concludes that any Colorado utility with a seasonal/nonseasonal ratio averaging 1.2:1 or more over a two-year period of time is an appropriate candidate for implementation.

c. Special Implementation Problems

The record in this proceeding demonstrates that this Commission is confronted with a number of obstacles to uniform implementation of time-of-use rates. As previously mentioned, this Commission does not have jurisdiction over wholesale sales of power in Colorado with the exception of those made by Colorado-Ute. Wholesale sales of power by Public Service Company, WAPA, and Tri-State are not within the jurisdiction of this Commission. If the ultimate purpose of implementing time-of-use rates is to encourage consumers to shift demand from peak to off peak and thereby, in the long run, minimize the need for additional plant, these wholesalers must be involved in the effort. The above wholesalers will be among the beneficiaries of the implementation of time-of-day rates, and yet, should they continue to charge their customers on a nontime-differentiated basis, the cost of power to retail utilities will not vary by time of use. Thus, without the participation of wholesale distributors in time-of-day rates, it makes little sense for this Commission to order retail utilities to charge on a time-of-use basis.[28]

PURPA provides no assistance in this regard. While each state regulatory authority and each nonregulated electric utility (which would include Public Service Company, WAPA, and Tri-State) must, pursuant to PURPA, consider the various federal standards and determine whether they are appropriate for implementation, Section 102(b) of the Act provides an exemption for sales of electric energy for purposes of resale. Thus, despite the interrelationship between rates charged at the wholesale level and rates charged at the retail level, there is no mechanism under PURPA for exploring the appropriateness of these federal standards by wholesalers. This Commission is therefore relegated to a partial and nonuniform implementation of time-of-use rates in Colorado. Unless and until this Commission can convince the above-mentioned wholesalers to consider and determine the appropriateness of implementing

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28 Perhaps the most ironic aspect of this proceeding was the fact that Intervenor DOE was strenuously urging this Commission to implement time-of-day pricing in Colorado even while DOE had not made any efforts to implement such rates for WAPA, a wholesale supplier housed within DOE. Nor had DOE even advocated such rates for other wholesalers in Colorado, such as Public Service Company, before FERC, the regulatory arm of DOE. Thus, DOE's own inaction and inconsistency in this regard have contributed to this Commission's inability to <u>fully</u> and effectively implement what DOE itself has recommended it do. The Commission would, of course, welcome DOE's elimination of this ironic situation.

similar rate reforms, time-of-day rates can be effectuated only on a partial basis.

The configuration of Colorado-Ute and its member distribution companies also presents a unique situation for the implemention of time-of-use rates. While Colorado-Ute is subject to the jurisdiction of this Commission (unlike the other wholesalers mentioned above), the question of how best to implement time-of-use rates for that system remains. Should Colorado-Ute commence charging its member distribution companies on a time-of-day basis, the members would have no mechanism to convert the time differentiated power costs into rates for their retail customers without a major investment in metering equipment. Moreover, to impose such rates on the industrial and large commercial customers of the distribution companies if their wholesale power costs do not vary by time of day makes no sense. However, the Commission is of the view that Colorado-Ute and its members should not be exempt from the implementation of time-of-use rates.

Accordingly, the Commission will view Colorado-Ute and its member distribution companies as a single entity for purposes of implementation of time-of-use rates. Thus, the retail members of Colorado-Ute will be required to file time-of-day rates for industrial and large commercial customers and a seasonal rate for all of its customers. The design of these rates should recognize the load characteristics of the entire system, rather than the load characteristics of the individual distribution member. Colorado-Ute and its member distribution companies will then be responsible for the development of a wholesale price structure which will accommodate that retail rate design.

As mentioned above, Tri-State is considered not to be subject to the rate jurisdiction of this Commission because of the interstate nature of its operations. Yet Tri-State generates a substantial amount of power within the state of Colorado which is delivered to member distribution companies also located within the state. In short, a large portion of Tri-State's operations clearly could be characterized as intrastate even though, as a technical matter, Tri-State's transmission lines do cross state lines. Without regard to how a court of law would now view this Commission's jurisdiction over Tri-State, and in light of its developing intrastate operations and the time-of-use intrastate rates required herein, the Commission expects Tri-State to cooperate in resolving the problems of implementing time-of-use rates within its system. The record in this proceeding clearly established that Tri-State has an extremely high summer peak, which largely is caused by increasing irrigation loads. Therefore, the utilization of seasonal rates is particularly appropriate for Tri-State and its system. However, at the present time, Tri-State employs a so-called "ratchet" in establishing wholesale rates to its distribution members. Basically, the ratchet operates to impose a demand charge in the off-peak season proportional to the demand imposed upon the system during the peak season. The effect of the ratchet is thus to levelize Tri-State's revenues attributable to its demand cost throughout the year. By the technique of ratchet, Tri-State's member distribution utilities are charged for demand during the off-peak season whether such demand is used or not. Such members then, by their rate structure, recover revenues necessary to pay such charges. Thus, instead of charging less during off-peak periods, Tri-State's member distribution utilities are encouraged, by the existence of ratchet, to charge uniform rates which do not reflect the seasonal variations in cost of power. Therefore, the use of rachet by Tri-State makes the implementation of seasonal rates by the distribution members counterproductive. Accordingly, the Commission will herein order implementation of seasonal rates for Tri-State's distribution companies, over which it has jurisdiction, and will make all efforts to persuade Tri-State to discontinue the use of ratchet as it relates to the implementation of time-of-use rates for the Tri-State system as a whole.

As previously mentioned, this Commission does not have jurisdiction over power sales by municipalities to customers within city limits. The jurisdiction of this Commission extends only to customers who reside outside the city limits, all in accordance with Article XXV of the Colorado Constitution. Yet, requiring municipalities, as we herein do, to charge those industrial and large commercial customers residing outside municipal boundaries on a time-of-day basis, when the Commission has no jurisdiction over similar customers who reside within municipal boundaries, appears to create potential inequities. Although the instant record is not complete on this issue, the Commission believes that the industrial and large commercial customers of such municipal utilities over which the Commission has jurisdiction are few. There is a greater likelihood that such municipal systems, particularly those systems having either a predominant agricultural or winter recreation customer mix, would be benefited by the implementation of seasonal rates. We are aware, of course, that many of the municipalities subject to this Commission's jurisdiction receive power from wholesalers over which the Commission has no jurisdiction. However, the Commission will not exempt municipalities from the requirements of this Order at this time. Rather, we expect municipalities to come forward with creative solutions to the problems outlined above, in that the solutions to those problems may well lead to an improvement in the system characteristics of such municipal utilities.

d. Implementation

While the record in this proceeding is sufficient to establish a prima facie case for implementing time-of-use pricing, it is not sufficiently detailed to permit the immediate implementation of such by order, even upon the limited basis as set forth above. Not only does PURPA require a consideration of time-of-day pricing and seasonal rates on a utility-by-utility basis, but, the Commission also concludes that it is proper finally to determine the appropriateness of the rate reforms in each utility's next rate proceeding. However, it should be clear from the above that there is now a presumption which favors the implementation of the instant rate reforms. In future rate proceedings the Commission will invoke this presumption and the affected utility will then bear the burden of showing that the costs of implementation outweigh the benefits in its particular case. While the Commission does not intend, in future rate hearings, to relitigate the issues considered in this generic proceeding, it will provide the opportunity for each utility and its customers to show that implementation may not be beneficial to its system.

However, all jurisdictional electric utilities will be ordered herein to file time-of-day rates applicable to their industrial and large commercial customers at the time of their next general rate filing but, in any event, not later than six months after the effective date of this Order. Each utility in such filing initially may delineate the customers to be included in these classifications, based upon the magnitude of their usage, and the type of metering available or the investment necessary for them, as well as all other factors justifying the appropriateness and cost-effectiveness of such classification. For example, a utility may wish to propose inclusion of all industrial and commercial customers with certain minimum usage, in order to maximize the cost-effectiveness of implementation. The Commission will review all proposals and will determine the classification as well as the rates as proposed to apply to such classification. In like manner, those utilities listed in Appendix D, which the Commission finds to have a sufficient and significant seasonal differential, shall file seasonal rates for all of their customer classifications at their next rate filing but, in any event, not later than six months from the effective date of this Order. In developing those filed rates, the utilities should develop and file an appropriate methodology for implementation suitable for their particular circumstances. An example of such methodology is provided in Appendix F. It should be noted that the Appendix F methodology is based upon average costs. The Commission has attempted, in developing that methodology, to make compliance with this Order as simple as possible and to minimize the burden upon the utilities in complying with this Order. And finally, as mentioned above, those utilities may, in addition, submit evidence which, in their opinion, would make implementation of such rate reforms inappropriate.

G.

DECLINING BLOCK RATES

The Commission believes that public misunderstanding of the design and usefulness of the declining block rate, and the controversy surrounding the rate, have made its continued use counterproductive. Public understanding and acceptability of any utility rate is an essential factor that must be considered by regulators in designing and approving rates. The lack of public understanding and acceptance of declining block rates requires this Commission to propose another rate form for the vast majority of Colorado residential and commercial electric customers. The rate form which we today order is no less cost-tracking than the declining block rate, but it has the advantage of not being fraught with widespread dissatisfaction and numerous catch phrases, and thus, we believe that it is amenable to public understanding and acceptance.

The declining block rate, which has been used predominantly for the Colorado residential and commercial classes, has been criticized severely in recent years because of its alleged promotional nature. Critics have characterized its operation as "the more you use, the less you pay." In general, the public views this rate as a benefit for the large user of electricity and a burden for the small user. Utilities justify the use of the declining block rate by arguing that it accurately tracks costs. The complexity of the cost-tracking argument, however, makes it not conducive to general public understanding.

Any rate which is designed to recover the costs of providing service must account for the three cost components of that overall cost; namely, the customer cost component, the energy cost component, and the demand cost component. The customer cost component is independent of usage and has been attributable to the cost of reading meters and preparing bills, as well as customer-related plant costs. The energy cost component is attributable to fuel expense and certain operation and maintenance expenses. The demand cost component is attributable to the utility plant investment necessary to supply the greatest amount of energy that must be supplied in any time interval. For most utility plant items, investment is related not to the total amount of energy that must be supplied, but to the greatest amount of energy that must be supplied in any time interval. Demand measures the maximum energy supplied in a fixed time interval, and thus measures the plant investment necessary to serve the required load.

Essentially the declining block rate is merely a usage rate. That is, the customer's bill is dependent only upon the amount of energy used, and no other component of cost is directly measured. Thus, the declining block rate is designed to recover the three cost components required in providing electricity, i.e., customer, demand, and energy, by relating the incurrence of each to the energy usage of the customer. It is the recovery of all of the component costs of providing electricity, through the vehicle of an energy usage rate, that has led to the misconception that the declining block rate is promotional in nature.

Clearly, the simplest component of the declining block rate to compute is the energy component in that it is the quantity directly measured by the electric meter. Thus, ideally, the energy component will be incorporated and recovered in each block of the rate.

The customer cost component of the declining block rate is incurred by the utility irrespective of the customer usage level. Accordingly, customer costs normally are recovered in the first blocks of usage, thereby assuring that all but a few customers (who for some reason might use very little energy in any given month) will pay rates which are sufficient for the utility to recover these costs. The recovery of customer costs in the first blocks of usage is reasonably well understood by the public. However, as far as public perspective is concerned, the recovery of the demand component of the rate is widely misunderstood.

The demand component of the customer's bill ideally should be directly proportional to the demand imposed by the customer. If demand were separately metered, the above would pose no problem. However, when only energy usage is metered, an attempt must be made to find a relationship between energy usage and the demand imposed, so that customer demand can be imputed and billed through the measurement of energy usage. Load research data has established that, on the average, as energy usage increases, energy is utilitized more uniformly over time, so that the demand imposed does not increase in direct proportion to the amount of energy used. It is this incremental leveling out characteristic of customer demand that necessitates decreasing the per-unit-demand charge with increasing levels of energy usage. In such fashion, it can be seen that a decreasing per-unit charge fairly and accurately tracks the demand costs imposed on the utility system by the customer.

When all of the aforementioned cost components to be recovered are added together, the declining block structure becomes apparent. For example, in the first block of customer usage, a customer is charged for most of his customer costs, his demand costs attributable to that usage as well as the uniform energy cost. The next block then recovers the balance of the customer costs, the demand cost attributable to that usage level, and finally, again, the uniform energy cost. Succeeding blocks will include recovery of the declining demand cost, the uniform energy charge, but no customer costs, which have previously been fully recovered. When these costs are added together, and recovered through the declining block rate, it does, incorrectly, appear that "the more you use, the less you pay," even though the reasons for the declining nature of the rate is the recovery of customer costs in the first several blocks as well as the declining nature of demand costs.

Largely as a result of the public misunderstanding of the declining block rate and the controversy surrounding its use, Congress provided in §111(d)(2) of PURPA that this Commission, as well as other state regulatory authorities, consider the following standard:

> The energy component of a rate, or the amount attributable to the energy component in a rate, charged by any electric utility providing electric service during any period to any class of electric customers may not decrease as kilowatt hour consumption by such class increases during such period except to the extent that such utility demonstrates that the cost to such utility of providing electric service to such class which costs are attributable to such energy component, decrease as such consumption increases during such period.

In essence, Congress has not prohibited the use of declining block rates. On the contrary, Congress has merely provided that the energy component of the rate should not decline with increased usage, unless the utility can demonstrate such a declining cost characteristic for the energy component of costs. As the above discussion demonstrates, the declining block rate used by utilities in Colorado does not contain a declining energy component. In Colorado, as above mentioned, the cost component that declines with increasing usage is that of demand and not of energy. Accordingly, the Commission in considering the above-mentioned federal standard finds that the declining block rates used in Colorado are in compliance therewith.

In essence, the Commission believes that a rate should be designed to recover each of the three herein-described cost components separately. For example, customer costs, defined to include expenses of billing and meter reading only, should be recovered from every customer as a flat monthly charge without regard to usage.[29] Energy costs should be recovered from each customer on a flat per-kilowatt-hour basis. Thus, in compliance with the above-mentioned standard of PURPA, as well as the economics of the situation, the energy component of the rate will be the same for all classes of customers at every usage level. And third, the rate should recover all demand-related costs, including customer-related plant costs in two or three separate blocks which recognized the decreasing nature of those costs. It is felt that separating the rate in this fashion will enhance public understanding of the nature and level of the costs to be recovered in the rate.

29 The Commission believes that any fixed costs previously recovered through the customer component of the declining block rate more properly are recovered through the demand component of the proposed rate.

A few additional comments are required concerning the demand component of the rate. As mentioned above, the decreasing per-unit-demand charge more accurately is recovered with a greater number of blocks. However, the Commission believes that to recapture such charge in an unduly large number of blocks in the decreasing block rate, or in the rate form as established hereby, is both unwieldy and does not lend itself to public understanding. Also, the Commission believes that the decreasing nature of the demand component of this established rate should be minimized to the extent possible to avoid any further misunderstanding in this regard. Accordingly, the Commission will expect that the rates filed in compliance with this Order will divide the demand cost into two or a maximum of three parts. The usage levels for the demand blocks initially will be determined by each utility. Such determination shall be based upon each utility's load research and customer characteristics. However, recognition should be given, in designing these blocks, to maximizing customer understanding thereof.

As an alternative to the three-part demand cost form as described above, the Commission also finds a two-part cost form acceptable. The two-part form should consist of a monthly service charge, which will encompass all customer-related costs, and a monthly energy charge which will encompass all demand and energy related costs on a flat per kWh basis. While the two-part form is not as refined as the three-part form, the two-part structure has the advantage of administrative simplicity and ease of customer understanding.

Accordingly, each utility under the jurisdiction of this Commission at its next general rate filing, or within six months of the effective date of this Order, shall file with the Commission, rate schedules for its residential, commercial, and industrial customers in accordance with the foregoing rate design concepts. Jurisdictional utilities should be prepared to engage in an educational program to explain fully and clearly to all consumers the operation of the new rate design. Specifically, the Commission will expect utilities to include bill inserts as well as other public explanations of the design characteristics of the established rate, in order to overcome public misunderstanding.

H.

LIFELINE RATES

Typically, the justification for lifeline rates as a pricing method is that a minimal amount of electricity is required by individuals to maintain an adequate standard of living. The traditional design of lifeline rates prices the first rate blocks below cost and thus attempts to assure that a subsistence quantity of electricity is within the reach of all. In practice, the above results in all residential customers who consume less than the subsistence level of electricity paying a rate below the cost of providing that service.

This traditional lifeline rate concept has been criticized in this proceeding by all of the utilities, and the industrial and commercial utility customers. Traditional lifeline rate structures are intended to benefit low-income residential customers; however, under such rate structures low consumption of electricity, rather than low-income consumers, is benefited. The evidence presented in this proceeding has failed to convince this Commission that low-usage consumers are coextensive with low-income consumers. Rather, it is quite probable that many low-income persons live in large uninsulated houses, in all-electric homes,[30] or if handicapped, require high usage life supporting devices, and consequently are large users. Conversely, many affluent customers with well-insulated apartments or houses, or second homes, may well benefit from such a lifeline rate. Some economists point out that the lifeline rate that departs from costs results in a subsidy, and thus could cause a misallocation of economic resources. There is also skepticism as to whether traditional lifeline rates encourage conservation, in that the rate is below that which otherwise would be charged. Finally, many argue that an independent, appointed commission should not concern itself with social welfare considerations. The argument runs that rate structures should not be used for income redistribution, which is a matter that should be determined by the elected legislature and handled through the public welfare system -- hence borne by taxpayers and not ratepayers.

Resultant from the many criticisms directed against the traditional lifeline approach, and coupled with a recognition of the inordinate burden that the accelerating costs of home heating was placing on the poor aged and poor handicapped, this Commission in an earlier proceeding

[30] For example, the average natural gas monthly usage required to heat a residence in the winter is 250 Ccf. Heating a comparable home with electricity would require 5,000 kWh per month, which is well above any conceivable lifeline usage.

attempted a different lifeline rate design. Subsequent to hearings in 1977, this Commission ordered Public Service Company, as well as all other gas distribution utilities in the State of Colorado (other than municipalities), to file a separate rate schedule. Such rate was to be applicable to residential gas customers who were eligible, by reason of their low income and age (or handicap), for the state property tax and rent relief. This eligible customer class then was to receive gas service during the winter months of the year at a rate below that charged other residential gas customers. This Commission firmly believed that the inability of low-income people, particularly the elderly and handicapped, to pay their wintertime heating bill had become critical and thus a low-income rate (unlike the traditional lifeline approach described above) was designed to help only such customers. Treating such customers differently was justified, in the Commission's view, because of the increased likelihood that the inability of such customers to meet their payments for service would cause termination. The resulting extreme hardship was deemed by us to be a legitimate regulatory concern. However, the above rate was invalidated by the Colorado Supreme Court on the grounds that it established preferential and unjustly discriminatory rates. The Supreme Court stated:

> . . . When the PUC ordered the utility companies to provide a lower rate to selected customers unrelated to the cost or type of the service provided, it violated section 40-3-106(1)'s prohibition against preferential rates. In this instance, the discount rate benefits an unquestionably deserving group, the low-income elderly and the low-income disabled. This, unfortunately, does not, make the rate less preferential. To find otherwise would empower the PUC, an appointed, non-elected body, to create a special rate for any group it determined to be deserving. The legislature clearly

> provided against such discretionary power when it prohibited public utilities from granting 'any preference'. In addition, section 40-3-102, C.R.S. 1973, directs the PUC to prevent unjust discriminatory rates. Establishing a discount gas rate plan which differentiates between economically needy individuals who receive the same service is unjustly discriminatory.

Mountain States Legal Foundation v. Public Utilities Commission, supra. The Mountain States opinion does not preclude this Commission from taking social considerations into account in exercising its ratemaking function. However, the Supreme Court, by such decision, has made it clear that the Commission may not establish a separate customer classification of service at a lower rate for the sole purpose of carrying out social policy. We do not interpret the Mountain States opinion as a bar to the Commission's consideration of other lifeline rate approaches available to all residential customers.

The only lifeline rate presented in this proceeding was that advocated by Mountain Plains Congress of Senior Organizations through its witness Dr. Eugene Coyle. Dr. Coyle proposed an inverted rate applicable to the residential class only. The rates at the tail block were proposed to be based on long-run incremental cost (LRIC), and rates at the initial block of up to 275 kWh per month were discounted to balance the excess revenues created by pricing the tail block in excess of embedded costs. This Commission will not adopt Dr. Coyle's approach, in that it suffers from the same practical and theoretical problems as other attempts to base rates upon marginal costs, as discussed earlier in this Decision. In brief, basing residential rates on LRIC, much like any other marginal cost approach, would require utilities to perform very complex studies. Many Colorado utilities are without the resources to perform complicated marginal cost studies, and this Commission is clearly without the resources to monitor the suitability of such studies. Further, the so-called "revenue gap" problem which Dr. Coyle solves essentially by creating a lifeline rate of less than 275 kWh makes the LRIC approach unworkable for the reasons set forth in Part II-F-4 of this Decision. Finally, Dr. Coyle advocated the LRIC methodology only for the residential class. If such methodology is sound, it follows that LRIC should be applicable to all classes of customers. Thus, the Commission concludes that the LRIC methodology was proposed by Dr. Coyle, not because it is an economically appropriate theory, but in order to achieve the limited goal of a lifeline rate for residential customers. For the foregoing reasons, the Commission rejects the lifeline approach proposed by Mountain Plains Congress of Senior Organizations.

As a result of the Mountain States opinion and the absence of a workable alternative lifeline approach, Colorado is now without a lifeline rate. Pursuant to §114 of PURPA, this Commission is required within two years of the date of the enactment of the Act, to determine, after an evidentiary hearing, whether a lifeline rate should be implemented by each Colorado utility. Since the Commission has not adopted a lifeline approach in this proceeding, §114(c) makes it clear that this proceeding does not qualify as one in which such a determination finally can be made. Thus, this Commission, in either a generic proceeding, or in an individual rate proceeding, will reconsider such issue. As a result of the above discussion, the parties to this proceeding as well as the public are put on notice of some of the legal and practical concerns of the Commission in any future consideration of a lifeline approach. It should be made clear that, within the above confines, the Commission will consider lifeline rates with an open mind.

I.

ALL-ELECTRIC RATES

All-electric customers in Colorado have experienced significant changes in ratemaking policy over recent years, and unfortunately all such have resulted in increasing bills. During the 1950s and 1960s utilities offered promotional rates to their all-electric customers. As intended, these promotional rates fostered the increased development of all-electric usage in Colorado. However, as is generally recognized, the 1950s and 1960s were a time period in which utilities were experiencing economies of scale. Thus, an increase in usage, which required an expansion of capacity, resulted in a concomitant decrease in the per-unit cost. Promotional rates did not necessarily constitute a cross-subsidy; they were simply intended to, and often succeeded in, distributing widely the benefits of economies of scale.

As energy became more expensive and utilities were required to build plants costing more than embedded costs in order to meet increased demand, this Commission ordered utilities to eliminate any promotional rate which resulted in all-electric customers not paying the full cost of such service. Elimination of promotional all-electric rates resulted in a sharp increase in the electric bills of all-electric customers, who had for years relied upon inexpensive electricity for home heating.

In late 1975, the Commission authorized Public Service Company to implement demand-energy rates for all new residential and commercial all-electric customers. Unlike the traditional declining block rate structure under which these customers were charged, the demand-energy rate measured not only usage, but also the maximum demand the customer placed on the system during a billing cycle. When demand-energy rates were mandated for all new residential and commercial all-electric customers, the Commission believed that all-electricc customers could save money over that previously charged by declining block rates by simple load management of their usage. For example, if such customers would have spread their load by not operating dishwashers, dryers, washers, and heating appliances at the same time, the same kilowatt-hour usage would have resulted in lower bills. The Commission also believed that load leveling, which would be encouraged under such demand-energy rates, would benefit Public Service Company as well as its customers.

All of the above reasons for the mandatory implementation of demand all-electric rates were valid. However, the lack of communication between Public Service Company, the homebuilders, and prospective purchasers of all-electric homes had not sufficiently been considered by the Commission in mandating such demand rates. Customers were not informed fully as to the means by which they could take advantage of the new demand-energy rates. Furthermore, many homebuilders, who were not apprised of the imminent implementation of such demand-energy rates, constructed homes, for example, with central heating systems, which did not provide realistic opportunities for customer-load management. Moreover, the future installation of solar heating with electric backup was discouraged under this rate. As a result of the above factors, which were brought to the attention of the Commission in Case No. 5685, Home Builders Association of Metropolitan Denver v. Public Service Company, the Commission, by Decision No. 89573, dated October 26, 1976, made demand-energy rates voluntary rather than mandatory. In Decision No. 89573, the Commission stated, "Whatever rate structures ultimately are established, it is quite evident that it will be necessary to implement the same as the result of adequate studies, sufficient lead time and appropriate consumer education. That has been the lesson of this proceeding."

With the above background in mind, the Commission in this proceeding is again presented with the issue of demand-energy rates for all-electric residential and commercial customers. There is no question that all-electric residential and commercial customers differ significantly from other residential and commercial customers in that their usage per month is much greater and typically the demand that they put on the system is higher.

The declining block rate structure, as mentioned, is designed to recover customer costs, demand costs, and energy costs. However, by the declining block rate, customers are charged upon the basis of energy usage and not upon the basis of demand. In designing declining block rates, the utility customarily will estimate a customer class daily load factor.[31] Thus, for example, to the extent that the residential class is relatively homogeneous, that is, the load factors of these customers are similar, the declining block rate will recover demand costs, more or

[31] In the case of Public Service Company, a 22 percent average daily load factor is assumed for the residential class.

less. However, customers with a less-than-average load factor will pay less than their demand costs while those with a greater-than-average load factor will pay more than their demand costs. A demand-energy rate will more precisely track costs for a utility than the declining block rate, when intraclass load factors vary significantly. The evidence in this proceeding reveals that the load factors among all-electric residential and commercial customers, generally, can vary considerably, thereby justifying, from a cost recovery point of view, the demand-energy rate.

In addition to recovering the utility's cost of providing service, a demand-energy rate can be utilized by customers for cost control purposes. Customer awareness of the demand component of electric usage should encourage minimization of demand. As mentioned, the spreading of load by not operating large appliances simultaneously can result in significant savings, as can electric heating which is controlled separately by room. Beyond such manual load control there is available, for a relatively small investment, various types of load control equipment which assures that load does not exceed a specified level at any given time. This may be effectuated by phasing the heating system or by a simple interlock device which prevents two or more appliances from operating simultaneously. Thus, with both the use of human awareness and/or an automated system, the consumer can utilize a demand-energy rate to cost and system advantage. Further, the load data collected by Public Service Company establishes that the average load factor of all-electric customers exceeds that of the residential class as a whole. This means that on the average all-electric customers would benefit at present, and in the foreseeable future, from a demand-energy rate, as opposed to the declining block rate.

The Commission is convinced from the record of this proceeding, that demand-energy rates are appropriate for all-electric residential and commercial customers. As mentioned, these rates are both compensatory to the utility and provide the customer with an opportunity to control energy costs through load management. Implementation of such should be mandatory for service to new homes, but only after sufficient information and education as to the effective use of such rate has been provided the consumers, homebuilders, and public at large, by the involved utility. To effectuate this implementation, the Commission believes that there must be a sufficient lead time, prior to establishment of the rate, so that the new homes to which this rate will apply can be designed by homebuilders to provide maximum opportunity for load management. Accordingly, each jurisdictional utility providing all-electric service shall file demand-energy rates for all new residential and commercial customers within six months subsequent to the effective date of this Decision, to be effective 18 months after filing thereof. All affected utilities should note that the Commission is of the opinion that it is appropriate to design demand-energy rates, as was done by Public Service Company, so that all-electric customers with a load factor greater than that built into the current rate schedules will be able to achieve savings.

Also, each utility shall offer simultaneously along with the mandatory rates, but on a voluntary basis, demand-energy rates for existing all-electric customers, residential customers with a minimum annual usage of 15,000 kWh, and existing commercial customers. The Commission believes that customers who can achieve savings pursuant to the new demand-energy rate should be given the opportunity to do so. Furthermore, all jurisdicional utilities should make every effort to give customers full information as to the operation of demand-energy rates so that consumers may elect to take such, armed with a full understanding thereof. Such educational program should include providing customers with a trial period, whereby a demand-energy meter is installed, but dual billings, composed of charges under both the previous and demand-energy rate structures, are rendered to the customers. The customer during such dual bill trial period will be charged under the previous rate structure. The above procedure will give customers an opportunity to determine what their bills would have been under the demand-energy rate structure as compared with the current rate structure.

J.

SOLAR ENERGY AND HEAT STORAGE RATES

Solar energy technology is in its infancy. As mentioned previously, the Commission believes that the regulation of electric utilities should accommodate new technology to the extent possible, while remaining neutral between competing technologies -- new and existing. We believe that the above approach will allow the orderly growth of solar technology without providing a subsidy therefor. Clearly, the development of solar technology will benefit society in that it will allow us to become less dependent upon increasingly expensive nonrenewable resources. However, whether solar technology ultimately becomes a reliable source of energy and a thriving industry depends mainly on the costs of implementing that technology as against the costs of competitive energy technologies. Thus, the Commission believes that rate structures developed by electric utilities for solar technology, which structures directly affect the costs to the consumer of utilizing that technology, should neither unduly benefit nor unduly hamper the solar alternative.

There is no question but that the usage pattern of solar electric customers varies significantly from other residential and commercial customers in general and from all-electric customers in particular. For example, the residential solar customer normally invests between $5,000 and $15,000 in solar hardware for the purpose of augmenting the space and/or water heating needs of the customer. The technology usually involves the installation of solar collectors which absorb the heat from the sun and when available store such in a system utilizing either water or rocks. The heat as thus stored can be drawn upon to provide heat as needed. Unfortunately, current technology cannot now assure that 100 percent of the solar customer's heating needs will be supplied through the solar system. Accordingly, a backup heating system must be installed to provide supplemental heat when the solar storage system does not meet heating needs.

As can be expected, after a series of sunless, and unusually cold days, the stored solar heat will be depleted. Such circumstance will usually necessitate the use of the backup system. Thus, for the utility, backup usage by the solar customer may well coincide with the utility's peak day, or with the days of its heaviest loads. The effects of solar customers have not yet had an important impact upon utilities because of the small numbers of such customers involved. However, as solar development occurs and increases, the above situation could become a problem for both utilities and their nonsolar customers.

At present, residential and commercial rate structures do not adequately accommodate current solar technology. For example, the implementation of a demand-energy rate could be extremely unfavorable for solar usage customers in that backup usage may occur only over two or three days of a winter month, but at a very high demand, which automatically will be reflected in the demand-energy charge. However, the declining block rate, being based on kWh usage may well be a subsidized rate for solar customers.

Solar systems may include the ability to store energy required for heating. The above would be most significant for the affected utility, in that such a customer would have the flexibility of managing load. Obviously, such a consumer could schedule his individual load so that it occurs during the utility's off-peak hours, and thus burden the system less. Moreover, any customer who has heat storage capacity, no matter whether it is for the purpose of collecting solar energy or not, can benefit the utility system as a whole by load management. Thus, any rate structure designed for solar customers should be available to any consumer that has the ability to store heat and thus manage load.

In this proceeding Public Service Company has proposed an alternative rate for solar customers. Fundamentally, such rate is a demand-energy rate which operates much like the rate for all-electric customers. However, such rate discounts the demand charge by 50 percent for solar customers during the period of 10 p.m. to 8 a.m. on a daily basis. The purpose of the proposed rate, from Public Service Company's point of view, is to encourage solar customers to recharge solar storage during off-peak hours. The 50 percent discount of the demand charge is offered as an inducement to customers to recharge storage at off-peak hours which clearly benefits the system as a whole. The Commission, however, must reject the proposed solar rate alternative. The proposed rate is designed to apply only to solar customers and thus is not neutral. There are other customers with attributes similar to solar customers who also should be given the benefit of any such rate. Furthermore, the Commission believes that it would be appropriate to recognize the difference in cost to the utility of recharging during peak as opposed to off-peak hours. Moreover, the Commission believes that a much simpler rate can be designed which would consider the costs imposed upon the system by such heat-storage customers, and yet would result in lower rates than the Public Service Company proposal. Finally, there was no evidence presented in this proceeding which would justify the 50 percent discount of the demand charge in off-peak hours.

While Public Service Company witnesses testified that the optimal shape of its load curve renders time-of-day rates not cost-effective for its system, from the instant record we cannot agree with such proposition, as explained in Part II-G above. Moreover, the number of designated residential and commercial customers who would be served by the time-of-day rate, as detailed below, would not be so large that it would impose undue metering costs upon the utility. And certainly, given the insignificant load that such customers now place on the system, or can be expected to place on the system in the near future, the Commission does not believe that they will have a substantial impact upon the utilities' load curve, whether or not such curve is now considered optimal. In fact, Public Service Company has indicated in this proceeding that time-varying rates can be offered to solar customers.

Thus, from the above and foregoing, the Commission believes that residential and commercial heat-storage customers should be charged on a simple time-of-day kilowatt-hour usage rate. Electricity used during peak hours should be charged at a higher rate than electricity used during off-peak hours. While such rate does not measure demand directly, it can be designed to account for the difference in costs of demand by time-of-day. Also, to the extent that energy costs vary by time-of-day, the rate also can be designed to reflect such as well. More importantly, the rate should be simple and thus easily understood by customers, and easily implemented by the utility. As with the all-electric rate mentioned above, the Commission believes that the solar rate should be offered on a mandatory basis for all new residential and commercial heat-storage customers, but only after a sufficient period of time to permit utilities the opportunity adequately to inform homebuilders, as well as customers regarding all aspects of the rate. Accordingly, each utility shall file such rates within six months after the effective date of this Decision to be effective 18 months thereafter. All residential and commercial heat storage customers existing at the time of the filing of the new rates shall be continued on their current rate structure. However, such prior customers also should be offered, on a voluntary basis, the opportunity to convert to the herein-established time-of-day kilowatt-hour usage rate. Again, the Commision expects all jurisdictional and affected utilities to engage in an informational program similar to that described in the section on demand-energy rates, Part II-I.

III.

ORDER

THE COMMISSION ORDERS THAT:

1. Each electric utility whose name is listed on Appendix B to this Decision be, and hereby is, directed to prepare interruptible rate schedules applicable to its industrial, commercial, and/or irrigation rate consumer classes based upon the rate design criteria as described in Appendix C to this Decision. Each such utility be, and hereby is, directed to file said rate schedules at its next general rate proceeding, but in no event later than six months after the effective date of this Decision.

2. Each electric utility subject to the jurisdiction of this Commission be, and hereby is, directed to survey its service territory and file with this Commission within six months after the effective date of this Decision, an inventory of all potential sites and joint ventures for co-generation (including a description of any economic, legal or engineering barriers to development of such potential sites and/or joint ventures) in conformity with the provisions of Part II-E of this Decision.

3. Each electric utility subject to the jurisdiction of this Commission be, and hereby is, directed to present testimony at its next general rate proceeding in support of and in explanation of the costing method of allocation used by said utility, as more fully discussed in Part II-F of this Decision.

4. Public Service Company of Colorado be, and hereby is, directed to modify its average and excess demand allocation methodology to reflect metering of all rate

classes for the same length interval and to cease and desist from using the arithmetic mean in the computation of the class maximum demand for its residential rate class, as more fully discussed in Part II-F of this Decision.

5. Each electric utility subject to the jurisdiction of this Commission be, and hereby is, ordered to file at its next general rate proceeding, but in no event later than six months after the effective date of this Decision, revised rate schedules implementing time-of-day rates for its industrial and large commercial rate classes as more fully discussed in Part II-F of this Decision.

6. Each electric utility whose name is listed on Appendix D as being required to file seasonally differentiated rates be, and hereby is, directed to file at its next general rate proceeding, but not later than six months after the effective date of this Decision, revised rate schedules implementing seasonally differentiated rates for all customer rate classes, as more fully discussed in Part II-F of this Decision.

7. Each electric utility subject to the jurisdiction of this Commission be, and hereby is, directed to file at its next general rate proceeding, but in no event later than six months after the effective date of this Decision, revised rate schedules for its residential rate customer class based upon either a two-part rate or three-part rate, as more fully discussed in Part II-G of this Decision.

8. Each electric utility subject to the jurisdiction of this Commission which provides all-electric service be, and hereby is, directed to file within six months after the effective date of this Decision, to become effective 18 months after the date of filing thereof,

demand-energy rates for all new residential and commercial customers, as more fully discussed in Part II-H of this Decision.

9. Each electric utility subject to the jurisdiction of this Commission be, and hereby is, directed to file within six months after the effective date of this Decision, to become effective 18 months after the date of filing thereof, demand-energy rate schedules (to be elected on a voluntary basis by the customer) applicable to (1) existing all-electric customers, (2) residential customers with a minimum annual usage of 15,000 kWh and (3) existing commercial customers, all as more fully discussed in Part II-H of this Decision.

10. Each electric utility subject to the jurisdiction of this Commission be, and hereby is, directed to file within six months after the effective date of this Decision, to become effective 18 months after the date of filing thereof, rate schedules applicable to all new residential and commercial heat-storage customers, as more fully discussed in Part II-H of this Decision.

11. Each electric utility subject to the jurisdiction of the Commission be, and hereby is, directed to file within six months after the effective date of this Decision, to become effective 18 months after the date of filing thereof, rate schedules applicable to existing residential and commercial heat-storage customers (to be elected on a voluntary basis by the customer), as more fully discussed in Part II-H of this Decision.

12. Each electric utility which is a member of a winter-peaking system, singularly or in combination with other utilities of the system, be, and hereby is, directed to conduct a study (or studies) to identify the classes of

customers which contribute to its or their) winter peak, and which would be most appropriate for interruptible rates. Said study (or studies) shall be filed with the Commission within six months after the effective date of this Decision. Colorado-Ute Electric Association, Inc., be, and hereby is, directed to participate in and assist its member utilities in the conduct of their study (or studies).

13. All motions not heretofore ruled upon be, and hereby are, denied.

This Order shall be effective 21 days subsequent to the date hereof.

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

____

____

Commissioners

COMMISSIONER DANIEL E. MUSE NOT
PARTICIPATING

Case No. 5693
Decision No. 1111

APPENDIX A

LIST OF EXHIBITS ADMITTED INTO EVIDENCE

EXHIBITS SUBMITTED BY PUBLIC WITNESSES

Exhibit Designation

1. The Impact of Rate Structure on Energy Conservation and the Economics for Improvement of Irrigation Pumping Plant Efficiencies by Robert A. Longenbaugh, Associate Professor of Civil Engineering, Colorado State University, Fort Collins, Colorado

2. Public Testimony of Kevin Markey on Behalf of The Friends of the Earth

EXHIBITS SUBMITTED BY PARTIES OF RECORD

A. Direct Testimony of J. H. Ranniger, Public Service Company of Colorado

Exhibits to Direct Testimony of J. H. Ranniger

1. Summary of Generic Rate Design Activities Throughout the United States

2. "The Power Company" Electric Department - Average and Excess Demand Cost Allocation Example

3. Construction of Block and Two Part Rates

4. Daily Load Curve Example

5. Available Generating Capability and Loads

6. Load Factors

7. National Residential Rate Comparisons

8. Electric Heating Customers

9. Comparison of Rate Application to Residential Heating Customers

10. Proposed Experimental Solar Rate

11. Impact of Lifeline Rates

12. National Lifeline Summary

13. Conservation Communication

14. Metering and Load Control Devises

15. EEI/EPRI National Rate Study Reports

B. Rebuttal Testimony of J. H. Ranniger, Public Service Company of Colorado

Exhibits to Rebuttal Testimony of J. H. Ranniger

16. Public Service Company of Colorado - Examples of Determination of Average and Excess Demand

17. Concurring Opinion of Commissioners Willaim Symons, Jr. and Vernon L. Sturgeon, a California Commission Decision Instituting So-called Lifeline Rates

C. Direct Testimony of Robert L. Dekker, Director, on Behalf of the Light and Power Department of the Town of Estes Park.

Exhibits to Direct Testimony of Robert L. Dekker

18. Town of Estes Park - Summary of Customers as of Year End 1976

19. Town of Estes Park - Retail Rates in Effect as of August 5, 1977

D. Direct Testimony of Joe D. Heckendorn, Public Service Company of Colorado

Exhibits to Direct Testimony of Joe D. Heckendorn

20. Samples of General Commercial Lighting Customers and Residential Underground Customers

21. Summary of Load Research Data - Monthly Load Factors (%)

22. Summary of Load Research Data - Average Demand Per Customer

23. Summary of Load Research Data - Monthly Coincidence Factors (%)

24. Summary of Load Research Data - R-1 Load Factor by Strata

E. Rebuttal Testimony of J. D. Heckendorn

Exhibits to Rebuttal Testimony of J. D. Heckendorn

25. Summary of Load Research Data - R-1 Demands

26. Comparison of 15- versus 30-Minute Demands for Large Electric Customers - September 1977 Year to Date

27. Public Service Company of Colorado, Colo. PUC No. 5, Electric Tariff Sheets-Seventh Revised Sheet 143 and Fourth Revised Sheet No. 143A

F. Rebuttal Testimony of Thomas J. Boardman on Behalf of Public Service Company of Colorado

Exhibits to Rebuttal Testimony of Thomas J. Boardman

28. Graph Showing Exponential Distribution of Contribution to Peak Load

29. Graph Showing Distribution of Average Peak Load Contribution of 35 Customers

Exhibits of Colorado Utilities Taskforce

30a Graph

30b Graph

30c Graph

G Direct Testimony of J. K. Fuller, Public Service Company of Colorado

Exhibits to Direct Testimony of J. K. Fuller

31. Increase in P.S.Co. Residential Customers and Increase in Colo. Population Age 25 and Above -- 1972-1981

32. Average Number of Residential Customers (and Percent Increase from Previous Year) - 1971-1981; Annual KWH Usage per Average Residential Customer (and Percent Increase from Previous Year) - 1971-1981; Residential KWH Sales (and Percent Increase from Previous Year) - 1971-1981

33. Commercial and Industrial Sales and Total Colorado Employment - 1971-1981

34. Kilowatt Hour Sales to Street Lighting, Public Authority and Resale Customers (and Percent Increase from Previous Year) - 1971-1981

35. Total Kilowatt Hour Sales (and Percent Increase from Previous Year) - 1971-1981

36. Maximum Net Firm Demand, Total Net Energy for Load and Loss - 1971-1981

37. Illustration of Typical Shift of Load From Peak Period to Off-Peak Period

38. Capacity Addition Schedule Used in the Base Case and Shaved Case

39. Percent Difference of Fuel Costs Between the Shaved Case and the Base Case

40. Percent Difference of the Accumulated Present Worth of the Fuel Costs between the Shaved Case and the Base Case

41. Year of Study - Loss of Load Probability-Shaved Case (A) vs. Base Case (B)

42. Capacity Addition Schedule Used in the Moderate Deferral Case

43. Year of Study - Loss of Load Probabilty-Moderate Deferred Case (A) vs. Base Case (B)

44. Capacity Addition Schedule Used in the Peaking Eliminated Case

45. Year of Study - Loss of Load Probability-Peaking Eliminated Case (A) vs. Base Case (B)

46. Percent Difference of the Accumulated Present Worth of the Fuel Costs between the Peaking Eliminated and the Base Case

47. Typical Summer Day Load Curve; Typical Winter Day Load Curve

48. Effective Cost of Fuel for the Year 1976

49. System Fuel Oil Consumption, System Coal Consumption, Annual Capacity Factor of Base Load Generating Units, System Heat Rate, and Total System Fuel Costs - With and Without Cabin Creek - 1977-1981

H. Rebuttal Testimony of J. K. Fuller, Public Service Company of Colorado

Exhibits to Rebuttal Testimony of J. K. Fuller

50. Number of Hours of Loads that were Larger than (or equal to) 85 Percent of Annual Peak

51. Monthly Peak and Energy Depressions - 1976 Data

Exhibits of Public Service Company of Colorado

52. Friday, December 9, 1977

53. Sunday, December 11, 1977

54. Public Service Company of Colorado - Electric Utility System Data - Volume 1 of 2, pages 1 through 400

55. Public Service Company of Colorado - Electric Utility System Data - Volume 2 of 2, pages 401 through 853

I Direct Testimony of Glenn W. Calvert, Electric Superintendent on Behalf of the City of Fort Morgan, Electric Department

J Direct Testimony of Glenn W. Calvert, President, Colorado Association of Municipal Utilities

K Direct Testimony of Larry R. Day, Colorado-Ute Electric Association, Inc.

Exhibits to Direct Testimony of Larry R. Day

56. Map - Colorado-Ute Electric Association - Member Systems - Certificated Service Areas

57. Load Growth 1975-1976 - Demand in KW

58. Day of Maximum Demand - Curve 1, System Demand Curve and Curve 2, Division of System Demand by Sources

59. Day of Maximum Demand- Curve 1, System Demand Curve and Curve 2, Division of System Demand by Sources

60. System Map

61. Colorado-Ute Electric Association, Inc., Marginal Cost Study, Calendar Year 1976 by Month

L Direct Testimony of Frederic A. Kuhlemeier, Colorado-Ute Electric Association, Inc.

Exhibit to Direct Testimony of Frederic A. Kuhlemeier

62. Rate Curves

M Direct Testimony of Donald Athen

Exhibit to Direct Testimony of Donald Athen

63. Customer Opinion Survey - Denver-Boulder Areas, Public Service Company of Colorado - November 3-11, 1977

N Direct Testimony of Irwin M. Stelzer

Exhibits to Direct Testimony of Irwin M. Stelzer

64. An Analysis of the Time-Differentiated Marginal Costs of The Public Service Company of Colorado by National Economic Research Associates, Inc., August 5, 1977

65. Rate Structure Revision - A Federal or State Problem? by Irwin M. Stelzer, National Economic Research Associates, Inc.

66. A Memorandum by William Shew and Karen Dybing Regarding the Connecticut Peak-Load Pricing Experiment and a Report by Alan Fishbein entitled, "An Appraisal of the Central Vermont Rate Experiment, together with an Executive Summary"

67. Energy Management Associates, Inc. Computations for Hourly Marginal Cost and Loss of Load Contribution

68. A Framework for Marginal Cost-Based Time-Differentiated Pricing in the United States: Topic 1.3, Prepared by National Economic Research Associates, Inc., Prepared for Electric Utility Rate Design Study: A nationwide effort by the Electric Power Research Institute, the Edison Electric Institute, the American Public Power Association, and the National Rural Electric Cooperative Association for the National Association of Regulatory Utility Commissioners, February 21, 1977

O Direct Testimony of Russell E. Dunn, Witness on Behalf of Intermountain Rural Electric Association

P Direct Testimony of Melvin C. Rich, Witness on Behalf of Intermountain Rural Electric Association

Q Direct Testimony of Walter M. Schirra, Witness on Behalf of Intermountain Rural Electric Association

R Direct Testimony of Gerald E. Hager, P.E., for Union Rural Electric Association, Inc.

Exhibits to Direct Testimony of Gerald E. Hager

69. Allocation of Utility Plant between Customer, Demand and Direct Components - Union Rural Electric Association, Inc. - December 31, 1976

70. Development of Average Monthly Customer Service Cost - Union Rural Electric Association, Inc. - December 31, 1976

S Rebuttal Testimony of Gerald E. Hager

Exhibit to Rebuttal Testimony of Gerald E. Hager

71. Table I - Consumer Characteristic Versus Monthly KWH Usage

T Direct Testimony of Jules Joskow

Exhibits to Direct Testimony of Jules Joskow

72. The Effect of Prices and Other Factors upon Company Sales and Loads

73. Statement of Qualifications for Kent P. Anderson

U Direct Testimony of Richard L. Arnold for Union Rural Electric Association, Inc.

Exhibits to Direct Testimony of Richard L. Arnold

74 Resolution of Union Rural Electric Association, Inc.

75 Resolution of Union Rural Electric Association, Inc.

V Rebuttal Testimony of Richard L. Arnold for Union Rural Electric Association, Inc.

W Direct Testimony of Richard L. Arnold for The Colorado Rural Electric Association

Exhibits to Direct Testimony of Richard L. Arnold

76. Resolution of Union Rural Electric Association, Inc.

77. Resolution of Union Rural Electric Association, Inc.

X Rebuttal Testimony of Richard L. Arnold for The Colorado Rural Electric Association

Y Direct Testimony of Lawrence A. Crowley for The Colorado Rural Electric Association

Exhibits to Direct Testimony of Lawrence A. Crowley

78 Consumer Density Per Mile of Line

79 Listing of Rural Electric Systems by Miles of Line, as of December 31, 1975

80 Southeast Colorado Power Association - Statistical Profile - 1976

Z Rebuttal Testimony of Dick Easton for The Colorado Rural Electric Association

AA Direct Testimony of Everett C. Johnson for The Colorado Rural Electric Association

BB Union Rural Electric Association, Inc. - Financial and Statistical Report and 1976 KWH Sales and Revenue

CC Direct Testimony of Delbert L. Hardy for The Colorado Rural Electric Association

DD Rebuttal Testimony of Delbert L. Hardy for The Colorado Rural Electric Association

EE Rebuttal Testimony of Alan F. Ingram

Exhibits to Rebuttal Testimony of Alan F. Ingram

81 Partial List of Recent Rate Study Work , November 1977

82 Colorado Map - Territories Served by REA Financed Cooperatives

83 Article from <u>Public Utilities Fortnightly</u> entitled "Long-run Incremental Costs and The Pricing of Electricity," Part I, March 11, 1976, and Part II, March 25, 1976

FF Direct Testimony of Donald A. Murry, Witness on Behalf of Intermountain Rural Electric Association

GG Supplemental Testimony of Donald A. Murry for the Intermountain Rural Electric Association

Exhibit to Direct Testimony of Donald A. Murry

84 Table 1, The Number of Intermountain Rural Electric Association Customers Classified by Type of Energy Used, Type of Residence and Consumption - April 1977; Table 2, Consumption of Electricity by Income Level, Customers of Intermountain Rural Electric Association (Percent of Customers); and Table 3, Income Levels of Customers with Lowest Annual KWH Consumption Intermountain Rural Electric Association - 1977

HH Rebuttal Testimony of Donald A. Murry for The Colorado Rural Electric Association

II Direct Testimony of Dick Wilkerson for The Colorado Rural Electric Association

Exhibits to Direct Testimony of Dick Wilkerson

85 List of Colorado Rural Electric Associations

86 Colorado Rural Electric Association - Board of Directors

87 Colorado Rural Electric Association - Statement of Position

JJ Direct Testimony of Stanley R. Lewandowski, Jr., for The Intermountain Rural Electric Association

KK Direct Testimony of Stanley R. Lewandowski, Jr., for The Colorado Rural Electric Association

LL Direct Testimony of Samuel M. Sampson for The Colorado Rural Electric Association

MM Rebuttal Testimony of Samuel M. Sampson for The Colorado Rural Electric Association

NN Rebuttal Testimony of Donald E. Smith for The Colorado Rural Electric Association

OO Direct Testimony of Carl N. Stover, Jr., Witness on Behalf of Intermountain Rural Electric Association

PP Supplemental Direct Testimony of Carl N. Stover, Jr.

Exhibit to Direct Testimony of Carl N. Stover, Jr.

88 Bill Frequency Analysis for Intermountain Rural Electric Association for the Residential and the Residential All-Electric and the Seasonal Rate Class for August 1976, December 1976, January 1977 and April 1977

QQ Direct Testimony of Carl N. Stover, Jr., for The Colorado Rural Electric Association

Exhibits to Direct Testimony of Carl N. Stover, Jr.

89 Summary of Various Electrical Utility Rate Cases in which Carl N. Stover, Jr., has participated

90 System Equity for Colorado Rural Electric Distribution Cooperatives as of 12/31/75

91 Consumer Density Per Mile of Line for Colorado Rural Electric Distribution Cooperatives as of 12/31/75

92 Annual KWH Sales Per Mile of Line for Colorado Rural Electric Distribution Cooperatives as of 12/31/75

93 Residential Sales Statistics for Colorado Rural Electric Distribution Cooperatives as of 12/31/75

RR Rebuttal Testimony of Carl N. Stover, Jr., for The Colorado Rural Electric Association

SS Direct Testimony of Keith R. Cardey on Behalf of Southern Colorado Power Division, Central Telephone & Utilities Corporation

Exhibits to Direct Testimony of Keith R. Cardey

94 Territory Served by Southern Colorado Power Division, Central Telephone & Utilities Corporation

95 Comparison of KWH Sales as Percentage of Annual Average - 1976

96 Summary of Commercial and Industrial Loads - 1976

97 Suggested Off-Peak Storage Rider; Suggested Off-Peak Power Rate; Suggested Interruptible Provision Added to Irrigation Rates

TT Direct Testimony of James Lim on Behalf of Climax Molybdenum Company, a Division of AMAX, Inc.

UU Direct Testimony of Louis W. Tempel on Behalf of Climax Molybdenum Company, a Division of AMAX, Inc.

VV Direct Testimony of Jann W. Carpenter Sponsored by CF&I Steel Corporation

WW Rebuttal Testimony of Jann W. Carpenter Sponsored by CF&I Steel Corporation

Exhibits of CF&I Steel Corporation

98(A) List of Exhibits 98-147 - Reports Prepared for ELECTRIC UTILITY RATE DESIGN STUDY: A nationwide effort by the Electric Power Research Institute, the Edison Electric Institute, the American Public Power Association, and the National Rural Electric Cooperative Association for the National Association of Regulatory Utility Commissioners

98 Attitudes and Opinions of Electric Utility Customers Toward Peak-Load Conditions and Time-of-Day Pricing. Customer Acceptance: Topic 10.1, January 3, 1977. Prepared by Elrick and Lavidge, Inc.

99 Customer Acceptance: Topic 10.2, January 4, 1977. Prepared by Task Force No. 10

100 Rate Experiments Involving Smaller Customers: Topic 3, January 21, 1977. Prepared by Task Force No. 3

101 Metering: Topic 7, January 12, 1977. Prepared by Task Force No. 7

102 Topic 7: Metering and Communication Systems; Topic 8: The Utilization of Off-Peak Electricity; Topic 9: Mechanical Controls and Penalty Pricing; January 15, 1977. Prepared by Arthur D. Little, Inc.

103 Mechanical Controls and Penalty Pricing: Topic 9, January 14, 1977. Prepared by Task Force No. 9

104 Analysis of Electricity Pricing in France and Great Britain, Topic 1.2, January 25, 1977. Prepared by National Economic Research Associates, Inc.

105 Ratemaking: Topic 5, February 4, 1977. Prepared by Task Force No. 5

106 An Overview of Regulated Ratemaking in the United States, Topic 1.1, February 2, 1977. Prepared by National Economic Research Associates, Inc.

107 Analysis of Various Pricing Approaches, Topic 1, February 2, 1977. Prepared by Task Force No. 1

108 Considerations of the Price Elasticity of Demand for Electricity, Topic 2, January 31, 1977. Prepared by National Economic Research Associates, Inc.

109 Elasticity of Demand, Topic 2, January 31, 1977. Prepared by Task Force No. 2

110 Elasticity of Demand, Topic 2, February 10, 1977. Prepared by J. W. Wilson & Associates, Inc.

111 The Development of Various Pricing Approaches: Topic 1.3, March 1, 1977. Prepared by Ebasco Services, Inc.

112 Potential Cost Advantages of Peak Load Pricing: Topic 6, February 15, 1977. Prepared by Power Technologies, Inc.

113 Estimating the Benefits of Peak-Load Pricing for Electric Utilities: Topic 6, February 22, 1977. Prepared by Systems Control, Inc.

114 Bibliography, March 21, 1977. Prepared by Task Forces and The Edison Electric Institute

115 Potential Cost Advantages of Load Management: Topic 6, March 4, 1977. Prepared by Task Force No. 6

116 Demonstration of the Use of the Westinghouse Model Loopeak: Topic 6, April 15, 1977. Prepared by Energy Utilization Systems, Inc.

117 Measuring the Potential Cost Advantages of Peak-Load Pricing: Topic 6, February 2, 1977. Prepared by Gordian Associates

118 Comments on Two Costing Approaches for Time-Differentiated Rates: March 8, 1977. Prepared by Task Force No. 4

119 How to Quantify Marginal Costs: Topic 4, March 10, 1977. Prepared by National Economic Research Associates, Inc.

120 Costing for Peak-Load Pricing: Topic 4, May 4, 1977. Prepared by Ebasco Services, Inc.

121 Ratemaking: Topic 5, June 6, 1977. Prepared by National Economic Research Associates, Inc.

122 Ratemaking: Topic 5 and Illustrative Rates for Five Utilities, June 6, 1977. Prepared by Ebasco Services, Inc.

123 Costing for Peak-Load Pricing: Topic 4, Results for Virginia Electric and Power Company, June 6, 1977. Prepared by Ebasco Services, Inc.

124 How to Quantify Marginal Costs: Topic 4, Results for Virginia Electric and Power Company, June 6, 1977. Prepared by National Economic Research Associates, Inc.

125 Ratemaking: Topic 5, Illustrative Rates for Virginia Electric and Power Company, June 6, 1977. Prepared by National Economic Research Associates, Inc.

126 Costing for Peak-Load Pricing: Topic 4, Results for the Portland General Electric Company, June 20, 1977. Prepared by Ebasco Services,Inc.

127 How to Quantify Marginal Costs: Topic 4, Results for the Portland General Electric Company, June 20, 1977. Prepared by National Economic Reserach Associates, Inc.

128 Ratemaking: Topic 5, Illustrative Rates for the Portland General Electric Company, June 20, 1977. Prepared by National Economic Research Associates, Inc.

129 Costing for Peak Load Pricing: Topic 4, Results for Carolina Light and Power Company, June 20, 1977. Prepared by Ebasco Services, Inc.

130 Costing for Peak Load Pricing: Topic 4, Results for The Omaha Public Power District, June 20, 1977. Prepared by Ebasco Services, Inc.

131 How to Quantify Marginal Costs: Topic 4, Results for the Dayton Power and Light Company, June 20, 1977. Prepared by National Economic Research Associates, Inc.

132 Ratemaking: Topic 5, Illustrative Rates for the Dayton Power and Light Company, June 20, 1977. Prepared by National Economic Research Associates, Inc.

133 Costing for Peak Load Pricing: Topic 4, Results for Minnesota Power and Light Company, June 20, 1977. Prepared by Ebasco Services Inc.

134 Attitudes and Opinions of Experimental Customers Toward Load Management Alternatives, August 5, 1977. Prepared by Elrick & Lavidge, Inc.

135 Making the Transition from Unit Marginal Costs to Rates: Results for Virginia Electric and Power Company, August 4, 1977. Prepared by National Economic Research Associates, Inc.

136 Technology for Utilizing Off-Peak Energy: Topic 8, October 15, 1977. Prepared by Task Force No. 8

137 EBASCO's Responses to Questions from Task Force 4: Topic 4, September 30, 1977. Prepared by Ebasco Services, Inc.

138 NERA's Responses to Questions from Task Force 4: Topic 4, August 3, 1977. Prepared by National Economic Research Associates, Inc.

139 Comments on National Economic Research Associates' Approach to Marginal Cost Pricing, September 15, 1977. Prepared by Ralph Turvey

140 Comments on Ebasco Service's Approach to Peak-Load Pricing, November 28, 1977. Prepared by Walter A. Morton

141 Critical Issues in Costing Approaches for Time-Differentiated Rates, January 12, 1978. Prepared by Task Force 4

142 How to Quantify Marginal Costs: Topic 4, Results for Tennessee Valley Authority, December 16, 1977. Prepared by National Economic Research Associates, Inc.

143 Making the Transition from Unit Marginal Costs to Rates: Results for Portland General Electric Company, December 20, 1977. Prepared by National Economic Research Associates, Inc.

144 State and Federal Regulatory Commissions Rate Design Activities July 12, 1977. Prepared by EPRI from responses to a questionnaire sent to state regulatory agencies in December 1975.

145 Measuring the Potential Cost Advantages of Peak-Load Pricing: Topic 6 (Phase B), December 15, 1977. Prepared by Gordian Associates.

146 1977 Survey State and Federal Regulatory Commissions Electric Utility Rate Design and Load Management Activities, October 25, 1977. Prepared by Elrick and Lavidge, Inc.

147 How to Quantify Marginal Costs: A Reply to Task Force 4 Comments, December 19, 1977. Prepared by National Economic Research Associates, Inc.

XX Direct Testimony of Joseph M. Cleary, Director of Corporate Utilities for Airco, Inc.

Exhibits to Direct Testimony of Joseph M. Cleary

148 Airco Consumption and Cost Data

148-S Supplement - Update of Exhibit No. 148

149 Airco Graphical Summary of Power Rate

149-S Supplement - Update of Exhibit No. 149

Exhibits of Public Service Company of Colorado

150 Commercial and Industrial Rate Comparisons - 25 Largest Cities - Public Service Co. of Colorado Study (December 1977)

151 Summary of Cabin Creek Operation 1976

YY Direct Testimony of Charles W. King on Behalf of J.C. Penney Company, Inc.

ZZ Direct Testimony of Alvin C. Phillips on Behalf of Phillips Control Corporation

AAA Direct Testimony of Alan Chalfant on Behalf of Colorado Association of Commerce and Industry - September 1977 - Project 2515

Exhibits to Direct Testimony of Alan Chalfant

152 Table 1 - Colorado Rate Structure Investigation - Survey of Marginal Cost Studies

153 Table II - Colorado Rate Structure Investigation - Example of the Impact of Various Methods of Reducing Marginal Costs to the Revenue Requirement

BBB Testimony of Alan Chalfant on Behalf of Multiple Invervenors - State of New York, Public Service Commission, Case 26806, Proceeding on Motion of the Commission as to rate design for electric corporations - August 1975 - Project 2383

CCC Statement of Alan Chalfant on Behalf of Industrial Energy Users - Before the Pennsylvania Public Utility Commission, Proceeding 76-PRMD-7, November 1976 - Project 2511

DDD Testimony of Mark Drazen on Behalf of Colorado Association of Commerce and Industry - September 1977 - Project 2515

EEE Testimony of Mark Drazen on Behalf of Multiple Intervenors - State of New York, Public Service Commission, Case 26806, Proceeding on motion of the Commission as to rate design for electric corporations - August 1975 - Project 2383

FFF Testimony of Maurice Brubaker on Behalf of Multiple Intervenors - State of New York, Public Service Commission, Case 2608, Proceeding on motion of the Commission as to rate design for electric corporations - August 1975 - Project 2383 - Adopted by Mark Drazen

GGG Statement of Maurice Brubaker on Behalf of Industrial Energy Users - Before the Pennsylvania Public Utility Commission, Proceeding 76-PRMD-7 - November 1976 - Project 2511 - Adopted by Mark Drazen

HHH Statement of Mark Drazen on Behalf of Industrial Energy Users - Before the Pennsylvania Public Uility Commission, Proceeding 76-PRMD-7 - November 1976 - Project 2511

III Rebuttal Testimony of Mark Drazen on Behalf of Colorado Association of Commerce and Industry

Exhibit of AMAX, Inc.

154 Primary Power Agreement Between Climax Molybdenum Company and Public Service Company of Colorado

JJJ Direct Testimony of Dr. Eugene Coyle on Behalf of Intervenors The Colorado Utilities Taskforce and Mountain Plains Congress of Senior Organizations - October 7, 1977

KKK Rebuttal Testimony of Dr. Eugene Coyle on Behalf of Intervenors The Colorado Utilities Taskforce and Mountain Plains Congress of Senior Organizations - November 11, 1977

LLL Rebuttal Testimony of Buie Seawell - Office of Energy Conservation, State of Colorado

Exhibits to Rebuttal Testimony of Buie Seawell

155 A Nation of Energy Efficient Buildings by 1990 - The American Institute of Architects

156 Energy and Labor Demand in the Conserver Society by Bruce M. Hannon, Energy Research Group, Center for Advanced Computation, University of Illinois at Urbana-Champaign, Urbana, Ill. 61801 - July 1976

157 Jobs & Energy - Environmentalists for Full Employment - Spring 1977

MMM Direct Testimony of William J. Gillen for Intervenor Environmental Defense Fund - November 11, 1977

NNN Direct Testimony of Ernst R. Habicht, Jr., on Behalf of Intervenor Environmental Defense Fund - September 9, 1977

OOO Direct Testimony of Craig R. Johnson on Behalf of the Department of Energy - September 8, 1977

Exhibits to Direct Testimony of Craig R. Johnson

158 Power System Statement of Public Service Company of Colorado for the Year Ended December 31, 1976 to the Federal Power Commission

159 Predicted Load Shift

160 Electric Utility Rate Demonstration Program - Findings to Date - Office of Conservation Federal Energy Administration - August 30, 1977

161 Price Elasticity of Electricity: Summary of Econometric Estimates

162 Status of Time-of-Use Rates and Rate Hearings in the United States - Office of Energy Conservation, Federal Energy Administration - September 8, 1977

163 Summary of Metering Options

PPP Rebuttal Testimony of Craig R. Johnson on Behalf of the Department of Energy - November 10, 1977

Exhibits to Rebuttal Testimony of Craig R. Johnson

164 Effects of Time-of-Day Pricing on PSCC Annual Load Duration Curve - Simulated 1976 Actual - Time-of-Day Rates: Cases 1, 2 and 3

165 Effects of Time-of-Day Pricing on PSCC Typical Weekday Loads - Summer, Spring/Fall and Winter - Simulated 1976 Actual - Time-of-Day Rates: Cases 1, 2 and 3

166 Results of Cost Benefit Analysis - Effects on Average Prices

167 Table I - Price Elasticities

168 Effects of Time-of-Day Pricing on PSCC Annual Load Duration Curve - Simulated 1976 Actual - Time-of-Day Rates: Company Case

Exhibits of the Department of Energy

169 Final Report - Investigations into the Effects of Rate Structure on Customer Electric Usage Patterns - State of Vermont, Public Service Board, by John C. Romano and Green Mountain Power Corporation by Charles A. Elliott, in cooperation with: Federal Energy Administration, Office of Conservation and Environment - Cooperative Agreement Number FEA #CA-04-50002-00

170 Final Report - Connecticut Peak Load Pricing Test - May 1977 - Connecticut Public Utilities Control Authority, Connecticut Department of Planning and Energy Policy, Connecticut Office of Consumer Counsel, Northeast Utilities - Conducted Pursuant to a Cooperative Agreement between the State of Connecticut and the U.S. Federal Energy Administration

171 Memorandum for Craig Johnson, Office of Regulatory Institutions - Through: Howard L. Walton, Acting Director, Office of Coal, Nuclear and Electric Power Analysis, and Robert L. Borlick, Chief, Electric Power Analysis Division - From: Scott E. Atkinson, Electric Power Analysis Division - Subject: Updated Arizona Time-of-Day Elasticity Estimates

172 Responsiveness to Time-of-Day Electricity Pricing: First Empirical Results by Scott E. Atkinson, Federal Energy Administration, Washington, D.C. 20461 - May 1977

173 Appendix B - Electrical Energy Load Management Demonstration Project - State of Arizona, Arizona Solar Energy Research Commission - in cooperation with U.S. Federal Energy Administration, Office of Conservation and Environment - February 14, 1977

Exhibits of Public Service Company of Colorado

174 1978 Rate Symposium on Problems of Regulated Industries - Kansas City, Missouri - Craig R. Johnson, Department of Energy, Branch Chief, Regulatory Economics and Standards, Office of Utility Systems, Economic Regulatory Administration - Transcribed from Commercially Produced Recording of Mr. Johnson's speech

175 Load Impact and Price Analysis

Exhibit of the Staff of the Public Utilities Commission of the State of Colorado

176 Exchange of Correspondence between Tucker K. Trautman, Assistant Attorney General, State of Colorado, and Bruce C. Driver, Office of General Counsel, Department of Energy, Washington, D.C.

Exhibits of the Department of Energy

177 Department of Energy Work Papers - Calculation of Metering Costs for Limited TOD Rate Implementation; Calculation of Net Benefits from Limited TOD Rate Implementation (Benefits Proportional to KWH %); Calculation of Net Benefits from Limited TOD Rate Implementation (Benefits Less than Proportional to KWH %); Calculation of Net System Benefits Under Full TOD Implementation (Including Meter Costs); Peak Loads and Total MWHs

178a Responses of the Department of Energy to Public Service Company's Interrogatories and Request for Production of Documents to Department of Energy, Economic Regulatory Administration - February 1, 1978

QQQ Direct Testimony of Whitfield A. Russell on Behalf of the Commission Staff

RRR Additional and Rebuttal Testimony of Whitfield A. Russell on Behalf of the Staff of the Commission - Dated: November 18, 1977

Exhibit to Additional and Rebuttal Testimony of Whitfield A. Russell

178 Topic 7: Metering and Communication Systems; Topic 8: The Utilization of Off-Peak Electricity; Topic 9: Mechanical Controls and Penalty Pricing - Prepared by Arthur D. Little, Inc. Prepared for Electric Utility Rate Design Study: A nationwide effort by the Electric Power Research Institute, the Edison Electric Institute, the American Public Power Association, and the National Rural Electric Cooperative Association for the National Association of Regulatory Utility Commissioners - January 15, 1977

SSS Direct Testimony of Dr. George J. Parkins on Behalf of the Staff of the Commission - October 14, 1977

Exhibit to Direct Testimony of Dr. George J. Parkins

179 Appendix A to Direct Testimony of Dr. George J. Parkins

TTT Direct Testimony of Commissioner Thomas K. Standish, Public Utilities Control Authority, State of Connecticut - on Behalf of the Staff of the Commission

Exhibit of AMAX, Inc.

180 Electricity Pricing and Load Management: Foreign Experience and California Opportunities - Prepared for the California State Energy Resources Conservation and Development Commission - March 1977 - Bridger M. Mitchell, Willard G. Manning, Jr., Jan Paul Acton - Published by The Rand Corporation

Exhibits of CF&I Steel Corporation

181 Electric Utility Rate Design Study - Rate Design and Load Control Issues and Directions - A Report to the National Association of Regulatory Utility Commissioners - November 1977

182 Making the Transition from Unit Marginal Costs to Rates: Results for Portland General Electric Company - Prepared by National Economic Research Associates, Inc. - Prepared for Electric Utility Rate Design Study: A nationwide effort by the Electric Power Research Institute, the Edison Electric Institute, the American Public Power Association, the National Rural Electric Cooperative Association for the National Association of Regulatory Utility Commissioners - December 20, 1977

183 Critical Issues in Costing Approaches for Time-Differentiated Rates - Prepared by Task Force 4 - Prepared by Electric Utility Rate Design Study: A nationwide effort by the Electric Power Research Institute, the Edison Electric Institute, the American Public Power Association, and the National Rural Electric Cooperative Association for the National Association of Regulatory Utility Commisioners - January 12, 1978

184 Technology for Utilizing Off-Peak Energy: Topic 8 - Prepared by Task Force No. 8 - Prepared for Electric Utility Rate Design Study: A nationwide effort by the Electric Power Researcch Institute, the Edison Electric Institute, the American Public Power Association, and the National Rural Electric Cooperative Association for the National Association of Regulatory Utility Commissioners - October 15, 1977

Exhibit of Public Service Company of Colorado

185 Derivation of Price Ratios; Table I - Comparison of NERA and DOE TOD Rates by Rating Period (cents per kwh); Table II - Effects of NERA Marginal Cost Rates on Average Loads by Rating Periods; Table III - Comparison of NER and DOE Price Ratios Between Periods - Department of Energy Work Papers

Exhibit of Colorado Association of Municipal Utilities

186 Certain Operating Information and Data Previously Requested by Counsel for the Commission during the Cross-Examination of Glenn W. Calvert, President of the Colorado Association of Municipal Utilities (CAMU) on January 18, 1978

EXHIBITS MARKED AND RECEIVED INTO EVIDENCE
PURSUANT TO COMMISSION DECISION NO. C78-717
DATED May 25, 1978

UUU Direct Testimony of Gerald D. Trotter, Director, on Behalf of the Utilities Department of the City of Longmont

VVV Direct Testimony of L.A. Blotiaux on Behalf of the City of Glenwood Springs Electric System

WWW Direct Testimony of Ralph Barbee, Superintendent, on Behalf of Las Animas Municipal Light and Power

XXX Direct Testimony of Frank J. Bustamento, Director of Public Utilities, City of Fountain

YYY Direct Testimony of Leon L. Wick, General Manager of Poudre Valley Rural Electric Association, Inc.

ZZZ Direct Testimony of Robert R. Goldenstein for K.C. Electric Association, Inc., Y-W Electric Association, Inc., and Highline Electric Association

AAAA Direct Testimony of Gary L. West, City Manager, on Behalf of the City of Gunnison

BBBB Direct Testimony of Bill D. Carnahan, Superintendent on Behalf of the Utilities Board of the City of Lamar

Exhibits to Direct Testimony of Bill D. Carnahan

187 Lamar Light and Power - Area Map of Distribution and Transmission Systems as Covered by the Colorado Public Utilities Commission Certificate Decision 76027, Dated 10-26-70

188 System Instant Demand Megawatts - 1974

189 System Instant Demand Megawatts - 1975

190 System Instant Demand Megawatts - 1976

191 Load Duration Curve & Generation Resources 1976 Peak Summer Day - July 25, 1976

192 Load Duration Curve & Generation Resources 1976 Low Winter Day - May 22, 1976

193 Comparison of Load Duration Curves for Days of Highest and Lowest Hourly Demands

194 Report on Future Power Supply, Arkansas River Power Authority - Electric System Load Growth of Lamar, Colorado

CCCC Written Cross-Examination of Bill D. Carnahan, Superintendent of the Utilities Board of the City of Lamar

Exhibits to Cross-Examination of Bill D. Carnahan

195 Energy Potential Through Bio-Conversion of Agricultural Wastes, Phase II, and Appendix 1 thereto

196 A Study of Converting Lamar Unit No. 6 to Coal Firing and Alternate Coal Fired Plants, Prepared for Lamar Utilities Board, Lamar, Colorado, by Stearns-Roger, Inc., Denver, Colorado

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APPENDIX B

INTERRUPTIBLE RATES
(The Following Utilities Shall File Interruptible Rates for the Type of Service as Checked by "X")

Utility	Commercial Air Conditioning	Industrial Rates	Irrigation	No Interruptible Rates to be Filed	See Reference Notes Below
Investor Owned					
Home Light & Power Co.				X	1
Public Service Co. of Colo.	X	X			2
Southern Colo. Power Co.	X	X			2
Tri-State Members					
Carbon Power & Light				X	3
Highline Electric Assoc.			X		4
K.C. Electric Assoc.			X		4
Morgan County REA			X		4
Mountain Parks Electric				X	1
Mountain View Electric				X	1
Poudre Valley REA		X			5
Rural Electric Co.				X	3
Union REA				X	1
Y-W Electric Assoc.			X		4
Colorado-Ute Members	See Text of Decision, Part II-D-2.				
Other REA					
Intermountain Rural Elec.				X	1
Kit Carson Elec. Coop.				X	3
Moon Lake Elec. Assn.		X			6
Springer Electric Coop.				X	3
Tri-County Electric Coop.				X	3
Wheatland Electric Coop.				X	3

Utility	Commercial Air Conditioning	Industrial Rates	Irrigation	No Interruptible Rates to be Filed	See Reference Notes Below
Municipally Owned					
Colorado Springs	X	X			7
Estes Park				X	1
Fort Morgan				X	1
Fountain				X	1
Glenwood Springs				X	1
Granada				X	1
Gunnison				X	1
Holly				X	1
La Junta				X	1
Lamar		X	X		8
Las Animas				X	1
Longmont				X	1
Loveland				X	1

REFERENCE NOTES

1. Because of a lack of any significant load that would be cost beneficial to interrupt.
2. Because of significant air conditioning and industrial loads.
3. Because of negligible loads in Colorado.
4. Because of large irrigation loads.
5. Because of large industrial loads especially the LP 5000 customers.
6. Because of large significant industrial loads.
7. Because of large significant air conditioning and industrial loads especially the Department of Defense loads.
8. Because of significant irrigation and industrial loads.

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APPENDIX C

INTERRUPTIBLE RATES
RATE DESIGN CRITERIA

The attribute of interruptibility most desirable for a utility is the unlimited ability to interrupt power for as long a duration, and for as many repetitions, as the utility deems appropriate. However, a utility customer is rarely, if ever, able effectively to use power unless he is secure in his knowledge of its amount, time of availability or rate of delivery.

The cost of interruptible power varies with its availability. If no guarantee is given that power will be available, it can be sold at a "dump" or commodity rate which includes only the variable costs associated with its production. If, on the other hand, the supplier of interruptible power must furnish specified amounts of energy within stated time periods, or can interrupt only after giving advance notice or under otherwise limited conditions, that supplier should recover some of the fixed costs associated with the provision thereof. Under such "limited" interruptible rates, however, the supplier should not recover the fully allocated fixed costs he would recover from a customer receiving firm service. The Commission takes no position on what demand charges discount should be attached to each attribute of interruptibility but rather leaves this to negotiation between the parties, subject to Commission review. However, the following criteria should be met before Commission approval of demand charges for interruptible rates is sought.

1. On an hourly basis, the interruptible service should be curtailed whenever a utility's incremental cost of energy exceeds the revenue the utility would receive from the customer for a service rendered at 100 percent load factor. In other words, a utility may continue rendering service when incremental cost exceeds the commodity component of the interruptible rate, but only until the point at which incremental cost equals the amount that the revenue from the customer would be at 100 percent load factor. We do not, however, eliminate the possibility of an agreement whereby the customer agrees to pay for energy costs which exceed the level at which the customer would otherwise be curtailed under this rule. Nor do we preclude use of time-varying interruptible rates.

2. All interruptible service must be terminable at the discretion of the utility rendering service without a requirement for giving advance notice to the customer. Should an interruptible customer be curtailed automatically by frequency-sensing devices, the device must be designed to curtail the interruptible customer before any firm customers are curtailed.

3. The Commission does not intend to encourage profiteering by the above policies. For example, interrupting customers in favor of a sale-for-resale simply because the sale-for-resale will yield more revenue than the sale to an interruptible customer will not be permitted. Such a situation would only be condoned by this

Commission if an emergency clearly exists on the utility system purchasing the "interrupted" power.

4. The Commission encourages establishment of a resale rate to be applicable when interruptions, voltage reductions or voltage blackouts are undertaken by one utility at the behest of another utility and paid for by the utility causing the curtailment of service.

5. Demand charges applicable to interruptible service shall not be recovered through the energy component of the rate.

6. The allocation of demand costs to an interruptible service shall be grounded upon a rational basis, which shall relate to the savings in capacity costs realized by rendering the interruptible service.

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APPENDIX D

SEASONAL RATES

COMPANY	
Investor Owned	
Home Light & Power Co. Public Service Co. of Colo. Southern Colo. Power Co.	Because the cost of power does not appear to have significant seasonal variations, these companies are not required to file seasonal rates.
Tri-State Members	Because of the significant seasonal variations in power costs, all Tri-State members should file seasonal rates for all customer classes. The only exceptions should be for Carbon Light and Power which has only 37 customers in Colorado and sells a negligible portion of its energy in Colorado, and Rural Electric Co. which should also be excepted.
Colorado-Ute and Colorado-Ute Members	Because of the significant seasonal variation in power costs, both Colorado-Ute and all its members should file seasonal rates for all customer classes.
Other REA	
Intermountain REA Moon Lake Electric Assoc.	Because the wholesale rates from the suppliers of Intermountain and Moon Lake are regulated by FERC and will not vary seasonally, neither Intermountain REA nor Moon Lake Electric Association should file seasonal rates unless their wholesale suppliers subsequently institute seasonal rates.
Kit Carson Elec. Coop. Springer Electric Coop. Tri-County Electric Coop. Wheatland Electric Coop.	Because of the small number of customers served in Colorado and the negligible energy sales in Colorado, these companies should not file seasonal rates unless their wholesale suppliers institute seasonal rates.
Municipally Owned	
Colorado Springs	Because the cost of power does not appear to vary significantly by season, the City of Colorado Springs is not required to file seasonal rates.

Estes Park, Fountain, Glenwood Springs, Las Animas, Longmont, & Loveland	Because neither their wholesale rates nor their loads vary significantly with season, these utilities are not required to file seasonal rates.
Fort Morgan Gunnison	Because a portion of their wholesale power will be purchased under a seasonal rate, the Cities of Fort Morgan and Gunnison should file seasonal rates for all jurisdictional customers to reflect this situation.
La Junta	Because of the very small number of jurisdictional customers, the City of La Junta is not required to file seasonal rates.
Lamar	Because the system load varies substantially with season, the City of Lamar should file seasonal rates for all jurisdictional customer classes.
Granada Holly	Because the cost of their wholesale power will vary seasonally, the Cities of Granada and Holly should file seasonal rates for all jurisdictional customer classes.

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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.

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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 particcularly 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.

customers which contribute to its (or their) winter peak, and which would be most appropriate for interruptible rates. Said study (or studies) shall be filed with the Commission within six months after the effective date of this Decision. Colorado-Ute Electric Association, Inc., be, and hereby is, directed to participate in and assist its member utilities in the conduct of their study (or studies).

13. All motions not heretofore ruled upon be, and hereby are, denied.

This Order shall be effective 21 days subsequent to the date hereof.

(S E A L)

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

EDYTHE S. MILLER

SANDERS G. ARNOLD

Commissioners

COMMISSIONER DANIEL E. MUSE NOT PARTICIPATING

ATTEST: A TRUE COPY

Harry A. Galligan Jr.

Harry A. Galligan, Jr.
Executive Secretary

MATRIX FOR C79-1111 GENERIC DECISION

By Whom	Action Required	Due To Be Filed
Each Electric Utility Listed on Appendix B	Prepare Interruptible Rate Schedules Applicable to Industrial, Commercial and/or Irrigation Rate Consumers Based on Criteria in Appendix C	At Next General Rate Proceeding, But No Later Than Six Months After the Effective Date of Decision
Each Electric Utility Subject to the Jurisdiction of this Commission	Survey Service Territory and Prepare an Inventory of All Potential Sites and Joint Ventures for Co-Generation	Filed With the Commission Within Six Months After the Effective Date of Decision
Each Electric Utility Subject to the Jurisdiction of the Commission	Present Testimony Re Explanation and Support of the Costing Method of Allocation	At Next General Rate Proceeding
Public Service Company	Modify Average and Excess Demand Allocation Methodology to Reflect Metering of All Rate Classes for Same Length Interval	At the Effective Date of this Decision
Public Service Company	Cease and Desist From Using the Arithmetic Mean in Computation of Class Maximum Demand For Residential Rate Class	At the Effective Date of this Decision
Each Electric Utility Subject to the Jurisdiction of the Commission	File T-O-D Rate Schedules for Industrial and Large Commercial Consumers	At Next General Rate Proceeding, But No Later Than Six Months After Effective Date of Decision
Each Electric Utility Listed on Appendix D	File Rate Schedules Implementing Seasonally Differentiated Rates For All Customer Classes	Next General Rate Case, But Not Later Than Six Months After Effective Date of Decision
Each Electric Utility Subject to the Jurisdiction of the Commission	File Revised Rate Schedules For Residential Customers (Two or Three Part Rates)	Next General Rate Case, But Not Later Than Six Months After Effective Date of Decision

By Whom	Action Required	Due To Be Filed
Each Utility Providing All-Electric Service	File Mandatory Demand-Energy Rates for All New Residential and Commercial Customers	Within Six Months After the Effective Date of this Decision To Be Effective 18 Months After Filing Thereof
Each Electric Utility Subject to the jurisdiction of this Commission	File Voluntary Demand-Energy Rates For All Existing All-Electric Customers, Residential Customers With Min. of 15,000 Kwh Annually	File Within Six Months After the Effective Date of Decision to Become Effective 18 Months After Filing
Each Electric Utility Subject to the Jurisdiction of this Commission	Mandatory Rate Schedules Applicable to All New Residential and Commercial Heat Storage Customers	File Within Six Months, To Become Effective 18 Months After Filing
Each Electric Utility Subject to the Jurisdiction of this Commission	Voluntary Rate Schedules Applicable to Existing Residential and Commercial Heat Storage Customers	File Within Six Months, To Become Effective 18 Months After Filing
Each Electric Utility Which is a Member of a Winter-Peaking System	Conduct a Study (or Studies) To Identify Customers Which Contribute to its Winter Peak and Would Be Appropriate For Interruptible Rates (Colo-Ute Directed to Participate and Assist Its Member Utilities in Conduct of Study)	Study To Be Filed Within Six Months After Effective Date of Decision

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:

1. Goals of Regulation (pp. 34-45)
2. The Federal Public Utility Regulatory Policy Act of 1978 (pp. 46-53)
3. Resource Management - Power Pooling (pp. 54-71)
4. Load Management (pp. 71-80)
5. Co-Generation (pp. 80-83)
6. Costing Methodology (pp. 84-131)
   a. Marginal and Average Cost
   b. Time-of-Day Rates
7. Declining Block Rates (pp.132-138)
8. Lifeline Rates (pp. 138-143)
9. All-Electric Rates (pp. 143-148)
10. Solar Energy and Heat Storage Rates (pp. 148-152)
11. Appendices A-F (pp. 157-193)

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 spearate 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.