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FUNCHES, J. L. Planning & Program Analysis Staff (post 851125)

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Arizona Nuclear Power Project
P.O. BOX 52034 • PHOENIX, ARIZONA 85072-2034

April 11, 1986
ANPP-36071-EEVB/KLM/98.06

Mr. Jesse L. Funches, Director
Planning and Program Analysis Staff
Office of Nuclear Reactor Regulation
Washington, D.C. 20555

Subject: Palo Verde Nuclear Regulatory Commission (PVNGS)
Unit 3
Docket No. STN 50-530
Updated Regulatory Guide 9.3 Information
File: 86-056-026; 86-007-220

Reference: Letter from J. L. Funches, NRC, to E. E. Van Brunt, Jr. ANPP, dated December 18, 1985. Subject: Palo Verde Nuclear Generating Station Unit 3 Docket No. 50-530A; Updated Regulatory Guide 9.3 Information Pursuant to the Commission's Operating License Antitrust Review

Dear Mr. Funches:

Enclosed is the updated Regulatory Guide 9.3 information as requested by the referenced letter. Included are five (5) copies of each response pursuant to Regulatory Guide 9.3 (section B.3).

Also enclosed is the required Regulatory Guide 9.3 information for Los Angeles Department of Water and Power and Southern California Public Power Company, the two recent Participants in ANPP.

If you should have any questions concerning the enclosed information, contact Mr. W. F. Quinn of my staff.

Very truly yours,

E E Van Brunt Jr/JH

E. E. Van Brunt, Jr.
Executive Vice President
Project Director

EEVB/KLM/rw
Enclosures

cc: W. Lambe (w/a)
A. C. Gehr (w/a)

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UPDATED INFORMATION REQUESTED BY
THE NRC FOR ANTITRUST REVIEW

EL PASO ELECTRIC COMPANY

UPDATED REGULATORY GUIDE 9.3
RESPONSES

Item 1a

Anticipated excess or shortage in generating capacity resources not expected at the construction permit stage. Reasons for the excess or shortage along with data on how the excess will be allocated, distributed or otherwise utilized, or how the shortage will be obtained.

Response

Since El Paso Electric Company's (EPE) submittal of information in October 1979 Regulatory Guide 9.3, there has been no change in anticipated excess or shortage in generating capacity resources.

Item 1b

New power pools or coordinating groups or changes in structure, activities, policies, practices or membership of power pools or coordinating groups in which the licensee was, is, or will be a participant.

Response

Inland Power Pool (IPP)

EPE became a formal member of the IPP in September 1980. Since this time, the IPP Agreement was renegotiated and revised by all Parties on November 23, 1983, to include additional operating and planning functions. There are currently twenty (20) interconnected utilities which are participating in the IPP with service areas in the states of Arizona, California, New Mexico, Texas, Colorado, Utah, Wyoming, Nevada, Nebraska and South Dakota.

New Mexico Power Pool (NMPP)

The NMPP was executed on October 2, 1969, and includes four (4) other participants in addition to EPE. All parties, including Western Area Power Administration, are now involved in revising the NMPP Agreement. This revision is appropriate to incorporate changes in the operating environments of the participants since the time of the original Agreement.

Southwest Bulk Power Market Experiment

EPE and five (5) other utilities were parties to the December 15, 1983 Southwest Bulk Power Market Experiment Participation Agreement. The primary purpose of this two-year Agreement was to provide for the interchange of power among the electric systems of the participants in an experiment designed to develop empirical data which would allow FERC to consider and justify changing regulations regarding wholesale power interchanges between electric utilities. The services rendered under this Agreement were Economy Energy, Block Energy and Transmission Service. The experiment commenced on January 1, 1984, and extended through 1985.

Interchange/Interconnection Agreements

In addition to the Power Pools described above, EPE has entered into fifteen (15) bilateral Interchange/Interconnection Agreements since 1979. The Agreements generally provide the terms and conditions under which the parties may engage in mutually beneficial inter-utility transactions.

Item 1c

Changes in transmission with respect to (1) the nuclear plant, (2) interconnections, or (3) connections to wholesale customers.

Since El Paso Electric Company's (EPE) response in October 1979 Regulatory Guide 9.3, there have been the following changes with respect to (1) nuclear plant, (2) interconnections and (3) connections to wholesale customers:

1. The Project 1 Line from Palo Verde to Seguaro 525 KV has been deferred by the participants. In May 1982, the participants elected to activate plans for the Palo Verde-Westwing No. 2 525 KV line which has been built.

   The Project 3 Line from Greenlee to Rio Grande 345 KV has been deferred by (EPE).

2. In September 1984, EPE established a new interconnection with Southwestern Public Service Company through a 345 KV transmission line from Artesia, New Mexico, to EPE's Amrad Substation. EPE is pursuing an interconnection at 345 KV from its system to Tucson Electric Power Company's system. This line will run from the area of EPE's Rio Grande Power Plant to TEP's Springerville Power Plant.

3. Since EPE's response in October 1979 Regulatory Guide 9.3, no new transmission voltage connections to wholesale customers have been made. Two such interconnections are presently under study. One is a 115 KV transformer connection for the All American Pipeline Project near Anthony, New Mexico. The second is the conversion of EPE's existing 69 KV connection to Rio Grande Electric Cooperative to 115 KV.

Item 1d

Changes in the ownership or contractual allocations of the output of the nuclear facility. Reasons and basis for such changes should be included.

Response

The contractual allocation submitted in October 1979 Regulatory Guide 9.3 was as follows:

APS - 29.1%
SRP - 29.1%
EPE - 15.8%
SCE - 15.8%
PNM - 10.2%

On January 29, 1986, Los Angeles Department of Water and Power (LADWP) acquired 5.70% ownership of Palo Verde because in 1977 SRP signed agreement whereby LADWP would acquire 5.7% ownership of Palo Verde from SRP when the first Palo Verde unit is determined to be available for firm operation. In September 1982, Southern California Public Power Authority (SCPPA) acquired 5.91% ownership from SRP. The current allocations are as follows:

APS - 29.1%
SRP - 17.49%
EPE - 15.80%
PNM - 10.20%*
SCE - 15.8%
SCPPA - 5.91%
LADWP - 5.70%

*PNM refinanced its portion of Unit 1 in a sale-leaseback agreement in December 1985. They still retain their generation entitlement and the corresponding obligations under the Arizona Nuclear Power Project Participation Agreement as amended.

Item 1e

Changes in design, provisions or conditions of rate schedules and reasons for such changes. Rate increases or decreases are not necessary.

Response

Since El Paso Electric Company's (EPE) submittal of information in October 1979 Regulatory Guide 9.3, there have been no changes in design, provisions or conditions of rate schedules.

Item 1f

List of all (1) new wholesale customers, (2) transfers from one rate schedule to another, including copies of schedules not previously furnished, (3) changes in licensee's service area and (4) licensee's acquisitions or mergers.

Response

With respect to new wholesale customers see Item 1h.

Transfers from one rate schedule to another EPE has had since its October 1979 Regulatory Guide 9.3 submittal are reflected in the attached schedule not previously furnished (Exhibit 1f-1).

Since EPE's response to October 1979 Regulatory Guide 9.3, EPE has had no changes with respect to licensee's service area or licensee's acquisitions or mergers.

EL PASO ELECTRIC COMPANY
ITEM 1f
Exhibit 1f-1

Line No.	Industrial Rates	Customer Charge	Demand Charge Per KW	Energy Charge Per KWH	Fuel Charge Per KWH
1	Texas Jurisdiction				
2	Schedule No. 15				
	Electrolytic Refining Service				
	First 5,000 KW per Month		$14.66		
	All Other KW per Month		13.08	$0.0052	$0.02699
3.	Schedule No. 25				
	Large Power Service	$ 437.15	16.66	0.00531	
	Transmission Fuel Rate				0.02699
	Primary Fuel Rate				0.02748
4	Schedule No. 29				
	Transmission Voltage		12.84	0.0052	0.02699
5	Schedule No. 29-A				
	Military Research Rate				
	First 10,000 KW per Month		16.03		
	All Other KW per Month		15.72	0.0052	0.02699
6	Schedule No. 30				
	Electric Furnace Rate				
	First 5,000 KW per Month		11.06		
	All Additional KW		16.50	0.0052	0.02699
7	New Mexico Jurisdiction				
	Schedule No. 9				
	Large Power Service		9.30	0.0105	0.030
8	Schedule No. 10				
	Military Research	1,387.00	9.25	0.0028	0.030

Item 1g

List of those generating capacity additions committed for operation after the nuclear facility, including ownership rights or power output allocations.

Response

Since El Paso Electric Company's (EPE) submittal of information in October 1979 Regulatory Guide 9.3, EPE has not committed for operation additional generating capacity after the nuclear facility.

Item 1h

Summary of requests or indications of interest by other electric power wholesale or retail distributors and licensee's response for any type of electric service or cooperative venture or study.

Response

During the past several years, El Paso Electric Company (EPE) has undertaken a vigorous bulk power marketing program due to forecasted availability of power on EPE's system in the years ahead. Over forty individual electric utility and/or consortiums have been contacted by EPE in this effort.

As a result of these efforts, EPE has entered into several firm energy sales commitments. The following list illustrates the organizations to which EPE has contracted to sell firm capacity and/or energy since 1979:

> Imperial Irrigation District (IID): In 1982, EPE negotiated a Power Sales Agreement with IID. As a result of this Agreement, EPE began providing IID with firm capacity and energy in 1984 on a long-term basis.
>
> Texas-New Mexico Power Company (TNP): EPE executed a Power Sales Agreement with TNP on December 9, 1981. As a result of this Agreement, EPE has been providing electrical service to TNP's Lordsburg-Silver City district since 1982.
>
> Southern California Edison Company (SCE): A Firm Capacity Agreement, dated March 10, 1980, was executed by EPE and SCE. Firm Capacity Sales to SCE commenced in May 1980 and extended through December 1982.
>
> Colorado-Ute Electric Association (CUEA): In accordance with the Economy Energy and Short-Term Capacity Agreement between EPE and CUEA executed February 18, 1983, CUEA purchased Firm Capacity from EPE during portions of 1983, 1984 and 1985.

Over the past several years, EPE has had the opportunity to sell economy energy on the wholesale market. In 1985 the utilities which purchased economy energy from EPE were Arizona Electric Power Cooperative, Imperial Irrigation District, Plains Electric Generating and Transmission Cooperative, Public Service Company of New Mexico, Southern California Edison Company, San Diego Gas and Electric Company, Salt River Project, Tucson Electric Power Company, Southwestern Public Service Company, Texas-New Mexico Power Company and the City of Riverside.

Item 2

Licensees whose construction permits include conditions pertaining to antitrust aspects should list and discuss those actions or policies which have been implemented in accordance with such conditions.

Response

There are no conditions pertaining to antitrust aspects in the PVNGS 1, 2, and 3 construction permits that relate to El Paso Electric Company.

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UPDATED INFORMATION REQUESTED BY
THE NRC FOR ANTITRUST REVIEW

SALT RIVER PROJECT AGRICULTURAL
AND IMPROVEMENT DISTRICT

UPDATED REGULATORY GUIDE 9.3

ITEM 1a

Anticipated excess or shortage in generating capacity resources not expected at the construction permit stage. Reasons for the excess or shortage, along with data on how the excess will be allocated, distributed, or otherwise utilized or how the shortage will be obtained.

RESPONSE

The attached Tables 1 and 2 show the differences between the Total Peak Load and Reserve Margins in the 1985 forecast and the 1979 forecast. The projected load growth has decreased from the 1979 forecast due to a reduced population growth rate, and due to conservation measures endorsed by Salt River Project and practiced by Salt River Project customers. As a result of the following changes in existing and future resources, projected reserve margins remain at approximately 20 percent.

Salt River Project sold a 5.91% (217 MW) entitlement of Palo Verde to the Southern California Public Power Authority (SCPPA), effective September 10, 1983.

In accordance with a 1977 agreement, on January 29, 1986, Salt River Project recaptured a 30% entitlement (210 MW) in Coronado Units 1 and 2 from the Los Angeles Department of Water and Power (LADWP) in exchange for a 5.7% interest in PVNGS Units 1, 2 and 3 (210 MW).

Both the 1979 and 1985 Loads and Resources Summaries reflect this transaction. Salt River Project now has a 17.49% share of PVNGS Units 1, 2, and 3 (214 MW per unit), but retains the option to recapture the 5.7% exchanged with LADWP fifteen years from the respective commercial dates of PVNGS Units 1, 2, and 3.

The Salt River Project has entered into an agreement with the Colorado River Commission (CRC) covering the period from 1981 to 1989 for the sale of firm capacity which is some of the excess on our system.

TABLE 1

ADJUSTED ANNUAL PEAK DEMAND

	1979 (MW)	1985 (MW)	Difference (MW)
1988	3282	3183	(99)
1989	3367	3259	(108)
1990	3475	3359	(116)
1991	3585	3454	(131)
1992	3693	3542	(151)

TABLE 2

RESERVE MARGINS

	1979 Estimate (MW)	1985 Estimate (MW)	Difference (MW)
1988	915	765	(150)
1989	1180	700	(480)
1990	1072	604	(468)
1991	962	859	(103)
1992	854	738	(116)

ITEM 1b

New power pools or coordinating groups or changes in structure, activities, policies, practices or membership of power pools or coordinating groups in which the licensee was, is, or will be a participant.

RESPONSE

The Salt River Project is a member of the Inland Power Pool. In the past the benefits of power pooling were to a limited extent derived from a number of bilateral agreements similar to the Power Coordination Agreement between Arizona Public Service and Salt River Project.

In November of 1983 nineteen entities signed the Revised Inland Power Pool Agreement. This agreement established requirements for carrying operating reserves, and included service schedules which provide for emergency assistance, scheduled outage assistance, economy energy interchange and transmission services. The parties to the agreement are located in the states of Colorado, Arizona, New Mexico, Utah, Wyoming and Nebraska. The pool provides a diverse and sizeable resource for sales and services for its members. It has acquired two new members since the document was signed, and has a combined load of over 16,000 MW.

The Inland Power Pool members are as follows:

Arizona Electric Power Cooperative
Arizona Public Service Company
Basin Electric Power Cooperative
City of Colorado Springs
City of Farmington
Colorado-Ute Electric Association
Deseret G&T Cooperative
El Paso Electric Company
County of Los Alamos
Plains Electric G & T Cooperative
Platte River Power Authority
Public Service of Colorado
Public Service of New Mexico
Salt River Project
Texas-New Mexico Power Company
Tri-State G&T Association
Tucson Electric Power
United States - Boulder City Area Office
United States - Loveland-Ft. Collins Area Office
United States - Salt Lake City Area Office
Wyoming Municipal Power Agency

Ten utilities in the west are on the verge of signing a new pooling document which will establish an operating pool on a "trial basis" with a term of two years. The pool will be called the Western Systems Power Pool and will have members in the states of California, Arizona, New Mexico and Washington. It

will provide for economy energy interchange, unit commitment service, and system capacity and energy sales or exchanges. The rates for these services will be based on market forces to the extent permissable by applicable regulatory authority. It is likely that if the experience of this pool is a positive one that the parties will establish a permanent pool and many more utilities in the area will become members.

The members of the Western Systems Power Pool will be as follows:

Arizona Electric Power Cooperative
Arizona Public Service Company
Northern California Power Agency
Pacific Gas & Electric Company
San Diego Gas & Electric Company
Southern California Edison Company
Public Service of New Mexico
Salt River Project
California Department of Water Resources
United States - Bonneville Power Admin.

ITEM 1c

Changes in transmission with respect to (1) the nuclear plant, (2) interconnections, or (3) connections to wholesale customers.

RESPONSE

(1) Since the October 1979 response, the Palo Verde-Saguaro and the Greenlee-Rio Grande lines have been indefinitely delayed.

The current PVNGS transmission system consists of the following lines that have been placed in service or planned to be completed as follows:

Palo Verde - Westwing #1	525 kV	Energized Nov. 1979
Palo Verde - Kyrene	525 kV	Energized May 1982
Palo Verde - Devers	525 kV	Energized May 1982
Palo Verde - Westwing #2	525 kV	Planned March 1986

(2) Since October 1979, Salt River Project has been involved in the following new interconnections:

(a) The Palo-Verde Westwing and Palo Verde-Kyrene 500kV lines were placed in service providing interconnections with the other ANPP Valley Transmission participants. This was later followed by the Palo Verde-Miguel 500kV line for San Diego Gas & Electric Company. In addition, the Palo Verde-Devers 500kV line provides an interconnection with Southern California Edison Company.

(b) Tucson Electric Power Company has built a 345kV line from their Springerville plant to SRP's Coronado station. This line was placed in service May 1982.

Also, Salt River Project is interconnected with Plains Generation & Transmission Cooperative at Coronado.

(c) Salt River Project has added additional interconnections with APS at Alexander, White Tanks and Deer Valley.

(3) Since October 1979, Salt River Project has no new interconnections or new connections with wholesale customers.

ITEM 1d

Changes in the ownership or contractual allocation of the output of the nuclear facility. Reasons and basis for such changes should be included.

RESPONSE

In October 1977, the Department of Water and Power of the City of Los Angeles (Department) contracted for the purchase of a 30-percent ownership interest in the Coronado Generating Station (Coronado) from SRP. The contractual arrangements provided that upon the Date of Firm Operation of Unit 1 of Palo Verde, the Department would exchange the Coronado ownership for a 5.7 percent ownership in Palo Verde. The Date of Firm Operation of Palo Verde Unit 1 occurred on January 27, 1986; and the ownership was exchanged on January 29, 1986.

In 1982, Southern California Public Power Authority (SCPPA) purchased from SRP a 5.91 percent interest (225 megawatts) in Palo Verde. The purchase also included certain rights to the high voltage switchyard as well as certain rights to transmission facilities. The present ownership interests in Palo Verde are shown below:

Arizona Public Service Company	29.10%
Salt River Project Agricultural Improvement and Power District	17.49
Southern California Edison Company	15.80
Public Service Company of New Mexico	10.20
El Paso Electric Company	15.80
Southern California Public Power Authority	5.91
Los Angeles Department of Water and Power	5.70
	100.00%

ITEM 1e

Changes in design, provisions or conditions of rate schedules and reasons for such changes. Rate increases or decreases are not necessary.

RESPONSE

The changes in Salt River Project rate schedules for major customer classifications since the October 1979 report to January 1986 are provided in Appendix A.

ITEM 1f

List of all (1) new wholesale customers, (2) transfers from one rate schedule to another, including copies of schedules not previously furnished, (3) changes in licensee's service area, and (4) licensee's acquisitions or mergers.

RESPONSE

The following response has excluded from consideration transactions between other ANPP participants and Salt River Project and any agency of the United States and Salt River Project.

(1) City of Anaheim, California
California Department of Water Resources
Colorado River Commission, State of Nevada
City of Farmington, New Mexico
Pacific Gas & Electric Company
City of Pasadena, California
Plains Electric Generation & Transmission Cooperative
City of Riverside, California
Southern California Public Power Authority

In addition, although no sales have yet been made, contractual arrangements have been made for possible future sales to:

City of Azusa, California
City of Banning, California
City of Colton, California
City of Glendale, Arizona
Imperial Irrigation District

(2) The City of Mesa, Arizona and the San Carlos Irrigation Project were transferred from a special contract rate to a modification of Salt River Project's E-39 (Large Industrial) rate in 1986.

(3) There have been no changes in Salt River Project's service area boundaries.

(4) Salt River Project has not acquired nor merged with any other utility.

ITEM 1g

List of those generating capacity additions committed for operation after the nuclear facility, including ownership rights or power output allocations.

RESPONSE

Salt River Project's current plans include the installation of Coronado Unit #3, a 350 MW intermediate-type coal-fired unit, scheduled for commercial operation on December 31, 1990. Salt River Project will be the Operating Agent and sole owner.

ITEM 1h

Summary of requests or indications of interest by other electric power wholesale or retail distributors, and licensee's response, for any type of electric service or cooperative venture or study.

RESPONSE

Since January of 1980, the Salt River Project has received inquiries and requests for electric service which resulted in the execution of agreements for such service from the following entities:

City of Anaheim, California
(Economy Energy Agreement)

City of Azusa, California
(Economy Energy Agreement)

City of Banning, California
(Economy Energy Agreement)

California Department of Water Resources
(Economy Energy Agreement)

Colorado River Commission of Nevada
(Power Sales Agreement)

City of Colton, California
(Economy Energy Agreement)

City of Glendale, California
(Economy Energy Agreement)

Imperial Irrigation District
(Economy Energy Agreement)

Nevada Power Company
(Economy Energy Agreement)

Pacific Gas & Electric Company
(Economy Energy Agreement)

Plains Electric Generation & Transmission Cooperative
(Interchange and Wheeling Agreement)

City of Riverside, California
(Economy Energy Agreement)

San Diego Gas & Electric Company
(Interchange Agreement)

Tucson Electric Power Company
(Interchange Agreement & Non-Firm Transmission Service)

Chandler Heights Citrus Irrigation District, Electrical District #5 (Maricopa), Electrical District #6, Queen Creek Irrigation District, Ocotillo Water Conservation District, Roosevelt Water Conservation District, San Tan Irrigation District, Williams Air Force Base

(Letter Agreements for wheeling of excess energy made available at various times by the Colorado River Storage Project)

Since January of 1980, the following entities have requested various types of electric service, including power and energy purchases, wheeling and transmission service for which discussions with the Salt River Project were terminated due to an apparent or expressed lack of continuing interest on the part of the requesting entity:

Arizona Electric Power Cooperative
City of Mesa, Arizona
City of Riverside, California
Colorado-Ute Electric Association
Deseret Generation & Transmission
Electrical District #1
Morenci Water & Electric Company
Nevada Power Company
San Carlos Irrigation Project
San Diego Gas & Electric Company
Texas-New Mexico Power Company
Utah Power & Light Company

Since January of 1985, the following inquiries and expressions of interest have been made by other entities with regard to a variety of electric service transactions in response to which the Salt River Project has declined to enter into an agreement with said entities:

(1) In late 1984, San Diego Gas & Electric Company expressed an interest in executing an interruptible transmission system. Salt River Project declined to enter into an agreement because of a lack of sufficient excess capacity in the transmission system.

(2) In early 1983, Arizona Electric Power Cooperative (AEPCO) expressed an interest in an exchange to utilize Coronado generators in exchange for AEPCO coal. No workable solution could be obtained because requirements did not mesh.

(3) In late 1982, Plains Generation & Transmission Cooperative expressed an interest in (a) non-firm wheeling, (b) marketing excess energy, and (c) purchase of excess reserves. It was mutually agreed that Salt River Project and Plains Generation & Transmission Cooperative could not enter into a reciprocal non-firm wheeling agreement because of inadequate points of interconnection. Salt River Project was not in a position to offer the other services.

(4) In early 1984, Plains Generation & Transmission Cooperative expressed an interest in receiving off-peak block energy or interruptible energy. Salt River Project declined to enter into such an agreement because it was not in a position to offer these services.

(5) In late 1980, the City of Mesa expressed an interest in obtaining wheeling capacity south-to-north on the Westwing-Moenkopi 500kV line (Navajo Southern Transmission System). At the time of the request, all capacity was allocated to participants; therefore, no capacity was available for Mesa.

(6) In late 1981, the Cities of Pasadena, Glendale, and Burbank expressed an interest in energy and wheeling on the Devers line. Salt River Project was unable to provide the services due to a commitment to the Los Angeles Department of Water & Power.

(7) In 1980, Plains Generation & Transmission Cooperative contacted Salt River Project with a request for power and energy. Discussions were discontinued when Salt River Project studies showed no excess short term energy and capacity available for the period in question.

As a result of requests for electric service from other entities, the Salt River Project is currently involved in the following evaluations and/or negotiations:

(1) Negotiations are currently underway with the M-S-R Public Power Agency for an Economy Energy Agreement.

(2) Negotiations are currently underway with the City of Vernon, California for an Economy Energy Agreement.

(3) Negotiations are currently underway with Tucson Electric Power Company for a swap of transmission capacity.

(4) A service request by Imperial Irrigation District for long term capacity until 1992 and increasing thereafter is being evaluated.

ITEM 2

Licensees whose construction permits include conditions pertaining to antitrust aspects should list and discuss those acitons or policies which have been implemented in accordance with such conditions.

RESPONSE

SRP has fulfilled the condition in its construction permit pertaining to antitrust aspects by transmitting bulk power over its transmission system, between or among entities with which it is interconnected, without restrictions on use or resale of the power so transmitted, provided that such services can reasonably be accommodated from a technical standpoint without impairing SRP's reliability or its own use of its facilities.

SRP has also included in its planning and construction program sufficient transmission capacity for such bulk power transactions described above, provided that SRP has received sufficient advance notice as may be necessary from a technical standpoint to accommodate the requirements of any requesting entity, and further provided that such entity (ies) are obligated as may agreed (i) to share the capital, operating and maintenance costs of such new transmission facilities to the extent that additional cost burdens would be imposed on SRP or (ii) to compensate SRP fully for the use of its system.

APPENDIX A

SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT

RATE SCHEDULES

SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT
AND POWER DISTRICT

Class of Customer Rate Schedule	January, 1986 Rate Schedules	January, 1979 Rate Schedules	Reasons to change
E-23 Residential Service	Rate May 15 - October 14 Customer Charge - $5.70/month $.0723/kWh First 1400 kWh $.0608/kWh All Additional October 15 - May 14 Customer Charge - $5.70/month $.0684/kWh First 400 kWh $.0512/kWh Next 400 kWh $.0345/kWh All Additional Minimum $5.70	Rate May 15 - October 14 Customer Charge - $2.50/month $.0627/kWh First 300 kWh $0.0471/kWh Next 1500 kWh $0.0379/kWh All Additional kWh October 15 - May 14 Customer Charge - $2.50/month $0.0595/kWh First 300 kWh $0.0325/kWh Next 400 kWh $0.0266/kWh Next 500 kWh $0.0195/kWh All Additional kWh Minimum $2.50	1. Changes in summer/winter periods to reflect load trends and cost of service. 2. Rate increases due to increased cost of service.
E-25 Residential Service - Rate Area II	Rate Eliminated	Rate May 15 - October 14 Customer Charge - $3.00/month $0.0729/kWh First 300 kWh $0.0471/kWh Next 1500 kWh $0.0379/kWh All Additional kWh	1. Eliminated due to lack of significant geographic cost differences.

SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT
AND POWER DISTRICT
(Contd.)

Class of Customer Rate Schedule	January, 1986 Rate Schedules	January, 1979 Rate Schedules	Reasons to change
E-32 Experimental Large Commercial Time-of-Day Rate Service	<u>Rate</u> May 15 - October 14 Customer Charge - $31.00/month <u>Service Charge</u> On-Peak $4.28/kW All kW Off-Peak None <u>Energy Charge</u> On-Peak $.0778/kWh All kWh Off-Peak $.0299/kWh All kWh October 15 - May 14 Customer Charge - $31.00/month <u>Service Charge</u> On-Peak - $2.94/kW All kW Off-Peak - None <u>Energy Charge</u> On-Peak - $.0553/kWh All kWh Off-Peak - $.0299/kWh All kWh Minimum: A. $31 B. Minimum monthly dollar amount as specified in the service agreement.	<u>Rate</u> May 15 - October 14 Customer Charge - $25.00/month <u>Service Charge</u> On Peak - $4.00/kW All kW Off-Peak - $1.00/kW All kW <u>Energy Charge</u> On-Peak - $0.030/kWh All kWh Off-Peak - $0.018/kWh All kWh October 15 - May 14 Customer Charge - $25.00/month <u>Service Charge</u> On-Peak - $2.00/kW All kW Off-Peak - $1.00/kW All kW <u>Energy Charge</u> On-Peak - $0.022/kWh All kWh Off-Peak - $0.013/kWh All kWh Minimum: A. $25.00 B. Minimum monthly dollar amount as specified in the service agreement.	1. Experimental rate first offered January, 1979 to reflect cost of service for time-of-day applications. 2. Rate increase due to increased cost of service. 3. Rate shift to the on-peak period to reflect higher cost period.

SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT
AND POWER DISTRICT
(Contd.)

Class of Customer Rate Schedule	January, 1986 Rate Schedules	January, 1979 Rate Schedules	Reasons to change
E-35 General Service	**Rate** May 15 - October 14 Customer Charge - $6.90/month Service Charge No Charge First 5 kW $2.97/kW All Additional kW Energy Charge $.0738/kWh First 4000 kWh $.0655/kWh Next 125 kWh/kW of billing demand, or if no billing demand all additional kWh. $.0492/kWh Next 50,000 kWh $.0368/kWh All Additional kWh October 15 - May 14 Customer Charge - $6.90/month Service Charge No Charge First 5 kW $1.64/kW All Additional kW Energy Charge $.0607/kWh First 4000 kWh $.0541/kWh Next 125 kWh/kW of billing demand, or if no billing demand all additional kWh. $.0428/kWh Next 50,000 kWh $.0304/kWh All Additional kWh Minimum $6.90	**Rate** May 15 - October 14 Customer Charge - $2.50/month Service Charge No Charge First 10 kW $2.61/kW Next 220 kW $1.50/kW All Additional kW Energy Charge $0.0683/kWh First 400 kWh $0.0548/kWh Next 3600 kWh $0.0513/kWh Next 100 kWh/kW of billing demand, or if no billing demand all additional kWh. $0.0312/kWh Next 50,000 kWh $0.0213/kWh All Additional kWh October 15 - May 14 Customer Charge - $2.50/month Service Charge No Charge First 10 kW $2.35/kW Next 220 kW $0.76/kW All Additional kW Energy Charge $0.0583/kWh First 400 kWh $0.0448/kWh Next 3600 kWh $0.0439/kWh Next 100 kWh/kW of billing demand, or if no billing demand all additional kWh. $0.0260/kWh Next 50,000 kWh $0.0190/kWh All Additional kWh Minimum $7.00	1. Reduction of rate blocks for simplification of rate structures. 2. Change in summer/winter periods to reflect shift in loading trends. 3. Rate increases due to increased financial requirements, i.e., capital programs, increased O&M, interest rates, etc.

SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT
AND POWER DISTRICT
(Contd.)

Class of Customer Rate Schedule	January, 1986 Rate Schedules	January, 1979 Rate Schedules	Reasons to change
E-37 General Service Rate Area II	Rate Eliminated	Rate May 15 - October 14 Customer Charge - $3.00/month Service Charge No Charge First 10 kW $2.61/kW Next 220 kW $1.50/kW All Additional kW Energy Charge $0.0782/kWh First 400 kWh $0.0548/kWh Next 3600 kWh $0.0513/kWh Next 100 kWh/kW of billing demand, or if no billing demand all additional kWh. $0.0312/kWh Next 50,000 kWh $0.0213/kWh All Additional kWh October 15 - May 14 Customer Charge - $3.00/month Service Charge No Charge First 10 kW $2.35/kW Next 220 kW $0.76/kW All Additional kW Energy Charge $0.0679/kWh First 400 kWh $0.0448/kWh Next 3600 kWh $0.0439/kWh Next 100 kWh/kW of billing demand, or if no billing demand all additional kWh. $0.0260/kWh Next 50,000 kWh $0.0190/kWh All Additional kWh Minimum $8.00	1. Eliminated due to lack of significant geographic cost differences.

SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT
AND POWER DISTRICT
(Contd.)

Class of Customer Rate Schedule	January, 1986 Rate Schedules	January, 1979 Rate Schedules	Reasons to change
E-39 Large Industrial Service	Rate	Rate	
	May 15 - October 14 Customer Charge - $1,320/month	May 15 - October 14	1. Rate increases due to increased cost of service.
	Service Charge On-Peak $4.05/kW All kW Off-Peak $1.54/kW All kW	Service Charge On-Peak - $2.78/kW All kW Off-Peak - $1.09/kW All kW	2. Customer charge instituted to reflect cost of substation, meter, meter reading, and billing.
	Energy Charge On-Peak $.0413/kWh All kWh Off-Peak $.0263/kWh All kWh	Energy Charge On-Peak - $0.0227/kWh First 4,000,000 kWh; $0.0213/kWh All Additional kWh Off-Peak - $0.0156/kWh First 4,000,000 kWh; $0.0137/kWh All Additional kWh	
	October 15 - May 14 Customer Charge - $1,320/month	October 15 - May 14	
	Service Charge On-Peak $3.13/kW All kW Off-Peak $1.39/kW All kW	Service Charge On-Peak - $2.18/kW All kW Off-Peak - $1.00/kW All kW	
	Energy Charge On-Peak $.0318/kWh All kWh Off-Peak $.0239/kWh First 4,000,000 kWh; $.0224/kWh All Additional kWh	Energy Charge On-Peak - $0.0210/kWh First 4,000,000 kWh; $0.0192/kWh All Additional kWh Off-Peak - $0.0151/kWh First 4,000,000 kWh; $0.0128/kWh All Additional kWh	

SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT
AND POWER DISTRICT
(Contd.)

Class of Customer Rate Schedule	January, 1986 Rate Schedules	January, 1979 Rate Schedules	Reasons to change
E-47 Agricultural Pumping Service	Rate	Rate	
	May 15 - October 14 Customer Charge - $6.90/month	May 15 - October 14	1. Customer charge instituted to reflect meter, meter reading, and billing expense.
	Service Charge $2.74/kW All kW	Service Charge $2.00/kW All kW	2. Rate increase due to increased cost of service.
	Energy Charge $.0479/kW All kWh	Energy Charge $0.0290/kWh All kWh	
	October 15 - May 14 Customer Charge - $6.90/month	October 15 - May 14	
	Service Charge $1.14/kW All kW	Service Charge $0.79/kW All kW	
	Energy Charge $.0388/kWh All kWh	Energy Charge $0.0255/kWh All kWh	
		Minimum $7.00	

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UPDATED INFORMATION REQUESTED BY
THE NRC FOR ANTITRUST REVIEW

ARIZONA PUBLIC SERVICE COMPANY

UPDATED REGULATORY GUIDE 9.3

Item 1a

Anticipated excess or shortage in generating capacity resources not expected at the construction permit stage. Reasons for the excess or shortage along with data on how the excess will be allocated, distributed or otherwise utilized or how the shortage will be obtained.

Response

In analyzing Arizona Puablic Service Company's (APS) current long-range forecast as it related to the above questions, APS anticipates the following excesses in the time frame of Palo Verde 1,2 and 3 which were not anticipated at the construction permit stage:

YEAR	EXCESS/(SHORTAGES) MW[a]
1986	21
1987	302

Decreasing load growth projection from the time Palo Verde was planned to the present has resulted in excess capacity in the year 1987. In mid 1985, APS presented to various entities offers to sell this excess. To date there have been no acceptances to APS' proposal.

(a) Based on long-range forecast dated May 31, 1985

Item 1b

New power pools or coordinating groups or changes in structure, activities, policies, practices or membership of power pools or coordinating groups in which the licensee was, is or will be a participant.

Response

In the past the benefits of power pooling were to a limited extent derived from a number of bilateral agreements similar to the Power Coordination Agreement between Arizona Public Service and Salt River Project.

In November of 1983 nineteen entities signed the Revised Inland Power Pool Agreement. This agreement established requirements for carrying operating reserves, and included service schedules which provide for emergency assistance, scheduled outage assistance, economy energy interchange and transmission services. The parties to the agreement are located in the states of Colorado, Arizona, New Mexico, Utah, Wyoming and Nebraska. The pool provides a diverse and sizeable resource for sales and services for its members. It has acquired two new members since the document was signed, and has a combined load of over 16000 MW.

The Inland Power Pool members are as follows:

Arizona Electric Power Cooperative
Arizona Public Service Company
Basin Electric Power Cooperative
City of Colorado Springs
City of Farmington
Colorado-Ute Electric Association
Deseret G & T Cooperative
El Paso Electric Company
County of Los Alamos
Plains Electric G & T Cooperative
Platte River Power Authority
Public Service of Colorado
Public Service of New Mexico
Salt River Project
Texas-New Mexico Power Company
Tri-State G & T Association
Tucson Electric Power
United States - Boulder City Area Office
United States - Loveland-Ft. Collins Area Office
United States - Salt Lake City Area Office
Wyoming Municipal Power Agency

Item 1b (Continued)

Ten utilities in the west are on the verge of signing a new pooling document which will establish an operating pool on a "trial basis" with a term of two years. The pool will be called the Western Systems Power Pool and will have members in the states of California, Arizona, New Mexico and Washington. It will provide for economy energy interchange, unit commitment service, and system capacity and energy sales or exchanges. The rates for these services will be based on market forces to the extent permissable by applicable regulatory authority. It is likely that if the experience of this pool is a positive one that the parties will establish a permanent pool and many more utilities in the area will become members.

The members of the Western Systems Power Pool will be as follows:

- Arizona Electric Power Cooperative
- Arizona Public Service Company
- Northern California Power Agency
- Pacific Gas and Electric Company
- San Diego Gas & Electric Company
- Southern California Edison Company
- Public Service of New Mexico
- Salt River Project
- California Department of Water Resources
- United States - Bonneville Power Admin.

Item 1c

Changes in transmission with respect to (1) the nuclear plant, (2) interconnections, or (3) connections to wholesale customers.

Response

(1) The Nuclear Plant:

Since the October 1979 response, the Palo Verde-Saguaro and the Greenlee-Rio Grande lines have been indefinitely delayed.

The current PVNGS transmission system consists of the following lines that have been placed in service or planned to be completed as follows:

Palo Verde - Westwing #1	525 kV Energized Nov. 1979
Palo Verde - Kyrene	525 kV Energized May 1982
Palo Verde - Devers	525 kV Energized May 1982
Palo Verde - Westwing #2	525 kV Planned March 1986

(2) Interconnections:

APS and San Diego Gas and Electric Company (SDG&E) have jointly constructed a 525 kV interconnection between the Palo Verde Substation and SDG&E's Miguel Substation. This line was energlized in May 1984.

Southern California Edison Co. is presently planning to construct a second 525 kV line from Palo Verde to Devers in 1990.

(3) Connections to wholesale customers:

No Change to the October 1979 response.

Item 1d

Changes in the ownership or contractual allocation of the output of the nuclear facility. Reasons and basis for such changes should be included.

Response

There have been no changes in Arizona Public Service's ownership or contractual allocation of the output of the nuclear facility.

Item 1e

Changes in design, provision or conditions of rate schedules and reasons for such changes. Rate increases or decreases are not necessary.

Response

Changes in design, provisions, or conditions of service that became effective since October 1, 1978 are shown on Table 1-1. Changes due only to "across-the-board" rate increases are not shown. Some minor rate schedules and riders are not included in Table 1-1.

TABLE 1-1

CHANGES IN APS' ELECTRIC RATES

October 1, 1978 to February 1, 1986

RATE SCHEDULE	A.C.C. No. AT 10/01/78	CHANGE EFF. 09/29/79		CHANGE EFF. 01/01/80		CHANGE EFF. 06/01/80		CHANGE EFF. 05/01/81		CHANGE EFF. 11/01/81		CHANGE EFF. 01/01/82	
		A.C.C. NO.	REASON*	A.C.C. NO.	REASON*	A.C.C. NO.	REASON*	A.C.C. NO.	REASON*	A.C.C. NO.	REASON*	A.C.C. NO.	REASON*
E-10	3000	--	--	--	--	3200	(10)	3443	(9)	3501	(10)	--	--
E-203-1	3002	--	--	--	--	3202	(10)	--	--	3503	(10)	--	--
E-203-2	3003	--	--	--	--	3203	(10)	--	--	3504	(10)	--	--
E-207	3004	--	--	--	--	3204	(10)	--	--	3505	(10)	--	--
E-32-1	3009	3212	(9)	--	--	3411	(10)	--	--	3512	(10)	--	--
E-32-2	3010	3141	(9)	--	--	3213	(10)	--	--	3513	(10)	--	--
E-33	3011	--	--	--	--	3214	(10)	--	--	3514	(10)	--	--
E-120	3013	--	--	--	--	3216	(10)	--	--	3516	(10)	--	--
E-126	3014	--	--	--	--	3217	(10)	--	--	3517	(10)	--	--
E-220	3015	--	--	--	--	3218	(10)	--	--	3518	(10)	--	--
E-38	3020	--	--	--	--	3224	(10)	--	--	3524	(10)	--	--
E-49	3024	--	--	--	--	3228	(10)	--	--	3528	(10)	--	--
E-57	3028	--	--	--	--	3232	(10)	--	--	3532	(10) (19)	--	--
E-58	3029	--	--	3144	(21)	3233	(10)	--	--	3533	(10)	--	--
E-58WM	3030	--	--	3145	(21)	3234	(10)	--	--	3534	(10)	--	--
E-110	3032	--	--	--	--	3236	(10)	--	--	3536	(10)	--	--
E-143	3033	--	--	--	--	3237	(10)	--	--	3537	(10)	--	--
E-221	3034R	--	--	--	--	3238	(10)	--	--	3538	(10)	--	--
E-251	3035	--	--	--	--	3240	(10)	--	--	3540	(10)	--	--
EC-1	--	--	--	--	--	--	--	3442	(7)	3500	(9) (10)	3561	(13)
E-12	--	--	--	--	--	--	--	--	--	--	--	--	--
ECT-1	--	--	--	--	--	--	--	--	--	--	--	3562	(7)
ET-1	--	--	--	--	--	--	--	--	--	--	--	3560	(7)
E-32	--	--	--	--	--	--	--	--	--	--	--	--	--
E-34	--	--	--	--	--	--	--	--	--	--	--	--	--

See explanation of changes - page 5 of 5.

TABLE 1-1

CHANGES IN APS' ELECTRIC RATES

October 1, 1978 to February 1, 1986

RATE SCHEDULE	CHANGE EFF. 05/01/82		CHANGE EFF. 11/01/82		CHANGE EFF. 12/02/82		CHANGE EFF. 01/01/83		CHANGE EFF. 07/01/83		CHANGE EFF. 10/01/83	
	A.C.C. NO.	REASON*	A.C.C. NO.	REASON*	A.C.C. NO.	REASON*	A.C.C. NO.	REASON*	A.C.C. NO.	REASON*	A.C.C. NO.	REASON*
E-10	--	--	--	--	3701	(17)	--	--	--	--	3802	(11)
E-203-1	--	--	--	--	3702	(17)	--	--	--	--	3804	(11)
E-203-2	--	--	--	--	3703	(17)	--	--	--	--	3805	(11)
E-207	--	--	--	--	3704	(17)	--	--	--	--	3806	(11)
E-32-1	--	--	--	--	3707	(17)	--	--	--	--	3814	(11)
E-32-2	--	--	--	--	3708	(17)	--	--	--	--	3815	(11)
E-33	--	--	--	--	3709	(17)	--	--	--	--	3816	(11)
E-120	--	--	--	--	3710	(17)	--	--	--	--	3818	(11)
E-126	--	--	--	--	3711	(17)	--	--	--	--	3819	(11)
E-220	--	--	--	--	3712	(17)	--	--	--	--	3820	(11)
E-38	--	--	--	--	3713	(17)	--	--	--	--	3826	(11)
E-49	--	--	--	--	3717	(17)	--	--	--	--	3830	(11)
E-57	--	--	--	--	3718	(17)	--	--	--	--	3834	(11)
E-58	--	--	--	--	3719	(17)	--	--	--	--	--	--
E-58WM	--	--	--	--	3720	(17)	--	--	--	--	--	--
E-110	--	--	--	--	3722	(17)	--	--	--	--	3838	(11)
E-143	--	--	--	--	3723	(17)	--	--	--	--	3839	(11)
E-221	--	--	--	--	3724	(17)	--	--	--	--	3840	(11)
E-251	--	--	--	--	3726	(17)	--	--	--	--	3842	(11)
EC-1	3565	(14)	3567	(15)	3700	(17)	--	--	3730	(16)	3800	(11)
E-12	--	--	--	--	--	--	--	--	3729	(7)	3801	(11)
ECT-1	--	--	--	--	3705	(17)	3727	(18)	--	--	3812	(11)
ET-1	--	--	--	--	3706	(17)	--	--	--	--	3813	(11)
E-32	--	--	--	--	--	--	--	--	--	--	--	--
E-34	--	--	--	--	--	--	--	--	--	--	--	--

See explanation of changes - page 5 of 5

TABLE 1-1

CHANGES IN APS' ELECTRIC RATES

October 1, 1978 to February 1, 1986

RATE SCHEDULE	CHANGE EFF. 11/01/83		CHANGE EFF. 08/01/84		CHANGE EFF. 10/10/84		CHANGE EFF. 10/12/84		CHANGE EFF. 01/14/85		CHANGE EFF. 02/01/85		CHANGE EFF. 05/13/85	
	A.C.C. NO.	REASON*	A.C.C. NO.	REASON*	A.C.C. NO.	REASON*	A.C.C. NO.	REASON*	A.C.C. NO.	REASON*	A.C.C. NO.	REASON*	A.C.C. NO.	REASON*
E-10	3902	(3)(9)	--	--	--	--	4102	(11)	--	--	4202	(11)(23)	--	--
E-203-1	3804	(8)	--	--	--	--	--	--	--	--	--	--	--	--
E-203-2	3805	(8)	--	--	--	--	--	--	--	--	--	--	--	--
E-207	3903	(1)(11)(20)	--	--	--	--	4103	(11)	--	--	4203	(11)(23)	4332	(8)
E-32-1	3814	(8)	--	--	--	--	--	--	--	--	--	--	--	--
E-32-2	3815	(8)	--	--	--	--	--	--	--	--	--	--	--	--
E-33	3816	(8)	--	--	--	--	--	--	--	--	--	--	--	--
E-120	3913	(1)(19)(20)	--	--	4039	(8)	--	--	--	--	--	--	--	--
E-126	3914	(1)(19)(20)	--	--	--	--	4113	(11)	4113	(8)	--	--	--	--
E-220	3915	(1)(19)(20)	--	--	--	--	4114	(11)	--	--	4213	(11)(23)	--	--
E-38	3923	(1)(6)(19)	4056	(6)	--	--	4123	(11)	--	--	4219	(11)(23)	--	--
E-49	3926	(20)	--	--	4042	(8)	--	--	--	--	--	--	--	--
E-57	3929	(1)(19)(20)	--	--	--	--	4127	(11)	--	--	4234	(11)(23)	--	--
E-58	--	--	--	--	--	--	4128	(22)	--	--	4229	(23)	--	--
E-58WM	--	--	--	--	--	--	4129	(22)	--	--	4230	(23)	--	--
E-110	3933	(1)(19)(20)	--	--	--	--	4130	(11)	--	--	4225	(11)(23)	4235	(8)
E-143	3839	(8)	--	--	--	--	--	--	--	--	--	--	--	--
E-221	3934	(1)(19)	4057	(6)	--	--	4131	(11)	--	--	4226	(11)(23)	--	--
E-251	3936	(1)(19)(20)	--	--	4045	(8)	--	--	--	--	--	--	--	--
EC-1	3901	(3)(9)	--	--	--	--	4101	(11)	--	--	4201	(11)(23)	--	--
E-12	3900	(9)(11)	--	--	--	--	4100	(11)	--	--	4200	(11)(23)	--	--
ECT-1	3909	(19)	--	--	--	--	4109	(11)	--	--	4209	(11)(23)	--	--
ET-1	3910	(19)	--	--	--	--	4110	(11)	--	--	4210	(11)(23)	--	--
E-32	3911	(7)	--	--	--	--	4111	(11)	--	--	4211	(11)(23)	--	--
E-34	3912	(7)	--	--	--	--	4112	(11)	--	--	4212	(11)(23)	--	--

See explanation of changes - page 5 of 5

TABLE 1-1

RATE SCHEDULE	A.C.C. NO. AT 2/1/86	CURRENT RATE APPLICABLE TO CUSTOMERS TRANSFERRED FROM CANCELLED RATES
E-10	4202	--
E-203-1	--	E-10
E-203-2	--	E-10
E-207	--	E-10
E-32-1	--	E-32
E-32-2	--	E-32
E-33	--	E-34
E-120	--	E-32
E-126	--	E-32
E-220	4233	--
E-38	4219	--
E-49	--	E-32
E-57	4234	--
E-58	4229	--
E-58WM	4230	--
E-110	--	E-32
E-143	--	E-38
E-221	4226	--
E-251	--	E-32
EC-1	4201	--
E-12	4200	--
ECT-1	4209	--
ET-1	4210	--
E-32	4211	--
E-34	4212	--

TABLE 1-1

EXPLANATION OF RATE CHANGES

(1) Separate "Basic Service Charge" added to rate blocks.

(2) Energy block lengths revised.

(3) May - October portion changed from "inverted step" form to "inverted/declining block" form.

(4) Demand ratchet period changed from six months (May - October) to five months (June - October).

(5) Demand ratchet basis changed from five months highest kw to five months average kw.

(6) Area of availability revised.

(7) New rate schedule.

(8) Rate cancelled.

(9) "Application" section of rate schedule revised.

(10) Amount of base purchased power and fuel costs included in rates was revised (roll-in). This was done in conjunction with a general rate increase.

(11) Rate design change in conjunction with general rate increase.

(12) "Inverted step/block" form changed to pure "inverted block" form.

(13) "Determination of kw" section of rate schedule revised.

(14) Demand charge limitation introduced for summer portion of rate.

(15) Demand charge limitation introduced for winter portion of rate.

(16) Demand charge component of rate was revised.

(17) Amount of base purchased power and fuel costs included in rates was revised (roll-in).

(18) Changed effective date of application of off-peak demand charge.

(19) Rate design changes resulting from hearing on rate design issues.

(20) Automatic annual increase provision added to "frozen" rate schedules.

(21) Addition and/or deletion of facilities provided and/or billed under street lighting rate schedules.

(22) Rate design changes for street lighting rate schedules.

(23) Performance incentive adjustment clause added to rate schedules.

Item 1f

List of all (1) new wholesale customers, (2) transfers from one rate schedule to another, including copies of schedules not previously furnished, (3) changes in licensee's service area and (4) licensee's acquisitions or mergers.

Response

(1) Since Arizona Public Service Company last submitted information requested by NRC (October 1, 1979), the Company has both acquired new wholesale customers and discontinued service to wholesale customers as follows:

(a) NEW WHOLESALE SERVICE

CUSTOMER	FERC RATE SCHEDULE NO.	EFFECTIVE DATE
Plains Electric Generation and Transmission Group	83	10/28/80
Washington Water Power Co.	84	12/16/80
Southern California Edison Co.	120	08/01/84

(b) DISCONTINUED WHOLESALE SERVICE

Navopache Electric Coop.	17	10/28/80 1/
Comision Federal de Electricidad		
Agua Prieta	54	12/31/82 2/
Sonoyta	53	10/19/82 2/
Plains Electric G&T Coop.	83	12/31/83
Washington Water Power Co.	84	10/11/85

NOTES:

1/ Full requirements of Navopache supplied by Plains Electric and G&T Coop.

2/ Export Sales

Item 1f (Continued)

(2) Attached are schedules of "Sales of Electricity by Rate Schedules" for calendar years 1979 through 1985. These schedules are taken from APS' annual reports to the Federal Energy Regulatory Commission (FERC Form No. 1), and show the number of customers, kwh sales and revenues for the Company's major rates. Page 4 of the response to Item 1e (Table 1-1) shows the currently existing rates to which customers under cancelled rates were transferred.

Appendix 1A contains copies of rate schedules currently in effect February 1, 1986, as shown on page 4 of Table 1-1.

(3) There have been no changes in APS' service area since the Company last submitted information requested by NRC (October 1, 1979).

(4) On August 27, 1984 APS purchased certain off-reservation distribution facilities from the Colorado River Indian Irrigation Project. Approval of this acquisition was received from FERC on April 4, 1985. The Company had no other acquisitions or mergers during the period of October 1, 1979 to the present time.

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the Kwh of electricity sold, revenue, average number of customers, average Kwh per customer, and average revenue per Kwh.

2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in Schedule entitled "Electric Operating Revenues," page 409. If the sales under any rate schedule are classified in more than one revenue account list the rate schedule and sales data under each applicable revenue account subheading.

3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.

4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).

5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.

Line No.	Number and Title of Rate Schedule (a)	Kwh Sold (b)	Revenue (c)	Average Number of Customers (d)	Kwh of Sales per Customer (e)	Revenue per Kwh Sold (f)
	440 Residential		$			Cents
1	E-10	3,417,316,865	192,260,974	334,943	10,203	5.63
2	E-47 Outdoor Lighting	3,599,512	418,114	**3,288	1,095	11.62
3	Miscellaneous Rates			** 16		
4		2,509,542	141,942	403	6,227	5.66
5	New Mexico Generation Tax Refund		(1,579,742)			
6	City of Page Reserve For Refund		(175,000)			
7	Total Residential	3,423,425,919	191,066,288	335,346	10,209	5.58
8	442 Commercial					
9	E-32	3,186,962,957	165,516,440	45,072	70,708	5.19
10	E-126	31,456,444	2,051,207	506	62,167	6.52
11	E-120	50,865,068	3,107,179	531	95,791	6.11
12	E-33	114,888,000	4,112,437	1	114,888,000	3.58
13	E-47 Outdoor Lighting	20,586,153	2,274,025	**6,218	3,311	11.05
14	E-220	21,319,414	947,050	239	89,203	4.44
15	E-40 Agr. Wind Machine	1,528,776	240,835	234	6,533	15.75
16	Miscellaneous Rates			** 27		
17		66,305,008	3,008,111	372	178,239	4.54
18	New Mexico Generation Tax Refund		(1,723,147)			
19	Total Commercial	3,493,911,820	179,534,137	46,955	74,410	5.14
20	442 Industrial & Irrigation					
21	E-32	856,139,921	37,495,449	1,666	513,890	4.38
22	E-38 Irrigation (1)	322,916,658	12,120,294	1,028	314,121	3.75
23	E-33	133,757,600	4,583,223	2	66,878,800	3.43
24	E-221	65,350,743	3,056,156	855	76,434	4.68
25	E-126	2,784,497	165,481	16	174,031	5.94
26	E-143	33,499,672	1,286,807	140	239,283	3.84
27	E-120	7,272,657	429,816	43	169,132	5.91
28	E-57	2,559,302	124,427	24	106,638	4.86
29	Special Contract	1,322,432,667	42,648,291	19	69,601,719	3.22
30	Miscellaneous Rates			* 237		
31		1,966,037	164,059	7	280,862	8.34
32	New Mexico Generation Tax Refund		(1,317,681)			
33	Total Industrial & Irrigation	2,748,679,754	100,756,322	3,800	723,337	3.67
34	444 Public Street Lighting	65,695,393	5,646,409	608	108,052	8.59
35	New Mexico Generation Tax Refund		(33,298)			
36	Total Public Street Lighting	65,695,393	5,613,111	608	108,052	8.54
37	445 Other Public Authorities	56,561,999	1,870,225	450	125,693	3.31
38	New Mexico Generation Tax Refund		(37,672)			
39	Total Other Public Authorities	56,561,999	1,832,553	450	125,693	3.24
40	447 Sales For Resale	1,796,622,740	42,955,724	30	59,887,425	2.39
41						
42	Total billed	11,584,897,625	521,758,135	387,189	29,921	4.50
43	Total unbilled revenue *			—	—	—
44	Total	11,584,897,625	521,758,135	387,189	29,921	4.50

*Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

**Duplicates

(1)Includes E-38-0

Note: Total revenue $33,917,602 from fuel adjustment clauses for the 12 months ended 12/31/79.

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the Kwh of electricity sold, revenue, average number of customers, average Kwh per customer, and average revenue per Kwh.

2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in Schedule entitled "Electric Operating Revenues," page 409. If the sales under any rate schedule are classified in more than one revenue account list the rate schedule and sales data under each applicable revenue account subheading.

3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.

4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).

5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.

Line No.	Number and Title of Rate Schedule (a)	Kwh Sold (b)	Revenue (c)	Average Number of Customers (d)	Kwh of Sales per Customer (e)	Revenue per Kwh Sold (f)
			$			Cents
1	440 Residential					
2	E-10	3,537,756,521	220,023,540	354,258	9,986	6.22
3	E-47 Outdoor Lighting	3,446,554	428,836	** 3,190	1,080	12.44
4	Miscellaneous Rates			** 11		
5		7,364,740	415,797	778	9,466	5.65
6	City of Page to Close the Refund Account		52,382			
7	Total Residential	3,548,567,815	220,920,555	355,036	9,995	6.23
8						
9	442 Commercial					
10	E-32	3,343,920,685	191,559,360	47,434	70,496	5.73
11	E-126	27,817,258	1,993,845	446	62,371	7.17
12	E-120	46,327,164	3,125,339	529	87,575	6.75
13	E-33	164,725,000	6,675,828	2	82,362,500	4.05
14	E-47 Outdoor Lighting	20,924,236	2,464,436	** 6,249	3,348	11.78
15	E-220	18,206,939	908,974	209	87,115	4.99
16	E-40 Agr. Wind Machine	396,640	191,481	225	1,763	48.28
17	Miscellaneous Rates			** 15		
18		65,887,953	3,306,489	377	174,769	5.02
19	Total Commercial	3,688,205,875	210,225,752	49,222	74,930	5.70
20						
21	442 Industrial & Irrigation					
22	E-32	909,726,935	43,589,204	1,687	539,257	4.79
23	E-38 Irrigation (1)	391,734,990	16,547,037	1,059	369,910	4.22
24	E-33	133,276,000	5,171,010	2	66,638,000	3.88
25	E-221	68,524,184	3,522,514	880	77,868	5.14
26	E-126	4,020,414	272,430	33	121,831	6.78
27	E-143	35,550,221	1,502,226	144	246,877	4.23
28	E-120	4,160,154	259,921	19	218,955	6.25
29	E-57	1,855,710	101,246	19	97,669	5.46
30	Special Contracts	1,146,696,148	43,697,115	18	63,705,342	3.81
31	Miscellaneous Rates			** 240		
32		2,166,072	206,299	7	309,439	9.52
33	Settlement Payment to Thunderbird Irrigation District		(10,000)			
34	Total Industrial & Irrigation	2,697,710,828	114,859,002	3,868	697,443	4.26
35						
36	444 Public Street Lighting	67,588,810	6,380,738	598	113,025	9.44
37						
38	445 Other Public Authorities	6,666,988	174,324	444	15,016	2.61
39						
40	447 Sales for Resale	1,868,982,398	52,835,654	31	60,289,755	2.83
41						
42	Total billed	11,877,722,714	605,396,025	409,199	29,027	5.10
43	Total unbilled revenue *			—	—	—
44	Total	11,877,722,714	605,396,025	409,199	29,027	5.10

*Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

**Duplicates
(1)Includes E-38D
Note: Total revenue $52,201,079 from fuel adjustment clauses for the 12 months ended 12/31/80

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1982	Dec. 31, 1981

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customers, average MWh per customer, and average revenue per MWh, excluding data for Sales for Resale is reported on pages 310-311.

2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," page 301. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.

3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.

4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).

5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.

6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	MWh of Sales per Customer (e)	Revenue per MWh Sold (f)
1	440 Residential					
2	E-10	3,766,602	$250,387,637	368,450	10.223	$ 66.5
3	E-47 Outdoor Lighting	3,347	474,794	3,108**	1.077	141.9
4	EC-1	24,215	1,649,763	1,786	13.558	68.1
5	Miscellaneous Rates			10**		
6		6,616	394,637	665	9.949	59.6
7	Total Residential	3,800,780	252,906,831	370,901	10.247	66.5
8						
9	442 Commercial					
10	E-32	3,565,487	218,650,092	49,772	71.636	61.3
11	E-126	26,710	2,077,798	415	64.361	77.8
12	E-120	45,340	3,267,985	500	90.680	72.1
13	E-33	178,689	7,437,950	2	89,344.500	41.6
14	E-47 Outdoor Lighting	21,206	2,829,937	6,265**	3.385	133.4
15	E-220	15,354	843,036	189	81.238	54.9
16	E-40 Agr. Wind Machine	208	189,583	203	1.025	911.5
17	Miscellaneous Rates			13**		
18		69,550	3,678,881	373	186.461	52.9
19	Total Commercial	3,922,544	238,975,262	51,454	76.234	60.9
20						
21	442 Industrial & Irrigation					
22	E-32	1,006,145	51,010,746	1,693	594.297	50.7
23	E-38 Irrigation (1)	473,927	19,747,627	1,134	417.925	41.7
24	E-33	127,155	5,153,831	2	63,577.500	40.5
25	E-221	70,450	3,817,245	906	77.759	54.2
26	E-126	2,861	228,384	29	98.655	79.8
27	E-143	44,170	1,872,530	159	277.799	42.4
28	E-120	3,931	267,046	19	206.895	67.9
29	E-57	2,314	131,895	17	136.118	57.0
30	Special Contracts	1,413,330	54,204,144	20	70,666.500	38.4
31	Miscellaneous Rates			231**		
32		2,225	218,577	7	317,857	98.2
33	Total Industrial & Irrigation	3,146,508	136,652,025	3,986	789.390	43.4
34						
35	444 Public Street Lighting	68,401	7,430,564	614	111.402	108.6
36	445 Other Public Authorities	7,140	189,416	440	16.227	26.5
37						
38						
39						
40						
41	Total Billed	10,945,373	636,154,098	427,395	25.610	58.1
42	Total Unbilled Rev. *(See Instr. 6)*			---	---	---
43	TOTAL	10,945,373	636,154,098	427,395	25.610	58.1

**Duplicates
(1) Includes E-38D
Note: Total revenue $3,003,542 from fuel adjustment clauses for the 12 months ended 12/31/81
Above rates ($1,724,914)
Sales for resale $4,728,456

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1983	Dec. 31, 19 82

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customers, average MWh per customer, and average revenue per MWh, excluding data for Sales for Resale is reported on pages 310-311.

2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," page 301. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.

3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.

4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).

5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.

6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	MWh of Sales per Customer (e)	Revenue per MWh Sold (f)
1	440 Residential					
2	E-10	3,618,055	$283,954,958	371,508	9.739	$ 78.5
3	E-47 Outdoor Lighting	3,210	518,688	2,976**	1.079	161.6
4	EC-1	128,976	9,717,127	9,527	13.538	75.3
5	Miscellaneous Rates			9**		
6		4,345	306,806	525	8.276	70.6
7	Total Residential	3,754,586	294,497,579	381,560	9.840	78.4
8						
9	442 Commercial					
10	E-32	3,623,738	262,870,033	51,842	69.900	72.5
11	E-126	24,207	2,186,586	388	62.389	90.3
12	E-120	38,505	3,293,779	464	82.985	85.5
13	E-33	179,518	9,038,794	2	89,759.000	50.4
14	E-47 Outdoor Lighting	20,824	3,190,447	6,149**	3.387	153.2
15	E-220	14,986	972,667	178	84.191	64.9
16	E-40 Agr. Wind Machine	453	207,617	187	2.422	458.3
17	Miscellaneous Rates			13**		
18		71,148	4,501,981	369	192.813	63.3
19	Total Commercial.	3,973,379	286,261,904	53,430	74.366	72.0
20						
21	442 Industrial & Irrigation					
22	E-32	932,275	56,521,152	1,655	563.308	60.6
23	E-38 Irrigation (1)	378,085	20,074,970	1,168	323.703	53.1
24	E-33	114,900	5,654,647	2	57,450.000	49.2
25	E-221	65,150	4,267,382	926	70.356	65.5
26	E-126	2,100	186,191	25	84.000	88.7
27	E-143	37,168	1,982,210	164	226.634	53.3
28	E-120	3,250	261,798	19	171.053	80.6
29	E-57	2,149	146,169	18	119.389	68.0
30	Special Contracts	1,333,257	62,490,424	21	63,488.429	46.9
31	Miscellaneous Rates			238**		
32		2,338	270,295	6	389.667	115.6
33	Total Industrial & Irrigation	2,870,672	151,855,238	4,004	716.951	52.9
34						
35	444 Public Street Lighting	66,163	8,690,841	639	103.541	131.4
36	445 Other Public Authorities	6,900	196,117	427	16.159	28.4
37	448 Interdepartmental Sales	11,524	668,477	1	11,524.000	58.0
38						
39						
40						
41	Total Billed	10,683,224	742,170,156	440,061	24.277	69.5
42	Total Unbilled Rev. *(See Instr. 6)*			-	-	-
43	TOTAL	10,683,224	742,170,156	440,061	24.277	69.5

**Duplicates

(1) Includes E-38D

Note: Total revenue $39,158,182 from fuel adjustment clauses for the 12 months ended 12/31/82
Above rates $33,709,008
Sales for resale $5,449,174

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Arizona Public Service Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customers, average MWh per customer, and average revenue per MWh, excluding data for Sales for Resale is reported on pages 310-311.

2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," page 301. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.

3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.

4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).

5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.

6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	MWh of Sales per Customer (e)	Revenue per MWh Sold (f)
1	440 Residential					
2	E-10	3,730,930	$288,345,154	370,864	10.060	$ 77.3
3	E-12	27,320	2,318,889	3,189	8.567	84.9
4	EC-1	312,505	22,669,732	19,329	16.168	72.5
5	E-47 Outdoor Lighting	3,053	494,906	2,837**	1.076	162.1
6	Miscellaneous Rates			8**		
7		8,697	575,672	815	10.671	66.2
8	Total Residential	4,082,505	314,404,353	394,197	10.357	77.0
9						
10	442 Commercial					
11	E-32	3,808,252	271,806,864	54,033	70.480	71.4
12	E-33	150,663	7,365,674	2	75,331.500	48.9
13	E-34	78,162	4,100,397	3	26,054.000	52.5
14	E-120	33,941	2,833,295	365	92.989	83.5
15	E-126	21,338	1,861,315	310	68.832	87.2
16	E-47 Outdoor Lighting	20,563	3,142,081	6,002**	3.426	152.8
17	E-220	14,284	944,338	169	84.521	66.1
18	E-40 Agr. Wind Machine	240	150,112	142	1.690	625.5
19	Miscellaneous Rates			11**		
20		67,782	4,160,170	347	195.337	61.4
21	Total Commercial	4,195,225	296,364,246	55,371	75.766	70.6
22						
23	442 Industrial & Irrigation					
24	E-32	877,955	52,268,466	1,635	536.976	59.5
25	E-38(1)	235,139	12,518,413	1,178	199.609	53.2
26	E-33	73,463	3,590,200	1	73,463.000	48.9
27	E-34	61,815	2,974,241	2	30,907.500	48.1
28	E-221	66,360	4,295,556	916	72.445	64.7
29	E-143	28,185	1,464,894	140	201.321	52.0
30	E-120	2,579	205,218	16	161.188	79.6
31	E-126	1,766	151,145	19	92.947	85.6
32	E-57	2,049	136,334	17	120.529	66.5
33	Special Contracts	1,316,507	59,425,670	20	65,825.350	45.1
34	Miscellaneous Rates			234**		
35		2,236	266,789	6	372.667	119.3
36	Total Industrial & Irrigation	2,668,054	137,296,926	3,950	675.457	51.5
37						
38	444 Public Street Lighting	68,178	8,924,646	654	104.248	130.9
39	445 Other Public Authorities	6,625	178,654	407	16.278	27.0
40	448 Interdepartmental Sales	42,484	2,772,492	1	42,484.000	65.3
41	Total Billed	11,063,071	759,941,317	454,580	24.337	68.7
42	Total Unbilled Rev. *(See Instr. 6)*			-	-	-
43	TOTAL	11,063,071	759,941,317	454,580	24.337	68.7

**Duplicates

(1) Includes E-380

Note: Total revenue $(12,562,481) from fuel adjustment clauses for the 12 months ended 12/31/83.
Above rates $(17,920,247)
Sales for resale $5,357,766

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Arizona Public Service Company	(1) ☒ An Original (2) ☐ A Resubmission	April 30, 1985	Dec. 31, 1984

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the kWh of electricity sold, revenue, average number of customers, average kWh per customer, and average revenue per kWh, excluding data for Sales for Resale is reported on pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," page 301. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales per Customer (e)	Revenue per KWh Sold (f)
1	440 Residential					
2	E-10	3,398,386	$298,142,193	348,781	9.744	$ 87.7
3	E-12	365,405	35,248,983	39,527	9.244	96.5
4	EC-1	549,842	43,926,883	28,766	19.114	79.9
5	ET-1	8,920	557,380	721	12.372	62.5
6	ECT-1	2,412	147,725	139	17.353	61.2
7	E-47 Outdoor Lighting	3,126	499,149	2,625**	1.191	159.7
8	Miscellaneous Rates	241	14,118	49	4.918	58.6
9	Total Residential	4,328,332	378,536,431	417,983	10.355	87.5
10						
11	442 Commercial					
12	E-32	3,903,138	308,006,817	56,985	68.494	78.9
13	E-34	493,249	27,169,698	16	30,828.063	55.1
14	E-221	70,176	4,590,388	312	224.923	65.4
15	E-47 Outdoor Lighting	21,409	3,491,235	5,840**	3.666	163.1
16	E-220	2,555	207,630	63	40.556	81.3
17	E-120	990	97,881	4	247.500	98.9
18	E-40 Agr. Wind Machine	188	131,092	114	1.649	697.3
19	Miscellaneous Rates			1**		
20		4,249	275,728	14	303.500	64.9
21	Total Commercial	4,495,954	343,970,469	57,508	78.180	76.5
22						
23	442 Industrial & Irrigation					
24	E-32	708,105	48,410,344	1,649	429.415	68.4
25	E-38(1)	402,753	24,003,040	1,340	300.562	59.6
26	E-34	347,254	18,890,755	12	28,937.833	54.4
27	E-221	76,711	5,450,904	835	91.869	71.1
28	E-57	24	9,848	4	6.000	410.3
29	Special Contracts	1,020,011	54,729,124	19	53,684.789	53.7
30	Miscellaneous Rates			228**		
31		1,600	233,437	2	800.000	145.9
32	Total Industrial & Irrigation	2,556,458	151,727,452	3,861	662.123	59.4
33						
34	444 Public Street Lighting	67,521	10,948,108	663	101.842	162.1
35	445 Other Public Authorities	5,656	113,838	359	15.755	20.1
36	448 Interdepartmental Sales	53,377	3,633,939	1	53,377.000	68.1
37						
38						
39						
40						
41	Total Billed	11,507,298	888,930,237	480,375	23.955	77.2
42	Total Unbilled Rev. *(See Instr. 6)*			-	-	-
43	TOTAL	11,507,298	888,930,237	480,375	23.955	77.2

**Duplicates

(1) Includes E-38D

Note: Total revenue $4,281,097 from fuel adjustment clauses for the 12 months

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Arizona Public Service Company	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 1985

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the kWh of electricity sold, revenue, average number of customers, average kWh per customer, and average revenue per kWh, excluding data for Sales for Resale is reported on pages 310-311.

2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," page 301. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.

3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.

4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).

5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.

6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales per Customer (e)	Revenue per KWh Sold (f)
1	440 Residential					
2	E-10	3,166,835	300,354,090	329,483	9,612	$0.0948
3	E-12	661,730	68,204,162	70,731	9,356	0.1031
4	EC-1	778,118	67,999,033	39,517	19,691	0.0874
5	ET-1	12,774	985,453	819	15,597	0.0771
6	ECT-1	3,730	262,105	192	19,427	0.0703
7	E-47	2,965	460,066	2,150*	1,210	0.1552
8	E-201	—	149	1	—	—
9	Total Residential	4,626,152	438,265,058	440,743	10,496	0.0947
10						
11	442 Commercial					
12	E-32	4,258,758	362,291,912	59,568	71,494	0.0851
13	E-34	518,063	30,427,524	16	32,378,938	0.0587
14	E-40	263	130,568	94	2,798	0.4965
15	E-47	21,378	3,615,393	5,687*	3,757	0.1691
16	E-57	79	12,848	6	13,167	0.1626
17	E-220	18	4,668	21	857	0.2593
18	E-221	69,296	4,956,282	317	218,599	0.0715
19	Total Commercial	4,861,855	401,439,195	60,022	81,101	0.0825
20						
21	442 Industrial & Irrigation					
22	E-32	742,289	54,235,665	1,623	457,356	0.0731
23	E-34	345,090	19,931,143	12	28,757,500	0.0578
24	E-38	329,328	21,360,441	1,295	254,307	0.0649
25	E-47	1,459	223,138	219*	6,662	0.1529
26	E-57	42	13,646	4	10,500	0.3249
27	E-221	75,694	5,759,045	759	99,729	0.0761
28	Special Contracts	1,196,075	56,583,261	16	74,754,688	0.0473
29	Total Industrial & Irrigation	2,689,977	158,106,939	3,709	725,257	0.0588
30						
31	444 Public Street Lighting	67,679	11,366,915	471	143,692	0.1680
32						
33	445 Other Public Authorities	5,517	197,706	340	16,226	0.0358
34						
35	448 Interdepartmental Sales	105,434	6,741,595	1	105,434,000	0.0639
36						
37						
38						
39						
40						
41	Total Billed	12,362,614	1,016,117,408**	505,286	24,467	0.0822
42	Total Unbilled Rev. (See Instr.6)	—	—	—	—	—
43	TOTAL	12,362,614	1,016,117,408**	505,286	24,467	0.0822

* Duplicates

** Includes $13,730,007 of fuel adjustment

Item 1g

List of those generating capacity additions committed for operation after the nuclear facility, including ownership rights or power output allocations.

Response

The capacity additions indicated in the October 1979 response have been delayed indefinitely beyond the year 2000.

APS has not made any firm commitments for any new generating capacity beyond the Palo Verde units.

Item 1h

Summary of requests or indications of interest by other electric power wholesale or retail distributors, and licensee's response for any type of electric service or cooperative venture of study.

Response

(1) Town of Wickenburg - The town and APS have entered into a firm wholesale contract. The town will start getting preference power in 1987.

(2) Town of Safford - Safford opted to continue as a municipality and does not have any contractual arrangements with APS.

(3) Colorado River Indian Irrigation Project - APS and SCE purchased CRIPP's off reservation facilities in 1985.

(4) Plains Electric Generation & Transmission Cooperative, Inc.

APS entered into agreements with Plains to provide both the requested wholesale service to Navopache (through May 1984) and the firm transmission service on a long term basis which were described in the October 1979 response.

[illegible]

Item 2

Licensees whose construction permits include conditions permits include conditions pertaining to antitrust aspects should list and discuss those actions or policies which have been implemented in accordance with such conditions.

Response

APS has fulfilled the condition in its construction permit pertaining to antitrust aspects by transmitting bulk power over its transmission system, between or among entities with which it is interconnected, without restrictions on use or resale of the power so transmitted, provided that such services can reasonably be accommodated from a technical standpoint without impairing APS' reliability or its own use of its facilities.

APS has also included in its planning and constructions program sufficient transmission capacity for such bulk power transactions described above, provided that APS has received sufficient advance notice as may be necessary from a technical standpoint to accommodate the requirements of any requesting entity, and further provided that such entity(ies) are obligated as may be agreed (i) to share the capital, operating and maintenance costs of such new transmission facilities to the extent that additional costs burdens would be imposed on APS or (ii) to compensate APS fully for the use of its system.

APPENDIX 1A

ARIZONA PUBLIC SERVICE COMPANY

RATE SCHEDULES

ELECTRIC RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: B. Paul Hart
Title: Vice President, Rates and Regulation
Date Original Filing: March 23, 1981
District: All Rate Areas

A.C.C. No. 4201
Cancelling A.C.C. No. 4101
Tariff or Schedule No. EC-1
Eleventh Revised Sheet No. 1
Effective: February 1, 1985

Filed: January 14, 1985

OPTIONAL RESIDENTIAL CAPACITY SERVICE

AVAILABILITY

In all territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

At customer's option, to residential electric service with an electric central refrigerated air conditioning system in individual private dwellings and in individually metered apartments when such service is supplied at one premise through one point of delivery and measured through one meter. Rate selection is subject to Sections numbered 3.2 and 3.3 of Schedule No. 1 of the Company's "Terms and Conditions," except that this rate schedule would become effective from the next meter reading after written notice to Company and after Company has installed the required kilowatt meter.[1/]

Not applicable to temporary, breakdown, standby, supplementary or resale service.

TYPE OF SERVICE

Single phase, 60 Hertz, at one standard voltage (120/240 or 120/208 as may be selected by customers subject to availability at the premises). Three phase service is furnished under the Company's standard rules covering line extensions. Transformation equipment is included in cost of extension. Three phase service is required for motors of an individual rated capacity of 7-1/2 HP or more.

MONTHLY BILL

RATE

May-Oct.	$11.46	Basic Service Charge, plus
Billing Cycles	9.11	per kw Capacity Charge (but not more than $0.0729 per kwh for all kwh use), plus
(Summer)	0.0391	per kwh for all kwh
Nov.-Apr.	$11.46	Basic Service Charge, plus
Billing Cycles	6.80	per kw Capacity Charge (but not more than $0.0544 per kwh for all kwh use), plus
(Winter)	0.0335	per kwh for all kwh

MINIMUM $11.46 per month

ADJUSTMENTS

(1) Subject to a purchased power and fuel (PPF) unit cost adjustment of plus or minus .0001¢/kwh for each .0001¢/kwh by which the PPF unit cost to the Company's electric operations exceeds or is less than 1.5135¢/kwh. The method of application is set forth in the filed "Plan for Administration of Adjustment for Purchased Power and Fuel Cost."

(2) Plus the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

(3) Plus or minus a Performance Incentive Adjustment Factor in fractions of dollars per kwh based upon the demonstrated operating performance standards of the Company's share of the Four Corners Generating Station and the Palo Verde Nuclear Generating Station Unit #1, compared to performance standards established by the Arizona Corporation Commission. The method of application is described in the filed "Plan for Administration of Performance Incentive Adjustment."

DETERMINATION OF KW CAPACITY

The average kw supplied during the 60-minute period of maximum use during the month, as determined from readings of the Company's meter. In the event the meter is inaccessible to the meter reader due to locked gates or because of safety limitations, the kw shall be that measured since the last resetting of the kw dial. If the kw dial was not reset, the Customer may request a resetting to zero for a charge of $10 per trip. However, the request from the Customer must be within three (3) days of notification by APS that the meter reader was unable to reset the kw dial. The kw dial will be reset to zero, unless the registered kw at the reset time is greater than the registered kw at the last scheduled reading. The billing kw shall be the kw registered on the kw dial at the next scheduled reading.

(CONTINUED ON REVERSE SIDE)

CONTRACT PERIOD

As provided for in Company's standard Agreement for Service.

TERMS AND CONDITIONS

Subject to Company's Terms and Conditions for the Sale of electric service.

1/ The type of meter required is not generally used for residential purposes and therefore their availability is limited. Additionally, it is not known how many meters may be required. Consequently, the Company cannot guarantee installation within any specific time.

ELECTRIC RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: B. Paul Hart
Title: Vice President, Rates and Regulation
Date Original Filing: October 14, 1968
District: All Rate Areas

A.C.C. No. 4202
Cancelling A.C.C. No. 4102
Tariff or Schedule No. E-10
Twenty-first Revised Sheet No. 1
Effective: February 1, 1985

Filed: January 14, 1985

RESIDENTIAL SERVICE

AVAILABILITY

In all territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

To all electric service, except as stated below, required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one premise through one point of delivery and measured through one meter. For those dwellings and apartments where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating or space heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes.

Service to locations with an electric central refrigerated air conditioning system is restricted to those customers served under this rate schedule on or before May 1, 1981.

Not applicable to temporary, breakdown, standby, supplementary or resale service, nor to service for which Rate Schedule EC-1 or E-12 is applicable.

TYPE OF SERVICE

Single phase, 60 Hertz, at one standard voltage (120/240 or 120/208 as may be selected by customers subject to availability at the premises). Three phase service is furnished under the Company's standard rules covering line extensions. Transformation equipment is included in cost of extension. Three phase service is required for motors of an individual rated capacity of 7-1/2 HP or more.

MONTHLY BILL

RATE

May-Oct.	$11.46	Basic Service Charge, plus
Billing Cycles	0.0677	per kwh first 400 kwh
(Summer)	0.0959	per kwh next 400 kwh
	0.0818	per kwh all additional kwh
Nov.-Apr.	$11.46	Basic Service Charge, plus
Billing Cycles	0.0685	per kwh for all kwh
(Winter)		

MINIMUM

$11.46 per month

ADJUSTMENTS

(1) Subject to a purchased power and fuel (PPF) unit cost adjustment of plus or minus .0001¢/kwh for each .0001¢/kwh by which the PPF unit cost to the Company's electric operations exceeds or is less than 1.5135¢/kwh. The method of application is set forth in the filed "Plan for Administration of Adjustment for Purchased Power and Fuel Cost."

(2) Plus the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

(3) Plus or minus a Performance Incentive Adjustment Factor in fractions of dollars per kwh based upon the demonstrated operating performance standards of the Company's share of the Four Corners Generating Station and the Palo Verde Nuclear Generating Station Unit #1, compared to performance standards established by the Arizona Corporation Commission. The method of application is described in the filed "Plan for Administration of Performance Incentive Adjustment."

CONTRACT PERIOD

As provided for in Company's standard Agreement for Service.

TERMS AND CONDITIONS

Subject to Company's Terms and Conditions for the sale of electric service.

ELECTRIC RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: B. Paul Hart
Title: Vice President, Rates and Regulation
Date Original Filing: July 1, 1983
District: All Rate Areas

A.C.C. No. 4200
Cancelling A.C.C. No. 4100
Tariff or Schedule No. E-12
Fifth Revised Sheet No. 1
Effective: February 1, 1985

Filed: January 14, 1985

RESIDENTIAL CAPACITY SERVICE

AVAILABILITY

In all territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

To all residential electric service with an electric central refrigerated air conditioning system where service is initially established after May 1, 1981, or where service is being re-established and where the immediately previous service was billed under Rate Schedule E-10 or E-207. Service is restricted to private dwellings and individually metered apartments where such service is supplied at one premise through one point of delivery and measured through one meter.

Not applicable to temporary, breakdown, standby, supplementary or resale service.

TYPE OF SERVICE

Single phase, 60 Hertz, at one standard voltage (120/240 or 120/208 as may be selected by customers subject to availability at the premises). Three phase service is furnished under the Company's standard rules covering line extensions. Transformation equipment is included in cost of extension. Three phase service is required for motors of an individual rated capacity of 7-1/2 HP or more.

MONTHLY BILL

RATE

May-Oct.	$11.46	Basic Service Charge, plus
Billing Cycles	0.0677	per kwh first 400 kwh
(Summer)	0.0959	per kwh next 400 kwh
	0.1120	per kwh all additional kwh
Nov.-Apr.	$11.46	Basic Service Charge, plus
Billing Cycles	0.0685	per kwh for all kwh
(Winter)		

MINIMUM

$11.46 per month

ADJUSTMENTS

(1) Subject to a purchased power and fuel (PPF) unit cost adjustment of plus or minus .0001¢/kwh for each .0001¢/kwh by which the PPF unit cost to the Company's electric operations exceeds or is less than 1.5135¢/kwh. The method of application is set forth in the filed "Plan for Administration of Adjustment for Purchased Power and Fuel Cost."

(2) Plus the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

(3) Plus or minus a Performance Incentive Adjustment Factor in fractions of dollars per kwh based upon the demonstrated operating performance standards of the Company's share of the Four Corners Generating Station and the Palo Verde Nuclear Generating Station Unit #1, compared to performance standards established by the Arizona Corporation Commission. The method of application is described in the filed "Plan for Administration of Performance Incentive Adjustment."

CONTRACT PERIODS

As provided for in Company's standard Agreement for Service.

TERMS AND CONDITIONS

Subject to Company's Terms and Conditions for the sale of electric service.

ELECTRIC RATES

ARIZONA PUBLIC SERVICE COMPANY	A.C.C. No. 4210
Phoenix, Arizona	Cancelling A.C.C. No. 4110
Filed by: B. Paul Hart	Tariff or Schedule No. ET-1
Title: Vice President, Rates and Regulation	Sixth Revised Sheet No. 1
Date Original Filing: December 10, 1981	Effective: February 1, 1985
District: All Rate Areas	Filed: January 14, 1985

OPTIONAL T.O.U. RESIDENTIAL SERVICE

AVAILABILITY

In all territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served, except that the total number of customers receiving service under this rate schedule shall be limited to 1,000.

APPLICATION

To all electric service required for residential purposes in specified individual private dwellings and in individually metered apartments when such service is supplied at one premise through one point of delivery and measured through one meter.

Rate selection is subject to Sections numbered 3.2 and 3.3 of Schedule No. 1 of the Company's "Terms and Conditions," except that this rate schedule would become effective from the next meter reading after written notice to Company and after Company has installed the required timed kilowatthour meter.1/

Not applicable to temporary, breakdown, standby, supplementary or resale service.

TYPE OF SERVICE

Single phase, 60 Hertz, at one standard voltage (120/240 or 120/208 as may be selected by customers subject to availability at the premises). Three phase service is furnished under the Company's standard rules covering line extensions. Transformation equipment is included in cost of extension. Three phase service is required for motors of an individual rated capacity of 7-1/2 HP or more.

MONTHLY BILL

RATE

May-Oct.	$14.93	Basic Service Charge, plus
Billing Cycles	0.1013	per kwh during On-Peak (9 a.m. - 10 p.m.)
(Summer)	0.0323	per kwh during Off-Peak (10 p.m. - 9 a.m.)
Nov.-Apr.	$14.93	Basic Service Charge, plus
Billing Cycles	0.0903	per kwh during On-Peak (9 a.m. - 10 p.m.)
(Winter)	0.0323	per kwh during Off-Peak (10 p.m. - 9 a.m.)

MINIMUM $14.93 per month

ADJUSTMENTS

(1) Subject to a purchased power and fuel (PPF) unit cost adjustment of plus or minus .0001¢/kwh for each .0001¢/kwh by which the PPF unit cost to the Company's electric operations exceeds or is less than 1.5135¢/kwh. The method of application is set forth in the filed "Plan for Administration of Adjustment for Purchased Power and Fuel Cost."

(2) Plus the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

(3) Plus or minus a Performance Incentive Adjustment Factor in fractions of dollars per kwh based upon the demonstrated operating performance standards of the Company's share of the Four Corners Generating Station and the Palo Verde Nuclear Generating Station Unit #1, compared to performance standards established by the Arizona Corporation Commission. The method of application is described in the filed "Plan for Administration of Performance Incentive Adjustment."

TIME PERIODS

Mountain Standard Time shall be used in the application of this rate schedule. In addition, to prevent radical changes in the system loads the beginning and ending hours for individual customers may be varied by up to one hour (total hours in each time period to remain unchanged) and because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

CONTRACT PERIOD

As provided for in Company's standard Agreement for Service.

TERMS AND CONDITIONS

Subject to Company's Terms and Conditions for the sale of electric service.

1/ The type of meter required is not generally used for residential purposes and therefore their availability is limited. Additionally, it is not known how many meters may be required. Consequently, the Company cannot guarantee installation within any specific time.

ELECTRIC RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: B. Paul Hart
Title: Vice President, Rates and Regulation
Date Original Filing: December 10, 1981
District: All Rate Areas

A.C.C. No. 4209
Cancelling A.C.C. No. 4109
Tariff or Schedule No. ECT-1
Eighth Revised Sheet No. 1
Effective: February 1, 1985

Filed: January 14, 1985

OPTIONAL T.O.U. RESIDENTIAL SERVICE

AVAILABILITY

In all territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served, except that the total number of customers receiving service under this rate schedule shall be limited to 1,000.

APPLICATION

To all electric service required for residential purposes in specified individual private dwellings and in individually metered apartments when such service is supplied at one premise through one point of delivery and measured through one meter.

Rate selection is subject to sections numbered 3.2 and 3.3 of Schedule No. 1 of the Company's "Terms and Conditions," except that this rate schedule would become effective from the next meter reading after written notice to Company and after Company has installed the required timed kilowatt meter.[1/]

Not applicable to temporary, breakdown, standby, supplementary or resale service.

TYPE OF SERVICE

Single phase, 60 Hertz, at one standard voltage (120/240 or 120/208 as may be selected by customers subject to availability at the premises). Three phase service is furnished under the Company's standard rules covering line extensions. Transformation equipment is included in cost of extension. Three phase service is required for motors of an individual rated capacity of 7-1/2 HP or more.

MONTHLY BILL

RATE

May-Oct.	$17.06	Basic Service Charge, plus
Billing Cycles	8.96	per kw Capacity Charge (9 a.m. - 10 p.m.)*, plus
(Summer)	0.0414	per kwh during On-Peak (9 a.m. - 10 p.m.)
	0.0239	per kwh during Off-Peak (10 p.m. - 9 a.m.)
Nov.-Apr.	$17.06	Basic Service Charge, plus
Billing Cycles	6.98	per kw Capacity Charge (9 a.m. - 10 p.m.)*, plus
(Winter)	0.0348	per kwh during On-Peak (9 a.m. - 10 p.m.)
	0.0239	per kwh during Off-Peak (10 p.m. - 9 a.m.)

*The following Off-peak capacity charge will become effective January 1, 1985: In the event that a kw demand is established between the hours of 10 p.m. and 9 a.m. during any period of the year which is greater than the highest kw established between the hours of 9 a.m. and 10 p.m. during the current or 11 preceding months, such greater kw shall be billed at 50% of the charge per kw for the period between 9 a.m. and 10 p.m. for the current month. This charge is at the Company's option. Exercise of this option by Company will require a special meter. Such meter will be installed and option exercised by Company after the Off-peak kwh use for two consecutive months has exceeded 90% of the On-peak kwh use during the current or 11 preceding months.

MINIMUM: $17.06 per month plus Capacity Charge

ADJUSTMENTS:

(1) Subject to a purchased power and fuel (PPF) unit cost adjustment of plus or minus .0001¢/kwh for each .0001¢/kwh by which the PPF unit cost to the Company's electric operations exceeds or is less than 1.5135¢/kwh. The method of application is set forth in the filed "Plan for Administration of Adjustment for Purchased Power and Fuel Cost."

(2) Plus the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

(CONTINUED ON REVERSE SIDE)

(3) Plus or minus a Performance Incentive Adjustment Factor in fractions of dollars per kwh based upon the demonstrated operating performance standards of the Company's share of the Four Corners Generating Station and the Palo Verde Nuclear Generating Station Unit #1, compared to performance standards established by the Arizona Corporation Commission. The method of application is described in the filed "Plan for Administration of Performance Incentive Adjustment."

1/ The type of meter required is not generally used for residential purposes and therefore their availability is limited. Additionally, it is not known how many meters may be required. Consequently, the Company cannot guarantee installation within any specific time.

DETERMINATION OF KW CAPACITY

The average kw supplied during the 60-minute period of maximum use between 9 a.m. and 10 p.m. of the billing month, as determined from readings of the Company's meter. In the event the meter is inaccessible to the meter reader due to locked gates or because of safety limitations, the kw shall be that measured since the last resetting of the kw dial. If the kw dial was not reset, the Customer may request a resetting to zero for a charge of $10 per trip. However, the request from the Customer must be within three (3) days of notification by APS that the meter reader was unable to reset the kw dial. The kw dial will be reset to zero, unless the registered kw at the reset time is greater than the registered kw at the last scheduled reading. The billing kw shall be the kw registered on the kw dial at the next scheduled reading.

TIME PERIODS

Mountain Standard Time shall be used in the application of this rate schedule. In addition, to prevent radical changes in the system loads the beginning and ending hours for individual customers may be varied by up to one hour (total hours in each time period to remain unchanged) and because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

CONTRACT PERIOD

As provided for in Company's standard Agreement for Service.

TERMS AND CONDITIONS

Subject to Company's Terms and Conditions for the sale of electric service.

ELECTRIC RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: B. Paul Hart
Title: Vice President, Rates and Regulation
Date Original Filing: July 1, 1983
District: All Rate Areas

A.C.C. No. 4211
Cancelling A.C.C. No. 4111
Tariff or Schedule No. E-32
Third Revised Sheet No. 1
Effective: February 1, 1985

Filed: January 14, 1985

GENERAL SERVICE

AVAILABILITY

In all of Company's Rate Areas at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

To all electric service required when such service is supplied at one point of delivery and measured through one meter. For those service locations where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes.

Not applicable to temporary, breakdown, standby, supplementary, residential or resale service nor to service for which Rate Schedule E-34 is applicable.

TYPE OF SERVICE

Single or three phase, 60 Hertz, at one standard voltage (12,500; 2400/4160; 480; 277/480; 120/240 or 120/208 volts as may be selected by customers subject to availability at the premises). Three phase service is furnished under Company's standard rules covering line extensions. Transformation equipment is included in cost of extension. Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceed 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

MONTHLY BILL

RATE

$12.50	Basic Service Charge, plus	
1.50	for each kw in excess of 5, plus	
0.0939	per kwh for the first	2,500*kwh
0.0657	per kwh next	42,000 kwh
0.0430	per kwh all additional kwh	

*Add 100 kwh per kw for each kw over 5 kw.

MINIMUM

$12.50 plus $3.36 for each kw in excess of five of the highest kw established during the 12 months ending with the current month, or the minimum kw specified in the Agreement for Service, whichever is the greater.

ADJUSTMENTS

(1) Subject to a purchased power and fuel (PPF) unit cost adjustment of plus or minus .0001¢/kwh for each .0001¢/kwh by which the PPF unit cost to the Company's electric operations exceeds or is less than 1.5135¢/kwh. The method of application is set forth in the filed "Plan for Administration of Adjustment for Purchased Power and Fuel Cost."

(2) Plus the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

(3) Plus or minus a Performance Incentive Adjustment Factor in fractions of dollars per kwh based upon the demonstrated operating performance standards of the Company's share of the Four Corners Generating Station and the Palo Verde Nuclear Generating Station Unit #1, compared to performance standards established by the Arizona Corporation Commission. The method of application is described in the filed "Plan for Administration of Performance Incentive Adjustment."

DETERMINATION OF KW

The greater of:

1. The average kw supplied during the 15-minute period of maximum use during the month, as determined from readings of the Company's meter.

2. 80% of the average of the highest kw measured during each of the 5 summer billing months (June-Oct.) of the 12 months ending with the current month.

(CONTINUED ON REVERSE SIDE)

CONTRACT PERIODS

0 - 1,999 kw:	As provided in Company's standard Agreement for Service.
2,000 kw and above:	Three (3) years, or longer, at Company's option for initial period when construction is required. One (1) year, or longer, at Company's option when construction is not required.

TERMS AND CONDITIONS

Subject to Company's Terms and Conditions for the sale of electric service.

ELECTRIC RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: B. Paul Hart
Title: Vice President, Rates and Regulation
Date Original Filing: July 1, 1983
District: All Rate Areas

A.C.C. No. 4212
Cancelling A.C.C. No. 4112
Tariff or Schedule No. E-34
Third Revised Sheet No. 1
Effective: February 1, 1985

Filed: January 14, 1985

EXTRA LARGE GENERAL SERVICE

AVAILABILITY

In all territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

To customers whose maximum monthly demand is 3,000 kw or more for three (3) consecutive months in any continuous twelve (12) month period ending with the current month. Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by individual customer's contract.

Not applicable to temporary, breakdown, standby, supplementary or resale service.

TYPE OF SERVICE

Three phase, 60 Hertz, at Company's standard voltages that are available within the vicinity of customer's premises.

MONTHLY BILL

RATE

$2,430.00	Basic Service Charge, plus
9.61	per kw, plus
0.0331	per kwh for all kwh

MINIMUM

$2,430.00 plus the kw charge.

ADJUSTMENTS

(1) Subject to a purchased power and fuel (PPF) unit cost adjustment of plus or minus .0001¢/kwh for each .0001¢/kwh by which the PPF unit cost to the Company's electric operations exceeds or is less than 1.5135¢/kwh. The method of application is set forth in the filed "Plan for Administration of Adjustment for Purchased Power and Fuel Cost."

(2) Plus the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

(3) Plus or minus a Performance Incentive Adjustment Factor in fractions of dollars per kwh based upon the demonstrated operating performance standards of the Company's share of the Four Corners Generating Station and the Palo Verde Nuclear Generating Station Unit #1, compared to performance standards established by the Arizona Corporation Commission. The method of application is described in the filed "Plan for Administration of Performance Incentive Adjustment."

DETERMINATION OF KW

The greater of:

1. The average kw supplied during the 15-minute period (or other period as specified by individual customer's contract) of maximum use during the month, as determined from readings of the Company's meter.
2. 80% of the highest kw measured during the five (5) summer billing months (June-October) of the 12 months ending with the current month.
3. The minimum kw specified in the Agreement for Service or individual customer's contract.

CONTRACT PERIODS

For service locations in:

a) Isolated Areas
Ten (10) years, or longer, at Company's option, with standard seven (7) year termination provision.

(CONTINUED ON REVERSE SIDE)

b) Other Areas
Three (3) years, or longer, at Company's option.

TERMS AND CONDITIONS

Subject to Company's Terms and Conditions for the sale of electric service, and/or special terms and conditions at Company's option as provided for in any Contract or Agreement for Service with any customer subject hereto.

ELECTRIC RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: B. Paul Hart
Title: Vice President, Rates and Regulation
Date Original Filing: November 20, 1957
District: Page and Environs

A.C.C. No. 4233
Cancelling A.C.C. No. 4213
Tariff or Schedule No. E-220
Fifteenth Revised Sheet No. 1
Effective: March 1, 1985

Filed: February 1, 1985

GENERAL SERVICE

FROZEN

AVAILABILITY

In the town of Page and environs at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

To all electric service required when such service is supplied at one point of delivery and measured through one meter. Applicable only to those customers being served under this rate schedule on October 1, 1978.

Not applicable to temporary, breakdown, standby, supplementary or resale service.

TYPE OF SERVICE

Single or three phase, 60 Hertz, at one standard voltage (12,500, 2400/4160, 480, 120/240 or 120/208 volts as may be selected by customer subject to availability at the premises). Three phase service is furnished under Company's standard rules covering line extensions. Transformation equipment is included in cost of extension. Three phase service is not furnished for motors of an individual rated capacity of less than 3 HP, except where facilities are already in place. Three phase service is required for motors of an individual rated capacity of 5 HP or more.

MONTHLY BILL

RATE

$11.59	Basic Service Charge, plus		
1.81	for each kw in excess of 5, plus		
0.1080	per kwh for the first	2,500*	kwh
0.0697	per kwh for next	42,000	kwh
0.0564	per kwh all additional kwh		

*Add 115 kwh per kw for the first 195 kw over 5 kw, 78 kwh per kw for all additional kw.

MINIMUM

$11.59 plus $3.60 for each kw in excess of 5 of the highest kw established during the 12 months ending with the current month, or the minimum kw specified in the Agreement for Service, whichever is the greater.

ADJUSTMENTS

(1) Subject to a purchased power and fuel (PPF) unit cost adjustment of plus or minus .0001¢/kwh for each .0001¢/kwh by which the PPF unit cost to the Company's electric operations exceeds or is less than 1.5125¢/kwh. The method of application is set forth in the filed "Plan for Administration of Adjustment for Purchased Power and Fuel Cost."

(2) Plus the applicable proportionate part of any taxes, or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

(3) Plus or minus a Performance Incentive Adjustment Factor in fractions of dollars per kwh based upon the demonstrated operating performance standards of the Company's share of the Four Corners Generating Station and the Palo Verde Nuclear Generating Station Unit #1, compared to performance standards established by the Arizona Corporation Commission. The method of application is described in the filed "Plan for Administration of Performance Incentive Adjustment."

SPECIAL PROVISION

This rate schedule shall be increased by 10% on March 1 of each year in addition to other general increases/decreases granted by the Arizona Corporation Commission until such time as it is void of customers.

DETERMINATION OF KW

The greater of:

1. The average kw supplied during the 15-minute period of maximum use during the month, as determined from readings of the Company's meter.
2. 80% of the highest kw measured during the 5 summer billing months (June-Oct.) of the 12 months ending with the current month.

(CONTINUED ON REVERSE SIDE)

CONTRACT PERIOD

0 - 1,999 kw: As provided in Company's standard Agreement for Service
2000 kw and above: Three (3) years, or longer, at Company's option for initial period when construction is required. One (1) year, or longer, at Company's option when construction is not required.

TERMS AND CONDITIONS

Subject to Company's Terms and Conditions for the sale of electric service.

ELECTRIC RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: B. Paul Hart
Title: Vice President, Rates and Regulation
Date Original Filing: July 18, 1935
District: Company's Rate Areas 1, 2 and 4
As Specified Under Availability

A.C.C. No. 4219
Cancelling A.C.C. No. 4121
Tariff or Schedule No. E-38
Thirty-fifth Revised Sheet No. 1
Effective: February 1, 1985

Filed: January 14, 1985

IRRIGATION POWER SERVICE

AVAILABILITY

In Company's Rate Areas 1 and 2, except for those areas in LaPaz County where total supply of power is purchased, and in Area 4 limited to Pinal County, and Yuma and its environs, at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

To electric service required for irrigation pumping when such service is supplied at one point of delivery and measured through one meter.

Not applicable to pumping of water for sale or distribution for non-agricultural purposes for delivery points initially served by Company after November 1, 1983.

Not applicable to temporary, breakdown, standby, supplementary, or resale service.

TYPE OF SERVICE

Three phase, 60 Hertz, at one standard voltage (12,500, 2400, 480 or 240 volts as may be selected by customer subject to availability at the premises). Measurement of service is at secondary voltage.

MONTHLY BILL

RATE

May.-Oct.	$12.50	Basic Service Charge, plus
Billing Cycles	0.39	for each kw, plus
(Summer)	0.0641	per kwh first 275 kwh per kw
	0.0536	per kwh all additional kwh
Nov.-Apr.	$12.50	Basic Service Charge, plus
Billing Cycles	0.39	for each kw, plus
(Winter)	0.0536	per kwh for all kwh

When customer owns the transformers and structures, a discount will be allowed on the first 275 kwh per kw as follows: $0.0027 per kwh on the first 55,000 kwh and $0.0009 per kwh on all additional kwh.

MINIMUM

$12.50 plus $2.33 for each kw of the highest kw established during the 12 months ending with the current month, or the minimum kw specified in the Agreement for Service, whichever is the greater, but not more than an amount sufficient to make the total charges for such 12 months equal to $27.96 for each of such highest kw, plus $150.00 but in no event less than $303.12.

ADJUSTMENTS

(1) Subject to a purchased power and fuel (PPF) unit cost adjustment of plus or minus .0001¢/kwh for each .0001¢/kwh by which the PPF unit cost to the Company's electric operations exceeds or is less than 1.5135¢/kwh. The method of application is set forth in the filed "Plan for Administration of Adjustment for Purchased Power and Fuel Cost."

(2) Plus the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

(3) Plus or minus a Performance Incentive Adjustment Factor in fractions of dollars per kwh based upon the demonstrated operating performance standards of the Company's share of the Four Corners Generating Station and the Palo Verde Nuclear Generating Station Unit #1, compared to performance standards established by the Arizona Corporation Commission. The method of application is described in the filed "Plan for Administration of Performance Incentive Adjustment."

DETERMINATION OF KW

The average kw supplied during the 15-minute period of maximum use during the month, as determined from readings from the Company's meter, or at Company's option, by test.

CONTRACT PERIOD

Three (3) years, or longer, at Company's option for initial period when construction is required. One (1) year, or longer, at Company's option when construction is not required.

TERMS AND CONDITIONS

Subject to Company's Terms and Conditions for the sale of electric service.

ELECTRIC RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: B. Paul Hart
Title: Vice President, Rates and Regulation
Date Original Filing: December 26, 1952
District: All Rate Areas
As Specified Under Availability

A.C.C. No. 4226
Cancelling A.C.C. No. 4131
Tariff or Schedule No. E-221
Twenty-fifth Revised Sheet No. 1
Effective: February 1, 1985

Filed: January 14, 1985

WATER PUMPING POWER SERVICE

AVAILABILITY

In all of Company's Rate Areas, except for those areas in LaPaz and Yuma Counties where the total supply of power is purchased, at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

To electric service required for irrigation pumping, and to electric service required by water utilities for pumping water to serve the citizens of a city, town, or unincorporated community. Service must be supplied at one point of delivery and measured through one meter.

Not applicable to temporary, breakdown, standby, supplementary or resale service.

TYPE OF SERVICE

Single or three phase, 60 Hertz, at one standard voltage (12,500; 2,400; 480; or 240 volts as may be selected by customer subject to availability at the premises). Measurement of service is at secondary voltage.

MONTHLY BILL

RATE	$12.50	Basic Service Charge, plus
	1.51	for each kw, plus
	0.0919	per kwh first 240 kwh
	0.0640	per kwh next 275 kwh per kw
	0.0534	per kwh all additional kwh

MINIMUM

$12.50 plus $3.34 for each kw of the highest kw established during the 12 months ending with the current month, or the minimum kw specified in the Agreement for Service, whichever is greater, but not more than an amount sufficient to make the total charges for such 12 months equal to $40.08 for each of such highest kw plus $150.00.

ADJUSTMENTS

(1) Subject to a purchased power and fuel (PPF) unit cost adjustment of plus or minus .0001¢/kwh for each .0001¢/kwh by which the PPF unit cost to the Company's electric operations exceeds or is less than 1.5135¢/kwh. The method of application is set forth in the filed "Plan for Administration of Adjustment for Purchased Power and Fuel Cost."

(2) Plus the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

(3) Plus or minus a Performance Incentive Adjustment Factor in fractions of dollars per kwh based upon the demonstrated operating performance standards of the Company's share of the Four Corners Generating Station and the Palo Verde Nuclear Generating Station Unit #1, compared to performance standards established by the Arizona Corporation Commission. The method of application is described in the filed "Plan for Administration of Performance Incentive Adjustment."

DETERMINATION OF KW

The average kw supplied during the 15-minute period of maximum use during the month, as determined from readings of the Company's meter, or at Company's option, by test.

CONTRACT PERIOD

Three (3) years, or longer, at Company's option for initial period when construction is required. One (1) year, or longer, at Company's option when construction is not required.

TERMS AND CONDITIONS

Subject to Company's Terms and Conditions for the sale of electric service.

ELECTRIC RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: B. Paul Hart
Title: Vice President, Rates and Regulation
Date Original Filing: May 1, 1951
District: Company's Rate Area 3

A.C.C. No. 4230
Cancelling A.C.C. No. 4129
Tariff or Schedule No. E-58WM
Thirtieth Revised Sheet No. 1
Effective: February 1, 1985

Filed: January 14, 1985

STREET LIGHTING SERVICE

AVAILABILITY

In those portions of cities, towns and unincorporated communities in which Company does a general retail electric business and where Company has installed a multiple or series street lighting system of adequate capacity for the service to be rendered.

APPLICATION

To service for lighting public streets, alleys, thoroughfares, public parks and playgrounds by use of Company's facilities where such service for the whole area is contracted for from Company by the city, town, other governmental entities, or a responsible person for unincorporated communities.

Service is from dusk to dawn and Company will own (except as provided below), operate, and maintain the street lighting system including lamps and glass replacements.

Incandescent Lamp, Standards and Underground Circuits Charges (Part II, A, B, & C of this rate schedule) are applicable and available only to those customers being served and those installations in service on October 1, 1978.

MONTHLY BILL

RATE

I. Non-Incandescent Lighting

A. Lamp, Luminaire & Bracket Charge (Lumens and wattages are nominal initial ratings)

Lumens	Watts / Type	Investment Cost Provided By: Company	Investment Cost Provided By: Others
5,800 lumens,	70 watts, hi-pressure sodium	$ 8.84	$2.85
7,000 lumens,	175 watts, mercury vapor	7.79	4.46
9,500 lumens,	100 watts, hi-pressure sodium	9.69	3.45
11,000 lumens,	250 watts, mercury vapor	10.11	5.96
16,000 lumens,	150 watts, hi-pressure sodium	11.09	4.39
20,000 lumens,	400 watts, mercury vapor	15.90	8.66
30,000 lumens,	250 watts, hi-pressure sodium	14.35	6.65
32,000 lumens,	400 watts, metal halide	16.59	9.57
50,000 lumens,	400 watts, hi-pressure sodium	15.44	9.24

B. Pole Charge

Type	Description	Investment Cost Provided By: Company	Investment Cost Provided By: Others
1.	An existing distribution pole suitable for street light use.	$0.68	$0.68
2.	A wood pole for street lighting only for light center mounting heights of 35 feet or less.	$5.54	$0.68
3.	A metal pole for light center mounting heights of 28 feet or less.	$6.06	$0.68
4.	A metal pole for light center mounting heights between 29 feet and 40 feet.	$7.59	$0.68
5.	An anchor base used with Pole Types 3 or 4.	$4.36	$0.68

C. Monthly Charges as Required Under "Special Provisions."

II. Incandescent Lighting

A. Lamps:

1,000 lumen incandescent	$3.02
2,500 lumen incandescent	5.04
4,000 lumen incandescent	6.96
6,000 lumen incandescent	9.53
10,000 lumen incandescent	15.52

FROZEN

(Continued on Reverse Side)

B. Standards: (See "Special Provisions")

FROZEN

	Investment Cost Provided By Company	Investment Cost Provided By Others
Type A	$13.71	$5.98
Type B	10.30	5.02
Type C	5.98	3.41
Type D	4.30	2.87
Type E	4.41	2.73
Type F	3.26	----
Type M	8.57	4.73
Type N	6.45	----

C. Underground Circuits

Per foot of cable, installed under paving	$0.0937	$0.000
Per foot of cable, not installed under paving	0.0334	0.000

MINIMUM $53.87

ADJUSTMENTS

(1) Subject to a purchased power and fuel (PPF) unit cost adjustment of plus or minus .0001¢/kwh for each .0001¢/kwh by which the PPF unit cost to the Company's electric operations exceeds or is less than 1.5135¢/kwh. The method of application is set forth in the filed "Plan for Administration of Adjustment for Purchased Power and Fuel Cost."

(2) Plus the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

(3) Plus or minus a Performance Incentive Adjustment Factor in fractions of dollars per kwh based upon the demonstrated operating performance standards of the Company's share of the Four Corners Generating Station and the Palo Verde Nuclear Generating Station Unit #1, compared to performance standards established by the Arizona Corporation Commission. The method of application is described in the filed "Plan for Administration of Performance Incentive Adjustment."

SPECIAL PROVISIONS

Facilities and Service

Street lighting facilities installed under this rate are of the type currently being furnished by Company as standard at the time service is initially requested. Company will maintain current street lighting construction standards and endeavor to keep abreast of all modern methods and practices.

The Company will use diligence in maintaining service. Monthly bills will not be reduced on account of lamp outages.

Presently installed units which do not conform to the above type will be billed in accordance with the type which is most nearly like such units.

Special Facilities

When Customer requests special (non-standard) street lighting facilities not provided by Company as standard, Company will use its best efforts to install, operate and maintain such facilities.

If the Company installs such special facilities, there will be an additional charge equal to 1-1/2 percent per month of the excess cost to the Company over standard facilities at time of installation and the maintenance of such facilities will be subject to time and ability to purchase replacement parts at reasonably equivalent prices of standard equipment. When the Company is currently using more than one standard for a particular type of installation, the excess cost to the Company shall be determined from the standard equipment with the highest cost within the range of standards for that particular type of installation.

The Customer may elect to substitute a one-time contribution in aid of construction equal to the excess costs in lieu of the additional charge.

The Company may decline to continue maintenance of special facilities due to inability to purchase replacement parts at reasonably equivalent prices of standard equipment. In this event, the Customer may elect to supply the required parts at no cost to the Company and the Company will then continue to maintain such facilities.

Extension of Street Lighting System

The Company will extend its standard street lighting system up to a distance of 300 feet for each additional lighting installation at the request of the customer. When the extension is underground, the Customer will provide the trench and backfill or conduit space. The Company will provide the trench and backfill or conduit space at Customer's request for an additional monthly charge of 1-1/2 percent of its cost or at option of Customer, a contribution in aid of construction equal to the cost of trench and backfill or conduit space.

(Continued on Page 3)

Additions to the street lighting system which are over 300 feet per installation or are of a non-standard nature not normally provided by the Company can be installed when the total cost to the Company of the installation does not exceed 6-1/2 times the annual revenue including the underground and/or special facilities charge. When the total cost to the Company of the installation does exceed 6-1/2 times the annual revenue, a monthly charge of 1-1/2 percent of the excess cost will be added to the billing in addition to any required special facilities charge and/or underground charge. Customer may elect to pay a contribution in aid of construction equal to such excess cost in lieu of the monthly charge of 1-1/2 percent.

Extensions to isolated areas requiring a substantial extension of the electric distribution system, as opposed to extension of the street lighting system, will require a special study to determine the conditions on which the Company will make such extension.

Investment Cost Provided By - Others

If the Customer elects to be billed under the column headed "Investment Cost Provided By - Others," it must install the system at its own expense in accordance with the Company's specifications, or make a non-refundable advance to cover the Company's cost of installing the system. The Company will maintain and operate the system.

The Company's Incandescent Street Light Standards Are As Follows:

Type A - Enclosed glass luminaire with 8-foot or less up-sweep bracket mounted on 35-foot anchor base monotube or fluted steel pole.

Type B - Enclosed glass luminaire with 8-foot or less up-sweep bracket mounted on 35-foot embedded base metal pole.*

Type C - Enclosed glass luminaire with 14-foot or less bracket mounted on wood pole carrying only street lighting equipment.

Type D - Enclosed glass luminaire with 14-foot or less bracket mounted on wood pole carrying distribution circuits, or on other type pole paid for under another standard charge.

Type E - Open type unit with 4-foot bracket mounted on wood pole carrying only street lighting equipment.

Type F - Open type unit with 4-foot bracket mounted on wood pole carrying distribution circuits.

Type M - Enclosed glass luminaire with 6-foot or less up-sweep bracket mounted on 30-foot embedded base metal pole.*

Type N - Identical to Type M except customer makes a contribution of $50 per light.

CONTRACT PERIOD

Ten (10) years or more, at option of Company.

TERMS AND CONDITIONS

Subject to Company's Terms and Conditions for the sale of electric service.

*Steel pipe or tubular steel at Company's option.

ELECTRIC RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: B. Paul Hart
Title: Vice President, Rates and Regulation
Date Original Filing: February 21, 1952
District: Company's Rate Areas
1, 2 & 4

A.C.C. No. 4229
Cancelling A.C.C. No. 4128
Tariff or Schedule No. E-58
Twenty-eighth Revised Sheet No. 1
Effective: February 1, 1985

Filed: January 14, 1985

STREET LIGHTING SERVICE

AVAILABILITY

In those portions of cities, towns and unincorporated communities in which Company does a general retail electric business and where Company has installed a multiple or series street lighting system of adequate capacity for the service to be rendered.

APPLICATION

To service for lighting public streets, alleys, thoroughfares, public parks and playgrounds by use of Company's facilities where such service for the whole area is contracted for from Company by the city, town, other governmental entities, or a responsible person for unincorporated communities.

Service is from dusk to dawn and Company will own (except as provided below), operate, and maintain the street lighting system including lamps and glass replacements.

The Incandescent Lamp, Standards and Underground Circuits Charges (Part II, A, B & C of this rate schedule) are applicable and available only to those customers being served and those installations in service on October 1, 1978.

MONTHLY BILL

RATE

I. Non-Incandescent Lighting

A. Lamp, Luminaire & Bracket Charge (Lumens and wattages are nominal initial ratings)

	Investment Cost Provided By Company	Investment Cost Provided By Others
5,800 lumens, 70 watts, hi-pressure sodium	$ 8.84	$2.85
7,000 lumens, 175 watts, mercury vapor	7.79	4.46
9,500 lumens, 100 watts, hi-pressure sodium	9.69	3.45
11,000 lumens, 250 watts, mercury vapor	10.11	5.96
16,000 lumens, 150 watts, hi-pressure sodium	11.09	4.39
20,000 lumens, 400 watts, mercury vapor	15.90	8.66
30,000 lumens, 250 watts, hi-pressure sodium	14.35	6.65
32,000 lumens, 400 watts, metal halide	16.59	9.57
50,000 lumens, 400 watts, hi-pressure sodium	15.44	9.24

B. Pole Charge

Type	Description	Investment Cost Provided By Company	Investment Cost Provided By Others
1.	An existing distribution pole suitable for street light use.	$ 0.68	$0.68
2.	A wood pole for street lighting only for light center mounting heights of 35 feet or less.	$ 5.54	$ 0.68
3.	A metal pole for light center mounting heights of 28 feet or less.	$ 6.06	$ 0.68
4.	A metal pole for light center mounting heights between 29 feet and 40 feet.	$ 7.59	$ 0.68
5.	An anchor base used with Pole Types 3 or 4.	$ 4.36	$ 0.68

C. Monthly Charges as Required Under "Special Provisions."

(Continu· on Reverse Side)

II. Incandescent Lighting

A. Lamps

2,500 lumen incandescent	$4.44
4,000 " "	6.25
6,000 " "	8.40
10,000 " "	13.49

B. Standards
(See "Special Provisions")

FROZEN

	Investment Cost Provided By Company	Others
Type A	$13.10	$4.88
Type B	9.50	4.00
Type C	5.34	2.75
Type D	3.65	2.27
Type E	4.88	2.27
Type F	3.06	---
Type M	7.64	3.81
Type N	5.34	---
Type P	9.88	6.09

C. Underground Circuits

Per foot of cable, installed under paving	$0.0937	$0.000
Per foot of cable, not installed under paving	$0.0334	0.000

MINIMUM $53.87

ADJUSTMENTS (1) Subject to a purchased power and fuel (PPF) unit cost adjustment of plus or minus .0001¢/kwh for each .0001¢/kwh by which the PPF unit cost to the Company's electric operations exceeds or is less than 1.5135¢/kwh. The method of application is set forth in the filed "Plan for Administration of Adjustment for Purchased Power and Fuel Cost."

(2) Plus the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

(3) Plus or minus a Performance Incentive Adjustment Factor in fractions of dollars per kwh based upon the demonstrated operating performance standards of the Company's share of the Four Corners Generating Station and the Palo Verde Nuclear Generating Station Unit #1, compared to performance standards established by the Arizona Corporation Commission. The method of application is described in the filed "Plan for Administration of Performance Incentive Adjustment."

SPECIAL PROVISIONS

Facilities and Service

Street lighting facilities installed under this rate are of the type currently being furnished by Company as standard at the time service is initially requested. Company will maintain current street lighting construction standards and endeavor to keep abreast of all modern methods and practices.

The Company will use diligence in maintaining service. Monthly bills will not be reduced on account of lamp outages.

Presently installed units which do not conform to the above types will be billed in accordance with the type which is most nearly like such units.

Special Facilities

When Customer requests special (non-standard) street lighting facilities not provided by Company as standard, Company will use its best efforts to install, operate and maintain such facilities.

If the Company installs such special facilities, there will be an additional charge equal to 1-1/2 percent per month of the excess cost to the Company over standard facilities at time of installation and the maintenance of such facilities will be subject to time and ability to purchase replacement parts at reasonably equivalent prices of standard equipment. When the Company is currently using more than one standard for a particular type of installation, the excess cost to the Company shall be determined from the standard equipment with the highest cost within the range of standards for that particular type of installation.

The Customer may elect to substitute a one-time contribution in aid of construction equal to the excess costs in lieu of the additional charge.

The Company may decline to continue maintenance of special facilities due to inability to purchase replacement parts at reasonably equivalent prices of standard equipment. In this event, the Customer may elect to supply the required parts at no cost to the Company and the Company will then continue to maintain such facilities.

(Continued on Page 3)

Extension of Street Lighting System

The Company will extend its standard street lighting system up to a distance of 300 feet for each additional lighting installation at the request of the customer. When the extension is underground the Customer will provide the trench and backfill or conduit space. The Company will provide the trench and backfill or conduit space at Customer's request for an additional monthly charge of 1-1/2 percent of its cost, or at option of Customer, a contribution in aid of construction equal to the cost of trench and backfill or conduit space.

Additions to the street lighting system which are over 300 feet per installation or are of a non-standard nature not normally provided by the Company can be installed when the total cost to the Company of the installation does not exceed 6-1/2 times the annual revenue including the underground and/or special facilities charge. When the total cost to the Company of the installation does exceed 6-1/2 times the annual revenue, a monthly charge of 1-1/2 percent of the excess cost will be added to the billing in addition to any required special facilities charge and/or underground charge. Customer may elect to pay a contribution in aid of construction equal to such excess cost in lieu of the monthly charge of 1-1/2 percent.

Extensions to isolated areas requiring a substantial extension of the electric distribution system, as opposed to extension of the street lighting system, will require a special study to determine the conditions on which the Company will make such extension.

Investment Cost Provided By - Others

If the Customer elects to be billed under the column headed "Investment Cost Provided By - Others", it must install the system at its own expense in accordance with the Company's specifications, or make a non-refundable advance to cover the Company's cost of installing the system. The Company will maintain and operate the system.

The Company's Incandescent Street Light Standards Are As Follows:

Type A - Enclosed glass luminaire with 8-foot or less up-sweep bracket mounted on 35-foot anchor base monotube or fluted steel pole.

Type B - Enclosed glass luminaire with 8-foot or less up-sweep bracket mounted on 35-foot embedded base metal pole.*

Type C - Enclosed glass luminaire with 14-foot or less bracket mounted on wood pole carrying only street lighting equipment.

Type D - Enclosed glass luminaire with 14-foot or less bracket mounted on wood pole carrying distribution circuits, or on other type pole paid for under another standard charge.

Type E - Open type unit with 4-foot bracket mounted on wood pole carrying only street lighting equipment.

Type F - Open type unit with 4-foot bracket mounted on wood pole carrying distribution circuits.

Type H - Enclosed glass luminaire with 6-foot or less up-sweep bracket mounted on 30-foot embedded base metal pole.*

Type N - Identical to Type H except customer makes a contribution of $50 per light.

Type P - Incandescent pole top luminaire mounted on 23-foot steel pipe pole.

CONTRACT PERIOD

Ten (10) years or more, at option of Company.

TERMS AND CONDITIONS

Subject to Company's Terms and Conditions for the sale of electric service.

*Steel pipe or tubular steel at Company's option.

ELECTRIC RATES

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: B. Paul Hart
Title: Vice President, Rates and Regulation
Date Original Filing: February 19, 1946
District: Company's Rate Areas 1 and 2 except Phoenix

A.C.C. No. 4234
Cancelling A.C.C. No. 4224
Tariff or Schedule No. E-57
Twenty-fifth Revised Sheet No. 1
Effective: March 1, 1985

Filed: February 1, 1985

SERVICE TO WATER UTILITIES FOR WATER PUMPING

FROZEN

AVAILABILITY

In Company's Rate Areas 1 and 2, except Phoenix, at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

To electric service required by water utilities for pumping water to serve the citizens of a city, town or unincorporated community and for fire protection when such service is supplied at one point of delivery and measured through one meter. Not applicable to temporary, breakdown, standby, supplementary or resale service nor to supplement a gravity water supply. All domestic water used within such city, town or unincorporated community must be pumped as it is the intention that the Company shall supply the full energy requirements of the water utility for water service. Applicable only to customers' delivery points being served by Company on May 1, 1972.

MONTHLY BILL

RATE

$15.02	Basic Service Charge, plus
1.81	for each kw, plus
0.0831	per kwh

MINIMUM $15.02 plus $1.82 for each kw

ADJUSTMENTS

(1) Subject to a purchased power and fuel (PPF) unit cost adjustment of plus or minus .0001¢/kwh for each .0001¢/kwh by which the PPF unit cost to the Company's electric operations exceeds or is less than 1.5135¢/kwh. The method of application is set forth in the filed "Plan for Administration of Adjustment for Purchased Power and Fuel Cost."

(2) Plus the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

(3) Plus or minus a Performance Incentive Adjustment Factor in fractions of dollars per kwh based upon the demonstrated operating performance standards of the Company's share of the Four Corners Generating Station and the Palo Verde Nuclear Generating Station Unit #1, compared to performance standards established by the Arizona Corporation Commission. The method of application is described in the filed "Plan for Administration of Performance Incentive Adjustment."

SPECIAL PROVISION

This rate schedule shall be increased by 10% on March 1 of each year in addition to other general increases/decreases granted by the Arizona Corporation Commission until such time as it is void of customers.

DETERMINATION OF KW

The greater of:

1. The average kw supplied during the 15-minute period of maximum use during the month, as determined from readings of the Company's meter, or the connected load, at the option of the Company.
2. 80% of the highest kw measured during the five summer billing months (June - Oct.) of the 12 months ending with the current month.

CONTRACT PERIOD

One (1) year, or longer, at Company's option.

TERMS AND CONDITIONS

Subject to Company's Terms and Conditions for the sale of electric service.

8604160038

UPDATED INFORMATION REQUESTED BY
THE NRC FOR ANTITRUST REVIEW

PUBLIC SERVICE COMPANY OF
NEW MEXICO

UPDATED REGULATORY GUIDE 9.3

LIST OF ABBREVIATIONS COMMONLY USED IN THIS RESPONSE

Arizona Public Service Company	APS
City of Farmington, New Mexico	Farmington
City of Gallup, New Mexico	Gallup
El Paso Electric Company	EPE
Federal Energy Regulatory Commission	FERC
Incorporated County of Los Alamos, New Mexico	LAC
New Mexico Public Service Commission	NMPSC
Palo Verde Nuclear Generating Station	PVNGS
Plains Electric Generation and Transmission Cooperative, Inc.	PGT
Public Service Company of New Mexico	PNM
Salt River Project Agricultural Improvement and Power District	SRP
San Diego Gas & Electric Company	SDG&E
San Juan Generating Station	San Juan
Southwestern Public Service Company	SPS
Texas-New Mexico Power Company	TNP
Tucson Electric Power Company	TEP
United States Bureau of Reclamation	USBR
Western Area Power Administration	WAPA

EXPLANATORY NOTES

1. The responses herein reflect PNM's understanding that discussion of transactions or interrelationships solely between PNM and other PVNGS participants and solely between PNM and federal agencies is to be excluded.

2. The responses herein are current as of March 14, 1986, unless otherwise noted.

Item 1a

Anticipated excess or shortage in generating capacity resources not expected at the construction permit stage. Reasons for the excess or shortage along with data on how the excess will be allocated, distributed, or otherwise utilized or how the shortage will be obtained.

Response

The following table shows PNM's installed resources and load forecast projections for the year 1988. Although the forecast for 1988 was not included in the 1979 PVNGS antitrust submittal (which included projections only through 1986), a forecast for 1988 did exist in 1979. The reason for the use of the 1988 date below is that by that date PVNGS Units 1, 2, and 3 are projected to be in commercial operation.

	1988
Installed Resources (MW) 1979 Forecast	2405
Installed Resources (MW) 1985 Forecast	1696
Load Forecast (MW) 1979	1839
Load Forecast (MW) 1985	987

The reasons for changes since the 1979 submittal are the following:

1. Rescheduling of the commercial operation dates of PVNGS Units 1, 2 & 3 to 01/86, 09/86, and 09/87 respectively.

2. Decision to delay proposed New Mexico Station and subsequent decision not to proceed with New Mexico Station as a PNM utility project. See discussion in Item 1g.

3. Cancellation of the Baca Geothermal Project, in 1982, which was to have provided approximately 50 MW by the mid-1980s.

4. Postponement of the Pumped Storage Project until the late 1990's. The Project was to provide approximately 600 MW in the late-1980's.

5. Decommissioning of five (5) units (Prager 1, 8 and 9, and Santa Fe 1 and 2) resulting in a 33 MW decrease in resources.

6. The PGT 15 MW Contingent Sale Agreement will now end in April 1987 rather than May 1989.

7. Block energy marketing targets start at 50 MW in 1988 and rise to 250 MW in the mid-1990's.*

8. Sale of 28.8 percent (approximately 136 MW) of San Juan Unit 4 to M-S-R** effective 1984 and repurchase of 100 MW from M-S-R between January 1, 1984 and April 30, 1995. This capacity repurchase increases to 105 in 1986 due to uprating of San Juan Unit 4.

9. Sale of 200 MW per hour of energy to SPS from January 1985 to December 31, 1989.*

10. Sale of 7.2 percent (approximately 36 MW) of San Juan Unit 4 to LAC effective July 1, 1985.

11. SDG&E purchase, in May 1982, of 236 MW of San Juan Unit 4 capacity contingent on commercial operation dates for PVNGS Units 1, 2, and 3 of 5/83, 5/85 and 5/87, respectively. Since PVNGS units have been delayed, SDG&E contract demand schedule is 106 MW between 2/86 and 9/86, 236 MW between 9/86 and 4/87, 106 MW between 5/87 and 9/87, and 236 MW between 10/87 and 4/88.

12. SDG&E purchase of 100 MW of system power between 5/88 and 4/01, with an option of another 100 MW.

13. Sale to Farmington of 8.475 percent (approximately 42 MW) of San Juan Unit 4 on November 17, 1981 and the purchase by PNM of 20 MW of Farmington's ownership in 1982 for one year.

*Energy sales are not reflected in load forecast number.
**M-S-R Public Power Agency--a joint exercise of powers agency organized under California law, comprising the electric utility systems of Modesto Irrigation District and the Cities of Santa Clara and Redding, California.

Item 1b

New power pools or coordinating groups or changes in structure, activities, policies, practices, or membership of power pools or coordinating groups in which the licensee was, is, or will be a participant.

1. Proposed Western Systems Power Pool

   Since early 1984, utilities in the far western states (Western Systems Coordinating Council area) have been exploring the feasibility of broader power pooling for increasing economics of power production and reliability of service above that already being accomplished. Utilities in the states of Arizona, California, New Mexico, and Nevada, in particular, have expressed interest to proceed with broader power pooling initially on an experimental basis, to the extent of prescheduled economy type transactions, such as economy interchange, unit commitment, capacity and energy sales and exchanges. To that end, a Letter of Intent and Agreement was executed in mid-October 1985 by the following participants: Bonneville Power Administration (BPA), State of California Department of Water Resources, SDG&E, Arizona Electric Power Cooperative, Inc. (AEPCO), Southern California Edison Co. (SCE), SRP, Northern California Power Agency (NCPA), APS, and PNM. Currently, the participants are proceeding to draft a definitive contract for implementing and operating the Western Systems Power Pool.

2. Inland Power Pool (IPP)

   The IPP Agreement was executed on May 6, 1974, with the initial membership comprising the following: Colorado-Ute Electric Association (CUEA), Platte River Power Authority (PRPA), Public Service Company of Colorado (PSCC), SRP, Tri-State Generation and Transmission Association, Inc. (TSGT), and USBR. The purpose of the Agreement was to plan for a greater installed reserve margin, to reduce operating reserve capacity, to provide for meeting emergency conditions with less likelihood of curtailment of service, and to strengthen the participants' ability to exchange power and energy with other members. Subsequently, several other utilities applied and were accepted for membership in IPP. They are as follows: City of Colorado Springs (CCS), Basin Electric Power Cooperative (BEPC), TEP, PNM, Wyoming Municipal Power Agency (WMP), Farmington, Arizona Electric Power Cooperative, Inc. (AEPCO), Deseret Generation & Transmission Cooperative (DGT), Western Area Power Administration - Boulder City Area (WAPA-BCA), APS, PGT, and EPE. In September 1979, the participants agreed to revise the Agreement to provide for an executive committee and a planning committee, to strengthen requirements for membership, and to incorporate three service schedules (economy energy, transmission service and pool coordinator services). After approximately four years of negotiations, the Revised IPP Agreement was signed and made effective on November 11, 1983 by the following participants: AEPCO, APS, BEPC, CCS, Farmington, CUEA, DGT, EPE, PGT, PRPA, PSC, PNM, SRP, TSGT, TEP, WAPA-Loveland-Fort Collins Area, WAPA-Salt Lake City Area, WAPA-Boulder City Area. Both LAC and TNP have applied and have become members in the Revised IPP.

3. Southwest Bulk Power Market Experiment

In January 1984, APS, Farmington, EPE, SRP, PNM, SPS, and TNP entered into the Southwest Bulk Power Market Experiment, sanctioned by the FERC, which was to be in effect for one year with an automatic 12-month renewal unless terminated by the majority of participants. The purpose of the Experiment was to provide for the interchange of power among the electric systems of the participants in an experiment designed to develop empirical data which would allow the FERC and other regulatory commissions to consider and justify changing regulations regarding certain wholesale power interchanges between electric utilities. The Experiment terminated in December 1985. A report on the first year of the Experiment has been published by Rand, Inc., under contract with FERC.

Item 1c

Changes in transmission with respect to:

1. The nuclear plant
2. Interconnections, or
3. Connections to wholesale customers

Response

1. The Nuclear Plant:

   See Item 1c of Section 1.

2. Interconnections:

   Major PNM-related interconnections not contemplated in late 1979 are:

   a. Interconnection completed with SPS at Blackwater DC Converter Station near Clovis, New Mexico, on December 31, 1984.

   b. Interconnection completed with LAC effective July 1, 1985, utilizing the existing transmission system.

3. Connections to Wholesale Customers

   New connections to wholesale customers not contemplated in late 1979 are:

   a. Navajo Indian Irrigation Project. This project, located in northwestern New Mexico, is served between the point of interconnection of PNM's Four Corners 230 kV bus and the Gallegos Substation 115 kV bus.

   b. City of Farmington, New Mexico. To serve additional load, Farmington was allowed to tap the PNM owned UW line at the Glade tap point, north of Farmington, with the concurrence of PNM and Colorado Ute Electric Association (CUEA).

   c. Incorporated County of Los Alamos. LAC proposes to add a 115 kV ring bus between the existing ETA and TA-3 ring bus that now services Los Alamos County. The ring bus will be fed from PNM's proposed Ojo Line Extension Project (OLE) and will provide a second source to serve the Los Alamos area. LAC is also a participant in the OLE project.

Item 1d

Changes in the ownership or contractual allocation of the output of the nuclear facility. Reasons and basis for such changes should be included.

Response

Sale/Leaseback of 72 Percent of PNM's Interest in PVNGS Unit 1

On December 31, 1985, PNM consummated three sale and leaseback transactions relating to a total of approximately 72 percent of its 10.2 percent undivided interest in PVNGS Unit 1 and related portions of PNM's undivided interest in certain PVNGS common facilities and real property interests (the interests sold and leased back in each transaction being hereinafter referred to as an "Interest" and collectively as the "Interests").

Prior to consummating these transactions, PNM obtained necessary regulatory approvals from the NMPSC, the FERC, the Nuclear Regulatory Commission (NRC), and the Securities and Exchange Commission (SEC). For detailed information regarding the Unit 1 sale/leaseback transactions, see the Application in Respect of a Sale and Leaseback Financing Transaction by PNM, dated October 18, 1985, filed with the NRC, in the Matter of Arizona Public Service Company, et al. (Palo Verde Nuclear Generating Station, Unit 1), Docket No. STN-50-528, and subsequent filings and NRC actions in such proceedings. Briefly, the transactions may be summarized as follows.

The Interests were sold by PNM to The First National Bank of Boston, as Owner Trustee under separate owner trust agreements with three institutional equity investors (the "Equity Investors"). The Owner Trustees (in such capacity, the "Lessors") leased their respective Interests to PNM under three separate lease agreements (the "Leases"), each having an initial term expiring January 15, 2015.

The total purchase price for the Interests was based on an independent appraisal and was paid by the Lessors in full at closing. Approximately 23 percent of the purchase price was provided to the Lessors by the Equity Investors. The balance of the purchase price was provided by a loan to each of the Lessors by First PV Funding Corporation ("First PV"), a corporation organized for the sole purpose of providing debt financing for lessors of interests in PVNGS purchased from and leased back to PNM. First PV obtained funds for its loans in respect of the Interests from bank borrowings. A public offering of long-term "lease obligation bonds" to be issued by First PV is planned July 1986 to replace the bank borrowings. The loans to the Lessors are secured by assignments of basic rent and certain other amounts payable by PNM under the Leases.

The Lessors are strictly passive owners and have no right to participate in the operation or output of Unit 1 during the terms of the Leases. The amendment to the Unit 1 License (NPF-41) issued by the NRC in connection with the Unit 1 transactions expressly states that "the lessors and anyone else who may acquire an interest under these transactions are prohibited from exercising directly or indirectly any control over the

licensees of Palo Verde Unit 1." In the transaction documents, each Lessor has warranted that, so long as PNM is in compliance with the terms of its Lease, PNM's sole possession and use of, and rights with respect to, the Interest during the term of the Lease shall not be interrupted by the Lessor or any person claiming through the Lessor. PNM is empowered with respect to each Interest to act as the "Participant" under the ANPP Participation Agreement (an agreement among the joint owners of and Participants in PVNGS governing its construction, operation and maintenance), with full and exclusive authority to exercise and perform all of the rights and duties of a Participant thereunder. Additionally, PNM retains the exclusive right to sell and dispose of the power and energy derived from the generation entitlement share in Unit 1 associated with the Interests. This structure of the transactions led the NRC staff to conclude in its report on the Unit 1 Application that "[since] the investor owners will not be acquiring any right to the electric power generated at the Palo Verde facility, and such electricity will continue to be distributed in the same manner as is now set forth in the [ANPP] Participation Agreement, <u>the transaction does not present any antitrust considerations not previously considered at the time of licensing</u>." SECY-85-367 (November 20, 1985) (emphasis added).

<u>Sale/Leaseback of Remainder of PNM's Interest in PVNGS Unit 1</u>

PNM also proposes to sell its remaining interests in Unit 1 in sale and leaseback transactions similar to the transactions consummated in 1985. On February 6, 1986, APS, on behalf of PNM, filed with the NRC a supplemental Application with respect to additional Unit 1 sale and leaseback transactions proposed to be consummated in 1986 by PNM. On February 24, 1986, PNM filed with the NMPSC an application requesting permission to sell to an affiliated company and to lease back all or a portion of the remaining portion of PNM's interest in PVNGS Unit 1 and related portions of its undivided interest in certain PVNGS common facilities and real property interests, on essentially the same terms as discussed above with regard to the December 31, 1985 sale and leaseback of the Interests. The NRC and NMPSC applications are currently pending.

<u>Sale/Leaseback of PNM's Interest in PVNGS Unit 2</u>

PNM proposes to sell and lease back all or a portion of its 10.2 percent undivided interest in PVNGS Unit 2, together with related portions of PNM's undivided interest in certain PVNGS common facilities and real property interests, upon terms substantially similar to those in the Unit 1 transactions consummated on December 31, 1985. PNM is presently seeking proposals from prospective equity investors for such transactions, but no commitments have been received as yet.

PNM has filed applications with the NRC (see Application in Respect of Sale and Leaseback Transaction by PNM, dated February 14, 1986, in the Matter of Arizona Public Service Company, et al. [Palo Verde Nuclear Generating Station, Unit 2], Docket No. STN-50-529) and with the NMPSC, seeking permission to consummate the proposed sale and leaseback transactions with respect to its interest in Unit 2. PNM requested authority in the Unit 2 NRC Application to enter into transactions with equity investors who may be subsidiaries or affiliates of electric utilities.

In its memorandum in Respect of Antitrust Reviews, dated February 21, 1986, filed in the Unit 2 proceeding, PNM addressed the question of whether the potential participation of such utility affiliates required an antitrust review by the U. S. Attorney General, and concluded that such review was not required. PNM has been advised by counsel that an application for an order from the FERC, such as was obtained in respect to Unit 1, will no longer be necessary because transactions of this nature have been ruled upon repeatedly by the FERC.

The proposed Unit 2 sale and leaseback transactions are to include the economic benefit to PNM of transferring to the lessors the investment tax credit available with respect to Unit 2 (which results in lower annual rent payments). Such transactions must be consummated within three months of the date on which Unit 2 is first synchronized (utilizing its nuclear steam supply system) with the transmission grid, the latter date being the date on which Unit 2 is first "placed in-service" for purposes of the investment credit under Section 46 of the Internal Revenue Code. Under current schedules, such first synchronization is expected to occur in April of 1986.

Item 1e

Changes in design, provisions, or conditions of rate schedules and reasons for such changes. Rate increases or decreases are not necessary.

Response

This response does not include matters relating only to interconnection agreements, economy interchanges and similar matters not affecting wholesale rate schedules, and similarly excludes discussion of retail rate schedules and customers. The changes since PNM's 1979 submittal in design, provisions, or conditions of wholesale rates* and reasons for such changes are as follows:

1. City of Gallup (Gallup)

   On April 21, 1978, PNM filed Docket ER78-338 with the FERC for a proposed change in rates for Gallup. This rate schedule is attached as Item 1 of Appendix 3A. That filing became effective November 9, 1981. The only activity relating to provision of service was the striking of late payment penalties from the Gallup tariff. PNM has served Gallup since 1959 under an electric service contract that has been amended numerous times.

   On June 28, 1978, PNM filed Docket ER79-479 with the FERC for a proposed change in rates for Gallup. This rate schedule is attached as Item 2 of Appendix 3A. That filing became effective March 29, 1982. The only activity relating to provision of service included the striking of the demand ratchet under which Gallup was billed (per agreement of the parties).

   On March 31, 1980, PNM filed Docket ER80-313 with the FERC for a proposed change in rates for Gallup. This rate schedule is attached as Item 3 of Appendix 3A. That filing became effective September 17, 1982. Provision of service was changed in this docket, as PNM added a fourth delivery point for Gallup service. The rate design was changed in this docket to provide for facilities charges for the four dedicated substations owned by PNM that are located at Gallup.

   On December 23, 1980, PNM filed Docket ER81-187 for a proposed change in rates for Gallup. This rate schedule is attached as Item 4 of Appendix 3A. That filing became effective May 12, 1983. No action was taken relative to the nature of the provision of service to Gallup in this docket.

*PNM rate schedules are provided in Appendix 3A.

On October 1, 1981, PNM filed Docket ER82-001 with the FERC for a proposed change in rates for Gallup. This rate schedule is attached as Item 5 of Appendix 3A. The filing became effective January 1, 1984, by agreement of the parties. No action was taken relative to the nature of the provision of service to Gallup in this docket.

On February 2, 1983, PNM filed Docket ER83-299 with the FERC for a proposed change in rates for Gallup. This rate schedule is attached as Item 6 of Appendix 3A. The filing became effective September 1, 1985, by agreement of the parties. No action was taken relative to the nature of the provision of service to Gallup in this docket.

2. <u>Plains Electric Generation and Transmission Cooperative, Inc. (PGT), Texas-New Mexico Power Company (TNP), Department of Energy--Los Alamos (DOE/LA), and City of Farmington (Farmington)</u>.

At the time of PNM's 1979 submittal, TNP operated under the name Community Public Service Company.

In PNM's previous submittal, FERC Dockets ER77-464 and ER78-337 were noted as having been submitted on July 20, 1977, and April 21, 1978, respectively, for these four customers. These rate schedules are attached as Item 7 of Appendix 3A. The filing in Docket ER77-464 became effective October 1, 1977, and the filing in Docket ER78-337 became effective December 1, 1978, both actions by agreement of the parties.

On June 28, 1979, PNM filed Docket ER79-479 with the FERC for a proposed change in rates for these four customers. These rate schedules are attached as Item 8 of Appendix 3A. Those filings became effective February 1, 1980, by agreement of the parties.

On March 31, 1980, PNM filed Docket ER80-313 with the FERC for a proposed change in rate for these four customers. These rate schedules are attached as Item 9 of Appendix 3A. Those filings became effective November 1, 1980, by agreement of the parties.

All four of the above mentioned dockets were settled simultaneously. Changes in the nature of the provision of service were incorporated into this settlement and adopted by the FERC. Those changes included the following:

a. TNP was to have costs allocated and rates designed on the basis of reserved demand, rather than actual demand, unless actual demand is used with other PNM wholesale customers.

b. Upon 36 months written notice, TNP was allowed to reduce reserved demand a maximum of 25 MW per year.

c. Upon written notice given PNM on or before February 1 of each year, TNP could decrease reserved demand by 10 percent, or 8 MW, whichever is greater. Such reduction would become effective at the beginning of any calendar month of the following year, as specified in said written notice.

d. Farmington was required to submit by February 1 of each year, a schedule of reserved demand for the following calendar year by month under the following conditions:

   (1) The months of July and August must equal reserved demand.

   (2) For any other month, the power supplied by PNM and received by Farmington may be scheduled below the reserved demand level. The sum of the monthly scheduled demands must, in any event, equal 70 percent (70%) of the total megawatt months that could be scheduled at the reserved demands in effect for that calendar year.

   (3) For cost allocation and rate design purposes, PNM will use the monthly scheduled demands as provided by Farmington rather than actual demands, unless actual demands are used with other PNM wholesale customers.

e. PGT's 1981 reserved demand schedule would be reduced, commencing June 1, 1981, through December 31, 1981, from a level of 85 MW to a level of 70 MW.

f. DOE/LA agreed to several modifications to its level of reserved demand as follows:

   (1) Reserved demand commencing on October 1, 1980 would be 24.5 MW.

   (2) On the later of January 1, 1981 or approval of the settlement package by the FERC, reserved demand would decrease to 21.5 MW. This level continued through September 30, 1981 constituting the 1981 reserved demand.

   (3) Prior to January 15, 1981, and for each ensuing year, DOE/LA will provide PNM with a revised ten-year reserved demand schedule. Each reserved demand year would commence with the beginning of the DOE/LA fiscal year (October 1).

   (4) DOE/LA was granted the right to reschedule reserved demand under the January 15 notice subject to the following restrictions:

      (a) No changes to the current calendar year.

      (b) Second through fifth reserved demand years could be increased up to 10 percent over the base reserved demand or decreased up to 12.5 percent below the base reserved demand. Base reserved demand was agreed to by the parties in Appendix A of the settlement document.

      (c) The sixth through ninth reserved demand years could be increased up to 25 percent above reserved demand

or decreased up to 25 percent below the reserved demand.

(d) The tenth reserved demand year could be specified by DOE/LA.

(5) DOE/LA was given the option to either adjust its annual date to commence its reserved demand year or to select use of a split seasonal reserved demand. This would enable use of two reserved demands, each effective for a six-month period coinciding with the WAPA Summer and Winter Water Seasons. This split reserved demand was conditioned on the restriction that the Winter Season's Reserved Demand would be equal to or greater than the previous Summer's Reserved Demand.

On December 23, 1980, PNM filed Docket ER81-187 with the FERC for a proposed change in rates for these four customers. This rate schedule is attached as Item 10 of Appendix 3A. That filing became effective August 1, 1981, by agreement of the parties. The only activity relating to provision of service was the modification of ratchet clauses to incorporate only actual demand rather than contract reserved demand and application of a "five-times" penalty charge to apply only to actual demands, not ratcheted demands.

On October 1, 1981, PNM filed Docket ER82-001 with the FERC for a proposed change in rates for these four customers. The rate schedules are attached as Item 11 of Appendix 3A. The filing became effective May 1, 1982, by agreement of the parties. Activities relating to provision of service in the above-mentioned ER81-187 docket were also incorporated into the agreement of the parties in this docket.

On February 2, 1983, PNM filed Docket ER83-299 with the FERC for a proposed change for these four customers. The rate schedules are attached as Item 12 of Appendix 3A. The filing became effective September 2, 1983, by agreement of the parties.

3. Following and during the same time frame as the above-mentioned rate filings, PNM has changed the nature of service within the following transactions:

a. <u>City of Farmington (Farmington)</u>.

On November 17, 1981, PNM sold an 8.475 percent undivided interest in San Juan Unit 4 to Farmington. During the first year following the sale, PNM agreed to purchase 20 MW of Farmington's ownership and to provide Farmington with firm and non-firm transmission service, hazard sharing, emergency assistance, and facilities under the PNM-Farmington Interconnection Agreement. PNM and Farmington also participate in an economy energy agreement. These transactions were approved by the NMPSC in Dockets 1675 and 1676.

b. <u>Incorporated County of Los Alamos (LAC)</u>.

On July 1, 1985, PNM sold a 7.2 percent undivided interest in San Juan Unit 4 to LAC. In addition, LAC purchased PNM's White Rock distribution system, located within the boundaries of Los Alamos County. On that same date, PNM and DOE/LA exchanged certain transmission facilities. These transactions were approved by the NMPSC in Dockets 1923 and 1925. As a result of these transactions, LAC now serves the White Rock load and DOE/LA. PNM continues to provide transmission service to the DOE, and provides various services to LAC, including emergency generation, hazard sharing, economy energy interchange, area control, firm transmission service, and transmission service through specific switchyard facilities. Until the end of 1990, PNM will purchase between 0 and 8 MW contingent capacity and associated energy from LAC's San Juan ownership.

4. PNM has also entered into several agreements to sell block energy during this time frame. These agreements generally specify a time period over which energy will be delivered, a maximum demand rate at which the delivery will be made, price of energy, and, in certain cases, a maximum amount of energy to be delivered. The specific transactions under this category are the following:

a. Cities of Burbank and Pasadena--Block Energy Agreement Number 11,393. This service schedule provided for delivery of energy to the Cities of Burbank and Pasadena, California from May 1, 1983, through April 30, 1984. Delivery was made at a rate up to 35 MW with a total energy delivery up to 307 GWh. Specific delivery terms and rates are included in the contract, which is attached as Item 13 of Appendix 3A.

b. Incorporated County of Los Alamos, Service Schedule I--Surplus Energy. This service schedule provides for the sale of surplus energy at varying rates of delivery by PNM to LAC. The contract term is from July 1, 1985 through December 31, 1990. Specific delivery levels and rates are included in the service schedule which is attached as Item 14 of Appendix 3A.

c. Nevada Power Company (NPC), Service Schedule E--Block Energy Sale. This service schedule provided for the sale of energy to NPC from July through September, 1985. Specific delivery terms and rates are included in the service schedule which is attached as Item 15 of Appendix 3A.

d. Southwestern Public Service Company Service Schedule D--Interruptible Power Service. This service schedule provides for the sale of firm surplus energy at a rate of deliver of 200 MW each hour (Base Energy) by PNM to SPS. At the request of SPS, PNM can deliver up to 20 MW additional (Additional Energy) firm energy. Base Energy is to be made available to SPS each hour during the term of the sale which began January 1, 1985. The sale will continue through December 31, 1989, although SPS has the option to extend the service through May 31, 1990. The

specific rates and terms are included in the service schedule which is attached as Item 16 of Appendix 3A.

e. Texas-New Mexico Power Company, Service Schedules F and I--Block Energy Sale. These service schedules provided for the sale of energy to TNP to reduce gas-fired generation of TNP's copper industry customers. Service Schedule F was effective from August 2, 1983 through February 28, 1985. It was superseded on expiration by Service Schedule I which had similar terms. Service Schedule I was terminable on December 31, 1985, but continues monthly by agreement of the parties. Service Schedule I also included specific allowances for recovery of third party wheeling expenses. Specific delivery terms and rates are included in the service schedules which are attached as Items 17 and 18 of Appendix 3A.

Item 1f

List all of (1) new wholesale customers, (2) transfers from one rate schedule to another, including copies of schedules not previously furnished, (3) changes in licensee's service area, and (4) licensee's acquisitions or mergers.

Response

This response does not include matters relating only to interconnection agreements, economy interchanges and similar matters not affecting wholesale rate schedules, and similarly excludes discussion of retail rate schedules and customers.

1. New Wholesale Customers Added Since PNM's 1979 submittal:

   a. Cities of Burbank and Pasadena, California.
   b. Incorporated County of Los Alamos, New Mexico.
   c. Nevada Power Company.
   d. San Diego Gas and Electric Company.
   e. Southwestern Public Service Company.
   f. Texas-New Mexico Power Company.

2. Transfers from One Rate Schedule to Another:

   PNM has had no requirements wholesale customers transferred between rate schedules during this time period. To the extent that several wholesale customers have changed the nature of the service, this item is covered in PNM's response to Item 1e.

3. Changes in Licensee's Service Area:

   Since PNM's 1979 submittal, three transactions have taken place which have affected PNM's service area. They are as follows:

   a. In NMPSC Docket 1812, PNM received approval to acquire the Clayton Electric System from the Town of Clayton, New Mexico. Clayton is located in the far northeast corner of the state and is now interconnected with PNM's integrated system.

   b. In Docket 1828, the NMPSC approved an exchange of certain retail customers between PNM and the Mora-San Miguel Electric Cooperative.

   c. In Dockets 1923 and 1925, the NMPSC approved PNM's sale of the assets representing PNM's White Rock distribution system to LAC. This transaction was undertaken simultaneously with the sale of a portion of San Juan Unit 4 to LAC as described in Item 1e above. White Rock is located within Los Alamos County and adjacent to the Los Alamos County utility system.

4. Licensee's Acquisition or Mergers:

PNM's only acquisition relating to electric service is described in Section 3 above regarding acquisition of the Clayton municipal utility, resulting in an expansion of PNM's service territory.

In January 1981, PNM's Board of Directors approved a plan of merger, whereby the electric utility business of New Mexico Electric Service Company (NMESC), would be merged into PNM. NMESC provided electric service to the communities of Hobbs, Jal and Eunice, New Mexico, and the surrounding areas, with its service territory being wholly within Lea County. The merger would have involved the issuance of shares of PNM common stock in exchange for all of the existing common stock of NMESC. An application for approval of this merger was filed with the NMPSC and with FERC. Following hearings in 1981, the NMPSC declined to approve the merger, and PNM's Board of Directors subsequently acted to terminate the plan of merger.

Item 1g

List of those generating capacity additions committed for operation after the nuclear facility, including ownership rights or power output allocations.

Response

NEW MEXICO GENERATING STATION

The 1979 submittal contained a summary of the then-current status of the "New Mexico Station" project (the "Project"). The Project, subsequently referred to as the "New Mexico Generating Station" Project, has now been discontinued as a PNM utility project. However, it remains under active consideration as a market-driven "entrepreneurial" project by a group of entities, including PNM, the Navajo Nation, General Electric Company, Combustion Engineering, Inc., and Bechtel Power Corporation, for possible operation in the early to middle 1990's.

Item 1h

Summary of requests or indications of interest by other electric power wholesale or retail distributors, and licensee's response, for any type of electric service or cooperative venture or study.

Response

This response generally does not include discussion of requests or indications of interest by federal agencies, as these are not deemed to be within the purview of this Item. Additionally, this response does not include discussion of contacts or agreements between PNM and potential co-generators and small power producers.

Arkansas River Power Authority (ARPA)

At the request of ARPA, PNM entered into an Economy Energy Agreement with ARPA on December 19, 1984. ARPA is a political subdivision of the State of Colorado which represents and purchases power for several municipalities in Colorado and northern New Mexico and based in Lamar, Colorado.

Citizens Energy Corporation (Citizens)

By letter dated May 30, 1985, Citizens, a nonprofit energy company based in Boston, Massachusetts, requested that PNM sell energy to Citizens for subsequent resale by Citizens to West Coast utilities. In December 1985, PNM submitted a proposal to Citizens. However, negotiations ceased when Citizens was unable to make appropriate transmission arrangements.

Citizens Utilities Company (Citizens Utilities)

By letter dated February 12, 1986, Citizens Utilities requested that PNM submit a proposal for a 7 to 10 MW summer peaking sale from June through September 1986. PNM sent such a proposal to Citizens Utilities in a letter dated March 10, 1986.

City of Anaheim, California (Anaheim)

By letter dated August 30, 1984, PNM forwarded to Anaheim its loads and resources table for 1983 through 1993, and also a scenario for the sale to Anaheim, of long-term system contingent and unit contingent power; and a scenario for a system contingent and ownership sale to the City. Negotiations ceased due to Anaheim's inability to make appropriate transmission arrangements.

City of Austin, Texas (Austin)

In mid-October 1984, PNM received from Austin a Request for Proposal entitled "Sale of Electric Power/Energy from Electric Power Producers 1984." The solicitation sought to identify several potential sources of power for purchase by Austin. In subsequent telephone conversations between representatives of Austin and PNM, the parties mutually concluded that there was insufficient transmission available between New Mexico and Texas. No formal response to the Request for Proposal was made by PNM.

Cities of Burbank and Pasadena, California (Burbank/Pasadena)

In a June 8, 1982 meeting, representatives from Burbank/Pasadena and the City of Glendale, California (Glendale) indicated interest in purchasing firm surplus energy from PNM. PNM provided the three municipalities with a proposed contract. During the negotiations, however, Glendale indicated it no longer had any need for PNM's energy. Negotiations continued between PNM and Burbank/Pasadena and in October 1982 the parties entered into an agreement for the sale by PNM of block energy to Burbank/Pasadena.

City of Colorado Springs, Colorado (CCS)

By letter dated April 11, 1984, CCS indicated interest in purchasing PNM surplus firm capacity as a possible alternative to constructing new generating capacity (Nixon Unit #2). PNM submitted a proposal. However, CCS indicated that based on its review of the proposal, PNM's offer would not meet its requirements.

City of Farmington, New Mexico (Farmington)

As discussed on page 13, above, on November 17, 1981, PNM sold an 8.475 percent undivided interest in San Juan Unit 4.

In 1984, Farmington requested to tap PNM's UW transmission line located north of Farmington. Subsequent negotiations also involved Colorado Ute Electric Association (CUEA). PNM has agreed to the tap.

City of Gallup, New Mexico (Gallup)

In the summer of 1985, Gallup made a request to PNM for projected electric service rates. At present, PNM is supplying power to Gallup under a full requirements contract which expires in 1993. PNM and Gallup are negotiating regarding Gallup's future power supply needs.

City of Riverside, California (Riverside)

As per a meeting on May 11, 1984 with Riverside, PNM forwarded a letter on May 22, 1984 with an attached outline for a 35 MW block energy sale to Riverside. Negotiations ceased due to transmission constraints. During November 1984, Riverside called requesting updated terms for a 35 MW peaking capacity block energy sale that contained a firming provision. This additional proposal would have aided Riverside in an attempt to gain wheeling rights through Southern California Edison's system. Negotiations ceased when Riverside was unable to make appropriate transmission arrangements.

By letter dated July 26, 1985, Riverside requested that PNM present a draft contract for short-term firm capacity service. A draft proposal was supplied but no response was received from Riverside.

City of Truth or Consequences, New Mexico (Truth or Consequences)

In early 1980, Truth or Consequences had been discussing with PNM the possibility of purchasing additional power and energy to supplement the hydro power received from WAPA. Subsequent discussions were held with WAPA toward reaching agreement on a three-party arrangement among WAPA, PNM and Truth or Consequences for the supply of supplemental power and energy. However, WAPA was not agreeable and no further action was taken by any of the parties.

City of Vernon, California (Vernon)

By letter dated March 20, 1985, Vernon requested that PNM supply a draft contract for the purchase of economy and non-firm energy by Vernon. A draft proposal was supplied by PNM, but no response was received.

Cochiti Dam Hydro Plant (Project)

In response to a letter dated August 6, 1980, from PRC Engineering Consultants, Inc., requesting PNM's cooperation in the study for a small hydro plant at Cochiti Dam, south of Santa Fe, New Mexico, PNM expressed interest in an interconnection or possible power purchase if the Project proved feasible. The Project is still in the preliminary stages. LAC has since expressed interest in participating in the Project.

Colorado Ute Electric Association, Inc. (CUEA) and Tucson Electric Power Company (TEP)

On December 21, 1979, PNM, TEP, and CUEA entered into a letter agreement which, among other things, provided for the interconnection of the Rifle-San Juan 345 kV line into the San Juan Switchyard, and also for the commonality of substation busses at San Juan, Four Corners, and Shiprock when the lines interconnecting those switchyards are all rated at 345 kV. This commonality of busses would allow the parties to exchange or deliver power and energy between those switchyards without charge. This letter also provided that the parties would proceed to incorporate these principles into an interconnection agreement.

On June 26, 1985, the San Juan Area Transmission Agreement was entered into which incorporated all of the above-mentioned items and also included WAPA as a participant.

Simultaneous to the negotiation of the San Juan Area Transmission Agreement and in order to facilitate the "common bus" concept embodied in both of the above-mentioned agreements, CUEA and WAPA approached the Four Corners Participants (APS, PNM, TEP, EPE, SRP, SCE) with the intent of securing an agreement to uprate the Shiprock-Four Corners 230 kV line to 345 kV and provide for that line's interconnection into the Four Corners 345 kV switchyard. At present, negotiations continue for that uprate and interconnection.

Incorporated County of Los Alamos (LAC)

On July 1, 1985, PNM and LAC consummated a transaction whereby LAC purchased from PNM a 7.2 percent undivided interest in San Juan Unit 4. In conjunction with this transaction, PNM and LAC also executed an Interconnection Agreement and PNM sold its White Rock, New Mexico distribution system to LAC.

Electrical District No. 6 of Pinal County, Arizona (ED-6)

By letter dated November 7, 1985, ED-6 declined a proposal submitted by PNM for the sale of block energy.

Houston Lighting & Power (HL&P)

By letter dated July 26, 1983, HL&P indicated that it would entertain the receipt of proposals for capacity in the range of 200 to 500 MW for 10 and/or 20 years starting in 1988-1990 time period. No response was received from HL&P, however, after PNM submitted a proposal.

Imperial Irrigation District (IID)

In early October 1981, PNM and IID discussed the possibility of IID acquiring ownership interest in PVNGS from PNM. IID was interested in acquiring 75 MW, 25 MW from each of PVNGS Units 1, 2, and 3. By letter dated October 19, 1981, PNM indicated that such a sale was feasible. Negotiations ensued. During the following months, PNM proposed several options to meet IID's requirements. However, based on a recommendation by IID's consultant, IID informed PNM that it would pursue negotiations with EPE. IID and EPE ultimately consummated an agreement for the purchase by IID of firm power.

On March 7, 1986, IID sent a letter requesting a 125 MW off-system purchase for the 1992-2000 time period. PNM is currently preparing a response.

Jicarilla-Apache Indian Reservation (Reservation)

In a letter dated March 19, 1982, HKM Associates, an engineering firm representing the Jicarilla-Apache Tribe, located in West Central New Mexico, requested an estimate of power availability and cost for evaluation of the feasibility of an irrigation project. PNM responded, by letter dated April 13, 1982, that as a party to a territorial agreement (approved by the NMPSC in Docket 1333) which established the service boundaries between PNM and Jemez Mountains Electric Cooperative, Inc., in the southern half of the Reservation and the lack of PNM transmission facilities in the northern half, it was unclear whether PNM could provide the necessary service to the proposed Reservation irrigation project. PNM suggested that the Tribe contact the Jemez Mountains Electric Cooperative, Inc. and pursue collaboration with the USBR.

Kansas Power and Light Company (KPL)

In response to a PNM letter dated July 16, 1982, KPL expressed interest in pursuing discussions with PNM in connection with a prospective power sale to PNM. In subsequent discussions, PNM pursued the possibility of interconnecting with KPL. PNM's decision, however, to obtain power from SPS ended further study of a Kansas interconnection and KPL power sale. (See SPS discussion on page 29.)

Montana Power Company (MPC)

In response to an August 30, 1979 letter from MCP regarding the sale of contingent capacity from San Juan, PNM sent a proposal setting forth proposed terms and conditions for said sale. However, no agreement was reached between the parties.

By letter dated May 30, 1980, MPC expressed interest in entering into an agreement with PNM for economy energy transactions outside the Western Systems Coordinating Council's Brokering Program. In early 1982, PNM and MPC entered into a non-firm energy agreement.

M-S-R Public Power Agency (M-S-R)

On September 26, 1983, PNM and M-S-R executed an Early Purchase and Participation Agreement wherein M-S-R agreed to purchase from PNM a 28.8 percent ownership interest in San Juan Unit 4. This transaction was consummated on December 31, 1983. As part of the transaction, PNM and M-S-R also executed an Interconnection Agreement.

Navajo Tribal Utility Authority (NTUA)

In March 1981, PNM entered into two separate agreements with NTUA contingent on the construction of PNM's proposed 500 kV Four Corner-Ambrosia-Pajarito (FCAP) transmission line. In the Firm Power Purchase Option Agreement, NTUA was granted the option of purchasing up to 30 MW of supplemental firm electric service until the year 2031. The second agreement entitled Agreement for Transmission Service to Con Paso Coal Tap allowed NTUA to tap PNM's proposed 230 kV transmission line between Four Corners Generating Station and Ambrosia Switching Station to serve an NTUA industrial customer. Since PNM has been unable to obtain necessary approvals for FCAP, NTUA has declared the aforementioned agreements null and void.

Nevada Power Company (NPC)

In approximately May 1985, NPC requested that PNM consider selling power to NPC during the summer of 1985. As a result, PNM and NPC executed a contract for such a power sale on July 1, 1985. In January 1986, NPC requested that PNM submit proposals to NPC for long-term power sales in the 1990's, and also for a short summer peaking sale in 1986. On March 18, 1986, PNM sent a proposal to NPC for long-term sales in the 1990's.

Pacific Gas & Electric Company (PG&E)

By letter dated December 10, 1981, PG&E indicated interest in pursuing economy energy transactions with PNM. PNM transmitted its economy energy contract for review by PG&E. In mid-1983, PNM and PG&E executed an economy energy agreement.

Plains Electric Generation and Transmission Cooperative Inc. (PGT)

1. As addressed in the 1979 submittal, PNM and PGT executed several agreements relating to the trade of wheeling services since each has substations served off of the 115 kV transmission lines of the other. Service Schedule A* exchanges 10 MW wheeling to PGT's Smith Lake Substation for 10 MW wheeling to PNM's Fort Wingate substation and was signed on February 28, 1977. Following discussions in 1979 regarding transformer loss calculations, a memorandum agreement amending Service Schedule A was executed on July 18, 1980, providing for the trade of transformer losses at Smith Lake Substation and Fort Wingate Substation. Service Schedule E, which exchanges the use of various taps, lines, and parts of switching stations, was signed on April 4, 1979. Service Schedule E provides for maintaining a current list of facilities and a current statement of balance of benefits. Since June 1982, when Palm Substation was added to the list of reciprocal use facilities, PGT and PNM have entered into several letter agreements to add certain new facilities to this list; i.e., Ambrosia Switchyard Expansion Agreement dated July 8, 1982, to add a breaker and associated facilities; Storrie Lake Breaker Agreement dated October 20, 1983 to add a breaker and associated facilities, and Letter of Principles dated December 20, 1984, to add the Clapham transformer and associated facilities. Updates to Service Schedule E await final cost accounting for the facilities in these letter agreements. A Contract of Sale Agreement signed concurrently with Service Schedule E adjusted ownership of facilities at the points of interconnection.

2. Per letter dated December 27, 1978, PGT requested to increase its transmission capacity to serve its load at PNM's Gulf Substation (Gulf). PNM also needed additional transmission capacity to Rio Rancho. On March 26, 1980, Service Schedule C was executed, superseding and terminating the previous wheeling agreements for Rio Rancho and Gulf, i.e., the Transmission Service Agreement of February 17, 1970, and Service Schedule D. In Service Schedule C, PNM agreed to wheel 20 MW to PGT's Gulf load and 10 MW for PGT from Hidalgo to Mimbres (associated with the PNM/PGT Agreement for Electric Service dated February 6, 1974) in exchange for 30 MW of service by PGT to Rio Rancho.

*All service schedules referred to in the PGT discussion are service schedules to the PNM/PGT Master Interconnection Agreement dated June 12, 1975.

3. Service Schedule B entered into August 3, 1976, and terminating by its terms on December 31, 1984, was an agreement by which PGT purchased firm power (reserved demand) and energy from PNM in amounts as reserved from time to time. Service Schedule B was initially expected to terminate May 30, 1984. In Amendment One, dated April 25, 1978, the amount of power purchased was changed by varying amounts for each of the contract years 1978 through 1983. In Amendment Two, dated October 29, 1980, PNM agreed to modify PGT's reserved demand by segmenting the contract year. Amendment Two also resolved FERC Dockets ER77-464, ER78-337, ER79-479, ER80-313, and ER80-376. In the fall of 1980, PGT requested additional power sales for 1983 through 1984. On August 4, 1981, Amendment Three to Service Schedule B and Service Schedule I were executed concurrently. (Under Service Schedule I, PGT purchases 15 MW of peaking capacity from PNM.) In Amendment Three, PNM agreed to add a second delivery point under Service Schedule B and to increase the June 1, 1983 to January 30, 1984, reserved demand by 72 MW. In addition, Amendment Three provided for a monthly variation in power purchases (monthly load patterning) limited in any contract year to the same MW-months as would be available at 75 percent of the reserved demand. PGT was also provided with the first rights to schedule power and energy above the reserved demand in amounts up to 33 1/3 percent of reserved demands in non-peak load months. Amendment Three implemented the principles that originated from settlement of FERC wholesale rate case ER81-187 as set forth in a letter agreement dated August 3, 1981. In the Spring of 1982, PNM and PGT began discussing a delay in PGT's Escalante Generating Station (PEGS) Unit 1 and PGT's need for power from June 1984 to December 1984. On January 19, 1983, Amendment Four to Service Schedule B was executed. In Amendment Four, the term of Service Schedule B was extended from June 1, 1984 through December 31, 1984. PGT's purchases were decreased from 119 MW to 115 MW from January 1, 1984 through May 30, 1984 and a 115 MW purchase was added from June 1, 1984 through December 31, 1984. Amendment Four also specified that PGT would waive its first rights to schedule power and energy in excess of applicable monthly reserved demands for 1984. Concurrently with Amendment Four, PNM and PGT agreed to Service Schedule J which provides for hazard sharing such that during outages of PEGS Unit 1, PGT receives 80 MW from San Juan Unit 4 and 25 MW from San Juan Unit 3, and such that during outages of San Juan Unit 3, PNM receives 25 MW from PEGS Unit 1 and during outages of San Juan Unit 4, PNM receives 80 MW from PEGS Unit 1.

4. In 1981 PNM and PGT began discussing means to provide electric service to northeastern New Mexico to enable PNM to serve the City of Clayton and PGT to serve Southwestern Electric Cooperative's (SWEC's) industrial customer, Amoco, located near Rosebud, New Mexico. In a Letter of Principles dated December 13, 1983, PNM, PGT, and SWEC agreed to the facilities to be provided, the ownership of the facilities, and the capacity rights of each party for the purpose of serving said loads. Payments for such capacity rights were contemplated to be in the form of transmission trades. PNM and PGT began joint investigations in 1982 to develop a methodology for

affecting such transmission capacity trades. By letter of May 8, 1984, PGT proposed a trade methodology to be applied in securing transmission to Clayton for PNM and transmission for PEGS Unit 1 which was under construction. PNM and PGT subsequently agreed in a Letter of Principles for Transmission Service dated December 20, 1984, to the resolution of PNM's need for transmission service to Clayton and PGT's need for transmission service for PEGS Unit 1, as well as to the implementation of certain changes to service provisions of the PNM-PGT Agreement for Electric Service at Hidalgo and Service Schedule C (Wheeling Trades). In this Letter of Principles, PNM and PGT agreed that effective January 1, 1985, PNM would provide firm and interruptible transmission service to PGT to transmit power and energy from PEGS Unit 1 to various PGT/PNM interconnection points; that PNM would expand to bidirectional capability PGT's use of the 10 MW transmission path between Hidalgo 345 kV and Mimbres 115 kV; that PNM would amend its contract with TNP, and the PNM-PGT Agreement for Electric Service such that PNM no longer reserves capacity on PGT's behalf in TNP's 345/115 kV transformer at Hidalgo (reference subparagraph 9 below); that PGT would provide to PNM 5 MW of transmission service to Clayton and that PGT would provide to PNM 50 percent capacity in the Clapham transformer to be accounted for under Service Schedule E and that PGT would receive service under the 1968 Contract for Transmission Service (Rowe) and 2 MW of the firm wheeling for PEGS in trade for a portion of the Clayton transmission service being provided to PNM. Drafting of the amendments and new contracts necessary to document these agreements are still underway. Operation is currently in accordance with the December 20, 1984 Letter of Principles.

5. In late 1983, PNM undertook studies to determine the impact on the PNM transmission system of PEGS Unit 1. These studies resulted in discussions between PNM and PGT concerning transmission service for precommercial energy generated by PEGS Unit 1 and the need for installation of a second 230/115 kV transformer at PNM's West Mesa Switching Station. By letter agreement dated May 18, 1984, PNM and PGT agreed that transmission service for a certain portion of PEGS precommercial energy would be provided by PNM under Service Schedule H. By letter agreement dated October 11, 1984, PNM and PGT agreed to share in the costs of installing the second West Mesa transformer. However, prior to the time of completion of the permanent installation of the second transformer, PNM and PGT agreed by way of letter dated December 6, 1984, to a temporary, quicker installation that would permit the larger transformer to be in-service prior to having both transformers operating in parallel, which would allow a higher output of PEGS Unit 1.

6. Per letter dated October 5, 1983, PGT formally requested a new delivery point at the Four Corners 345 kV bus starting January 1, 1984, in order to serve Navopache Electric Cooperative Inc. with power and energy purchased under Service Schedule B. Negotiations between PNM and PGT ceased in December 1983 when PGT announced that WAPA would supply the Navopache load through Four Corners, and that PGT would work out the details of the arrangement with APS.

7. From time to time, PNM and PGT have studied the possibilities of joint ownership, cost sharing, or transmission capacity trade agreements for transmission lines proposed for construction in New Mexico. Included in these are (a) the proposed 345 kV line between Taos, New Mexico and San Luis Valley, Colorado, (b) the proposed 500 kV line between Four Corners and Albuquerque, New Mexico and (c) the proposed 345 kV line connecting PNM's Norton Station near Santa Fe, New Mexico to the San Juan-Ojo 345 kV line near Espanola, New Mexico.

   Several agreements between PNM and PGT have been made in anticipation of construction of such facilities, even though to date none of the proposed facilities are currently under construction. PNM expects to continue in joint efforts with PGT to realize additional transmission capability within the state in order to ensure quality of service for customers of both utilities.

8. In 1982, PNM and PGT began discussions related to PGT's participation with PNM in the proposed sales/purchases arrangements that PNM was discussing with SPS and the associated proposed transmission line known as the Eastern Interconnection Project (EIP). The EIP is an asynchronous transmission line connecting the Albuquerque area with the SPS transmission system near Clovis, New Mexico. Per letter dated January 1, 1983, PNM offered PGT the right to participate in up to 25 percent of the firm energy sale and subsequent interruptible power purchase that PNM had made with SPS together with an associated share of transmission service or ownership over the EIP. The negotiation deadline of June 1, 1983, was extended to August 1, 1983 at PGT's request. A draft Letter of Principles was submitted to PGT on September 15, 1983 then revised and resubmitted on January 26, 1984. PNM was subsequently informed that PGT would not participate initially in the SPS transaction or the EIP, but that deliveries over the EIP to PGT customers in northeastern New Mexico may eventually require construction of a tap into the EIP. The EIP transmission line was placed into commercial service in December 1984 and the power sale to SPS began on January 1, 1985.

9. The Agreement for Electric Service, entered into on February 6, 1974, provided that PNM furnish up to 30 MW of power and associated energy for delivery to PGT in southern New Mexico at a proposed substation to be located near Silver City, New Mexico (Cow Springs). In order to provide this service PNM agreed to construct the proposed Cow Springs Switching Station and a line between TNP's existing Central substation near Silver City and Cow Springs. The contract term extends until September 1, 2005. Amendment 1 executed October 14, 1974, relocated the point of delivery to the Hidalgo 115 kV Switching Station near Lordsburg, New Mexico. One bay at the Hidalgo 115 kV Station was dedicated to PGT and a wheeling path of 9 MW was provided from Hidlago to the Mimbres 115 kV substation near Deming, New Mexico through TNP's system in order to allow a portion of the Hidalgo energy to be delivered to PGT's loads at Deming.

   In Amendment 2, executed August 3, 1976, PNM agreed to waive the 5 times excess demands charge for billing demands established in

peak months in excess of the Contract Reserved Demand and PGT agreed to the fixed maximum on scheduled demands for the life of the Agreement. An additional charge of 1.0 mill/kWh was included for Hidalgo energy delivered to PGT over PNM's lines between Deming and Lordsburg. In 1978, PNM and PGT began discussing adding the Mimbres substation near Deming as a second delivery point under the Agreement for Electric Service. Subsequently, PGT acquired the 115 kV transmission line of the United States between Albuquerque and Deming. In October 1979, PGT requested that PNM research the availability and cost of providing additional transmission service between Hidalgo (Lordsburg) and Deming (Mimbres). This resulted in Amendment 3 to the Agreement for Electric Service, in which (a) the delivery point was changed from the Hidalgo 115 kV bus to the Hidalgo 345 kV bus, (b) PGT agreed to compensate PNM for its payments to TNP for services for PGT through the Hidalgo 345/115 kV transformer and 115 kV line terminal connecting PGT's 115 kV Playas Line to Hidalgo and (c) PNM agreed to provide for up to 10 MW of deliveries from Hidalgo 345 kV to Mimbres 115 kV at no additional charge (reference Service Schedule C addressed in subparagraph 2 above). Presently, in conjunction with the December 20, 1984, Letter of Principles discussed in subparagraph 4 above and in response to PGT's request, PNM has agreed to a further amendment to the Agreement for Electric Service, which will enable PGT to directly compensate TNP for PGT's use of the Hidalgo 345/115 kV transformer and Hidalgo 115 kV line terminal. Drafting of this amendment is underway.

10. Per letter dated September 25, 1984, PGT requested that PNM provide a cost estimate of supplying up to 15 MW of replacement capacity to PGT to serve the proposed papermill near McNary, Arizona. PNM submitted an energy sales proposal to PGT in early 1985. Per letter dated July 25, 1985, PGT requested that PNM extend the proposal an additional six months to allow time for final project approvals. PGT is still waiting for approvals.

Public Service Company of Colorado (PSCC)

By letter dated March 13, 1981, PSCC requested the opportunity to discuss the possible sale of 100 MW of PNM contingent capacity for the mid-1980's. Consummation of this purchase would have required the construction of new transmission facilities. Discussions regarding this new transmission system surfaced numerous technical problems. As negotiations continued, new PSCC resource requirements slipped from the mid-1980's to the early 1990's. PSCC has indicated that cogeneration considerations and softening power market conditions have slowed interest in reaching agreement. However, negotiations are continuing.

Raton Public Service Company (RPS)

At the request of RPS, PNM entered into a transmission agreement with RPS on November 16, 1982, under which PNM will provide transmission service to RPS until November 30, 1987. By letter of April 6, 1984, RPS requested that PNM participate in a joint study to determine the feasibility of constructing a 20-mile transmission line from Raton, New Mexico

to a point near Trinidad, Colorado. PNM responded favorably to the idea, discussions ensued, but no definitive action has been taken on the joint study matter.

Roosevelt Conservation District, Arizona (RWCD)

By letter dated November 7, 1985, RWCD declined a proposal submitted by PNM for the sale of block energy.

San Diego Gas & Electric Company (SDG&E)

On October 30, 1979, PNM and SDG&E executed a 236 MW Contingent Capacity Agreement, wherein SDG&E agreed to purchase up to 236 MW of power and energy from PNM until April 1988.

In the summer of 1985, SDG&E requested that PNM sell SDG&E precommercial energy from PVNGS Unit 1. On September 27, 1985, PNM and SDG&E executed a Letter Agreement for such a sale. Negotiations will soon commence for precommercial sales to SDG&E from PVNGS Units 2 and 3.

On November 4, 1985, PNM and SDG&E executed a 100 MW System Power Agreement in which SDG&E agreed to purchase 100 MW of power and energy from PNM (with an option to purchase an additional 100 MW) from May 1988 until 2001.

Silver States Power Association (SSPA)

By letter dated August 26, 1983, L. S. Gold and Associates, an engineering firm retained by SSPA, requested the assistance of PNM in supplying information on availability of generating capacity and associated energy and transmission. This information would have been incorporated in a 20-year power supply study for SSPA. The members of SSPA include: Lincoln County Power District No. 1, Overton Power District No. 5, The City of Boulder City and Valley Electric Association, Inc. All SSPA members are located in the State of Utah. PNM contacted L. S. Gold and indicated PNM would assist. Since SSPA did not have the means at that time to transmit PNM energy and power from Four Corners to its load centers, further discussions between PNM and SSPA ceased.

Southwestern Public Service Company (SPS)

On November 23, 1982, PNM and SPS executed an Interconnection Agreement with a service schedule that provided for PNM to sell energy at a rate of approximately 200 MW to SPS from 1985 until 1990. An additional service schedule provides for PNM to purchase up to 200 MW from SPS from 1991 until 2011.

Sunflower Electric Cooperative, Inc. (SEC)

On August 25-26, 1982, representatives of PGT, PNM, and SEC met to discuss details of a power supply proposal by SEC and to outline a joint study of a Kansas to New Mexico transmission interconnection. Subsequently, PNM and SEC entered into a power sale letter agreement reflecting the parties' intent to enter into a definitive power sale

contract by December 31, 1982, for the purchase by PNM of 100 MW of unit-contingent capacity and 50 MW of interruptible capacity. However, with PNM's decision to enter into an agreement with SPS for both the sale and purchase of power and energy, no further transactions involving the SEC agreement were undertaken.

Texas-New Mexico Power Company (TNP)

In February 1980, TNP, then called Community Public Service Company, contacted PNM requesting power to serve the Kennecott Co. in southwestern New Mexico. The request was understood to be for 15 MW. Subsequent discussions indicated that PNM did not have enough surplus capacity available to serve the full requirements nor did it have the necessary transmission rights in the time period specified. TNP then indicated that 8 MW would serve the load. PNM stated that this requirement could be met within provisions of an existing contract. Since no formal request was pursued by TNP, no further action was taken by PNM.

In early May 1983, TNP requested PNM consider selling TNP energy to help serve TNP's mining loads. PNM proposed to supply TNP with 150 gigawatt hours at a rate of delivery of up to 50 MW under a new service schedule to the PNM-TNP Interconnection Agreement which had been in effect since February 28, 1974. On August 2, 1983, TNP and PNM executed Service Schedule F providing for the sale to TNP of block energy. By August 30, 1983, TNP and PNM were discussing the possibility of increasing sales to TNP of both block energy in the near-term and capacity for the 1985+ time period. Negotiations ensued. Based on a proposal by PNM for the sale to TNP of 370 gigawatt hours at a rate of delivery of up to 50 megawatts, the parties executed, on January 31, 1985, Service Schedule H to the aforementioned Interconnection Agreement. Subsequently, and as a result of the execution of Service Schedule H, Service Schedule F was terminated on February 28, 1985.

In January 1986, TNP requested that PNM to submit a proposal to TNP for the sale of block energy to TNP in 1986. Transmission constraints within the existing New Mexico transmission system may prevent such a sale, but negotiations are continuing.

Texas-New Mexico Power Company (TNP) and El Paso Electric Company (EPE)

On April 29, 1977, TNP, EPE, and PNM executed the Southwest New Mexico Transmission System Participation Agreement (Agreement) entitled the Southwestern New Mexico Transmission (SWNMT) Project to build two segmented 345 kV transmission lines and related facilities (SWNMT) (see paragraph 6 under Item 1h of the 1979 antitrust submittal). At EPE's request, the Agreement was amended twice by SWNMT Letter Agreement dated March 18, 1983, and SWNMT Letter Agreement-Supplement dated June 11, 1984, to allow EPE to construct the Springerville-Luna-El Paso Transmission line with an in-service date of no later than June 1, 1987. In return, EPE is to supply TNP and PNM with emergency energy backup at EPE's expense. Additionally, upon completion of the Springerville-Luna-El Paso transmission line, EPE is to become the Operating Agent for SWNMT.

Town of Clayton, New Mexico (Clayton)

In approximately 1981, Clayton requested PNM and other utilities to submit proposals for purchasing Clayton's electric system, and for supplying power to Clayton thereafter. In August 1983, PNM purchased Clayton's electric system and began providing power to Clayton.

Tucson Electric Power Company (TEP)

In July 1984, TEP requested that PNM cooperate with TEP's efforts to form a subsidiary, Alamito Company. As a result, PNM and TEP amended the San Juan Project Agreements on October 25, 1984 to reflect Alamito's acquired ownership interest in San Juan Unit 3.

Utah Municipal Power Agency (UMPA)

By letter dated June 22, 1983, UMPA requested information to ascertain the availability and possible arrangements by which power could be provided by PNM to UMPA and its members. Members of UMPA are: Town of Levan, City of Manti, City of Nephi, City of Payson, City of Provo, City of Salem, City of Spanish Fork, and City of Springville. PNM responded in a letter dated July 12, 1983, indicating its interest to pursue discussions for the purpose of meeting UMPA's needs. PNM offered to arrange delivery of energy to Four Corners at such time that UMPA had the means of transmitting to its load center. No response has been received from UMPA.

Utah Power and Light (UP&L)

In a letter dated September 30, 1980, UP&L expressed interest in the purchase of contingent capacity from San Juan Unit 4. PNM submitted its proposed contract terms and conditions as well as costing data. However, no response by UP&L was made on this issue.

In February 1982, PNM received a telephone call from UP&L indicating UP&L's need for base-load capacity beginning in 1985 for the purpose of supplying power to a new oil/gas development project in Wyoming. PNM submitted a proposal, dated May 28, 1982, for the sale of peaking capacity, base-load contingent capacity, or a combination of the two. PNM pursued the request until the oil/gas development project pulled out and there was no longer a UP&L need for additional capacity.

West Texas Municipal Power Agency (Agency)

By letter dated November 4, 1985, the Agency requested that PNM submit a proposal for selling power to the Agency from 1990 to 1995. PNM submitted a proposal in February 1986. The Agency, based in Austin, Texas, is a municipal corporation and political subdivision of the State of Texas which represents and purchases power for several Texas municipalities.

JOINT STUDIES

The following is a summary of several joint study efforts with other utilities which are not solely PVNGS Units 1, 2 and 3 owners.

PNM/SDG&E San Juan to Palo Verde Transmission Study

Date Formed: March 1984

Parties: Arizona Public Service Company
Public Service Company of New Mexico
Salt River Project Agricultural Improvement and Power District
San Diego Gas & Electric Company
Western Area Power Administration

Status: Final Report completed 1986

Purpose: Provide a technically acceptable path to deliver 100 MW from San Juan to PVNGS to provide backup for sales to SDG&E normally delivered at PVNGS.

PNM/Plains Escalante Generating Station (PEGS) Study

Date Formed: 1982

Parties: Plains Electric Generation and Transmission Cooperative, Inc.
Public Service Company of New Mexico

Status: Final Reports completed March 1985

Purpose: Determine PEGS operational and impact effects on New Mexico transmission system.

New Mexico Power Pool Planning and Engineering Committee

Date Formed: 1965

Parties: El Paso Electric Company
Plains Electric Generation and Transmission Cooperative, Inc.
Public Service Company of New Mexico
Texas-New Mexico Power Company
Western Area Power Administration

Status: Active

Purpose: Performs annual operating studies.

Kansas-New Mexico HVDC Interconnection Study

Date Formed: 1982

Parties: Plains Electric Generation and Transmission Cooperative, Inc.
Public Service Company of New Mexico
Sunflower Electric Cooperative, Inc.

Status: Study was cancelled in 1982 by mutual agreement.

Purpose: Study potential construction of a transmission line and associated termination facilities to interconnect New Mexico and Kansas.

Navajo/Palo Verde Joint Operating Study Task Force

Date Formed: 1984

Parties: Arizona Public Service Company
El Paso Electric Company
Public Service Company of New Mexico
Southern California Public Power Authority
Los Angeles Department of Water & Power
Tucson Electric Power Company
Imperial Irrigation District
Southern California Edison Company
Salt River Project Agricultural Improvement and Power District
Arizona Nuclear Power District
Nevada Power Company
San Diego Gas & Electric Company
Western Area Power Administration

Status: Active--operating studies for 1986 are in progress. Was previously called Arizona Nuclear Power Plant (ANPP) Ad Hoc Transmission System Planning Committee.

Purpose: Perform annual operating studies for Navajo and PVNGS Plants and associated transmission.

New Mexico-Arizona-Southern California Transmission Study

Date Formed: 1982

Parties: Arizona Public Service Company
Southern California Edison Company
Tucson Electric Power Company
Los Angeles Department of Water & Power
Pacific Gas & Electric Company
Arizona Electric Power Cooperative
El Paso Electric Company
Public Service Company of New Mexico
Salt River Project Agricultural Improvement and Power District
San Diego Gas & Electric Company
Western Area Power Administration

Status: Final Report issued 1982

Purpose: Increase transmission capability from the Four Corners area to Phoenix and Southern California.

Los Alamos County: El Vado/Abiquiu Hydro-Electric Interconnection

Date Formed: 1986

Parties: Public Service Company of New Mexico
Los Alamos County Utilities
Northern Rio Arriba Cooperative
Plains Electric Generating and Transmission Cooperative, Inc.

Status: Just beginning studies

Purpose: Determine technically acceptable interconnection of proposed hydro units in northwestern New Mexico

PGT/PNM B-A to Clovis 345 kV Tap

Date Formed: 1982

Parties: Plains Electric Generation and Transmission Cooperative, Inc.
Public Service Company of New Mexico

Status: A joint study was not made. Individual analyses were shared and discussed and were determined not economically justified at that time (1983).

Purpose: PGT was preparing to serve a future projected demand of one of its industrial customers (AMOCO). PNM was interested in providing future transmission support for PNM's Las Vegas, New Mexico, load area, located between the B-A to Clovis 345 kV tap and the AMOCO load.

Item 2

Licensees whose construction permits include conditions pertaining to antitrust aspects should list and discuss those actions or policies which have been implemented in accordance with such conditions.

Response

The construction permits for PVNGS Units 1, 2, and 3 (CPPR 141, 142, and 143) contain no antitrust conditions pertaining to PNM.

APPENDIX 3A

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - WHOLESALE

CITY OF GALLUP

RATE SCHEDULE

APPLICABILITY:

This rate is available to the City of Gallup (Customer) which purchases power for resale and which has entered into a special contract at three delivery points for a definite capacity commensurate with its normal requirements but in no case less than 10,000 kW nor more than 30,000 kW of capacity.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE:

The service available under this Schedule shall be three-phase service, 60 hertz, delivered at Company's available distribution voltage of 13,800 volts.

PROTECTIVE EQUIPMENT:

Customer shall provide at its expense suitable protective equipment and devices so as to protect Company's system and its service to other electric users from disturbances or faults that may occur on customer's system or equipment.

All such protective equipment is to be installed by Customer and shall be of an approved design and shall conform to the Company's standards.

Customer shall at all times keep each of the three phases balanced as far as practicable so as not to affect service and voltage to other customers served by the Company. Customer shall not operate any equipment in a manner which will cause voltage disturbances elsewhere on Company's system.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION:

The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,181.00/Delivery Point

(B) DEMAND CHARGE: $9.18/kW of billing kilowatt demand

(C) ENERGY CHARGE: 12.631 mills/kWh

(D) POWER FACTOR ADJUSTMENT:

The above rates are based on a power factor of 90 percent or higher and the Company will supply, without additional charge, a maximum of 0.48 kvar (Reactive Kilovolt Amperes) per kW of billing demand. The monthly bill will be increased $.25 for each kvar in excess of the allowed 0.48 RkVA per kW of billing demand.

(E) FUEL COST ADJUSTMENT:

The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order 517 issued November 13, 1974.

1. This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

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"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Tear 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

2. Fuel costs (F) shall be the cost of:

   (a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

   (b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

   (c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

   (d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

4. To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.852 percent.

5. The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT:

Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND:

Metering shall be at 13,800 volts at each point of delivery.

The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

1. The kilowatt demand experienced during the billing month; or

2. the contracted minimum demand of 10,000 kW specified in this Schedule; or

3. 75 percent of the highest monthly billing kilowatt demand established during the preceding 11 months.

DISPUTED BILLS:

In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of one percent (1%) per month from the original due date.

MONTHLY MINIMUM CHARGE:

The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT:

All bills are net and payable within ten (10) days from date of bill.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - WHOLESALE

CITY OF GALLUP

RATE SCHEDULE

APPLICABILITY:

This rate is available to the City of Gallup (Customer) which purchases power for resale and which has entered into a special contract at three delivery points for a definite capacity commensurate with its normal requirements but in no case less than 10,000 kW nor more than 30,000 kW of capacity.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE:

The service available under this Schedule shall be three-phase service, 60 hertz, delivered at Company's available distribution voltage of 13,800 volts.

PROTECTIVE EQUIPMENT:

Customer shall provide at its expense suitable protective equipment and devices so as to protect Company's system and its service to other electric users from disturbances or faults that may occur on customer's system or equipment.

All such protective equipment is to be installed by Customer and shall be of an approved design and shall conform to the Company's standards.

Customer shall at all times keep each of the three phases balanced as far as practicable so as not to affect service and [illegible]age to other customers served by the Company. Customer shall not operate any equipment in a manner which will cause [illegible]tage disturbances elsewhere on Company's system.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION:

The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,027/Delivery Point

(B) DEMAND CHARGE: $11.02/kW of billing kilowatt demand

(C) ENERGY CHARGE: $.012803/kWh

(D) POWER FACTOR ADJUSTMENT:

The above rates are based on a power factor of 90 percent or higher and the Company will supply, without additional charge, a maximum of 0.48 kvar (Reactive Kilovolt Amperes) per kW of billing demand. The monthly bill will be increased $.25 for each kvar in excess of the allowed 0.48 kvar per kW of billing demand.

(E) FUEL COST ADJUSTMENT:

The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order 517 issued November 13, 1974.

1. This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{Fm}{Sm} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

Filed in compliance with an order of the Federal Energy Regulatory Commission issued on March 29, 1982, in Docket No. ER79-478.

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

2. Fuel costs (F) shall be the cost of:

   (a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

   (b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

   (c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

   (d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

4. To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 95.504 percent.

5. The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT:

Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND:

Metering shall be at 13,800 volts at each point of delivery.

The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

1. The kilowatt demand experienced during the billing month; or

2. the contracted minimum demand of 10,000 kW specified in this Schedule.

DISPUTED BILLS:

In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of one percent (1%) per month from the original due date.

MONTHLY MINIMUM CHARGE:

The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT:

All bills are net and payable within ten (10) days from date of bill.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - WHOLESALE

CITY OF GALLUP

SERVICE SCHEDULE A

APPLICABILITY:

This rate is available to the City of Gallup (Customer) which purchases power for resale and which has entered into a special contract dated October 30, 1962, as amended at three delivery points (facilities: Allison, Sunshine, and Fort Wingate) for a definite capacity commensurate with its normal requirements but in no case less than 10,000 kW nor more than 30,000 kW of capacity.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE:

The service available under this Schedule shall be three-phase service, 60 hertz, delivered at Company's available distribution voltage of 13,800 volts.

PROTECTIVE EQUIPMENT:

Customer shall provide at its expense suitable protective equipment and devices so as to protect Company's system and its service to other electric users from disturbances or faults that may occur on customer's system or equipment.

All such protective equipment is to be installed by Customer and shall be of an approved design and shall conform to the Company's standards.

Customer shall at all times keep each of the three phases balanced as far as practicable so as not to affect service and voltage to other customers served by the Company. Customer shall not operate any equipment in a manner which will cause voltage disturbances elsewhere on Company's system.

NET RATE PER MONTH OR PART THEREOF:

The rate for electric service provided shall be the sum of A, B, C, D, E, F, and G:

(A)	SYSTEM CHARGE:	$1,035/Delivery Point (3)
(B)	DEMAND CHARGE:	$14.74/kW of Billing Kilowatt Demand
(C)	ENERGY CHARGE:	13.196 mills/kWh of Billing Energy
(D)	FACILITIES CHARGE:	$2,244/Delivery Point (3) [Allison, Sunshine, and Fort Wingate]

(E) POWER FACTOR ADJUSTMENT:

The above rates are based on a power factor of 90 percent or higher and the Company will supply, without additional charge, a maximum of 0.48 kvar (Reactive Kilovolt Amperes) per kW of billing demand. The monthly bill will be increased $.25 for each kvar in excess of the allowed 0.48 kvar per kW of billing demand.

(F) FUEL COST ADJUSTMENT:

The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order 517 issued November 13, 1974.

1. This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Tear 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

2. Fuel costs (F) shall be the cost of:

   (a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

   (b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

   (c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

   (d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

4. To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.485 percent.

(G) SPECIAL TAX AND ASSESSMENT ADJUSTMENT:

Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND:

Metering shall be at 13,800 volts at each point of delivery.

Total Gallup Demand shall be defined as the sum of the highest demand measured at each and every point of delivery serving Gallup and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company.

Billing Demand under this Service Schedule A shall be either Total Gallup Demand or 30,000 kW, whichever is less, but in no case less than the contract minimum of 10,000 kW.

DETERMINATION OF BILLING ENERGY

Total Gallup Delivered Energy shall be defined as the sum of all energy deliveries at each and every delivery point serving Gallup.

If Total Gallup Demand as defined above does not exceed 30,000 kW, then Billing Energy under Service Schedule A shall be equal to Total Gallup Delivered Energy.

If Total Gallup Demand exceeds 30,000 kW, then Billing Energy under Service Schedule A shall be equal to:

$$\frac{30{,}000 \text{ kW}}{\text{Total Gallup Demand}} \times \text{Total Gallup Delivered Energy}$$

DISPUTED BILLS:

In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of one percent (1%) per month from the original due date.

MONTHLY MINIMUM CHARGE:

The monthly minimum charge under this Schedule shall be the facilities charge plus the demand charge applied to the billing demand, if any, as determined above.

TERMS OF PAYMENT:

All bills are net and payable within ten (10) days from date of bill.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - WHOLESALE

CITY OF GALLUP

SERVICE SCHEDULE B

APPLICABILITY:

This rate is available to the City of Gallup (Customer) which purchases power for resale and which has entered into a special contract dated December 10, 1979, for services to a fourth delivery point upon the completion and in-service date of that fourth point of delivery and for electric service in excess of 30,000 kW of capacity.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE:

The service available under this Schedule shall be three-phase service, 60 hertz, delivered at Company's available distribution voltage of 13,800 volts.

PROTECTIVE EQUIPMENT:

Customer shall provide at its expense suitable protective equipment and devices so as to protect Company's system and its service to other electric users from disturbances or faults that may occur on customer's system or equipment.

All such protective equipment is to be installed by Customer and shall be of an approved design and shall conform to the Company's standards.

Customer shall at all times keep each of the three phases balanced as far as practicable so as not to affect service and voltage to other customers served by the Company. Customer shall not operate any equipment in a manner which will cause voltage disturbances elsewhere on Company's system.

NET RATE PER MONTH OR PART THEREOF:

The rate for electric service provided shall be the sum of A, B, C, D, E, F, and G:

(A) SYSTEM CHARGE:	$1,035/Delivery Point
(B) DEMAND CHARGE:	$14.74/kW of Billing Demand
(C) ENERGY CHARGE:	13.196 mills/kWh of Billing Energy
(D) FACILITIES CHARGE (FOURTH DELIVERY POINT):	$12,404/Delivery Point

(E) POWER FACTOR ADJUSTMENT:

The above rates are based on a power factor of 90 percent or higher and the Company will supply, without additional charge, a maximum of 0.48 kvar (Reactive Kilovolt Amperes) per kW of billing demand. The monthly bill will be increased $.25 for each kvar in excess of the allowed 0.48 kvar per kW of billing demand.

(F) FUEL COST ADJUSTMENT:

The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order 517 issued November 13, 1974.

1. This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Tear 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

2. Fuel costs (F) shall be the cost of:

   (a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

   (b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

   (c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

   (d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

4. To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.485 percent.

(G) SPECIAL TAX AND ASSESSMENT ADJUSTMENT:

Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND:

Metering shall be at 13,800 volts at each point of delivery.

Total Gallup Demand shall be defined as the sum of the highest demand measured at each and every point of delivery serving Gallup and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company.

Billing Demand under this Service Schedule B shall be Total Gallup Demand less the 30,000 kW provided under Service Schedule A but in no case less than zero.

DETERMINATION OF BILLING ENERGY

Total Gallup Delivered Energy shall be defined as the sum of all energy deliveries at each and every delivery point serving Gallup.

If Total Gallup Demand as defined above does not exceed 30,000 kW, then Billing Energy under Service Schedule B shall be zero.

If Total Gallup Demand exceeds 30,000 kW, then Billing Energy under Service Schedule B shall be equal to:

$$\frac{\text{Total Gallup Demand} - 30{,}000\text{ kW}}{\text{Total Gallup Demand}} \times \text{Total Gallup Delivered Energy}$$

DISPUTED BILLS:

In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of one percent (1%) per month from the original due date.

MONTHLY MINIMUM CHARGE:

The monthly minimum charge under this Schedule shall be the facilities charge plus the demand charge applied to the billing demand, if any, as determined above.

TERMS OF PAYMENT:

All bills are net and payable within ten (10) days from date of bill.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - WHOLESALE

CITY OF GALLUP

SERVICE SCHEDULE A

APPLICABILITY:

This rate is available to the City of Gallup (Customer) which purchases power for resale and which has entered into a special contract dated October 30, 1962, as amended at three delivery points (facilities: Allison, Sunshine, and Fort Wingate) for a definite capacity commensurate with its normal requirements but in no case less than 10,000 kW nor more than 30,000 kW of capacity.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE:

The service available under this Schedule shall be three-phase service, 60 hertz, delivered at Company's available distribution voltage of 13,800 volts.

PROTECTIVE EQUIPMENT:

Customer shall provide at its expense suitable protective equipment and devices so as to protect Company's system and its service to other electric users from disturbances or faults that may occur on customer's system or equipment.

All such protective equipment is to be installed by Customer and shall be of an approved design and shall conform to the Company's standards.

Customer shall at all times keep each of the three phases balanced as far as practicable so as not to affect service and voltage to other customers served by the Company. Customer shall not operate any equipment in a manner which will cause voltage disturbances elsewhere on Company's system.

NET RATE PER MONTH OR PART THEREOF;

The rate for electric service provided shall be the sum of A, B, C, D, E, F, and G:

(A) SYSTEM CHARGE:	$1,207/Delivery Point (3)
(B) DEMAND CHARGE:	$16.25/kW of Billing Kilowatt Demand
(C) ENERGY CHARGE:	15.306 mills/kWh of Billing Energy
(D) FACILITIES CHARGE:	$2,280/Delivery Point (3) [Allison, Sunshine, and Fort Wingate]

(E) POWER FACTOR ADJUSTMENT:

The above rates are based on a power factor of 90 percent or higher and the Company will supply, without additional charge, a maximum of .48 kvar (Reactive Kilovolt Amperes) per kW of billing demand. The monthly bill will be increased $.25 for each kvar in excess of the allowed 0.48 kvar per kW of billing demand.

(F) FUEL COST ADJUSTMENT:

The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order 517 issued November 13, 1974.

1. This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

2. Fuel costs (F) shall be the cost of:

   (a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

   (b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below

   (c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

   (d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

4. To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.054 percent.

5. The adjustment factor developed according to this procedure may be further modified to allow the recovery of the gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues. The Loss Adjustment Factor of 97.054 percent will be modified to properly allow for the recovery of the Regulatory Commission Tax of .5 percent. Customer's Revised Loss Adjustment Factor = 97.054 percent ÷ (1-.005) = 97.542 percent.

(G) SPECIAL TAX AND ASSESSMENT ADJUSTMENT

Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND:

Metering shall be at 13,800 volts at each point of delivery.

Total Gallup Demand shall be defined as the sum of the highest demand measured at each and every point of delivery serving Gallup and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company.

Billing Demand under this Service Schedule A shall be either Total Gallup Demand or 30,000 kW, whichever is less, but in no case less than the contract minimum of 10,000 kW.

DETERMINATION OF BILLING ENERGY

Total Gallup Delivered Energy shall be defined as the sum of all energy deliveries at each and every delivery point serving Gallup.

If Total Gallup Demand as defined above does not exceed 30,000 kW, then Billing Energy under Service Schedule A shall be equal to Total Gallup Delivered Energy.

If Total Gallup Demand exceeds 30,000 kW, then Billing Energy under Service Schedule A shall be equal to:

$$\frac{30{,}000 \text{ kW}}{\text{Total Gallup Demand}} \times \text{Total Gallup Delivered Energy}$$

DISPUTED BILLS:

In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of one percent (1%) per month from the original due date.

MONTHLY MINIMUM CHARGE:

The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charges and facilities charges.

TERMS OF PAYMENT:

All bills are net and payable within ten (10) days from date of bill.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - WHOLESALE

CITY OF GALLUP

SERVICE SCHEDULE B

APPLICABILITY:

This rate is available to the City of Gallup (Customer) which purchases power for resale and which has entered into a special contract dated December 10, 1979, for services to a fourth delivery point upon the completion and in-service date of that fourth point of delivery and for electric service in excess of 30,000 kW of capacity.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE:

The service available under this Schedule shall be three-phase service, 60 hertz, delivered at Company's available distribution voltage of 13,800 volts.

PROTECTIVE EQUIPMENT:

Customer shall provide at its expense suitable protective equipment and devices so as to protect Company's system and its service to other electric users from disturbances or faults that may occur on customer's system or equipment.

All such protective equipment is to be installed by Customer and shall be of an approved design and shall conform to the Company's standards.

Customer shall at all times keep each of the three phases balanced as far as practicable so as not to affect service and voltage to other customers served by the Company. Customer shall not operate any equipment in a manner which will cause voltage disturbances elsewhere on Company's system.

NET RATE PER MONTH OR PART THEREOF;

The rate for electric service provided shall be the sum of A, B, C, D, E, F, and G:

(A) SYSTEM CHARGE:	$1,207/Delivery Point
(B) DEMAND CHARGE:	$16.25/kW of Billing Demand
(C) ENERGY CHARGE:	15.306 mills/kWh of Billing Energy
(D) FACILITIES CHARGE (FOURTH DELIVERY POINT):	$15,600/Month

(E) POWER FACTOR ADJUSTMENT:

The above rates are based on a power factor of 90 percent or higher and the Company will supply, without additional charge, a maximum of .48 kvar (Reactive Kilovolt Amperes) per kW of billing demand. The monthly bill will be increased $.25 for each kvar in excess of the allowed 0.48 kvar per kW of billing demand.

(F) FUEL COST ADJUSTMENT:

The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order 517 issued November 13, 1974.

1. This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

2. Fuel costs (F) shall be the cost of:

   (a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

   (b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below

   (c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

   (d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

4. To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.054 percent.

5. The adjustment factor developed according to this procedure may be further modified to allow the recovery of the gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues. The Loss Adjustment Factor of 97.054 percent will be modified to properly allow for the recovery of the Regulatory Commission Tax of .5 percent. Customer's Revised Loss Adjustment Factor = 97.054 percent ÷ (1-.005) = 97.542 percent.

(G) SPECIAL TAX AND ASSESSMENT ADJUSTMENT

Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND:

Metering shall be at 13,800 volts at each point of delivery.

Total Gallup Demand shall be defined as the sum of the highest demand measured at each and every point of delivery serving Gallup and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company.

Billing Demand under this Service Schedule A shall be either Total Gallup Demand or 30,000 kW, whichever is less, but in no case less than the contract minimum of 10,000 kW.

DETERMINATION OF BILLING ENERGY

Total Gallup Delivered Energy shall be defined as the sum of all energy deliveries at each and every delivery point serving Gallup.

If Total Gallup Demand as defined above does not exceed 30,000 kW, then Billing Energy under Service Schedule A shall be equal to Total Gallup Delivered Energy.

If Total Gallup Demand exceeds 30,000 kW, then Billing Energy under Service Schedule A shall be equal to:

$$\frac{30{,}000\ \text{kW}}{\text{Total Gallup Demand}} \times \text{Total Gallup Delivered Energy}$$

DISPUTED BILLS:

In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of one percent (1%) per month from the original due date.

MONTHLY MINIMUM CHARGE:

The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charges and facilities charges.

TERMS OF PAYMENT:

All bills are net and payable within ten (10) days from date of bill.

effective Jan 1, 1977
Full

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - WHOLESALE

CITY OF GALLUP

SERVICE SCHEDULE A

APPLICABILITY:

This rate is available to the City of Gallup (Customer) which purchases power for resale and which has entered into a special contract dated October 30, 1962, as amended at three delivery points (facilities: Allison, Sunshine, and Fort Wingate) for a definite capacity commensurate with its normal requirements but in no case less than 10,000 kW nor more than 30,000 kW of capacity.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE:

The service available under this Schedule shall be three-phase service, 60 hertz, delivered at Company's available distribution voltage of 13,800 volts.

PROTECTIVE EQUIPMENT:

Customer shall provide at its expense suitable protective equipment and devices so as to protect Company's system and its service to other electric users from disturbances or faults that may occur on customer's system or equipment.

All such protective equipment is to be installed by Customer and shall be of an approved design and shall conform to the Company's standards.

Cus[illegible]r shall at all times keep each of the three phases balanced as far as practicable so as not to affect service and vol[illegible] to other customers served by the Company. Customer shall not operate any equipment in a manner which will cause voltage disturbances elsewhere on Company's system.

NET RATE PER MONTH OR PART THEREOF:

The rate for electric service provided shall be the sum of A, B, C, D, E, F, and G:

(A) SYSTEM CHARGE: $500/Delivery Point (3)

(B) DEMAND CHARGE: $19.56/kW of Billing Kilowatt Demand

(C) ENERGY CHARGE: 16.269 mills/kWh of Billing Energy

(D) FACILITIES CHARGE: $2,150/Delivery Point (3) [Allison, Sunshine, and Fort Wingate]

(E) POWER FACTOR ADJUSTMENT:

The above rates are based on a power factor of 90 percent or higher and the Company will supply, without additional charge, a maximum of 0.48 kvar (Reactive Kilovolt Amperes) per kW of billing demand. The monthly bill will be increased $.25 for each kvar in excess of the allowed 0.48 kvar per kW of billing demand.

(F) FUEL COST ADJUSTMENT:

The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order 517 issued November 13, 1974.

1. This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Tear 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

2. Fuel costs (F) shall be the cost of:

   (a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

   (b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

   (c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

   (d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

4. To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.7375 percent.

5. The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues. The Loss Adjustment Factor of 97.7375 percent will be modified to properly allow for the recovery of the Regulatory Commission Tax of .5 percent. Customer's Revised Loss Adjustment Factor = 97.7375 percent ÷ (1-.005) = 98.2286 percent.

(G) SPECIAL TAX AND ASSESSMENT ADJUSTMENT:

Bi[illegible]gs under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Re[illegible]pts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND:

Metering shall be at 13,800 volts at each point of delivery.

Total Gallup Demand shall be defined as the sum of the highest demand measured at each and every point of delivery serving Gallup and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company.

Billing Demand under this Service Schedule A shall be either Total Gallup Demand or 30,000 kW, whichever is less, but in no case less than the contract minimum of 10,000 kW.

DETERMINATION OF BILLING ENERGY

Total Gallup Delivered Energy shall be defined as the sum of all energy deliveries at each and every delivery point serving Gallup.

If Total Gallup Demand as defined above does not exceed 30,000 kW, then Billing Energy under Service Schedule A shall be equal to Total Gallup Delivered Energy.

If Total Gallup Demand exceeds 30,000 kW, then Billing Energy under Service Schedule A shall be equal to:

$$\frac{30{,}000\ \text{kW}}{\text{Total Gallup Demand}} \times \text{Total Gallup Delivered Energy}$$

DISPUTED BILLS:

In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upo :ermination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate .. one percent (1%) per month from the original due date.

MONTHLY MINIMUM CHARGE:

The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charges and facilities charges.

TERMS OF PAYMENT:

All bills are net and payable within ten (10) days from date of bill.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - WHOLESALE

CITY OF GALLUP

SERVICE SCHEDULE B

APPLICABILITY:

This rate is available to the City of Gallup (Customer) which purchases power for resale and which has entered into a special contract dated December 10, 1979, for services to a fourth delivery point upon the completion and in-service date of that fourth point of delivery and for electric service in excess of 30,000 kW of capacity.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE:

The service available under this Schedule shall be three-phase service, 60 hertz, delivered at Company's available distribution voltage of 13,800 volts.

PROTECTIVE EQUIPMENT:

Customer shall provide at its expense suitable protective equipment and devices so as to protect Company's system and its service to other electric users from disturbances or faults that may occur on customer's system or equipment.

All such protective equipment is to be installed by Customer and shall be of an approved design and shall conform to the Company's standards.

Customer shall at all times keep each of the three phases balanced as far as practicable so as not to affect service and voltage to other customers served by the Company. Customer shall not operate any equipment in a manner which will cause voltage disturbances elsewhere on Company's system.

NET RATE PER MONTH OR PART THEREOF:

The rate for electric service provided shall be the sum of A, B, C, D, E, F, and G:

(A) SYSTEM CHARGE:	\$500/Delivery Point
(B) DEMAND CHARGE:	\$19.56/kW of Billing Demand
(C) ENERGY CHARGE:	16.269 mills/kWh of Billing Energy
(D) FACILITIES CHARGE (FOURTH DELIVERY POINT):	\$23,835/Month

(E) POWER FACTOR ADJUSTMENT:

The above rates are based on a power factor of 90 percent or higher and the Company will supply, without additional charge, a maximum of 0.48 kvar (Reactive Kilovolt Amperes) per kW of billing demand. The monthly bill will be increased \$.25 for each kvar in excess of the allowed 0.48 kvar per kW of billing demand.

(F) FUEL COST ADJUSTMENT:

The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order 517 issued November 13, 1974.

1. This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Tear 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

2. Fuel costs (F) shall be the cost of:

   (a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

   (b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

   (c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

   (d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

4. To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.7375 percent.

5. The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues. The Loss Adjustment Factor of 97.7375 percent will be modified to properly allow for the recovery of the Regulatory Commission Tax of .5 percent. Customer's Revised Loss Adjustment Factor = 97.7375 percent ÷ (1-.005) = 98.2286 percent.

(G) SPECIAL TAX AND ASSESSMENT ADJUSTMENT:

Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND:

Metering shall be at 13,800 volts at each point of delivery.

Total Gallup Demand shall be defined as the sum of the highest demand measured at each and every point of delivery serving Gallup and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company.

Billing Demand under this Service Schedule B shall be Total Gallup Demand less the 30,000 kW provided under Service Schedule A but in no case less than zero.

DETERMINATION OF BILLING ENERGY

Total Gallup Delivered Energy shall be defined as the sum of all energy deliveries at each and every delivery point serving Gallup.

If Total Gallup Demand as defined above does not exceed 30,000 kW, then Billing Energy under Service Schedule B shall be zero.

If Total Gallup Demand exceeds 30,000 kW, then Billing Energy under Service Schedule B shall be equal to:

$$\frac{\text{Total Gallup Demand} - 30{,}000 \text{ kW}}{\text{Total Gallup Demand}} \times \text{Total Gallup Delivered Energy}$$

DISPUTED BILLS:

In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of one percent (1%) per month from the original due date.

MONTHLY MINIMUM CHARGE:

The monthly minimum charge under this Schedule shall be the facilities charge plus the demand charge applied to the billing demand, if any, as determined above.

TERMS OF PAYMENT:

All bills are net and payable within ten (10) days from date of bill.

PUBLIC SERVICE COMPANY OF NEW MEXICO
BULK POWER RESALE - WHOLESALE
CITY OF GALLUP
SERVICE SCHEDULE A

APPLICABILITY:

This rate is available to the City of Gallup (Customer) which purchases power for resale and which has entered into a special contract dated October 30, 1962, as amended at three delivery points (facilities: Allison, Sunshine, and Fort Wingate) for a definite capacity commensurate with its normal requirements but in no case less than 10,000 kW nor more than 30,000 kW of capacity.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms and Conditions available at the Company's office and on file with the the New Mexico Public Service Commission (NMPSC) and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE:

The service available under this Schedule shall be three-phase service, 60 hertz, delivered at Company's available distribution voltage of 13,800 volts.

PROTECTIVE EQUIPMENT:

Customer shall provide at its expense suitable protective equipment and devices so as to protect Company's system and its service to other electric users from disturbances or faults that may occur on customer's system or equipment.

All such protective equipment is to be installed by Customer and shall be of an approved design and shall conform to the Company's standards.

Customer shall at all times keep each of the three phases balanced as far as practicable so as not to affect service and voltage to other customers served by the Company. Customer shall not operate any equipment in a manner which will cause voltage disturbances elsewhere on Company's system.

NET RATE PER MONTH OR PART THEREOF:

The rate for electric service provided shall be the sum of A, B, C, D, E, F, and G:

(A) SYSTEM CHARGE:	\$500/Delivery Point (3)
(B) DEMAND CHARGE:	\$22.19/kW of Billing Kilowatt Demand
(C) ENERGY CHARGE:	15.149 mills/kWh of Billing Energy
(D) FACILITIES CHARGE	\$2,690/Delivery Point (3) (Allison, Sunshine, and Fort Wingate)

(E) POWER FACTOR ADJUSTMENT:

The above rates are based on a power factor of 90 percent or higher and the Company will supply, without additional charge, a maximum of 0.48 kvar (Reactive Kilovolt Amperes) per kW of billing demand. The monthly bill will be increased \$.25 for each kvar in excess of the allowed 0.48 kvar per kW of billing demand.

(F) FUEL COST ADJUSTMENT:

The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

1. This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{FB}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

   "F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

2. Fuel costs (F) shall be the cost of:

   (a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

   (b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

   (c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatc basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

   (d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

4. To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.699 percent.

5. The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues. The Loss Adjustment Factor of 97.699 percent will be modified to properly allow for the recovery of the Regulatory Commission Tax of .5 percent. Customer's Revised Loss Adjustment Factor = 97.699 percent ÷ (1-.005) = 98.190 percent.

6. Provided, that on and after September 2, 1986, whenever the foregoing determination would be affected by energy produced from facilities undergoing operational testing prior to being placed into commercial operation, the components of "F" shall be adjusted so that its value will be no higher than it would have been if such test energy were not available.

Test energy not sold off-system will then be deemed available to firm wholesale customers at a price which is equal to or less than the "economy market price" as defined below. In cases where energy is displaced from PNM's electric resources, test energy will be priced at the lower of the economy market price or the fuel cost of displaced energy. This price would be charged to the current customers through the fuel adjustment clause. The revenues received for the value of test energy will be recorded in the construction account.

The economy market price will be determined by taking a simple average of (1) the latest calendar month/four-week weighted average of the prices received by PNM for economy sales and (2) the latest calendar month/four-week weighted average of the prices paid for economy purchases by PNM. All averages will be calculated for the on-peak and off-peak periods depending on the time at which the dispatch transaction occurred. Emergency-type transactions are not included in the determination of the economy market price.

(G) SPECIAL TAX AND ASSESSMENT ADJUSTMENT:

Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state, and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND:

Metering shall be at 13,800 volts at each point of delivery.

Total Gallup Demand shall be defined as the sum of the highest demand measured at each and every point of delivery serving Gallup and shall be the highest 15 minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company.

Billing Demand under this Service Schedule A shall be either Total Gallup Demand or 30,000 kW, whichever is less, but in no case less than the contract minimum of 10,000 kW.

DETERMINATION OF BILLING ENERGY:

Total Gallup Delivered Energy shall be defined as the sum of all energy deliveries at each and every delivery point serving Gallup.

If Total Gallup Demand as defined above does not exceed 30,000 kW, then Billing Energy under Service Schedule A shall be zero.

If Total Gallup Demand exceeds 30,000 kW, then Billing Energy under Service Schedule A shall be equal to:

$$\frac{\text{30,000 kW}}{\text{Total Gallup Demand}} \times \text{Total Gallup Delivered Energy}$$

DISPUTED BILLS:

In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of one percent (1%) per month from the original due date.

MONTHLY MINIMUM CHARGE:

The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system and facilities charges.

TERMS OF PAYMENT:

All bills are net and payable within ten (10) days from date of bill.

PUBLIC SERVICE COMPANY OF NEW MEXICO
BULK POWER RESALE - WHOLESALE
CITY OF GALLUP
SERVICE SCHEDULE B

APPLICABILITY:

This rate is available to the City of Gallup (Customer) which purchases power for resale and which has entered into a special contract dated December 10, 1979, for services to a fourth delivery point upon the completion and in-service date of that fourth point of delivery and for electric service in excess of 30,000 kW of capacity.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the the New Mexico Public Service Commission (NMPSC) and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE:

The service available under this Schedule shall be three-phase service, 60 hertz, delivered at Company's available distribution voltage of 13,800 volts.

PROTECTIVE EQUIPMENT:

Customer shall provide at its expense suitable protective equipment and devices so as to protect Company's system and its service to other electric users from disturbances or faults that may occur on customer's system or equipment.

All such protective equipment is to be installed by Customer and shall be of an approved design and shall conform to the Company's standards.

Customer shall at all times keep each of the three phases balanced as far as practicable so as not to affect service and voltage to other customers served by the Company. Customer shall not operate any equipment in a manner which will cause voltage disturbances elsewhere on Company's system.

NET RATE PER MONTH OR PART THEREOF:

The rate for electric service provided shall be the sum of A, B, C, D, E, F, and G:

(A) SYSTEM CHARGE: $500/Delivery Point

(B) DEMAND CHARGE: $22.19/kW of Billing Demand

(C) ENERGY CHARGE: 15.149 mills/kWh of Billing Energy

(D) FACILITIES CHARGE (FOURTH DELIVERY POINT): $23,835/Month

(E) POWER FACTOR ADJUSTMENT:

The above rates are based on a power factor of 90 percent or higher and the Company will supply, without additional charge, a maximum of 0.48 kvar (Reactive Kilovolt Amperes) per kW of billing demand. The monthly bill will be increased $.25 for each kvar in excess of the allowed 0.48 kvar per kW of billing demand.

(F) FUEL COST ADJUSTMENT:

The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

1. This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{FB}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

2. Fuel costs (F) shall be the cost of:

   (a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

   (b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

   (c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

   (d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

4. To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.699 percent.

5. The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues. The Loss Adjustment Factor of 97.699 percent will be modified to properly allow for the recovery of the Regulatory Commission Tax of .5 percent. Customer's Revised Loss Adjustment Factor = 97.699 percent ÷ (1-.005) = 98.190 percent.

6. Provided, that on and after September 2, 1986, whenever the foregoing determination would be affected by energy produced from facilities undergoing operational testing prior to being placed into commercial operation, the components of "F" shall be adjusted so that its value will be no higher than it would have been if such test energy were not available.

Test energy not sold off-system will then be deemed available to firm wholesale customers at a price which is equal to or less than the "economy market price" as defined below. In cases where energy is displaced from PNM's electric resources, test energy will be priced at the lower of the economy market price or the fuel cost of displaced energy. This price would be charged to the current customers through the fuel adjustment clause. The revenues received for the value of test energy will be recorded in the construction account.

The economy market price will be determined by taking a simple average of (1) the latest calendar month/four-week weighted average of the prices received by PNM for economy sales and (2) the latest calendar month/four-week weighted average of the prices paid for economy purchases by PNM. All averages will be calculated for the on-peak and off-peak periods depending on the time at which the dispatch transaction occurred. Emergency-type transactions are not included in the determination of the economy market price.

(G) SPECIAL TAX AND ASSESSMENT ADJUSTMENT:

Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state, and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND:

Metering shall be at 13,800 volts at each point of delivery.

Total Gallup Demand shall be defined as the sum of the highest demand measured at each and every point of delivery serving Gallup and shall be the highest 15 minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company.

Billing Demand under this Service Schedule A shall be Total Gallup Demand less the 30,000 kW provided under Service Schedule A but in no case less than zero.

DETERMINATION OF BILLING ENERGY:

Total Gallup Delivered Energy shall be defined as the sum of all energy deliveries at each and every delivery point serving Gallup.

If Total Gallup Demand as defined above does not exceed 30,000 kW, then Billing Energy under Service Schedule B shall be zero.

If Total Gallup Demand exceeds 30,000 kW, then Billing Energy under Service Schedule B shall be equal to:

$$\frac{\text{Total Gallup Demand} - 30{,}000\text{ kW}}{\text{Total Gallup Demand}} \times \text{Total Gallup Delivered Energy}$$

DISPUTED BILLS:

In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of one percent (1%) per month from the original due date.

MONTHLY MINIMUM CHARGE:

The monthly minimum charge under this Schedule shall be the facilities charge plus the demand charge applied to the billing demand, if any, as determined above.

TERMS OF PAYMENT:

All bills are net and payable within ten (10) days from date of bill.

ITEM 7

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

(a) Community Public Service, ER77-464, ER78-337

(b) City of Farmington, ER77-464, ER78-337

(c) Department of Energy, ER78-337

(d) U. S. Energy Research and Development Administration, ER77-464

(e) Plains Electric Generation and Transmission Cooperative, Inc., ER77-464, ER78-337

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

COMMUNITY PUBLIC SERVICE

RATE SCHEDULE

APPLICABILITY: This rate is available to Community Public Service Company (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE: The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 345 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION: The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000.00/Delivery Point

(B) DEMAND CHARGE: $9.90/kW of billing kilowatt demand

(C) ENERGY CHARGE: 12.129 mills/kWh

(D) POWER FACTOR ADJUSTMENT: The above rates are based on a power factor of 100 percent and the Company will not supply reactive power on a regular basis.

(E) FUEL COST ADJUSTMENT: The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

(1) This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

(2) Fuel costs (F) shall be the cost of:

(a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

(b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

(c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(3) Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

(4) To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.852 percent.

(5) The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT: Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND: The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

(1) The kilowatt demand experienced during the billing month; or

(2) the contract reserved demand; or

(3) 75 percent of the highest monthly billing kilowatt demand established during the preceding 11 months.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand will be charged at a rate of five (5) times the demand charge for the excess demand.

DISPUTED BILLS: In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of one percent (1%) per month from the original due date.

MONTHLY MINIMUM CHARGE: The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT: All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of one percent (1%) per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

CITY OF FARMINGTON

RATE SCHEDULE

APPLICABILITY: This rate is available to the City of Farmington (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE: The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 115 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION: The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000.00/Delivery Point

(B) DEMAND CHARGE: $9.95/kW of billing kilowatt demand

(C) ENERGY CHARGE: 12.190 mills/kWh

(D) POWER FACTOR ADJUSTMENT: The above rates are based on a power factor of 100 percent and the Company will not supply reactive power.

(E) FUEL COST ADJUSTMENT: The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

(1) This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

(2) Fuel costs (F) shall be the cost of:

(a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

(b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

(c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(3) Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

(4) To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.852 percent.

(5) The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues. The Loss Adjustment Factor of 97.852 percent will be modified to properly allow for the recovery of the Regulatory Commission Tax of .5 percent. Customer's Revised Loss Adjustment Factor = 97.852 percent ÷ (1 - .005) = 98.343 percent.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT: Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND: The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

(1) The kilowatt demand experienced during the billing month; or

(2) the contract reserved demand; or

(3) 75 percent of the highest monthly billing kilowatt demand established during the preceding 11 months.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand will be charged at a rate of five (5) times the demand charge for the excess demand.

DISPUTED BILLS: In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of one percent (1%) per month from the original due date.

MONTHLY MINIMUM CHARGE: The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT: All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of one percent (1%) per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

DEPARTMENT OF ENERGY

RATE SCHEDULE

APPLICABILITY: This rate is available to the Department of Energy (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE: The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 115 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION: The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000.00/Delivery Point

(B) DEMAND CHARGE: $9.95/kW of billing kilowatt demand

(C) ENERGY CHARGE: 12.190 mills/kWh

(D) POWER FACTOR ADJUSTMENT: The above rates are based on a power factor of 100 percent and the Company will not supply reactive power on a regular basis.

(E) FUEL COST ADJUSTMENT: The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

(1) This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

(2) Fuel costs (F) shall be the cost of:

(a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

(b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

(c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(3) Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

(4) To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.852 percent.

(5) The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues. The Loss Adjustment Factor of 97.852 percent will be modified to properly allow for the recovery of the Regulatory Commission Tax of .5 percent. The Department of Energy's Revised Loss Adjustment Factor = 97.852 percent ÷ (1 - .005) = 98.343 percent.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT: Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND: The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by company but in no event shall be less than the highest of the following:

(1) The kilowatt demand experienced during the peak period of the billing month; or

(2) 66.7 percent of the kilowatt demand experienced during the Base Period of the billing month; or

(3) the contract reserved demand; or

(4) 75 percent of the highest monthly billing kilowatt demand established during the preceding eleven months.

Where: The Peak period is that period of time from 0800 hours to 2159 hours, inclusive, Monday through Saturday; and

The Base Period is that period of time from 2400 hours to 0759 hours, inclusive, Monday through Saturday; and on Sunday, the Base Period is from 2400 hours to 2359 hours, inclusive; and

The hours indicated above shall be determined by local clock time.

Further: For the months of June, July, and August billing kilowatt demands which exceed contract reserved demand will be charged at a rate of five (5) times the demand charge for excess demand.

DELIVERIES IN EXCESS OF BILLING DEMAND: This rate schedule does not convey any right for customer to receive higher amounts of firm power and energy than agreed to in the contract to which this rate schedule is attached. However, if the Company agrees to provide power and energy in any month at rates of delivery which would create a Billing Demand in excess of the contract reserved demand, then Customer has a right to firm power and energy up to Billing Demand created for all of the month.

All power and energy provided pursuant to the Rate Schedule at rates of delivery (actual kilowatt demand experienced) greater than the Customer's Billing Demand shall be rendered by Company only on an interruptible basis. Interruptions of deliveries in excess of Billing Demand shall be made as the Company determines they are necessary. However, the Company will not interrupt such excess deliveries for the purpose of making energy available for other deliveries on the basis of profitability. Customer will be curtailed ratably based on its contract reserved demand.

DISPUTED BILLS: In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of interest, as specified in Customer's special contract, per month from the original due date.

MONTHLY MINIMUM CHARGE: The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT: All bills are net and payable within twenty (20) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of interest, as specified in Customer's special contract, per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

PLAINS ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE, INC.

Service Schedule B

RATE SCHEDULE

APPLICABILITY: This rate is available to Plains Electric Generation and Transmission Cooperative, Inc. (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE: The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 115 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION: The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000.00/Delivery Point

(B) DEMAND CHARGE: $9.90/kW of billing kilowatt demand

(C) ENERGY CHARGE: 12.129 mills/kWh

(D) POWER FACTOR ADJUSTMENT: The above rates are based on a power factor of 100 percent. The monthly bill will be increased $.25 for each RkVA supplied and for which PNM is liable to a third party for VAR support.

(E) FUEL COST ADJUSTMENT: The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

(1) This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

(2) Fuel costs (F) shall be the cost of:

(a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

(b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

(c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(3) Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

(4) To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.852 percent.

(5) The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT: Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND: The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

(1) The kilowatt demand experienced during the billing month; or

(2) the contract reserved demand; or

(3) 75 percent of the highest monthly billing kilowatt demand established during the preceding 11 months.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand will be charged at a rate of five (5) times the demand charge for the excess demand.

DISPUTED BILLS: In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of three-fourths of one percent (3/4%) per month from the original due date.

MONTHLY MINIMUM CHARGE: The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT: All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of three-fourths of one percent (3/4%) per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

PLAINS ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE, INC.

AGREEMENT FOR ELECTRIC SERVICE

RATE SCHEDULE

APPLICABILITY: This rate is available to Plains Electric Generation and Transmission Cooperative, Inc. (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE: The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 345 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION: The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000.00/Delivery Point

(B) DEMAND CHARGE: $9.90/kW of billing kilowatt demand

(C) ENERGY CHARGE: 12.129 mills/kWh

(D) POWER FACTOR ADJUSTMENT: The above rates are based on a power factor of 100 percent. The monthly bill will be increased $.25 for each RkVA supplied and for which PNM is liable to a third party for VAR support.

(E) FUEL COST ADJUSTMENT: The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

(1) This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49{,}141{,}998}{4{,}663{,}160{,}000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

(2) Fuel costs (F) shall be the cost of:

(a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

(b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

(c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(3) Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

(4) To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.852 percent.

(5) The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT: Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND: The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

(1) The kilowatt demand experienced during the billing month; or

(2) the contract reserved demand; or

(3) 75 percent of the highest monthly billing kilowatt demand established during the preceding 11 months.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand will be charged at a rate of five (5) times the demand charge for the excess demand.

DISPUTED BILLS: In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of three-fourths of one percent (3/4%) per month from the original due date.

MONTHLY MINIMUM CHARGE: The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT: All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of three-fourths of one percent (3/4%) per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

COMMUNITY PUBLIC SERVICE

RATE SCHEDULE

APPLICABILITY: This rate is available to Community Public Service Company (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE: The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 345 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION: The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000.00/Delivery Point

(B) DEMAND CHARGE: $7.61/kW of billing kilowatt demand

(C) ENERGY CHARGE: 12.250 mills/kWh

(D) POWER FACTOR ADJUSTMENT: The above rates are based on a power factor of 100 percent and the Company will not supply reactive power on a regular basis.

(E) FUEL COST ADJUSTMENT: The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

(1) This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

(2) Fuel costs (F) shall be the cost of:

(a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

(b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

(c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(3) Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

(4) To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 96.632 percent.

(5) The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT: Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND: The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

(1) The kilowatt demand experienced during the billing month; or

(2) the contract reserved demand; or

(3) 75 percent of the highest monthly billing kilowatt demand established during the preceding 11 months.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand will be charged at a rate of five (5) times the demand charge for the excess demand.

DISPUTED BILLS: In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of one percent (1%) per month from the original due date.

MONTHLY MINIMUM CHARGE: The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT: All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of one percent (1%) per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

CITY OF FARMINGTON

RATE SCHEDULE

APPLICABILITY: This rate is available to the City of Farmington (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE: The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 115 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION: The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000.00/Delivery Point

(B) DEMAND CHARGE: $7.65/kW of billing kilowatt demand

(C) ENERGY CHARGE: 12.286 mills/kWh .

(D) POWER FACTOR ADJUSTMENT: The above rates are based on a power factor of 100 percent and the Company will not supply reactive power.

(E) FUEL COST ADJUSTMENT: The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

(1) This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49{,}141{,}998}{4{,}663{,}160{,}000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

(2) Fuel costs (F) shall be the cost of:

(a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

(b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

(c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(3) Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

(4) To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 96.632 percent.

(5) The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues. The Loss Adjustment Factor of 96.632 percent will be modified to properly allow for the recovery of the Regulatory Commission Tax of .5 percent. Customer's Revised Loss Adjustment Factor = 96.632 percent ÷ (1 - .005) = 97.118 percent.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT: Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND: The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

(1) The kilowatt demand experienced during the billing month; or

(2) the contract reserved demand; or

(3) 75 percent of the highest monthly billing kilowatt demand established during the preceding 11 months.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand will be charged at a rate of five (5) times the demand charge for the excess demand.

DISPUTED BILLS: In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of one percent (1%) per month from the original due date.

MONTHLY MINIMUM CHARGE: The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT: All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of one percent (1%) per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

U.S. ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION

RATE SCHEDULE

APPLICABILITY: This rate is available to the Department of Energy (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE: The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 115 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION: The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000.00/Delivery Point

(B) DEMAND CHARGE: $7.65/kW of billing kilowatt demand

(C) ENERGY CHARGE: 12.286 mills/kWh

(D) POWER FACTOR ADJUSTMENT: The above rates are based on a power factor of 100 percent and the Company will not supply reactive power on a regular basis.

(E) FUEL COST ADJUSTMENT: The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

(1) This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

(2) Fuel costs (F) shall be the cost of:

(a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

(b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

(c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(3) Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

(4) To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 96.632 percent.

(5) The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues. The Loss Adjustment Factor of 96.632 percent will be modified to properly allow for the recovery of the Regulatory Commission Tax of .5 percent. The Department of Energy's Revised Loss Adjustment Factor = 96.632 percent ÷ (1 - .005) = 97.118 percent.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT: Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND: The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by company but in no event shall be less than the highest of the following:

(1) The kilowatt demand experienced during the peak period of the billing month; or

(2) 66.7 percent of the kilowatt demand experienced during the Base Period of the billing month; or

(3) the contract reserved demand; or

(4) 75 percent of the highest monthly billing kilowatt demand established during the preceding eleven months.

Where: The Peak period is that period of time from 0800 hours to 2159 hours, inclusive, Monday through Saturday; and

The Base Period is that period of time from 2400 hours to 0759 hours, inclusive, Monday through Saturday; and on Sunday, the Base Period is from 2400 hours to 2359 hours, inclusive; and

The hours indicated above shall be determined by local clock time.

Further: For the months of June, July, and August billing kilowatt demands which exceed contract reserved demand will be charged at a rate of five (5) times the demand charge for excess demand.

DELIVERIES IN EXCESS OF BILLING DEMAND: This rate schedule does not convey any right for customer to receive higher amounts of firm power and energy than agreed to in the contract to which this rate schedule is attached. However, if the Company agrees to provide power and energy in any month at rates of delivery which would create a Billing Demand in excess of the contract reserved demand, then Customer has a right to firm power and energy up to Billing Demand created for all of the month.

All power and energy provided pursuant to the Rate Schedule at rates of delivery (actual kilowatt demand experienced) greater than the Customer's Billing Demand shall be rendered by Company only on an interruptible basis. Interruptions of deliveries in excess of Billing Demand shall be made as the Company determines they are necessary. However, the Company will not interrupt such excess deliveries for the purpose of making energy available for other deliveries on the basis of profitability. Customer will be curtailed ratably based on its contract reserved demand.

DISPUTED BILLS: In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of interest, as specified in Customer's special contract, per month from original due date.

MONTHLY MINIMUM CHARGE: The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT: All bills are net and payable within twenty (20) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of interest, as specified in Customer's special contract, per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

PLAINS ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE, INC.

AGREEMENT FOR ELECTRIC SERVICE

RATE SCHEDULE

APPLICABILITY: This rate is available to Plains Electric Generation and Transmission Cooperative, Inc. (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE: The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 345 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION: The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000.00/Delivery Point

(B) DEMAND CHARGE: $7.61/kW of billing kilowatt demand

(C) ENERGY CHARGE: 12.250 mills/kWh

(D) POWER FACTOR ADJUSTMENT: The above rates are based on a power factor of 100 percent. The monthly bill will be increased $.25 for each RkVA supplied and for which PNM is liable to a third party for VAR support.

(E) FUEL COST ADJUSTMENT: The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

(1) This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

(2) Fuel costs (F) shall be the cost of:

(a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

(b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

(c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(3) Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

(4) To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 96.632 percent.

(5) The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT: Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND: The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

(1) The kilowatt demand experienced during the billing month; or

(2) the contract reserved demand; or

(3) 75 percent of the highest monthly billing kilowatt demand established during the preceding 11 months.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand will be charged at a rate of five (5) times the demand charge for the excess demand.

DISPUTED BILLS: In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of three-fourths of one percent (3/4%) per month from the original due date.

MONTHLY MINIMUM CHARGE: The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT: All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of three-fourths of one percent (3/4%) per month from the due date of payment.

ITEM 8

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

(a) Community Public Service

(b) City of Farmington

(c) Department of Energy

(d) Plains Electric Generation and Transmission Cooperative, Inc.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

COMMUNITY PUBLIC SERVICE

RATE SCHEDULE

APPLICABILITY: This rate is available to Community Public Service Company (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE: The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 345 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION: The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000.00/Delivery Point

(B) DEMAND CHARGE: $11.17/kW of billing kilowatt demand

(C) ENERGY CHARGE: 12.850 mills/kWh

(D) POWER FACTOR ADJUSTMENT: The above rates are based on a power factor of 100 percent and the Company will not supply reactive power on a regular basis.

(E) FUEL COST ADJUSTMENT: The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

(1) This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

(2) Fuel costs (F) shall be the cost of:

(a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

(b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

(c) the net energy cost of energy purchases, exclusive of capacity, or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(3) Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

(4) To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 95.504 percent.

(5) The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT: Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND: The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

(1) The kilowatt demand experienced during the billing month; or

(2) the contract reserved demand; or

(3) 75 percent of the highest monthly billing kilowatt demand established during the preceding 11 months.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand will be charged at a rate of five (5) times the demand charge for the excess demand.

DISPUTED BILLS: In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of one percent (1%) per month from the original due date.

MONTHLY MINIMUM CHARGE: The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT: All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of one percent (1%) per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

CITY OF FARMINGTON

RATE SCHEDULE

APPLICABILITY: This rate is available to the City of Farmington (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE: The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 115 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION: The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000.00/Delivery Point

(B) DEMAND CHARGE: $11.22/kW of billing kilowatt demand

(C) ENERGY CHARGE: 12.915 mills/kWh

(D) POWER FACTOR ADJUSTMENT: The above rates are based on a power factor of 100 percent and the Company will not supply reactive power.

(E) FUEL COST ADJUSTMENT: The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

(1) This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

(2) Fuel costs (F) shall be the cost of:

(a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

(b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

(c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(3) Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

(4) To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 95.504 percent.

(5) The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues. The Loss Adjustment Factor of 95.504 percent will be modified to properly allow for the recovery of the Regulatory Commission Tax of .5 percent. Customers' Revised Loss Adjustment Factor = 95.504 percent ÷ (1 - .005) = 95.984 percent.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT: Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND: The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

(1) The kilowatt demand experienced during the billing month; or

(2) the contract reserved demand; or

(3) 75 percent of the highest monthly billing kilowatt demand established during the preceding 11 months.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand will be charged at a rate of five (5) times the demand charge for the excess demand.

DISPUTED BILLS: In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of one percent (1%) per month from the original due date.

MONTHLY MINIMUM CHARGE: The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT: All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of one percent (1%) per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

DEPARTMENT OF ENERGY

RATE SCHEDULE

APPLICABILITY: This rate is available to the Department of Energy (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE: The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 115 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION: The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000.00/Delivery Point

(B) DEMAND CHARGE: $11.22/kW of billing kilowatt demand

(C) ENERGY CHARGE: 12.915 mills/kWh

(D) POWER FACTOR ADJUSTMENT: The above rates are based on a power factor of 100 percent and the Company will not supply reactive power on a regular basis.

(E) FUEL COST ADJUSTMENT: The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

(1) This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49{,}141{,}998}{4{,}663{,}160{,}000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

(2) Fuel costs (F) shall be the cost of:

(a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

(b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

(c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(3) Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

(4) To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 95.504 percent.

(5) The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues. The Loss Adjustment Factor of 95.504 percent will be modified to properly allow for the recovery of the Regulatory Commission Tax of .5 percent. The Department of Energy's Revised Loss Adjustment Factor = 95.504 percent ÷ (1 - .005) = 95.984 percent.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT: Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND: The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by company but in no event shall be less than the highest of the following:

(1) The kilowatt demand experienced during the peak period of the billing month; or

(2) 66.7 percent of the kilowatt demand experienced during the Base Period of the billing month; or

(3) the contract reserved demand; or

(4) 75 percent of the highest monthly billing kilowatt demand established during the preceding eleven months.

Where: The Peak period is that period of time from 0800 hours to 2159 hours, inclusive, Monday through Saturday; and

The Base Period is that period of time from 2400 hours to 0759 hours, inclusive, Monday through Saturday; and on Sunday, the Base Period is from 2400 hours to 2359 hours, inclusive; and

The hours indicated above shall be determined by local clock time.

Further: For the months of June, July, and August billing kilowatt demands which exceed contract reserved demand will be charged at a rate of five (5) times the demand charge for excess demand.

DELIVERIES IN EXCESS OF BILLING DEMAND: This rate schedule does not convey any right for customer to receive higher amounts of firm power and energy than agreed to in the contract to which this rate schedule is attached. However, if the Company agrees to provide power and energy in any month at rates of delivery which would create a Billing Demand in excess of the contract reserved demand, then Customer has a right to firm power and energy up to Billing Demand created for all of the month.

All power and energy provided pursuant to the Rate Schedule at rates of delivery (actual kilowatt demand experienced) greater than the Customer's Billing Demand shall be rendered by Company only on an interruptible basis. Interruptions of deliveries in excess of Billing Demand shall be made as the Company determines they are necessary. However, the Company will not interrupt such excess deliveries for the purpose of making energy available for other deliveries on the basis of profitability. Customer will be curtailed ratably based on its contract reserved demand.

DISPUTED BILLS: In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of interest, as specified in Customer's special contract, per month from the original due date.

MONTHLY MINIMUM CHARGE: The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT: All bills are net and payable within twenty (20) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of interest, as specified in Customer's special contract, per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

PLAINS ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE, INC.

Service Schedule B

RATE SCHEDULE

APPLICABILITY: This rate is available to Plains Electric Generation and Transmission Cooperative, Inc. (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE: The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 115 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION: The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000.00/Delivery Point

(B) DEMAND CHARGE: $11.17/kW of billing kilowatt demand

(C) ENERGY CHARGE: 12.850 mills/kWh

(D) POWER FACTOR ADJUSTMENT: The above rates are based on a power factor of 100 percent. The monthly bill will be increased $.25 for each RkVA supplied and for which PNM is liable to a third party for VAR support.

(E) FUEL COST ADJUSTMENT: The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

(1) This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

(2) Fuel costs (F) shall be the cost of:

(a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

(b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

(c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(3) Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

(4) To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 95.504 percent.

(5) The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT: Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND: The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

(1) The kilowatt demand experienced during the billing month; or

(2) the contract reserved demand; or

(3) 75 percent of the highest monthly billing kilowatt demand established during the preceding 11 months.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand will be charged at a rate of five (5) times the demand charge for the excess demand.

DISPUTED BILLS: In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of three-fourths of one percent (3/4%) per month from the original due date.

MONTHLY MINIMUM CHARGE: The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT: All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of three-fourths of one percent (3/4%) per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

PLAINS ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE, INC.

AGREEMENT FOR ELECTRIC SERVICE

RATE SCHEDULE

APPLICABILITY: This rate is available to Plains Electric Generation and Transmission Cooperative, Inc. (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE: The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 345 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION: The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000.00/Delivery Point

(B) DEMAND CHARGE: $11.17/kW of billing kilowatt demand

(C) ENERGY CHARGE: 12.850 mills/kWh

(D) POWER FACTOR ADJUSTMENT: The above rates are based on a power factor of 100 percent. The monthly bill will be increased $.25 for each RkVA supplied and for which PNM is liable to a third party for VAR support.

(E) FUEL COST ADJUSTMENT: The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

(1) This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

(2) Fuel costs (F) shall be the cost of:

(a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

(b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

(c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(3) Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

(4) To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 95.504 percent.

(5) The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT: Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND: The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

(1) The kilowatt demand experienced during the billing month; or

(2) the contract reserved demand; or

(3) 75 percent of the highest monthly billing kilowatt demand established during the preceding 11 months.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand will be charged at a rate of five (5) times the demand charge for the excess demand.

DISPUTED BILLS: In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of three-fourths of one percent (3/4%) per month from the original due date.

MONTHLY MINIMUM CHARGE: The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT: All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of three-fourths of one percent (3/4%) per month from the due date of payment.

ITEM 9

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

(a) Community Public Service

(b) City of Farmington

(c) Department of Energy

(d) Plains Electric Generation and Transmission Cooperative, Inc.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

COMMUNITY PUBLIC SERVICE

RATE SCHEDULE

APPLICABILITY: This rate is available to Community Public Service Company (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE: The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 345 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION: The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000.00/Delivery Point

(B) DEMAND CHARGE: $15.78/kW of billing kilowatt demand

(C) ENERGY CHARGE: 13.274 mills/kWh

(D) POWER FACTOR ADJUSTMENT: The above rates are based on a power factor of 100 percent and the Company will not supply reactive power on a regular basis.

(E) FUEL COST ADJUSTMENT: The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

(1) This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

(2) Fuel costs (F) shall be the cost of:

(a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

(b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

(c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(3) Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

(4) To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.485 percent..

(5) The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT: Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND: The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

(1) The kilowatt demand experienced during the billing month; or

(2) the contract reserved demand; or

(3) 75 percent of the highest monthly billing kilowatt demand established during the preceding 11 months.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand will be charged at a rate of five (5) times the demand charge for the excess demand.

DISPUTED BILLS: In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of one percent (1%) per month from the original due date.

MONTHLY MINIMUM CHARGE: The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT: All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of one percent (1%) per month from the due date of payment.

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PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

CITY OF FARMINGTON

RATE SCHEDULE

APPLICABILITY: This rate is available to the City of Farmington (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE: The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 115 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION: The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000.00/Delivery Point

(B) DEMAND CHARGE: $15.86/kW of billing kilowatt demand

(C) ENERGY CHARGE: 13.340 mills/kWh

(D) POWER FACTOR ADJUSTMENT: The above rates are based on a power factor of 100 percent and the Company will not supply reactive power.

(E) FUEL COST ADJUSTMENT: The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

(1) This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

(2) Fuel costs (F) shall be the cost of:

(a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

(b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

(c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(3) Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

(4) To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.485 percent.

(5) The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues. The Loss Adjustment Factor of 97.485 percent will be modified to properly allow for the recovery of the Regulatory Commission Tax of .5 percent. Customer's Revised Loss Adjustment Factor = 97.485 percent ÷ (1 - .005) = 97.975 percent.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT: Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND: The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

(1) The kilowatt demand experienced during the billing month; or

(2) the contract reserved demand; or

(3) 75 percent of the highest monthly billing kilowatt demand established during the preceding 11 months.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand will be charged at a rate of five (5) times the demand charge for the excess demand.

DISPUTED BILLS: In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of one percent (1%) per month from the original due date.

MONTHLY MINIMUM CHARGE: The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT: All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of one percent (1%) per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

DEPARTMENT OF ENERGY

RATE SCHEDULE

APPLICABILITY: This rate is available to the Department of Energy (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE: The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 115 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION: The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000.00/Delivery Point

(B) DEMAND CHARGE: $15.86/kW of billing kilowatt demand

(C) ENERGY CHARGE: 13.340 mills/kWh

(D) POWER FACTOR ADJUSTMENT: The above rates are based on a power factor of 100 percent and the Company will not supply reactive power on a regular basis.

(E) FUEL COST ADJUSTMENT: The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

(1) This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

(2) Fuel costs (F) shall be the cost of:

(a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

(b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

(c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(3) Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

(4) To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.485 percent.

(5) The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues. The Loss Adjustment Factor of 97.485 percent will be modified to properly allow for the recovery of the Regulatory Commission Tax of .5 percent. The Department of Energy's Revised Loss Adjustment Factor = 97.485 percent ÷ (1 - .005) = 97.975 percent.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT: Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND: The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by company but in no event shall be less than the highest of the following:

(1) The kilowatt demand experienced during the peak period of the billing month; or

(2) 66.7 percent of the kilowatt demand experienced during the Base Period of the billing month; or

(3) the contract reserved demand; or

(4) 75 percent of the highest monthly billing kilowatt demand established during the preceding eleven months.

Where: The Peak period is that period of time from 0800 hours to 2159 hours, inclusive, Monday through Saturday; and

The Base Period is that period of time from 2400 hours to 0759 hours, inclusive, Monday through Saturday; and on Sunday, the Base Period is from 2400 hours to 2359 hours, inclusive; and

The hours indicated above shall be determined by local clock time.

Further: For the months of June, July, and August billing kilowatt demands which exceed contract reserved demand will be charged at a rate of five (5) times the demand charge for excess demand.

DELIVERIES IN EXCESS OF BILLING DEMAND: This rate schedule does not convey any right for customer to receive higher amounts of firm power and energy than agreed to in the contract to which this rate schedule is attached. However, if the Company agrees to provide power and energy in any month at rates of delivery which would create a Billing Demand in excess of the contract reserved demand, then Customer has a right to firm power and energy up to Billing Demand created for all of the month.

All power and energy provided pursuant to the Rate Schedule at rates of delivery (actual kilowatt demand experienced) greater than the Customer's Billing Demand shall be rendered by Company only on an interruptible basis. Interruptions of deliveries in excess of Billing Demand shall be made as the Company determines they are necessary. However, the Company will not interrupt such excess deliveries for the purpose of making energy available for other deliveries on the basis of profitability. Customer will be curtailed ratably based on its contract reserved demand.

DISPUTED BILLS: In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of interest, as specified in Customer's special contract, per month from the original due date.

MONTHLY MINIMUM CHARGE: The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT: All bills are net and payable within twenty (20) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of interest, as specified in Customer's special contract, per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

PLAINS ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE, INC.

AGREEMENT FOR ELECTRIC SERVICE

RATE SCHEDULE

APPLICABILITY: This rate is available to Plains Electric Generation and Transmission Cooperative, Inc. (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE: The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 345 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION: The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000.00/Delivery Point

(B) DEMAND CHARGE: $15.78/kW of billing kilowatt demand

(C) ENERGY CHARGE: 13.274 mills/kWh

(D) POWER FACTOR ADJUSTMENT: The above rates are based on a power factor of 100 percent. The monthly bill will be increased $.25 for each RkVA supplied and for which PNM is liable to a third party for VAR support.

(E) FUEL COST ADJUSTMENT: The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

(1) This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

(2) Fuel costs (F) shall be the cost of:

(a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

(b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

(c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(3) Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

(4) To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.485 percent.

(5) The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT: Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND: The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

(1) The kilowatt demand experienced during the billing month; or

(2) the contract reserved demand; or

(3) 75 percent of the highest monthly billing kilowatt demand established during the preceding 11 months.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand will be charged at a rate of five (5) times the demand charge for the excess demand.

DISPUTED BILLS: In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of three-fourths of one percent (3/4%) per month from the original due date.

MONTHLY MINIMUM CHARGE: The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT: All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of three-fourths of one percent (3/4%) per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

PLAINS ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE, INC.

Service Schedule B

RATE SCHEDULE

APPLICABILITY: This rate is available to Plains Electric Generation and Transmission Cooperative, Inc. (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE: The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 115 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION: The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000.00/Delivery Point

(B) DEMAND CHARGE: $15.78/kW of billing kilowatt demand

(C) ENERGY CHARGE: 13.274 mills/kWh

(D) POWER FACTOR ADJUSTMENT: The above rates are based on a power factor of 100 percent. The monthly bill will be increased $.25 for each RkVA supplied and for which PNM is liable to a third party for VAR support.

(E) FUEL COST ADJUSTMENT: The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

(1) This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49{,}141{,}998}{4{,}663{,}160{,}000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

(2) Fuel costs (F) shall be the cost of:

(a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

(b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

(c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(3) Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

(4) To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.485 percent.

(5) The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT: Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND: The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

(1) The kilowatt demand experienced during the billing month; or

(2) the contract reserved demand; or

(3) 75 percent of the highest monthly billing kilowatt demand established during the preceding 11 months.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand will be charged at a rate of five (5) times the demand charge for the excess demand.

DISPUTED BILLS: In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of three-fourths of one percent (3/4%) per month from the original due date.

MONTHLY MINIMUM CHARGE: The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT: All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of three-fourths of one percent (3/4%) per month from the due date of payment.

ITEM 10

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

(a) Plains Electric Generation and Transmission Cooperative, Inc.

(b) Texas-New Mexico Power Company

(c) Department of Energy

(d) City of Farmington

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

PLAINS ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE, INC.

AGREEMENT FOR ELECTRIC SERVICE

RATE SCHEDULE

APPLICABILITY:

This rate is available to Plains Electric Generation and Transmission Cooperative, Inc. (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE:

The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 345 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION:

The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000.00/Delivery Point

(B) DEMAND CHARGE: $16.35/kW of billing kilowatt demand

(C) ENERGY CHARGE: 15.266 mills/kWh

(D) POWER FACTOR ADJUSTMENT:

The above rates are based on a power factor of 100 percent. The monthly bill will be increased $.25 for each RkVA supplied and for which PNM is liable to a third party for VAR support.

(E) FUEL COST ADJUSTMENT:

The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

1. This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{Fm}{Sm} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,003,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

2. Fuel costs (F) shall be the cost of:

   (a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

   (b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

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(c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

4. To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 96.829 percent.

5. The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT:

Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND:

The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

1. The kilowatt demand experienced during the billing month; or

2. the contract reserved demand; or

3. 75 percent of the highest monthly kilowatt demand established by demands actually imposed (or scheduled) by Customer during the preceding 11 months. Provided, however, in instances where Customer has invoked its contractual right to reduce its contract reserved demand, this ratchet provision shall not be invoked unless it was in effect prior to the reduction in contract reserved demand, in which event, this Item 3 shall be the sum of currently effective contract reserved demand and the difference between the previously effective ratcheted billing kilowatt demand and its corresponding reserved demand.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand, and which are established by use rather than the operation of any ratchet provision herein, will be charged at a rate of five (5) times the demand charge for the excess demand.

Provided: Power delivered by virtue of the Company providing emergency service, scheduled outage assistance, or other services pursuant to specific provisions at rates set forth in the contract to which this rate schedule is attached shall not be included in the determination of monthly billing kilowatt demand.

DISPUTED BILLS:

In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of three-fourths of one percent (3/4%) per month from the original due date.

MONTHLY MINIMUM CHARGE:

The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT:

All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of three-fourths of one percent (3/4%) per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

PLAINS ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE, INC.

SERVICE SCHEDULE B

RATE SCHEDULE

APPLICABILITY:

This rate is available to Plains Electric Generation and Transmission Cooperative, Inc. (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE:

The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 115 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION:

The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000.00/Delivery Point

(B) DEMAND CHARGE: $16.35/kW of billing kilowatt demand

(C) ENERGY CHARGE: 15.266 mills/kWh

(D) POWER FACTOR ADJUSTMENT:

The above rates are based on a power factor of 100 percent and the Company will not supply reactive power on a regular basis.

(E) FUEL COST ADJUSTMENT:

The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

1. This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

2. Fuel costs (F) shall be the cost of:

   (a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

   (b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

(c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

4. To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 96.829 percent.

5. The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT:

Billings under this schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND:

The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

1. The kilowatt demand experienced during the billing month; or

2. the contract reserved demand; or

3. 75 percent of the highest monthly kilowatt demand established by demands actually imposed (or scheduled) by Customer during the preceding 11 months. Provided, however, in instances where Customer has invoked its contractual right to reduce its contract reserved demand, this ratchet provision shall not be invoked unless it was in effect prior to the reduction in contract reserved demand, in which event, this Item 3 shall be the sum of currently effective contract reserved demand and the difference between the previously effective ratcheted billing kilowatt demand and its corresponding reserved demand.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand, and which are established by use rather than the operation of any ratchet provision herein, will be charged at a rate of five (5) times the demand charge for the excess demand.

Provided: Power delivered by virtue of the Company providing emergency service, scheduled outage assistance, or other services pursuant to specific provisions at rates set forth in the contract to which this rate schedule is attached shall not be included in the determination of monthly billing kilowatt demand.

DISPUTED BILLS:

In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of three-fourths of one percent (3/4%) per month from the original due date.

MONTHLY MINIMUM CHARGE:

The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT:

All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of three-fourths of one percent (3/4%) per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

TEXAS-NEW MEXICO POWER COMPANY

RATE SCHEDULE

APPLICABILITY:

This rate is available to Texas-New Mexico Power Company (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE:

The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 345 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION:

The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000.00/Delivery Point

(B) DEMAND CHARGE: $16.35/kW of billing kilowatt demand

(C) ENERGY CHARGE: 15.266 mills/kWh

(D) POWER FACTOR ADJUSTMENT:

The above rates are based on a power factor of 100 percent and the Company will not supply reactive power on a regular basis.

(E) FUEL COST ADJUSTMENT:

The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

1. This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

2. Fuel costs (F) shall be the cost of:

   (a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

   (b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

   (c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis.

Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

4. To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 96.829 percent.

5. The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT:

Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND:

The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

1. The kilowatt demand experienced during the billing month; or

2. the contract reserved demand; or

3. 75 percent of the highest monthly kilowatt demand established by demands actually imposed (or scheduled) by Customer during the preceding 11 months. Provided, however, in instances where Customer has invoked its contractual right to reduce its contract reserved demand, this ratchet provision shall not be invoked unless it was in effect prior to the reduction in contract reserved demand, in which event, this Item 3 shall be the sum of currently effective contract reserved demand and the difference between the previously effective ratcheted billing kilowatt demand and its corresponding reserved demand.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand, and which are established by use rather than the operation of any ratchet provision herein, will be charged at a rate of five (5) times the demand charge for the excess demand.

Provided: Power delivered by virtue of the Company providing emergency service, scheduled outage assistance, or other services pursuant to specific provisions at rates set forth in the contract to which this rate schedule is attached shall not be included in the determination of monthly billing kilowatt demand.

DISPUTED BILLS:

In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of one percent (1%) per month from the original due date.

MONTHLY MINIMUM CHARGE:

The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT:

All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of one percent (1%) per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

DEPARTMENT OF ENERGY

RATE SCHEDULE

APPLICABILITY:

This rate is available to the Department of Energy (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE:

The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 115 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION:

The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000.00/Delivery Point

(B) DEMAND CHARGE: $16.44/kW of billing kilowatt demand

(C) ENERGY CHARGE: 15.342 mills/kWh

(D) POWER FACTOR ADJUSTMENT:

The above rates are based on a power factor of 100 percent and the Company will not supply reactive power on a regular basis.

(E) FUEL COST ADJUSTMENT:

The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

1. This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

2. Fuel costs (F) shall be the cost of:

(a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

(b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

(c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis.

Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

4. To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 96.829 percent.

5. The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues. The Loss Adjustment Factor of 96.829 percent will be modified to properly allow for the recovery of the Regulatory Commission Tax of .5 percent. The Department of Energy's Revised Loss Adjustment Factor = 96.829 percent ÷ (1-.005) = 97.316 percent.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT:

Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND:

The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

1. The kilowatt demand experienced during the peak period of the billing month; or

2. 66.7 percent of the kilowatt demand experienced during the Base Period of the billing month; or

3. the contract reserved demand; or

4. 75 percent of the highest monthly kilowatt demand established by demands actually imposed (or scheduled) by Customer during the preceding 11 months. Provided, however, in instances where Customer has invoked its contractual right to reduce its contract reserved demand, this ratchet provision shall not be invoked unless it was in effect prior to the reduction in contract reserved demand, in which event, this Item 3 shall be the sum of currently effective contract reserved demand and the difference between the previously effective ratcheted billing kilowatt demand and its corresponding reserved demand.

where: The Peak Period is that period of time from 0800 hours to 2159 hours, inclusive, Monday through Saturday; and

The Base Period is that period of time from 2400 hours to 0759 hours, inclusive; and from 2200 hours to 2359 hours, inclusive, Monday through Saturday; and on Sunday, the Base Period is from 2400 hours to 2359 hours, inclusive; and

The hours indicated above shall be determined by local clock time.

further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand, and which are established by use rather than the operation of any ratchet provision herein, will be charged at a rate of five (5) times the demand charge for the excess demand.

provided: Power delivered by virtue of the Company providing emergency service, scheduled outage assistance, or other services pursuant to specific provisions at rates set forth in the contract to which this rate schedule is attached shall not be included in the determination of monthly billing kilowatt demand.

DELIVERIES IN EXCESS OF BILLING DEMAND:

This Rate Schedule does not convey any right for customer to receive higher amounts of firm power and energy than agreed to in the contract to which this rate schedule is attached. However, if the Company agrees to provide power and energy in any month at rates of delivery which would create a Billing Demand in excess of the contract reserved demand, then customer has a right to firm power and energy up to the Billing Demand created for all of that month.

All power and energy provided pursuant to this Rate Schedule at rates of delivery (actual kilowatt demand experienced) greater than the customer's Billing Demand shall be rendered by Company only on an interruptible basis. Interruptions of deliveries in excess of Billing Demand shall be made as the Company determines they are necessary. However, the Company will not interrupt such excess deliveries for the purpose of making energy available for other deliveries on the basis of profitability. Customer will be curtailed ratably based on its contract reserved demand.

DISPUTED BILLS:

In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of interest, as specified in Customer's special contract, per month from the original due date.

MONTHLY MINIMUM CHARGE:

The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT:

All bills are net and payable within twenty (20) days from date of receipt of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of interest, as specified in Customer's special contract, per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

CITY OF FARMINGTON

RATE SCHEDULE

APPLICABILITY:

This rate is available to the City of Farmington (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE:

The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 115 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION:

The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000.00/Delivery Point

(B) DEMAND CHARGE: $16.44/kW of billing kilowatt demand

(C) ENERGY CHARGE: 15.342 mills/kWh

(D) POWER FACTOR ADJUSTMENT:

The above rates are based on a power factor of 100 percent and the Company will not supply reactive power.

(E) FUEL COST ADJUSTMENT:

The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

1. This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

2. Fuel costs (F) shall be the cost of:

(a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

(b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

(c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

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(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

4. To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 96.829 percent.

5. The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues. The Loss Adjustment Factor of 96.829 percent will be modified to properly allow for the recovery of the Regulatory Commission Tax of .5 percent. Customer's Revised Loss Adjustment Factor = 96.829 percent ÷ (1-.005) = 97.316 percent.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT:

Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND:

The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

1. The kilowatt demand experienced during the billing month; or

2. the contract reserved demand; or

3. 75 percent of the highest monthly kilowatt demand established by demands actually imposed (or scheduled) by Customer during the preceding 11 months. Provided, however, in instances where Customer has invoked its contractual right to reduce its contract reserved demand, this ratchet provision shall not be invoked unless it was in effect prior to the reduction in contract reserved demand, in which event, this Item 3 shall be the sum of currently effective contract reserved demand and the difference between the previously effective ratcheted billing kilowatt demand and its corresponding reserved demand.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand, and which are established by use rather than the operation of any ratchet provision herein, will be charged at a rate of five (5) times the demand charge for the excess demand.

Provided: Power delivered by virtue of the Company providing emergency service, scheduled outage assistance, or other services pursuant to specific provisions at rates set forth in the contract to which this rate schedule is attached shall not be included in the determination of monthly billing kilowatt demand.

DISPUTED BILLS:

In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of one percent (1%) per month from the original due date.

MONTHLY MINIMUM CHARGE:

The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT:

All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of one percent (1%) per month from the due date of payment.

ITEM 11

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

(a) Plains Electric Generation and Transmission Cooperative, Inc.

(b) Texas-New Mexico Power Company

(c) Department of Energy

(d) City of Farmington

APPENDIX A

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

PLAINS ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE, INC.

AGREEMENT FOR ELECTRIC SERVICE

RATE SCHEDULE

APPLICABILITY:

This rate is available to Plains Electric Generation and Transmission Cooperative, Inc. (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE:

The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 345 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION:

The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000/Delivery Point

(B) DEMAND CHARGE: $20.47/kW of billing kilowatt demand

(C) ENERGY CHARGE: 16.188 mills/kWh

(D) POWER FACTOR ADJUSTMENT:

The above rates are based on a power factor of 100 percent. The monthly bill will be increased $.25 for each RkVA supplied and for which PNM is liable to a third party for VAR support.

(E) FUEL COST ADJUSTMENT:

The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

1. This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where:} \ \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

2. Fuel costs (F) shall be the cost of:

   (a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

   (b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

(c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

4. To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.7375 percent.

5. The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT:

Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND:

The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

1. The kilowatt demand experienced during the billing month; or

2. the contract reserved demand; or

3. 75 percent of the highest monthly kilowatt demand established by demands actually imposed (or scheduled) by Customer during the preceding 11 months. Provided, however, in instances where Customer has invoked its contractual right to reduce its contract reserved demand, this ratchet provision shall not be invoked unless it was in effect prior to the reduction in contract reserved demand, in which event, this Item 3 shall be the sum of currently effective contract reserved demand and the difference between the previously effective ratcheted billing kilowatt demand and its corresponding reserved demand.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand, and which are established by use rather than the operation of any ratchet provision herein, will be charged at a rate of five (5) times the demand charge for the excess demand.

Provided: Power delivered by virtue of the Company providing emergency service, scheduled outage assistance, or other services pursuant to specific provisions at rates set forth in the contract to which this rate schedule is attached shall not be included in the determination of monthly billing kilowatt demand.

DISPUTED BILLS:

In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of three-fourths of one percent (3/4%) per month from the original due date.

MONTHLY MINIMUM CHARGE:

The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT:

All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of three-fourths of one percent (3/4%) per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

PLAINS ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE, INC.

SERVICE SCHEDULE B

RATE SCHEDULE

APPLICABILITY:

This rate is available to Plains Electric Generation and Transmission Cooperative, Inc. (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE:

The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 115 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION:

The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000/Delivery Point

(B) DEMAND CHARGE: $20.47/kW of billing kilowatt demand

(C) ENERGY CHARGE: 16.188 mills/kWh

(D) POWER FACTOR ADJUSTMENT:

The above rates are based on a power factor of 100 percent and the Company will not supply reactive power on a regular basis.

(E) FUEL COST ADJUSTMENT:

The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

1. This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

2. Fuel costs (F) shall be the cost of:

   (a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

   (b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

(c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

4. To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.7375 percent.

5. The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT:

Billings under this schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND:

The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

1. The kilowatt demand experienced during the billing month; or

2. the contract reserved demand; or

3. 75 percent of the highest monthly kilowatt demand established by demands actually imposed (or scheduled) by Customer during the preceding 11 months. Provided, however, in instances where Customer has invoked its contractual right to reduce its contract reserved demand, this ratchet provision shall not be invoked unless it was in effect prior to the reduction in contract reserved demand, in which event, this Item 3 shall be the sum of currently effective contract reserved demand and the difference between the previously effective ratcheted billing kilowatt demand and its corresponding reserved demand.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand, and which are established by use rather than the operation of any ratchet provision herein, will be charged at a rate of five (5) times the demand charge for the excess demand.

Provided: Power delivered by virtue of the Company providing emergency service, scheduled outage assistance, or other services pursuant to specific provisions at rates set forth in the contract to which this rate schedule is attached shall not be included in the determination of monthly billing kilowatt demand.

DISPUTED BILLS:

In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of three-fourths of one percent (3/4%) per month from the original due date.

MONTHLY MINIMUM CHARGE:

The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT:

All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of three-fourths of one percent (3/4%) per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

TEXAS-NEW MEXICO POWER COMPANY

RATE SCHEDULE

APPLICABILITY:

This rate is available to Texas-New Mexico Power Company (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE:

The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 345 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION:

The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000/Delivery Point

(B) DEMAND CHARGE: $20.47/kW of billing kilowatt demand

(C) ENERGY CHARGE: 16.188 mills/kWh

(D) POWER FACTOR ADJUSTMENT:

The above rates are based on a power factor of 100 percent and the Company will not supply reactive power on a regular basis.

(E) FUEL COST ADJUSTMENT:

The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

1. This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141.998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

2. Fuel costs (F) shall be the cost of:

   (a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

   (b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

   (c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis.

Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

4. To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.7375 percent.

5. The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT:

Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND:

The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

1. The kilowatt demand experienced during the billing month; or

2. the contract reserved demand; or

3. 75 percent of the highest monthly kilowatt demand established by demands actually imposed (or scheduled) by Customer during the preceding 11 months. Provided, however, in instances where Customer has invoked its contractual right to reduce its contract reserved demand, this ratchet provision shall not be invoked unless it was in effect prior to the reduction in contract reserved demand, in which event, this Item 3 shall be the sum of currently effective contract reserved demand and the difference between the previously effective ratcheted billing kilowatt demand and its corresponding reserved demand.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand, and which are established by use rather than the operation of any ratchet provision herein, will be charged at a rate of five (5) times the demand charge for the excess demand.

Provided: Power delivered by virtue of the Company providing emergency service, scheduled outage assistance, or other services pursuant to specific provisions at rates set forth in the contract to which this rate schedule is attached shall not be included in the determination of monthly billing kilowatt demand.

DISPUTED BILLS:

In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of one percent (1%) per month from the original due date.

MONTHLY MINIMUM CHARGE:

The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT:

All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of one percent (1%) per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

DEPARTMENT OF ENERGY

RATE SCHEDULE

APPLICABILITY:

This rate is available to the Department of Energy (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE:

The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 115 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION:

The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000/Delivery Point

(B) DEMAND CHARGE: $20.58/kW of billing kilowatt demand

(C) ENERGY CHARGE: 16.269 mills/kWh

(D) POWER FACTOR ADJUSTMENT:

The above rates are based on a power factor of 100 percent and the Company will not supply reactive power on a regular basis.

(E) FUEL COST ADJUSTMENT:

The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

1. This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

2. Fuel costs (F) shall be the cost of:

   (a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

   (b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

   (c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis.

Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

4. To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.7375 percent.

5. The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues. The Loss Adjustment Factor of 97.7375 percent will be modified to properly allow for the recovery of the Regulatory Commission Tax of .5 percent. The Department of Energy's Revised Loss Adjustment Factor = 97.7375 percent ÷ (1-.005) = 98.2286 percent.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT:

Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND:

The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

1. The kilowatt demand experienced during the peak period of the billing month; or

2. 66.7 percent of the kilowatt demand experienced during the Base Period of the billing month; or

3. the contract reserved demand; or

4. 75 percent of the highest monthly kilowatt demand established by demands actually imposed (or scheduled) by Customer during the preceding 11 months. Provided, however, in instances where Customer has invoked its contractual right to reduce its contract reserved demand, this ratchet provision shall not be invoked unless it was in effect prior to the reduction in contract reserved demand, in which event, this Item 3 shall be the sum of currently effective contract reserved demand and the difference between the previously effective ratcheted billing kilowatt demand and its corresponding reserved demand.

where: The Peak Period is that period of time from 0800 hours to 2159 hours, inclusive, Monday through Saturday; and

The Base Period is that period of time from 2400 hours to 0759 hours, inclusive; and from 2200 hours to 2359 hours, inclusive, Monday through Saturday; and on Sunday, the Base Period is from 2400 hours to 2359 hours, inclusive; and

The hours indicated above shall be determined by local clock time.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand, and which are established by use rather than the operation of any ratchet provision herein, will be charged at a rate of five (5) times the demand charge for the excess demand.

DELIVERIES IN EXCESS OF BILLING DEMAND:

This Rate Schedule does not convey any right for customer to receive higher amounts of firm power and energy than agreed to in the contract to which this rate schedule is attached. However, if the Company agrees to provide power and energy in any month at rates of delivery which would create a Billing Demand in excess of the contract reserved demand, then customer has a right to firm power and energy up to the Billing Demand created for all of that month.

All power and energy provided pursuant to this Rate Schedule at rates of delivery (actual kilowatt demand experienced) greater than the customer's Billing Demand shall be rendered by Company only on an interruptible basis. Interruptions of deliveries in excess of Billing Demand shall be made as the Company determines they are necessary. However, the Company will not interrupt such excess deliveries for the purpose of making energy available for other deliveries on the basis of profitability. Customer will be curtailed ratably based on its contract reserved demand.

DISPUTED BILLS:

In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of interest, as specified in Customer's special contract, per month from the original due date.

MONTHLY MINIMUM CHARGE:

The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT:

All bills are net and payable within twenty (20) days from date of receipt of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of interest, as specified in Customer's special contract, per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

CITY OF FARMINGTON

RATE SCHEDULE

APPLICABILITY:

This rate is available to the City of Farmington (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE:

The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 115 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION:

The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000/Delivery Point

(B) DEMAND CHARGE: $20.58/kW of billing kilowatt demand

(C) ENERGY CHARGE: 16.269 mills/kWh

(D) POWER FACTOR ADJUSTMENT:

The above rates are based on a power factor of 100 percent and the Company will not supply reactive power.

(E) FUEL COST ADJUSTMENT:

The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

1. This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

2. Fuel costs (F) shall be the cost of:

   (a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

   (b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

   (c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

4. To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.7375 percent.

5. The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues. The Loss Adjustment Factor of 97.7375 percent will be modified to properly allow for the recovery of the Regulatory Commission Tax of .5 percent. Customer's Revised Loss Adjustment Factor = 97.7375 percent ÷ (1-.005) = 98.2286 percent.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT:

Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND:

The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

1. The kilowatt demand experienced during the billing month; or

2. the contract reserved demand; or

3. 75 percent of the highest monthly kilowatt demand established by demands actually imposed (or scheduled) by Customer during the preceding 11 months. Provided, however, in instances where Customer has invoked its contractual right to reduce its contract reserved demand, this ratchet provision shall not be invoked unless it was in effect prior to the reduction in contract reserved demand, in which event, this Item 3 shall be the sum of currently effective contract reserved demand and the difference between the previously effective ratcheted billing kilowatt demand and its corresponding reserved demand.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand, and which are established by use rather than the operation of any ratchet provision herein, will be charged at a rate of five (5) times the demand charge for the excess demand.

Provided: Power delivered by virtue of the Company providing emergency service, scheduled outage assistance, or other services pursuant to specific provisions at rates set forth in the contract to which this rate schedule is attached shall not be included in the determination of monthly billing kilowatt demand.

DISPUTED BILLS:

In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of one percent (1%) per month from the original due date.

MONTHLY MINIMUM CHARGE:

The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT:

All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of one percent (1%) per month from the due date of payment.

ITEM 12

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

(a) Plains Electric Generation and Transmission Cooperative, Inc.

(b) Texas-New Mexico Power Company

(c) Department of Energy

(d) City of Farmington

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

PLAINS ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE, INC.

AGREEMENT FOR ELECTRIC SERVICE

RATE SCHEDULE

APPLICABILITY:

This rate is available to Plains Electric Generation and Transmission Cooperative, Inc. (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE:

The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 345 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION:

The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000/Delivery Point

(B) DEMAND CHARGE: $23.22/kW of billing kilowatt demand

(C) ENERGY CHARGE: 14.943 mills/kWh

(D) POWER FACTOR ADJUSTMENT:

The above rates are based on a power factor of 100 percent. The monthly bill will be increased $.25 for each RkVA supplied and for which PNM is liable to a third party for VAR support.

(E) FUEL COST ADJUSTMENT:

The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

1. This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

2. Fuel costs (F) shall be the cost of:

   (a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

   (b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

(c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

4. To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.699 percent.

5. The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT:

Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND:

The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

1. The kilowatt demand experienced during the billing month; or

2. the contract reserved demand; or

3. 75 percent of the highest monthly kilowatt demand established by demands actually imposed (or scheduled) by Customer during the preceding 11 months. Provided, however, in instances where Customer has invoked its contractual right to reduce its contract reserved demand, this ratchet provision shall not be invoked unless it was in effect prior to the reduction in contract reserved demand, in which event, this Item 3 shall be the sum of currently effective contract reserved demand and the difference between the previously effective ratcheted billing kilowatt demand and its corresponding reserved demand.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand, and which are established by use rather than the operation of any ratchet provision herein, will be charged at a rate of five (5) times the demand charge for the excess demand.

Provided: Power delivered by virtue of the Company providing emergency service, scheduled outage assistance, or other services pursuant to specific provisions at rates set forth in the contract to which this rate schedule is attached shall not be included in the determination of monthly billing kilowatt demand.

DISPUTED BILLS:

In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of three-fourths of one percent (3/4%) per month from the original due date.

MONTHLY MINIMUM CHARGE:

The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT:

All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of three-fourths of one percent (3/4%) per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

PLAINS ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE, INC.

SERVICE SCHEDULE B

RATE SCHEDULE

APPLICABILITY:

This rate is available to Plains Electric Generation and Transmission Cooperative, Inc. (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE:

The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 115 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION:

The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000/Delivery Point

(B) DEMAND CHARGE: $23.22/kW of billing kilowatt demand

(C) ENERGY CHARGE: 14.943 mills/kWh

(D) POWER FACTOR ADJUSTMENT:

The above rates are based on a power factor of 100 percent and the Company will not supply reactive power on a regular basis.

(E) FUEL COST ADJUSTMENT:

The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

1. This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

2. Fuel costs (F) shall be the cost of:

   (a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

   (b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

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(c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

4. To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.699 percent.

5. The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT:

Billings under this schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND:

The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

1. The kilowatt demand experienced during the billing month; or

2. the contract reserved demand; or

3. 75 percent of the highest monthly kilowatt demand established by demands actually imposed (or scheduled) by Customer during the preceding 11 months. Provided, however, in instances where Customer has invoked its contractual right to reduce its contract reserved demand, this ratchet provision shall not be invoked unless it was in effect prior to the reduction in contract reserved demand, in which event, this Item 3 shall be the sum of currently effective contract reserved demand and the difference between the previously effective ratcheted billing kilowatt demand and its corresponding reserved demand.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand, and which are established by use rather than the operation of any ratchet provision herein, will be charged at a rate of five (5) times the demand charge for the excess demand.

Provided: Power delivered by virtue of the Company providing emergency service, scheduled outage assistance, or other services pursuant to specific provisions at rates set forth in the contract to which this rate schedule is attached shall not be included in the determination of monthly billing kilowatt demand.

DISPUTED BILLS:

In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of three-fourths of one percent (3/4%) per month from the original due date.

MONTHLY MINIMUM CHARGE:

The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT:

All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of three-fourths of one percent (3/4%) per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

TEXAS-NEW MEXICO POWER COMPANY

RATE SCHEDULE

APPLICABILITY:

This rate is available to Texas-New Mexico Power Company (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE:

The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 345 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION:

The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000/Delivery Point

(B) DEMAND CHARGE: $23.22/kW of billing kilowatt demand

(C) ENERGY CHARGE: 14.943 mills/kWh

) POWER FACTOR ADJUSTMENT:

The above rates are based on a power factor of 100 percent and the Company will not supply reactive power on a regular basis.

(E) FUEL COST ADJUSTMENT:

The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

1. This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

2. Fuel costs (F) shall be the cost of:

   (a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

   (b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

   (c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis.

Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

4. To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.699 percent.

5. The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT:

Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND:

The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

1. The kilowatt demand experienced during the billing month; or

2. the contract reserved demand; or

3. 75 percent of the highest monthly kilowatt demand established by demands actually imposed (or scheduled) by Customer during the preceding 11 months. Provided, however, in instances where Customer has invoked its contractual right to reduce its contract reserved demand, this ratchet provision shall not be invoked unless it was in effect prior to the reduction in contract reserved demand, in which event, this Item 3 shall be the sum of currently effective contract reserved demand and the difference between the previously effective ratcheted billing kilowatt demand and its corresponding reserved demand.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand, and which are established by use rather than the operation of any ratchet provision herein, will be charged at a rate of five (5) times the demand charge for the excess demand.

Provided: Power delivered by virtue of the Company providing emergency service, scheduled outage assistance, or other services pursuant to specific provisions at rates set forth in the contract to which this rate schedule is attached shall not be included in the determination of monthly billing kilowatt demand.

DISPUTED BILLS:

In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of one percent (1%) per month from the original due date.

MONTHLY MINIMUM CHARGE:

The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT:

All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of one percent (1%) per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

DEPARTMENT OF ENERGY

RATE SCHEDULE

APPLICABILITY:

This rate is available to the Department of Energy (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms, and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE:

The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 115 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION:

The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000/Delivery Point

(B) DEMAND CHARGE: $23.33/kW of billing kilowatt demand

(C) ENERGY CHARGE: 15.017 mills/kWh

(D) POWER FACTOR ADJUSTMENT:

The above rates are based on a power factor of 100 percent and the Company will not supply reactive power on a regular basis.

(E) FUEL COST ADJUSTMENT:

The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

1. This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

2. Fuel costs (F) shall be the cost of:

   (a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

   (b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

   (c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis.

Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

4. To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.699 percent.

5. The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues. The Loss Adjustment Factor of 97.699 percent will be modified to properly allow for the recovery of the Regulatory Commission Tax of .5 percent. The Department of Energy's Revised Loss Adjustment Factor = 97.699 percent ÷ (1-.005) = 98.190 percent.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT:

Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND:

The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

1. The kilowatt demand experienced during the peak period of the billing month; or

2. 66.7 percent of the kilowatt demand experienced during the Base Period of the billing month; or

3. the contract reserved demand; or

4. 75 percent of the highest monthly kilowatt demand established by demands actually imposed (or scheduled) by Customer during the preceding 11 months. Provided, however, in instances where Customer has invoked its contractual right to reduce its contract reserved demand, this ratchet provision shall not be invoked unless it was in effect prior to the reduction in contract reserved demand, in which event, this Item 3 shall be the sum of currently effective contract reserved demand and the difference between the previously effective ratcheted billing kilowatt demand and its corresponding reserved demand.

where: The Peak Period is that period of time from 0800 hours to 2159 hours, inclusive, Monday through Saturday; and

The Base Period is that period of time from 2400 hours to 0759 hours, inclusive; and from 2200 hours to 2359 hours, inclusive, Monday through Saturday; and on Sunday, the Base Period is from 2400 hours to 2359 hours, inclusive; and

The hours indicated above shall be determined by local clock time.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand, and which are established by use rather than the operation of any ratchet provision herein, will be charged at a rate of five (5) times the demand charge for the excess demand.

DELIVERIES IN EXCESS OF BILLING DEMAND:

This Rate Schedule does not convey any right for customer to receive higher amounts of firm power and energy than agreed to in the contract to which this rate schedule is attached. However, if the Company agrees to provide power and energy in any month at rates of delivery which would create a Billing Demand in excess of the contract reserved demand, then customer has a right to firm power and energy up to the Billing Demand created for all of that month.

All power and energy provided pursuant to this Rate Schedule at rates of delivery (actual kilowatt demand experienced) greater than the customer's Billing Demand shall be rendered by Company only on an interruptible basis. Interruptions of deliveries in excess of Billing Demand shall be made as the Company determines they are necessary. However, the Company will not interrupt such excess deliveries for the purpose of making energy available for other deliveries on the basis of profitability. Customer will be curtailed ratably based on its contract reserved demand.

DISPUTED BILLS:

case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of interest, as specified in Customer's special contract, per month from the original due date.

MONTHLY MINIMUM CHARGE:

The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT:

All bills are net and payable within twenty (20) days from date of receipt of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of interest, as specified in Customer's special contract, per month from the due date of payment.

PUBLIC SERVICE COMPANY OF NEW MEXICO

BULK POWER RESALE - SUPPLEMENTAL WHOLESALE

CITY OF FARMINGTON

RATE SCHEDULE

APPLICABILITY:

This rate is available to the City of Farmington (Customer) which purchases power for resale and which has entered into a special contract for a definite capacity commensurate with its normal requirements for that load specified in its special contract.

Service will be furnished in accordance with the following stipulations and in accordance with the Company's General Rules, Terms and Conditions available at the Company's office and on file with the New Mexico Public Service Commission and/or the Federal Energy Regulatory Commission, which General Rules or subsequent revisions thereof are a part of this Schedule as if fully written herein.

TYPE OF SERVICE:

The service available under this Schedule shall be three-phase service, 60 hertz, and furnished and metered at Company's bulk transmission voltage of 115 kV.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION:

The rate for electric service provided shall be the sum of A, B, C, D, E, and F:

(A) SYSTEM CHARGE: $1,000/Delivery Point

(B) DEMAND CHARGE: $23.33/kW of billing kilowatt demand

(C) ENERGY CHARGE: 15.017 mills/kWh

(D) POWER FACTOR ADJUSTMENT:

The above rates are based on a power factor of 100 percent and the Company will not supply reactive power.

(E) FUEL COST ADJUSTMENT:

The fuel cost adjustment clause in this rate is designed in accordance with the provisions of Section 35.14 of the Code of Federal Regulations as amended by FPC Order No. 517 issued November 13, 1974.

1. This fuel clause provides for monthly adjustments per kWh for sales equal to the difference between the fuel cost per kWh of sales in the base period of Test Year 1977 (as determined in FERC Docket ER77-464) and in the current month:

$$\text{Adjustment Factor} = \frac{FM}{SM} - \frac{Fb}{Sb}$$

$$\text{Where: } \frac{Fb}{Sb} = \frac{\$49,141,998}{4,663,160,000\text{kWh}} = \$.010538/\text{kWh}$$

"F" is the expense of fossil and nuclear fuel in the base period (b) of Test Year 1977 (as determined in FERC Docket ER77-464) and the current month (M); and "S" is the kWh sales in the base and current periods, all as defined below:

2. Fuel costs (F) shall be the cost of:

   (a) fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly-owned or leased plants.

   (b) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below.

   (c) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) the cost of fossil and nuclear fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be all kWh's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (a) generation, (b) purchases, (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) intersystem sales referred to in 2-d above, less (f) total system losses.

4. To properly allow for losses, the adjustment factor developed according to this procedure shall be multiplied by customer's Loss Adjustment Factor of 97.699 percent.

5. The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and, other similar revenue based tax charges occasioned by the fuel adjustment revenues. The Loss Adjustment Factor of 97.699 percent will be modified to properly allow for the recovery of the Regulatory Commission Tax of .5 percent. Customer's Revised Loss Adjustment Factor = 97.699 percent + (1-.005) = 98.190 percent.

(F) SPECIAL TAX AND ASSESSMENT ADJUSTMENT:

Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF BILLING DEMAND:

The monthly billing kilowatt demand shall be determined by measurement and shall be the highest 15-minute integrated or thermal kW demand as measured by standard metering equipment or by calculations based upon measurements made by other types of standard metering equipment furnished by Company but in no event shall be less than the highest of the following:

1. The kilowatt demand experienced during the billing month; or

2. the contract reserved demand; or

3. 75 percent of the highest monthly kilowatt demand established by demands actually imposed (or scheduled) by Customer during the preceding 11 months. Provided, however, in instances where Customer has invoked its contractual right to reduce its contract reserved demand, this ratchet provision shall not be invoked unless it was in effect prior to the reduction in contract reserved demand, in which event, this Item 3 shall be the sum of currently effective contract reserved demand and the difference between the previously effective ratcheted billing kilowatt demand and its corresponding reserved demand.

Further: For the months of June, July and August billing kilowatt demands which exceed contract reserved demand, and which are established by use rather than the operation of any ratchet provision herein, will be charged at a rate of five (5) times the demand charge for the excess demand.

Provided: Power delivered by virtue of the Company providing emergency service, scheduled outage assistance, or other services pursuant to specific provisions at rates set forth in the contract to which this rate schedule is attached shall not be included in the determination of monthly billing kilowatt demand.

DISPUTED BILLS:

In case a portion of any bill be in dispute, the undisputed amount shall be paid when due, and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of one percent (1%) per month from the original due date.

MONTHLY MINIMUM CHARGE:

The monthly minimum charge under this Schedule shall be the demand charge applied to the billing demand as determined above plus the system charge.

TERMS OF PAYMENT:

All bills are net and payable within ten (10) days from date of bill and payments for service not made on or before the due date shall be paid with interest accrued at the rate of one percent (1%) per month from the due date of payment.

ITEM 13

CITIES OF BURBANK AND PASADENA

BLOCK ENERGY AGREEMENT NUMBER 11,393

BLOCK ENERGY AGREEMENT NO. 11,393

BETWEEN

PUBLIC SERVICE COMPANY OF NEW MEXICO

AND

THE CITY OF BURBANK

AND

THE CITY OF PASADENA

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BLOCK ENERGY AGREEMENT

BETWEEN

PUBLIC SERVICE COMPANY OF NEW MEXICO

AND

THE CITY OF BURBANK

AND

THE CITY OF PASADENA

SECTION 1: PARTIES

1.1 The Parties to this Block Energy Agreement ("Agreement") are PUBLIC SERVICE COMPANY OF NEW MEXICO (hereinafter referred to as PNM), a corporation organized and existing under and by virtue of the laws of the state of New Mexico (hereinafter referred to as a Party); and THE CITY OF BURBANK, a municipal corporation of the state of California (hereinafter referred to individually as "Burbank"); and THE CITY OF PASADENA, a municipal corporation of the state of California (hereinafter referred to individually as "Pasadena"), Burbank and Pasadena are hereinafter referred to severally as a "Party" or "City" and collectively as "Cities."

SECTION 2: RECITALS

2.1 This Agreement is made with reference to the following facts, among others:

2.2 The Cities and PNM are engaged in the generation, transmission, and/or distribution of electric power and energy, including but not limited to, the states of California and New Mexico, respectively.

2.3 PNM will have, in addition to energy already reserved for other customers, surplus energy available during the mid-1980s.

2.4 Burbank and Pasadena anticipate having the ability to reduce the generation of oil- and gas-fired energy from their generation resources through the purchase of other energy at least for the period May 1983 through April 1984.

2.5 Electrical system interconnections exist which will allow scheduled deliveries of electrical energy by PNM to the Burbank and Pasadena electrical systems, subject to prudent operating practices and principles, and subject to constraints which may arise from time to time.

2.6 The Parties now desire by this Agreement to establish terms and conditions under which Block Energy may be sold by PNM to Burbank and Pasadena thereby making more efficient use of the Parties' electrical system resources.

SECTION 3: AGREEMENT

3.1 In consideration of the promises herein and the mutual benefit to be derived herefrom, the Parties hereto agree as follows:

SECTION 4: DEFINITIONS

4.1 The following terms, when used herein, whether singular or plural, shall have the meanings specified:

4.2 Authorized Representative: A person designated pursuant to the provisions of Section 8 hereof.

4.3 Lead Agency: The Party selected by Burbank and Pasadena to represent the Cities for all operating matters under this Agreement, including energy scheduling and billings. Unless a different Party is selected by mutual agreement of Burbank and Pasadena, as evidenced by at least ten (10) days advance written notice to PNM signed by the Cities' Authorized Representative, Pasadena shall be the Lead Agency.

4.4 Date of Initial Service: May 1, 1983, the date upon which deliveries of Block Energy by PNM to the Cities shall commence.

4.5 Block Energy: Interruptible energy to be provided by PNM to the Cities during the term of this Agreement. Such energy shall be considered to have a lower delivery priority than energy required to meet PNM's firm load or other PNM prior sales of capacity and associated energy and a higher delivery priority than other nonfirm PNM energy deliveries.

4.6 Points(s) of Delivery: The Point(s) of Delivery for transactions hereunder shall be:

4.6.1 The 500 kV bus of the high voltage switchyard of Palo Verde Nuclear Generating Station (hereinafter "Palo Verde").

4.6.2 Other delivery points as may be mutally agreed upon by the PNM and Lead Agency dispatchers at which the Parties may effect an interconnection through arrangements with third parties.

SECTION 5: EFFECTIVE DATE AND TERM

5.1 This Agreement shall become effective upon its execution by the Parties subject to the Agreement being accepted for filing by the Federal Energy Regulatory Commission and shall continue in force and effect until April 30, 1984, unless extended by the Parties in accordance with Section 5.2. Such termination shall not relieve Burbank and Pasadena of their obligations to make payment, in accordance with Section 7 hereof, for energy purchased prior to the termination date.

5.2 The Parties, subject to mutual agreement, may extend the term of this Agreement for not more than two successive periods of twelve months duration each upon at least six months advance written request by Burbank and Pasadena indicating the amount of energy to be purchased by the Cities and acceptance of such request by PNM three months prior to the expiration of the original term hereof or any extension thereof.

5.3 Burbank and Pasadena individually and collectively acknowledge their obligation to provide alternate sources of energy for their own customer needs, upon termination of this Agreement, from suppliers other than PNM. Burbank and Pasadena, therefore, waive any and all rights that they may have to seek administrative or judicial extensions of this Agreement or to seek allocations of PNM energy between the Cities and PNM's other customers beyond April 30, 1984. PNM hereby makes its retail electric firm customers third-party beneficiaries of Burbank and Pasadena's waivers of any rights to seek extensions or allocations.

SECTION 6: SCHEDULING AND DELIVERY OF BLOCK ENERGY

6.1 PNM shall make available to the Cities, and the Cities shall purchase during the initial term hereof Block Energy in and amount up to 307 GWh and at a rate of delivery of 35 MW each hour, subject to the conditions set forth in this Section 6. Unless otherwise mutually agreed by Burbank and Pasadena, each shall purchase an equal one-half share of such Block Energy.

6.2 When made available by PNM, each hour the Cities through their Lead Agency shall schedule energy deliveries equal to the rate of delivery made available by PNM, up to 35 MW; provided the Cities' transmission capability under their contracts with their transmission agent is not curtailed by their transmission agent.

6.3 The Cities shall have the right to suspend the obligations of PNM and the Cities respectively to supply and receive energy hereunder during as many as two (2) periods of not less than thirty (30) days duration each, nor jointly more than ninety-one (91) days in total. During such periods of suspension both PNM and the Lead Agency shall have the right to curtail deliveries or to refuse to schedule, respectively, at the sole discretion of the PNM and Lead Agency system dispatchers. Such periods shall be initiated and, if required, terminated by the Cities' Authorized Representative upon written notice to PNM's Authorized Representative received at least seven (7) days in advance of the Cities' desired date of suspension or reinstatement of service hereunder.

6.4 In the event the Lead Agency does not schedule all of the Block Energy made available by PNM in any given hour due to unavailability of transmission capacity as provided under Section 6.2 or during the period(s) specified in Section 6.3, PNM shall have the right to sell the undelivered energy to third parties.

6.5 Deliveries of Block Energy shall be made on an interruptible basis and may be made at variable rates of delivery for any hour at the Point of Delivery. PNM shall use its best efforts to accommodate the Lead Agency's requests to schedule deliveries of Block Energy when such schedules will not affect the reliability of PNM's electric system nor interfere with PNM's prior agreements to sell capacity and associated energy to third parties; at which times, PNM shall have the right to curtail deliveries upon verbal notice to the Lead Agency/dispatcher.

6.6 The amount of Block Energy to be delivered hereunder shall be reduced by the amount of interruptions of deliveries experienced (kWh) due to (i) the unavailability of transmission capacity as provided under Section 6.2, (ii) the suspension of obligations hereunder during the period(s) specified in Section 6.3, and (iii) curtailments of deliveries by PNM pursuant to Section 6.5.

6.7 PNM's obligation to make available Block Energy shall terminate upon the expiration date of this Agreement.

6.8 Insofar as practicable, hourly schedules for energy transactions shall be arranged between the PNM and Lead Agency power schedulers or system dispatchers on a tentative basis at least 24 hours in advance, subject to later modification by the power schedulers or system dispatchers. Establishing procedures for scheduling of energy hereunder shall be a responsibility of the Authorized Representatives. All scheduling hereunder shall be based on Mountain Standard Time (MST).

6.9 The Cities through separate transmission contracts with Southern California Edison Company have or will have obtained, prior to the Date of Initial Service, at least a total of 35 MW of firm transmission service from the Point of Delivery to the Cities' systems. Therefore, unless otherwise mutually agreed, responsibility for providing transmission service from the Point of Delivery to the Cities' systems shall rest with Burbank and Pasadena who also shall be responsible for coordinating the scheduling of energy deliveries from the Point of Delivery to the Cities' systems with other parties, if required.

SECTION 7: PAYMENTS FOR SURPLUS ENERGY

7.1 Commencing on the Date of Initial Service, and in consideration of the faithful performance of the convenants of this Agreement, Burbank and Pasadena, through the Lead Agency, shall pay PNM for all Block Energy delivered on an hourly basis three and six tenths cents ($.036) per kWh.

7.1.1 In addition to the charges set forth in Section 7.1 the total of any and all taxes, fees, or charges imposed or required to be paid by federal, state, county, municipal, or other governmental authorities, based upon the service rendered or other right or privilege of rendering the service, or on any object or event incidental to the rendition of the service, shall be billed in their entirety to the Cities.

7.2 Billings and payments with respect to Block Energy sales hereunder shall be based upon records of the amounts of energy scheduled, hour by hour, between the respective power schedulers or dispatchers in the form directed by the Authorized Representatives, except as the Authorized Representatives may arrange otherwise for particular situations.

7.3 A bill for Block Energy scheduled and received under this Agreement shall be rendered monthly by PNM to the Lead Agency on or before the 10th day of the month following the month in which such

energy is received. Bills received shall be due by the fifteenth (15th) calendar day from the date of receipt of the bill. Amounts not paid on or before the due date shall be payable with interest at the rate of one and one-half percent (1½%) per month from the due date to date of payment.

7.4 In case a portion of any bill be in dispute, the undisputed amount shall be paid when due and the remainder, if any, upon determination of the correct amount, shall be paid promptly after such determination with interest accrued at the rate of one and one-half percent (1½%) per month computed from the original due date.

7.5 The monthly billings shall be addressed to the Cities, through the Lead Agency, as follows:

7.5.1 Lead Agency:

Mr. Alex Szabo
Department of Water and Power
City of Pasadena
45 East Glenarm Avenue
Pasadena, CA 91105

SECTION 8: AUTHORIZED REPRESENTATIVES

8.1 There shall be two Authorized Representatives under this Agreement. The Cities and PNM shall each designate an Authorized Representative. Such Authorized Representatives shall be authorized by the Party(ies) by whom he is designated, to act on its (their) behalf in

carrying out the provisions of this Agreement designated to be responsibilities of the Authorized Representatives and to provide liaison between the Parties. The Cities, through the Lead Agency, and PNM shall each notify the other within thirty (30) calendar days after execution of this Agreement of the designation of their (its) Authorized Representative and shall promptly notify the other of any subsequent changes in such designation. The Authorized Representatives shall establish operating procedures for implementing the provisions of Sections 6 and 7 hereof and shall act for the respective Parties thereunder. Procedures established by the Authorized Representatives pursuant to this Section 8.1 shall be by agreement of the Authorized Representatives who shall issue such procedures in writing to the Parties.

8.2 The Authorized Representatives shall have no authority to modify any of the provisions of this Agreement unless specifically set forth herein.

SECTION 9: UNCONTROLLABLE FORCES

9.1 No Party shall be considered to be in default in the performance of any of its obligations hereunder other than obligations of Burbank and Pasadena to make payment for Block Energy previously delivered, when a failure of performance shall be due to uncontrollable forces. The term "uncontrollable forces" shall mean any cause beyond the control of the Party unable to perform such obligation, including, but not limited to, failure of or threat of failure of facilities,

flood, earthquake, storm, fire, lightning, and other natural catastrophes; epidemic, war, riot, civil disturbance or disobedience, strike, labor dispute, labor or material shortage, sabotage, government priorities, and restraint by court order or public authority, and action or nonaction by or failure to obtain the necessary authorizations or approvals from any governmental agency or authority, which by exercise of due diligence such Party could not reasonably have been expected to avoid and which by exercise of due diligence it shall be unable to overcome. Nothing contained herein shall be construed as to require a Party to settle any strike or labor dispute in which it may be involved.

SECTION 10: LIABILITY AND INDEMNITY

10.1 Each Party shall indemnify and save the other Parties harmless from liability, loss, damage, claim, costs, and expenses (including attorney fees) on account of injury to persons (including death), or damage or destruction of property, occasioned by the sole negligence, whether active or passive, or the intentional wrongdoing, of the indemnifying Party's officers, directors, employees, or contractors; provided, however, that:

10.1.1 Each Party shall be solely responsible for the claims or any payments to any employee or agent for injuries occurring in connection with their employment or arising out of any Worker's Compensation law.

10.1.2 No Party shall be liable for any loss of earnings, revenues, indirect or consequential damages, or injury which may occur to any other as a result of outages in delivery of services hereunder by reason of any cause whatsoever, including negligence.

10.2 Each Party shall indemnify and save the other Parties harmless from any liability, loss, claim, cost (including attorney fees) for any claims made by the indemnifying Party's electric service customers as a result of any failure of a Party to provide electric energy contemplated by this Agreement for any reason or any cause whatsoever including the negligence of any other Party.

SECTION 11: ELECTRIC DISTURBANCES

11.1 Each Party shall design, construct, operate, and maintain its system in conformance with generally accepted modern electric utility practices:

11.2 To minimize electric disturbances, such as, but not limited to, an abnormal flow of power which may damage or interfere with the system or customers of the other Parties or the system of any third party connected with the system of any Party; and

11.3 To minimize the effect on its system, and on its customers, of such electric disturbances originating on the system of the other Parties or any third party.

SECTION 12: ASSIGNMENT OF AGREEMENT

12.1 No Party shall assign this Agreement or any part thereof without the written consent of the other Parties, except in connection with the sale or merger of a substantial portion of its properties. Such written consent shall not be unreasonably withheld.

SECTION 13: NONDEDICATION OF FACILITIES

13.1 No undertaking by one Party to any other under any provision of this Agreement shall constitute the dedication of the system or any portion thereof of such Party to the public or to another Party, and it is understood and agreed that any such undertaking by any Party shall cease upon the termination by such Party of its obligations hereunder.

SECTION 14: NOTICES

14.1 Any formal notice, demand or request provided for in this Agreement, or served, given or made in this Agreement, or served, given or made in connection with it, shall be in writing and shall be deemed properly served, given or made if delivered in person or sent by United States mail, postage prepaid, to the persons specified below:

To or upon PNM:

Public Service Company of New Mexico
Secretary of the Company
Alvarado Square
Albuquerque, NM 87158

To or upon the Cities: Public Service Department
City of Burbank
Post Office Box 631
Burbank, CA 91503

ATTENTION: General Manager

Water and Power Department
City of Pasadena
100 N. Garfield Avenue
Pasadena, CA 91109

ATTENTION: General Manager

14.2 Any Party may at any time and from time to time, by notice to the other Parties, change the designation or address of the person so specified as the one to receive notices pursuant to this Agreement.

SECTION 15: GOVERNING LAW

15.1 This Agreement is made in the state of New Mexico and shall, in all respects, be interpreted and construed and the rights of the Parties hereto shall be governed by New Mexico law. Further, the Parties expressly agree to the jurisdiction of New Mexico courts.

SECTION 16: REGULATORY AUTHORITY

16.1 Nothing contained herein shall be construed as affecting in any way the right of the Party furnishing service under this Agreement to unilaterally make application to the Federal Energy Regulatory Commission for a change in rates, charges, classifications of service, or in any rule, regulation, or contract relating thereto, under Section 205

of the Federal Power Act and pursuant to the Commission Rules and Regulations promulgated thereunder; provided however that such change shall become effective only after a Commission Order determining just and reasonable rates.

SECTION 17: WAIVERS

17.1 Any waiver at any time by a Party of its right with respect to a default under this Agreement, or with respect to any other matter arising in connection therewith, shall not be deemed a waiver with respect to any subsequent default or matter. Any delay, short of the statutory period of limitation, in asserting or enforcing any right shall not be deemed a waiver of such right.

SECTION 18: EXECUTION BY COUNTERPART

18.1 This Agreement shall be executed in three counterparts and shall be deemed to constitute a single document with the same force and effect as if all Parties hereto, having signed a counterpart, had signed all other counterparts. Each City shall deliver a signed counterpart to PNM, which shall prepare a composite conformed copy and deliver the same to the Cities.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed.

PUBLIC SERVICE COMPANY OF NEW MEXICO

By C D Bedford
Sector Vice President
October 1, 1982

CITY OF BURBANK

Attest By ______________________

Title ______________________

Date ______________________

By ______________________
General Manager
Public Service Department
October __, 1982

CITY OF PASADENA WATER AND POWER DEPARTMENT

Attest By Pamela S Swift

Title City Clerk

Date October 21, 1982

By ______________________
General Manager
October 15, 1982

APPROVED AS TO FORM:

Victor J Kaleta
Deputy City Attorney

DATE 10/15/82

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed.

PUBLIC SERVICE COMPANY OF NEW MEXICO

By C D Bedford
Sector Vice President
October 1, 1982

OFFICIAL SEAL

INCORPORATED 1911

Attest By Evelyn L. Haley

Title City Clerk

Date Oct 15, 1982

CITY OF BURBANK

By [illegible]
General Manager
Public Service Department
October 15, 1982

CITY OF PASADENA WATER AND POWER DEPARTMENT

Attest By ____________________

Title ____________________

Date ____________________

By ____________________
General Manager
October__, 1982

ITEM 14

INCORPORATED COUNTY OF LOS ALAMOS

SERVICE SCHEDULE I--SURPLUS ENERGY

INTERCONNECTION AGREEMENT

BETWEEN

PUBLIC SERVICE COMPANY OF NEW MEXICO

AND

THE INCORPORATED COUNTY OF LOS ALAMOS, NEW MEXICO

SERVICE SCHEDULE I

SALE OF SURPLUS ENERGY

BY PNM TO COUNTY

THIS SERVICE SCHEDULE I is agreed upon as a part of the Interconnection Agreement between Public Service Company of New Mexico (PNM) and the Incorporated County of Los Alamos, New Mexico (County), hereinafter referred to collectively as the "Parties", and sets forth the terms and conditions of PNM's sale to County of energy which is surplus to PNM's firm load requirements, and is made in conjunction with the participation by County with PNM in San Juan Unit 4 (Unit 4) pursuant to the Municipal Electric Generation Act (Sec. 3-24-11 NMSA 1978).

I.1 RECITALS

I.1.1 WHEREAS, County is, or will be, engaged in the generation, transmission and distribution of electric power and energy for the Los Alamos service area, located principally within the County of Los Alamos, New Mexico;

I.1.2 WHEREAS, PNM presently anticipates having energy available that is surplus to its firm load requirements; and

I.1.3 WHEREAS, County desires to purchase energy to support County's projected energy needs.

I.1.4 In consideration of the mutual covenants and conditions set forth herein, the Parties agree as follows:

I.2 DEFINITIONS

I.2.1 Base Energy - Energy generated by PNM's generating resources which is surplus to PNM's currently projected energy needs for future loads.

I.2.2 Additional Energy - Energy supplied only during Western System Coordinating Council (WSCC) off-peak hours from PNM sources which energy is in addition to Base Energy. Additional Energy shall be made available only after all PNM firm load and block energy requirements have been satisfied.

I.3 EFFECTIVE DATE AND TERM

I.3.1 This Service Schedule I shall become effective on the same date as the Interconnection Agreement pursuant to Section 2.1 thereof, subject to the acceptance for filing of this Service Schedule I by the Federal Energy Regulatory Commission (FERC). The Parties expect that the

effective date will be April 1, 1985 (Date of Initial Service). This Service Schedule I shall continue in effect until December 31, 1990. County shall have the right to request an extension of the term through December 31, 1992, by written request provided to PNM no later than January 1, 1989. Should PNM concur with the request, the term shall be extended subject to obtaining any necessary regulatory approvals.

I.4 POINT OF DELIVERY

I.4.1 The primary point of delivery shall be the Norton Interconnection. Other points of delivery as provided for in Section 3 of the Interconnection Agreement may be used as secondary points of delivery upon the mutual agreement of the Parties' system dispatchers.

I.5 SERVICE TO BE PROVIDED

I.5.1 Subject to the provisions of Section I.6, PNM shall make available Base Energy at rates of delivery as shown on the following table and for the time periods indicated:

From	To	MW Per Hour
Date of Initial Service	11/30/85	15 MW
12/1/85	06/30/86	10 MW
07/01/86	11/30/86	17 MW
12/1/86	12/31/90	10 MW

I.5.2 Upon written request by County, PNM shall supply additional Base Energy at increased rates of delivery in MW increments up to an additional 10 MW per hour. The request shall be provided to PNM at least

three months in advance and shall specify: i) the exact amount of the additional Base Energy required, and ii) the time period during which the additional Base Energy will be required, which shall not be less than three months unless otherwise agreed by the Parties.

I.5.3 During WSCC off-peak hours, PNM will provide Additional Energy in MW increments up to 10 MW per hour, upon request by County.

I.5.4 For dispatch purposes, County shall preschedule deliveries with PNM, on a daily basis, indicating hourly schedules of the amount of Base Energy and Additional Energy to be delivered.

I.5.5 The quantity of Base Energy and Additional Energy actually delivered in any month shall, for so long as Section H.3.2 of Service Schedule H is in effect, be determined after the fact. The Operating Committee shall develop accounting and billing procedures to accomplish such after the fact determination. Should Section H.3.2 of Service Schedule H be terminated, the Operating Committee shall develop revised scheduling and billing procedures as deemed appropriate.

I.6 INTERRUPTIBILITY

I.6.1 PNM may interrupt or curtail delivery of Base Energy and Additional Energy to County as follows:

I.6.1.1 For both Base Energy and Additional Energy, immediately without notice if due to Uncontrollable Forces as defined in Section 9 of the Interconnection Agreement.

I.6.1.2 For both Base Energy and Additional Energy immediately with verbal notice in the event of transmission system limitations due to unscheduled transmission line outages which would prevent PNM from delivering such energy.

I.6.1.3 For Base Energy, with two hours' verbal notice in the event of an unscheduled outage or curtailment of any of PNM's base load coal or nuclear generating units which outage is expected to last more than 24 hours and would necessitate PNM having to generate Base Energy from gas- or oil-fired units.

I.6.1.4 For Additional Energy, immediately upon verbal notice if PNM's incremental cost of providing such Additional Energy exceeds, or is expected to exceed, the price which County is to pay for such Additional Energy.

I.7 SETTLEMENTS

I.7.1 The price to be paid PNM by County for all Base Energy shall be comprised of an energy charge (Energy Charge) and a reservation fee (Reservation Fee), the total of which shall be equal to the values indicated for the respective periods below:

From	To	Price
Date of Initial Service	12/31/85	42 mills/kWh
1/1/86	12/31/86	44 mills/kWh
1/1/87	12/31/87	54 mills/kWh
1/1/88	12/31/88	59 mills/kWh
1/1/89	12/31/90	64 mills/kWh
If Extended, 1/1/91	12/31/92	64 mills/kWh

I.7.1.1 The Energy Charge in mills/kWh, which will be provided to County prior to the first day of each month, shall be equal to PNM's actual system average fuel cost for the most recent month in which accounting data is available. The Energy Charge shall be billed on all Base Energy delivered to County.

I.7.1.2 The Reservation Fee in mills/kWh, shall be adjusted monthly so that the Reservation Fee plus the monthly Energy Charge equals the rate indicated in Section I.7.1 during the applicable period. The Reservation Fee shall be billed and paid by County on all Base Energy made available by PNM whether or not delivered to County.

I.7.2 The rate for Additional Energy delivered in any month shall be 1.5 times the Energy Charge for Base Energy delivered in that month.

I.7.3 For settlement purposes, the amount of Base Energy available to County in each month shall equal the rate of delivery set forth in Section I.5.1 times the number of hours in that month and shall be deemed to be taken prior to any Additional Energy being taken. The amount of Additional Energy available to County in each month shall equal up to 10 MW per hour times the number of WSCC off-peak hours in that month. For monthly bill computation purposes, the quantity of Base Energy and

Additional Energy delivered to County shall be determined using the schedules submitted by County pursuant to Section I.5.4. An adjustment shall be made in the succeeding schedules if the actual quantity delivered, determined pursuant to Section I.5.5, differs from the scheduled quantity.

I.8 OTHER PROVISIONS

I.8.1 Nothing contained herein shall be construed as affecting in any way the right of the Party furnishing service under this Service Schedule to unilaterally make application to the FERC for a change in rates under Section 205 of the Federal Power Act and pursuant to the FERC's Rules and Regulations promulgated thereunder; however, should PNM make any such application, County may, at its option, within thirty (30) days thereafter elect to terminate its obligations to purchase Base Energy and Additional Energy from PNM. Should County thus terminate, it shall notify PNM of the date on which such termination will be effective, which date shall be no sooner than thirty (30) days from the date of County's notice of termination.

Executed this 18th day of February 1985.

PUBLIC SERVICE COMPANY OF NEW MEXICO

By: J. F. Wilkins
Senior Vice President

THE INCORPORATED COUNTY OF LOS ALAMOS, NEW MEXICO

By: Morris B Pongratz

Its: Chairman, County Council

ATTEST

Jeanine Ratts
County Clerk, Deputy

By: Fred A Gross Jr.

Its: Chairman, Board of Public Utilities

ITEM 15

NEVADA POWER COMPANY

SERVICE SCHEDULE E--BLOCK ENERGY SALE

INTERCONNECTION AGREEMENT

BETWEEN

PUBLIC SERVICE COMPANY OF NEW MEXICO

AND

NEVADA POWER COMPANY

SERVICE SCHEDULE E

BLOCK ENERGY SALE

This Service Schedule E is entered into as of July 1, 1985, and is agreed upon as part of the Interconnection Agreement between Nevada Power Company (NPC) and Public Service Company of New Mexico (PNM), dated December 28, 1978.

SECTION 1

PURPOSE

1.1 PNM will have, in addition to energy already reserved for other customers, surplus energy available for the term of this Service Schedule. NPC will have the ability to reduce the generation of gas-fired energy from its generation resources through the purchase of more economical energy during the term of this Service Schedule. NPC will also be able to utilize such energy as a result of unusual circumstances on its system for the term of this Service Schedule, due to the loss of a coal-fired generation resource. The Parties now desire by this Service Schedule E to establish terms and conditions under which Block Energy may

be sold by PNM to NPC thereby making more efficient use of electrical resources.

SECTION 2

TERM

2.1 This Service Schedule E shall become effective upon its execution by the Parties subject to its acceptance for filing by the Federal Energy Regulatory Commission. This Service Schedule E shall continue in force and effect through September 15, 1985, or such later date as may be mutually agreed to in writing by the Parties. Such termination shall not relieve NPC of its obligation to make payments, in accordance with Section 6 hereof, for energy purchased prior to the termination date.

2.2 The date of initial service, upon which date deliveries of Block Energy to NPC shall commence (hereinafter referred to as the "Date of Initial Service"), shall be July 1, 1985.

SECTION 3

SERVICE

3.1 PNM shall make available to NPC, and NPC shall purchase during the term hereof, Block Energy delivered at a rate of 33 megawatts (MW) per hour, subject to the conditions set forth in this Section 3 and Section 4 hereof.

3.2 NPC shall schedule the Block Energy hereof seven days per week, twenty-four (24) hours per day. On-peak hours shall be defined as Monday through Saturday, hour ending 0700 through hour ending 2200, Mountain Standard Time, not including Independence Day or Labor Day. All other hours are defined as off-peak hours.

3.3 A Party's obligation to schedule or deliver Block Energy shall cease upon the termination of this Service Schedule E.

SECTION 4

INTERRUPTIBILITY

4.1 PNM may curtail or interrupt deliveries to NPC due to Uncontrollable Forces in accordance with the following:

4.1.1 Immediately and without notice if due to Uncontrollable Forces, as defined in Section 8.1 of the Interconnection Agreement.

4.1.2 In the instance of loss of a PNM generation resource and scheduled energy is needed to serve PNM's native load or customers under contracts executed prior to this Service Schedule E, then PNM shall provide verbal notice to NPC.

4.1.3 NPC may request that PNM maintain scheduled deliveries after PNM gives NPC notice and in the event PNM is able to continue such schedule, NPC agrees to pay for such deliveries at PNM's incremental cost to generate the energy plus fifteen (15) percent, or at PNM's incremental

cost to procure the energy plus one (1) mill, unless PNM's dispatcher verbally agrees to waive these respective 15 percent or 1 mill adders.

4.2 NPC may reduce or interrupt its scheduled deliveries of Block Energy from PNM in accordance with the following:

4.2.1 Immediately, without notice, if due to Uncontrollable Forces, as defined in Section 8.1 of the Interconnection Agreement.

4.3 In the event Block Energy schedules are reduced, curtailed or interrupted pursuant to Sections 4.1 or 4.2 hereof, Block Energy schedules shall be reinstated upon two hours notice by the Party originating the reduction, curtailment or interruption of schedule unless the system dispatchers mutually agree to a different period. Such notification to resume Block Energy schedules shall be given by the originating Party as soon as possible after any such reduction, curtailment or interruption.

SECTION 5

POINT OF DELIVERY

5.1 The Point of Delivery for transactions hereunder shall be the 230 kV bus at the Four Corners Generating Station, the Shiprock 230 kV Switching Station, or as otherwise mutually agreed upon by the Parties' respective system dispatchers.

SECTION 6

RATES

6.1 Commencing on the Date of Initial Service, and in consideration of the faithful performance of the covenants of this Service Schedule E, NPC shall pay PNM 33 mills/kWh for the energy delivered during on-peak hours, and 22 mills/kWh for energy delivered during off-peak hours, such on-peak and off-peak hours as defined in Section 3.2.

6.2 The rate for service specified in Section 6.1 hereof shall remain in effect during the term of this Service Schedule E, and shall not be subject to change through application to the Federal Energy Regulatory Commission pursuant to the provisions of Section 205 of the Federal Power Act absent the agreement of the Parties hereto.

6.3 The monthly billings and payments shall be addressed as follows:

6.3.1 Billings: Nevada Power Company
Post Office Box 230
Las Vegas, Nevada 89151

Attention: Power Supervisor

6.3.2 Payments: Public Service Company of New Mexico
Post Office Box 902
Albuquerque, New Mexico 87103

Attention: Cash Management

SECTION 7

OTHER PROVISIONS

7.1 Other terms and conditions of this Service Schedule E, as applicable, shall be as set forth in the Interconnection Agreement between the Parties dated December 28, 1978.

IN WITNESS WHEREOF, the Parties have caused this Service Schedule E to be executed by their duly authorized officers as of the day and year first herein written.

ATTEST

Secretary

NEVADA POWER COMPANY

Its Vice-President

PUBLIC SERVICE COMPANY OF NEW MEXICO

Its SENIOR VICE PRESIDENT
POWER SUPPLY

ITEM 16

SOUTHWESTERN PUBLIC SERVICE COMPANY

SERVICE SCHEDULE D--INTERRUPTIBLE POWER SERVICE

SERVICE SCHEDULE D

FIRM SURPLUS ENERGY

PNM has energy presently available that is surplus to its firm load requirements. PNM has entered into this Service Schedule D as an opportunity sale with SPS to make use of available surplus energy and enable SPS to purchase energy from PNM at a cost anticipated to be lower than the cost SPS would otherwise incur by generating on natural gas.

Section 1: Service to be Provided

A. Quantity

1. During the term of this Service Schedule, PNM shall make available to SPS and SPS shall purchase from PNM an amount of firm surplus energy (Base Energy) at Clovis or West Mesa, at a delivery rate of 200 MW each hour, subject to the conditions set forth in this Section 1.

2. PNM will, at the request of SPS, supply additional firm surplus energy (Additional Energy) of up to 10 percent of the Base Energy for a total hourly

delivery rate of 220 MW, if PNM's incremental cost of providing such Additional Energy does not exceed the rate SPS will pay PNM for such energy as specified in Section 2.D. hereof.

B. Banking

In the event SPS cannot take, in any hour, all energy available under Section 1.A.1. above, at the request of SPS, PNM will bank energy (Banked Energy) made available, but not delivered to SPS, in the following amounts for the periods as designated below:

1. Up to thirty (30%) percent of the energy made available during each month of the period commencing on the Date of Initial Service and terminating on December 31, 1985.

2. Up to twenty (20%) percent of the energy made available each month during the twelve (12) month period commencing January 1, 1986.

3. Up to ten (10%) percent of energy made available each month during the period commencing January 1,

1987, and continuing for the remaining term of this Service Schedule D.

Each hour, SPS shall schedule Base Energy prior to scheduling any Banked Energy. Banked Energy shall be delivered to SPS at West Mesa or the Point of Delivery near Clovis, New Mexico, and at times mutually agreeable to the Parties' respective system operators. Banked Energy shall be scheduled by SPS within the term of this Service Schedule, after which period PNM's obligation to return such Banked Energy shall terminate.

C. Interruptibility

1. Inasmuch as the value of this transaction to SPS is based on the costs avoided by SPS in not operating one or more of its existing gas-fired generating units, it is required that the deliveries hereunder be classified as firm for a given day. However, in the event an unscheduled outage or curtailment occurs on any of PNM's base load coal or nuclear generating units which outage would be expected to last more than 24 hours and

would cause PNM to generate the Base Energy from gas or oil-fired units, PNM shall provide notice to SPS that such an event has occurred and PNM may curtail or interrupt deliveries of all energy deliverable hereunder upon verbal notice to SPS' system operator, with the change of schedule to take effect two hours beyond SPS' system peak for that day.

2. Additional Energy and Banked Energy shall be subject to immediate interruption by PNM upon verbal notice.

3. In the event that the Interconnection is out of service, PNM will make available the Base Energy and Additional Energy at West Mesa.

Section 2: Rates

A. The rate for the Base Energy delivered at Clovis during the term of this Service Schedule shall be comprised of a reservation fee (Reservation Fee) and energy charge (Energy Charge) which together shall equal the values indicated below for each respective period:

Period	Rate
Date of Initial Service thru 12/31/85	42 Mills/kwh
1/1/86-12/31/86	44 Mills/kwh
1/1/87-12/31/87	54 Mills/kwh
1/1/88-12/31/88	59 Mills/kwh
1/1/89-12/31/89	64 Mills/kwh
Option Extension 1/1/90-5/31/90	64 Mills/kwh

1. The Energy Charge, which will be provided to SPS prior to the first day of each month, shall be equal to PNM's actual system average energy cost for the most recent month in which accounting data is available, in Mills/kwh.

2. The Reservation Fee shall be adjusted monthly so that the Reservation Fee plus the monthly Energy Charge equals the rate indicated in the above table during the applicable period.

B. The Reservation Fee for Base Energy delivered at West Mesa during any month shall be reduced by the amount of wheeling fees paid by SPS to third parties for transmission of Base Energy to SPS' system but in no event shall such reduction exceed 6 Mills/kwh.

C. The Reservation Fee for Base Energy made available by PNM but not delivered to SPS in any month shall be equal to the fee as determined in accordance with Section 2.A.2 for the month such energy was made available by PNM. If SPS is unable to accept the energy at West Mesa, the Reservation Fee and Energy Charge will be suspended for the period of PNM's inability to deliver at the Point of Delivery near Clovis, New Mexico.

D. The rate for Additional Energy delivered in any month shall be 1.5 times the Energy Charge for Base Energy delivered in that month.

E. The rate for Banked Energy shall be comprised of an Energy Charge calculated and charged as set forth in Section 2.A.1. for the month such energy is delivered to SPS.

Section 3: Term

A. This Service Schedule shall have a term commencing upon the date of initial service (Date of Initial Service) and extending through December 31, 1989. SPS shall have the option to extend the term through May 31, 1990 upon twelve months advance written notice. The Date of

Initial Service shall be the later of:

1. January 1, 1985, or

2. The date on which PNM has placed its part of The Interconnection in service.

B. Within 90 days of its execution, PNM will tender this Service Schedule D for filing with the Federal Energy Regulatory Commission (FERC) as an initial rate schedule and request that the FERC grant a waiver of the notice requirement under Section 35.3 of the regulations promulgated under the Federal Power Act. If the FERC does not grant a waiver of the above referenced notice provision and fails to accept this entire Agreement as an initial rate schedule within 120 days of its filing, or if the FERC requires any modification hereto, PNM may unilaterally terminate this Service Schedule D by providing SPS notice of intention to terminate within 30 days following final FERC action that imposes such modifications or that fails to accept this Service Schedule for filing within 120 days from filing of this Service Schedule D. If such notice is provided, this Service Schedule D shall thereafter terminate effective 30 days later.

PNM shall also file this Service Schedule D with the New Mexico Public Service Commission (NMPSC) requesting its approval as to proposed rate treatment. If the NMPSC does not, within 120 days after request of approval of such rate treatment, grant rate treatment agreeable to PNM, then in that event PNM may terminate this Service Schedule D by providing notice of intention to terminate within 30 days following final NMPSC action that fails to adopt rate treatment satisfactory to PNM. If such notice is provided, this Service Schedule D shall thereafter terminate effective 30 days later.

SPS may file this Service Schedule D with the Public Utility Commission of Texas (PUCT) requesting its aproval as to proposed rate treatment. If the PUCT does not, within 120 days after request of approval of such rate treatment, grant rate treatment agreeable to SPS, then in that event SPS may terminate this Service Schedule D by providing notice of intention to terminate within 30 days following final PUCT action that fails to adopt rate treatment satisfactory to SPS. If such notice is provided, this Service Schedule D shall thereafter terminate effective 30 days later.

Section 4: Other Provisions

Nothing contained herein shall be construed as affecting in any way the right of the party furnishing service under this Service Schedule to unilaterally make application to the Federal Energy Regulatory Commission for a change in rates under section 205 of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder; however, should PNM make any such application, SPS may, at its option, within thirty (30) days thereafter elect to terminate its obligations to purchase service from PNM. Should SPS elect to terminate under the foregoing provisions, it shall notify PNM of the termination and the date on which such termination will be effective, which date shall be no sooner than thirty (30) days from the date of the SPS notice of termination.

Either party may, likewise, terminate this Service Schedule should the Federal Energy Regulatory Commission order a change in PNM's filing to require a change in rates, classification of service, or any contract provision relating thereto, whether or not such change is to become effective subject to refund. Such election to terminate by either Party must be made in writing within sixty (60) days from the date of making such change. Such notice to terminate shall provide the date on which such

termination is effective, which shall be no sooner than thirty (30) days from the date of the notice of termination.

Signed this 23rd day of November, 1982.

PUBLIC SERVICE COMPANY OF NEW MEXICO

By: C D Bedford
Sector Vice President

SOUTHWESTERN PUBLIC SERVICE COMPANY

By: [illegible signature]
Vice President

ITEM 17

TEXAS-NEW MEXICO POWER COMPANY

SERVICE SCHEDULE F--BLOCK ENERGY SALE

SERVICE SCHEDULE F

BLOCK ENERGY SALE

This Service Schedule F is entered into as of August 2, 1983, and is agreed upon as part of the Interconnection Agreement between Texas-New Mexico Power Company (TNP) and Public Service Company of New Mexico (PNM), dated February 28, 1974, as amended.

SECTION 1

PURPOSE

1.1 PNM will have, in addition to energy already reserved for other customers, surplus energy available for the term of this Service Schedule. TNP will have the ability to reduce the generation of gas-fired energy from generation resources of its copper industry customers (Coppers) through the purchase of more economical energy during the term of this Service Schedule. The parties now desire by this Service Schedule F to establish terms and conditions under which nonfirm Block Energy may be sold by PNM to TNP thereby making more efficient use of electrical resources.

SECTION 2

TERM

2.1 This Service Schedule F shall become effective upon its execution by the parties subject to its acceptance for filing by the Federal Energy Regulatory Commission. This Service Schedule F shall continue in

force and effect until February 29, 1984, and from month to month thereafter, until terminated by either party in accordance with Section 2.3. Such termination shall not relieve TNP of its obligation to make payments, in accordance with Section 6 hereof, for energy purchased prior to the termination date.

2.2 The date of initial service, upon which date deliveries of Block Energy to TNP shall commence (hereinafter referred to as the "Date of Initial Service"), shall be one day after this Service Schedule F is signed by the parties.

2.3 Either party may unilaterally terminate this Service Schedule F upon at least 30 days' written notice to the other party specifying a termination date, provided that such termination date shall not be earlier than February 29, 1984. In the event both parties give notice of termination, in accordance with the above, the earliest date selected shall be the termination date.

2.4 In the event that the Coppers shut down their operations due to economic conditions, TNP is relieved of any obligation to take Block Energy hereunder until such time as the Coppers are again operating and willing to take Block Energy.

SECTION 3

SERVICE

3.1 PNM shall make available to TNP, and TNP intends to purchase during the term hereof, Block Energy solely and exclusively for serving the Coppers, in the amount of up to one hundred fifty (150) gigawatt hours, at a rate of delivery of up to 50 megawatts (MW), each days' hourly deliveries as scheduled by TNP's system dispatcher 12 hours in advance, and such deliveries shall be subject to the conditions set forth in this Section 3 and Section 4 hereof.

3.2 TNP shall schedule the Block Energy hereof prior to purchasing nonfirm, block or economy energy from third parties, unless PNM curtails TNP pursuant to Section 4.1.2, in which event TNP shall have the right to purchase nonfirm energy from third parties until PNM notifies TNP that Block Energy is again available for TNP pursuant to Section 4.3 hereof. Provided, however, nothing contained in this Agreement shall affect TNP's right to schedule the firm energy that TNP obtains from PNM pursuant to the PNM/TNP Contract for Electric Service dated February 28, 1974, as amended.

3.3 A party's obligation to schedule or deliver Block Energy shall cease upon the termination of this Service Schedule F.

SECTION 4

INTERRUPTIBILITY

4.1 PNM may curtail or interrupt deliveries to TNP in accordance with the following:

4.1.1 Immediately, upon verbal notice to TNP, if the scheduled energy is required to serve PNM's firm customer load, or without notice if due to Uncontrollable Forces, as defined in Section 8.1 of the Interconnection Agreement.

4.1.2 During WSCC Peak Hours, as such WSCC Peak Hours are defined by the Western Systems Coordinating Council and set out in Exhibit A, attached hereto and made a part hereof, upon providing a minimum of two hours' verbal notice to TNP, if PNM's cost to generate (or otherwise procure) energy hereunder during WSCC Peak Hours and deliver it to the Point of Delivery is more than the rates specified in Sections 6.1.1 and 6.1.2 as applicable; provided, however, that TNP may request that PNM maintain schedule for up to eight hours after PNM gives TNP notice and in such event TNP agrees to pay for such deliveries at PNM's incremental cost to generate (or otherwise procure) the energy plus fifteen (15) percent for the lesser of the last six hours or the number of hours until WSCC Peak Hours end, unless PNM's dispatcher verbally agrees to waive this cost plus 15 percent provision.

4.2 TNP may reduce or interrupt its scheduled deliveries of Block Energy from PNM in accordance with the following:

4.2.1 Immediately, without notice, if due to Uncontrollable Forces, as defined in Section 8.1 of the Interconnection Agreement.

4.2.2 Upon providing a minimum verbal notice of two hours to PNM, if system operating conditions, including request of TNP's industrial customers and other than Uncontrollable Forces, limit TNP's ability to import energy hereunder.

4.3 In the event Block Energy schedules are reduced, curtailed or interrupted pursuant to Section 4.1 or 4.2 hereof, Block Energy schedules shall be reinstated two hours after notification by the party originating the reduction, curtailment or interruption of schedule that it is prepared to resume the schedule unless the system dispatchers mutually agree to a different period. Such notification to resume Block Energy schedules shall be given by the originating party as soon as possible after any such reduction, curtailment or interruption.

SECTION 5

POINT OF DELIVERY

5.1 The Point of Delivery for transactions hereunder shall be "Hidalgo" 345 kV switching station, located near Lordsburg, New Mexico.

5.2 Other delivery points may be mutually agreed upon by the parties' respective system dispatchers if energy deliveries cannot be made available by PNM, or accepted by TNP, at Hidalgo.

SECTION 6

RATES

6.1 Commencing on the Date of Initial Service, and in consideration of the faithful performance of the covenants of this Service Schedule, TNP shall pay PNM for the energy delivered hereunder as follows:

6.1.1 For all energy scheduled for delivery during Billing Peak Hours, as such Billing Peak Hours are set out in Exhibit B, attached hereto and made a part hereof, according to the following schedule:

6.1.1.1 For each hour that the scheduled rate of delivery is less than or equal to 25 MW, $30.50 per MWh;

6.1.1.2 For each hour that the scheduled rate of delivery is greater than 25 MW, $29.50 on every MWh above 25 MWh, plus $30.50 per MWh on the first 25 MWh.

6.1.2 For all hours other than Billing Peak Hours, according to the following schedule:

6.1.2.1 For each hour that the scheduled rate of delivery is less than or equal to 15 MW, $26.70 per MWh;

6.1.2.2 For each hour that the scheduled rate of delivery is greater than 15 MW but less than or equal to 25 MW, $23.00 on every MWh above 15 MWh, plus $26.70 per MWh on the first 15 MWh.

6.1.2.3 For each hour that the scheduled rate of delivery is greater than 25 MW, to a maximum of 50 MW unless a higher MW value is mutually agreeable to the system dispatchers, $19.30 on every MWh above 25 MWh, plus $23.00 on every MWh above 15 MWh to 25 MWh, plus $26.70 per MWh on the first 15 MWh.

6.2 The rates for service specified in Sections 6.1.1 and 6.1.2 hereunder shall remain in effect during the term of this Service Schedule F, and shall not be subject to change through application to the Federal Energy Regulatory Commission pursuant to the provisions of Section 205 of the Federal Power Act absent the agreement of the parties hereto.

6.3 The monthly billings and payments shall be addressed as follows:

6.3.1 Texas-New Mexico Power Company
501 West Sixth Street
Fort Worth, Texas 76102

Attention: General Accounting Department

6.3.2 Public Service Company of New Mexico
Alvarado Square
Albuquerque, New Mexico 87158

Attention: Cash Management

SECTION 7

OTHER PROVISIONS

7.1 Other terms and conditions of this Service Schedule F, as applicable, shall be as set forth in the Interconnection Agreement between the parties of February 28, 1974, as amended.

IN WITNESS WHEREOF, the parties have caused this Service Schedule F to be executed by their duly authorized officers as of the day and year first herein written.

ATTEST:

TEXAS-NEW MEXICO POWER COMPANY

Asst. Vice President

PUBLIC SERVICE COMPANY OF NEW MEXICO

C D Bedford

Senior Vice President

EXHIBIT A TO SERVICE SCHEDULE F

WSCC PEAK HOURS
(Reference Section 4.1.2)

WSCC Peak Hours are defined by the Western Systems Coordinating Council (WSCC) to be one or the other of the following as applicable:

1. During the Winter Period (1), Monday through Saturday, 7 a.m. to 11 p.m. MST, exluding Holidays (2).

2. During the Summer Period (1), Monday through Saturday, 7 a.m. to 11 p.m. MDT (i.e., 6 a.m. to 10 p.m. MST), excluding Holidays (2).

---

(1) Winter Period, for purposes of this Service Schedule F, means the period that Albuquerque is on Mountain Standard Time (MST); Summer Period means the period that Albuquerque is on Mountain Daylight Time (MDT).

(2) For the purpose of Exhibit A, Holidays shall be:

Labor Day
Thanksgiving Day
Christmas Day
New Year's Day
Memorial Day
Independence Day

EXHIBIT B TO SERVICE SCHEDULE F

BILLING PEAK HOURS FOR TNP PURCHASE
(Reference Section 6.1.1)

Billing Peak Hours for the purposes of this Service Schedule F shall include one or the other of the following, as applicable:

1. During the Winter Period (1), Monday through Friday, 7 a.m. to 11 p.m. MST, excluding Holidays (2).

2. During the Summer Period (1), Monday through Friday, 7 a.m. to 11 p.m. MDT (i.e., 6 a.m. to 10 p.m. MST), excluding Holidays (2).

---

(1) For purposes of this Service Schedule F, Winter Period means the period when Albuquerque is on Mountain Standard Time (MST); Summer Period means the period when Albuquerque is on Mountain Daylight Time (MDT).

(2) For the purposes of this Exhibit B, Holidays shall be the same as specified in Exhibit A.

PNM PUBLIC SERVICE COMPANY OF NEW MEXICO
ALVARADO SQUARE ALBUQUERQUE, NEW MEXICO 87158

August 20, 1984

Mr. James M. Tarpley
Texas-New Mexico Power Company
501 West Sixth Street
Fort Worth, TX 76102

Dear Mr. Tarpley:

Subject: Amendment to Service
Schedule F

By letter dated July 19, 1984, Public Service Company of New Mexico (PNM) agreed for the limited period between July 27, 1984, up to but not later than October 31, 1984, to waive Texas-New Mexico Power's (TNP) obligation of Section 3.2 of our Service Schedule F to buy non-firm energy for TNP's Coppers (i.e., the Phelps Dodge-Tyrone Plant) from PNM. This waiver allows up to 10 MWh of non-firm energy each hour to be served to the Tyrone Plant from energy that the Phelps Dodge Hidalgo Plant cannot take during its maintenance period. In return for PNM's waiver, TNP has agreed to pay PNM an additional 3.8 mills/kWh for the sales which have been displaced, in order to compensate PNM for foregone deliveries which would have been made to Phelps Dodge by TNP from purchases under Service Schedule F.

In order to bill TNP, PNM understands that TNP's system dispatcher will advise PNM's dispatcher of the amount of energy that TNP displaced as soon as practicable after the end of each month. On each month's billing made pursuant to Service Schedule F, PNM will add 3.8 mills/kWh to each kWh of energy that PNM has supplied under Service Schedule F for sales to Phelps Dodge during that billing period, such adder to be made on each kWh up to but not to exceed the amount of energy TNP displaced in that billing period. In the event PNM is unable to bill for 100 percent of the displaced energy prior to the November billing, PNM will bill for any balance due as a part of the November bill.

If the above is acceptable to TNP, please acknowledge by signing in the space provided below, and return one original of this letter.

Sincerely,

J L Wilkins
J. L. Wilkins
Senior Vice President

RPK:pls

Approved by: F B Von Hutten

Title: Vice President, Secretary & General Counsel

Date: August 24, 1984

ITEM 18

TEXAS-NEW MEXICO POWER COMPANY

SERVICE SCHEDULE I--BLOCK ENERGY SALE

SERVICE SCHEDULE I

BLOCK ENERGY SALE

This Service Schedule I is entered into as of January 31, 1985, and is agreed upon as part of the Interconnection Agreement between Texas-New Mexico Power Company (TNP) and Public Service Company of New Mexico (PNM), dated February 28, 1974, as amended.

SECTION 1

PURPOSE

1.1 PNM will have, in addition to energy already reserved for other customers, surplus energy available for the term of this Service Schedule. TNP will have the ability to reduce the generation of gas-fired energy from generation resources of its copper industry customers (Coppers) through the purchase of more economical energy during the term of this Service Schedule. The parties now desire by this Service Schedule I to establish terms and conditions under which nonfirm Block Energy may be sold by PNM to TNP thereby making more efficient use of electrical resources.

SECTION 2

TERM

2.1 This Service Schedule I shall become effective upon its execution by the parties, subject to its acceptance for filing by the Federal Energy Regulatory Commission. This Service Schedule I shall continue in

force and effect until December 31, 1985, and from month to month thereafter, until terminated by either party in accordance with Section 2.3. Such termination shall not relieve TNP of its obligation to make payments, in accordance with Section 6 hereof, for energy purchased prior to the termination date.

2.2 The date of initial service, upon which date deliveries of Block Energy to TNP shall commence (Date of Initial Service), shall be the first day of March 1985.

2.3 Either party may unilaterally terminate this Service Schedule I upon at least 30 days' written notice to the other party specifying a termination date, provided that such termination date shall not be earlier than December 31, 1985. In the event both parties give notice of termination in accordance with the above, the earliest date selected shall be the termination date.

2.4 In the event that the Coppers shut down their operations due to economic conditions, TNP is relieved of any obligation to take Block Energy hereunder until such time as the Coppers are again operating and willing to take Block Energy.

SECTION 3

SERVICE

3.1 PNM shall make available to TNP, and TNP intends to purchase during the term thereof, Block Energy solely and exclusively for serving

the Coppers, in an amount of up to 370 gigawatt hours (GWh), at a rate of delivery of up to 50 megawatts (MW), each day's hourly deliveries as scheduled by TNP's system dispatcher 12 hours in advance, and such deliveries shall be subject to the conditions set forth in this Section 3 and Section 4 hereof.

3.2 TNP shall schedule the Block Energy hereof prior to purchasing nonfirm, block or economy energy from third parties, unless PNM reduces, curtails, or interrupts TNP pursuant to Section 4.1.2, in which event TNP shall have the right to purchase nonfirm energy from third parties until reinstatement of Block Energy by the parties pursuant to Section 4.3 hereof. Provided, however, nothing contained in this Agreement shall affect TNP's right to schedule the firm energy that TNP obtains from PNM pursuant to the PNM/TNP Contract for Electric Service dated February 28, 1974, as amended.

3.3 A party's obligation to schedule or deliver Block Energy shall cease upon termination of this Service Schedule I.

SECTION 4

INTERRUPTIBILITY

4.1 PNM may reduce, curtail or interrupt deliveries to TNP in accordance with the following:

4.1.1 Immediately, upon verbal notice to TNP, for whatever portion of the scheduled energy that is required to serve PNM's firm customer

load, or without notice if due to Uncontrollable Forces, as defined in Section 8.1 of the Interconnection Agreement.

4.1.2 Upon providing a minimum of two hours' verbal notice to TNP, for whatever portion of the scheduled energy for which PNM's cost to generate (or otherwise procure) energy hereunder plus PNM's cost pursuant to Section 6.1.4 for delivering it to the Point of Delivery is more than the rates specified in Section 6.1.1 and 6.1.2 as applicable; provided, however, that TNP may request that PNM maintain schedule for up to eight hours after PNM gives TNP notice and PNM shall maintain the schedule. In such event, TNP agrees to pay for deliveries occurring in the last six hours of the eight hour period pursuant to Section 6.1.3 hereof. Such period may be extended upon mutual agreement of the respective system dispatchers.

4.1.3 Within the hour, upon verbal notice to TNP, if due to transmission system limitations; provided, however, that any reductions, curtailments or interruptions to TNP arising from this Section 4.1.3 shall be on a pro rata basis with other simultaneous block energy sales by PNM which affect the transmission system used for deliveries hereunder, and provided further that all economy energy sales by PNM which contribute to such transmission system limitations have been interrupted. Block Energy deliveries hereunder may be interrupted or curtailed by PNM prior to interrupting or curtailing service to PNM's firm customer loads.

4.2 TNP may reduce, curtail, or interrupt its scheduled deliveries of Block Energy from PNM in accordance with the following:

4.2.1 Immediately, without notice, if due to Uncontrollable Forces, as defined in Section 8.1 of the Interconnection Agreement.

4.2.2 Upon providing a minimum verbal notice of two hours to PNM, if system operating conditions, including request of TNP's copper industry customers and other than Uncontrollable Forces, limit TNP's ability to import energy hereunder.

4.3 In the event Block Energy schedules are reduced, curtailed or interrupted pursuant to Section 4.1 or 4.2 hereof, Block Energy schedules shall be reinstated at the beginning of the next Billing Peak Hour period that occurs after the reduction, curtailment or interruption of schedule, unless the system dispatchers mutually agree to a shorter period. Billing Peak Hours are set forth in Exhibit A, attached hereto and made a part hereof.

SECTION 5

POINT OF DELIVERY

5.1 The Point of Delivery for transactions hereunder shall be "Hidalgo" 345 kV switching station, located near Lordsburg, New Mexico.

5.2 Other delivery points may be mutually agreed upon by the parties' respective system dispatchers if energy deliveries cannot be made available by PNM, or accepted by TNP, at Hidalgo.

SECTION 6

RATES

6.1 Commencing on the Date of Initial Service, and in consideration of the faithful performance of the covenants of this Service Schedule, TNP shall pay PNM for the energy delivered hereunder as follows:

6.1.1 For all energy scheduled for delivery during Billing Peak Hours, as such Billing Peak Hours are set out in Exhibit A, except any energy provided pursuant to Section 4.1.2, at the rate of $32.00/MWh.

6.1.2 For all energy scheduled for delivery in hours other than Billing Peak Hours, except any energy provided pursuant to Section 4.1.2, at the rate of $24.00/MWh.

6.1.3 For energy scheduled for delivery pursuant to Section 4.1.2 hereof, in accordance with the applicable of the following:

6.1.3.1 For energy procured by PNM when the cost to procure and deliver such energy exceeds the rates in Section 6.1.1 or 6.1.2 above, as applicable, by $3/MWh or less, TNP shall pay PNM's cost.

6.1.3.2 For energy procured by PNM when the cost to procure and deliver such energy exceeds the rates in Section 6.1.1 or 6.1.2 above, as applicable, by more than $3/MWh, TNP shall pay PNM's cost plus $1/MWh.

6.1.3.3 For energy generated by PNM units, TNP shall pay PNM incremental fuel cost incurred plus 15 percent.

6.1.4 PNM's cost to deliver energy scheduled hereunder shall be deemed to be $2.50/MWh.

6.2 The rates for service specified in Section 6.1.1, 6.1.2, 6.1.3, and 6.1.4 hereunder shall remain in effect during the term of this Service Schedule I, and shall not be subject to change through application to the Federal Energy Regulatory Commission pursuant to the provisions of Section 205 of the Federal Power Act absent the agreement of the parties hereto.

6.3 The monthly billings and payments shall be addressed as follows:

6.3.1 Texas-New Mexico Power Company
501 West Sixth Street
Fort Worth, Texas 76102

Attention: General Accounting Department

6.3.2 Public Service Company of New Mexico
Alvarado Square
Albuquerque, New Mexico 87158

Attention: Cash Management

SECTION 7

OTHER PROVISIONS

7.1 Other terms and conditions of this Service Schedule I, as applicable, shall be as set forth in the Interconnection Agreement between the parties of February 28, 1974, as amended.

IN WITNESS WHEREOF, the parties have caused this Service Schedule I to be executed by their duly authorized officers as of the day and year first herein written.

TEXAS-NEW MEXICO POWER COMPANY

Jack V. Chambers

Asst. Vice President

PUBLIC SERVICE COMPANY OF NEW MEXICO

Senior Vice President

EXHIBIT A TO SERVICE SCHEDULE I

BILLING PEAK HOURS FOR TNP PURCHASE

(Reference Section 6.1.1)

Billing Peak Hours for the purposes of this Service Schedule I shall include one of the following, as applicable:

1. During the Winter Period (1), Monday through Friday, 7 a.m. to 11 p.m. MST, excluding Holidays (2).

2. During the Summer Period (1), Monday through Friday, 7 a.m. to 11 p.m. MDT (i.e., 6 a.m. to 10 p.m. MST), excluding Holidays (2).

---

(1) For purposes of this Service Schedule I, Winter Period means the period when Albuquerque is on Mountain Standard Time (MST); Summer Period means the period when Albuquerque in on Mountain Daylight Time (MDT).

(2) For purposes of this Service Schedule I, Holidays shall be:

Labor Day
Thanksgiving Day
Christmas Day
New Year's Day
Memorial Day
Independence Day

8604160098

UPDATED INFORMATION REQUESTED BY
THE NRC FOR ANTITRUST REVIEW

SOUTHERN CALIFORNIA EDISON COMPANY

UPDATED REGULATORY GUIDE 9.3

Item 1a

Anticipated excess or shortage in generating capacity resources not expected at the construction permit stage. Reasons for the excess or shortage along with data on how the excess will be allocated, distributed, or otherwise utilized or how the shortage will be obtained.

Response

Since October 1979, there has been no change in anticipated excess or shortage in generating capacity resources. Southern California Edison's resource plans have a planning criteria of installed capacity margins of 18% ± 2%. Recorded reserve margins for the years 1980 through 1985 were as follows:

1980	20.7%
1981	13.5%
1982	16.7%
1983	21.5%
1984	14.3%
1985	21.9%

Extremes in weather accounted for recorded deviations in planned reserve margins.

Item 1b

New power pools or coordinating groups or changes in structure, activities, policies, practices, or membership of power pools or coordinating groups in which the licensee was, is, or will be a participant.

Response

(1) By letter dated December 11, 1981, the Federal Energy Regulatory Commission (FERC) accepted for filing an Integrated Operations Agreement between SCE and each of the Cities of Azusa, Banning and Colton.

(2) By letter dated November 4, 1982, the Federal Energy Regulatory Commission (FERC) accepted for filing an Integrated Operations Agreement between SCE and the City of Vernon.

(3) In a letter dated December 30, 1983, Southern California Edison Company solicited interest on behalf of itself and other California utilities from WSCC Members and Affiliate Members in forming a Western Systems Power Pool. A Letter of Intent and Agreement for Establishing the Western Systems Power Pool was agreed to by Southern California Edison Company, Northern California Power Agency, San Diego Gas & Electric Company, State of California Water Resources, Bonneville Power Administration, Pacific Gas and Electric Company, Arizona Public Service Company, Salt River Project, Public Service Company of New Mexico, and Arizona Electric Power Corp., Inc. on October 15, 1985.

(4) The State of California Department of Water Resources and Edison executed the Edison-CDWR Coordination Agreement on October 13, 1983, providing for the sale of non-firm energy, short term exchange of energy, Edison's participation in pumpback operations at San Luis Reservoir, and seasonal capacity and energy exchange, all when available.

Item 1c

Changes in transmission with respect to (1) the nuclear plant, (2) interconnections or (3) connections to wholesale customers.

Response

(1) The Nuclear Plant

The Southern California Edison Company Palo Verde-Devers 500 kv Transmission Line went into service March 1982. This 500 kv transmission line is connected to the ANPP Switchyard.

(2) Interconnections

Execution of the ANPP High Voltage Switchyard Participation Agreement dated August 20, 1981, provides for the interconnection of Edison's Palo Verde-Devers 500 kv Transmission Line with the ANPP Switchyard.

As a participant in the ANPP Switchyard, Edison executed the Palo Verde-North Gila Line ANPP High Voltage Switchyard Interconnection Agreement June 7, 1984. This interconnection agreement interconnects the North Gila Transmission Line, owned by Arizona Public Service, Imperial Irrigation District, and San Diego Gas & Electric Company, with the ANPP Switchyard.

The IID-Edison Mirage 115/92 kv Interconnection Agreement, executed May 30, 1985, establishes an interconnection between Imperial Irrigation District's 92 kv system and Edison's 115 kv system at Edison's Mirage Substation.

By letter dated December 13, 1983, Arizona Electric Power Cooperative, Inc. (AEPCO) requested a proposal from Edison for providing AEPCO a new interconnection point in the area south of Hemet, California which would be evaluated as part of AEPCO's planning to serve Anza Electric Cooperative's (Anza) future loads in the 1990's. AEPCO also requested additional firm transmission service from Mead Substation (Nevada) to the new interconnection point when Anza's loads exceed the 10 MW level of service as provided by an existing agreement (Edison-AEPCO Firm Transmission Service Agreement, executed May 8, 1981).

By letter dated March 19, 1984, Edison proposed a new 115 kv interconnection at Stetson and indicated that service above 10 MW would require further study and negotiations before Anza's load approached such level. In addition, by letter dated November 26, 1985, Edison indicated that, since Anza's 1985 load was only 5 MW and may not exceed 10 MW until the next century, Edison would be willing to reconsider the amount of transmission service available at such time when Anza's load is actually approaching 10 MW.

On January 31, 1985, the operating voltage of the Pacific Intertie DC Transmission Line from Celillo to Sylmar was increased from $\pm$ 400kv to $\pm$ 500kv, thus increasing the power transfer capability of the DC Line by 400 MW. This voltage upgrade has increased Edison's interconnection to the Northwest by 86 MW. Studies are continuing regarding a second proposed upgrade which would entail adding new terminal facilities at both ends of the DC Intertie Line to increase the total rated capacity of the facility from 1955 MW to 2986 MW.

The State of California Department of Water Resources and Edison executed a Power Contract October 11, 1979 providing for the purchase, sale and exchange of electrical capacity and energy, for interconnection arrangements, and for the purchase and sale of transmission service. An agreement to amend the Power Contract was executed by Edison and sent to CDWR for execution. The agreement will amend the Power Contract by increasing the amount of firm transmission service from Sylmar to Vincent, provide firm transmission service from Vincent to Sylmar and change the amount of firm transmission service to CDWR's power plant and pumping plants as requested by CDWR.

(3) Connections

Edison expanded the two-line 220 kv service to the City of Anaheim's Lewis Substation by looping the Barre/Villa Park 220 kv line into the Lewis Substation in June 1981. This resulted in a total of four 220 kv lines serving Lewis Substation.

Item 1d

Changes in the ownership or contractual allocation of the output of the nuclear facility. Reasons and basis for such changes should be included.

Response

There have been no changes in Southern California Edison's ownership or contractual allocation of the output of the nuclear facility.

Item 1e

Changes in design, provisions, or conditions of rate schedules and reasons for such changes. Rate increases or decreases are not necessary.

Response

Since our original submittal, Edison has submitted to FERC the following changes in rates and rate schedules.

1. Docket No. ER81-177 (see Exhibit Nos. 1 & 1A)
   - original submittal dated December 16, 1980
   - revised submittal dated March 13, 1981

2. Docket No. ER82-427 (see Exhibit No. 2)
   - original submittal dated March 31, 1982

3. Docket No. ER84-75 (see Exhibit Nos. 3 & 3A)
   - original submittal dated November 8, 1983
   - revised submittal dated June 18, 1984

4. Docket No. ER86-271 (see Exhibit No. 4)
   - original submittal dated January 30, 1986

Item 1f

List of all (1) new wholesale customers, and (2) transfers from one rate to another, including copies of schedules not previously furnished, (3) changes in licensee's service area, and (4) licensee's acquisitions or mergers.

Response

Since our original submittal, Edison has added two small wholesale customers, namely, Arizona Public Service - Buckskin, and Arizona Public Service - Moonridge. Edison has also lost one wholesale customer, namely, Anza Cooperative. There have been no transfers between rate schedules, no major changes in service area, and no acquisitions or mergers since October 1979.

Item 1g

List of those generating capacity additions committed for operation after the nuclear facility, including ownership rights or power output allocations.

Response

Since October 1979, the following generating capacity additions were committed for operation:

(1) Big Creek #3, Unit 5, 38 MW.
(2) San Onofre Nuclear Generating Station Units #2 & 3. (75.05% owned by Edison, 24.95% owned by others).
(3) Palo Verde Nuclear Generating Station Unit 1. 15.8% owned by Edison, 84.2% owned by others).

Item 1h

Summary of requests or indications of interest by other electric power wholesale or retail distributors, and licensee's response, for any type of electric service or cooperative venture or study.

Response

(1) Pursuant to Special Condition No. 12 of FERC Tariff Schedule No. R-3-1, the cities of Anaheim, Azusa, Banning, Colton, Riverside, and Vernon sent notices of their intent to purchase and import power from third parties, on a nonintegrated basis, with the intent of reducing their billing demands on Edison, on and after January 1, 1987. The notices provide for the cities to be importing about 197 MW during 1987. In the notices sent July of 1985, each city requested that Edison provide firm transmission service for such power. In addition, Vernon sent notice pursuant to said Special Condition No. 12, of its intent to import non-firm energy on a nonintegrated basis, commencing January 1, 1987, so as to reduce the amounts of energy that it purchases from Edison. In response to the cities' request for firm transmission service, Edison sent letters to each city in December 1985, stating Edison would provide firm transmission service from Victorville-Lugo, Midway, and Goodrich to each of the city's points of delivery for the 197 MW. However, Edison declined Vernon's request to import non-firm energy under Special Condition No.12 inasmuch as that Condition applies only to firm capacity and associated energy.

(2) Pursuant to the Integrated Operations Agreement between Anaheim and Edison executed November 29, 1977, Anaheim has requested integration of non-firm energy it might purchase from third parties. Supplemental agreements have been executed by Edison and Anaheim integrating non-firm energy from the following third parties:

Western Area Power Administration	Executed 4-15-81
Nevada Power Company	Executed 1-30-81
Salt River Project	Executed 2-8-82
Arizona Public Service Company	Executed 2-8-82
Arizona Electric Power Co-op.	Executed 2-8-82
Washington Water Power Company	Executed 1-26-83
Public Service Company of New Mexico	Executed 1-26-83

California Department of Water Resources	Executed 11-7-83 Executed 11-12-84
Plains Electric Generation & Transmission Cooperative, Inc.	Executed 1-25-85
El Paso Electric Company	Executed 4-4-85

(3) Edison has received letters from Anaheim requesting integration of non-firm energy from various third parties. Edison has acknowledged the requests and is in the process of providing agreements to Anaheim for execution, integrating non-firm energy from the following third parties:

Pasadena	Request received 12-4-85	Letter of Acceptance 12-13-85
Glendale	Request received 12-6-85	Letter of Acceptance 12-13-85
WAPA	Request received 12-20-85	Letter of Acceptance 12-31-85
Montana	Request received 3-7-86	Letter of Acceptance 3-14-86

(4) By letter dated January 11, 1980, Anaheim requested integration of its share of the Intermountain Power Project and the related transmission facilities. Edison accepted Anaheim's capacity entitlement and associated energy in the Intermountain Power Project for integration for planning purposes in a letter dated March 13, 1980. Supplemental and firm transmission service agreements are in the process of execution.

(5) In a letter dated January 22, 1982, Anaheim stated its desire to increase its ownership interest in the San Onofre Nuclear Generating Station Units 2 and 3. In a Letter Agreement dated July 28, 1981 Edison agreed to Anaheim's purchase of an additional 1.5 percent ownership interest and to integrate such interest for planning purposes in San Onofre Nuclear Generating Station Units 2 and 3.

(6) By letter dated August 15, 1980, Anaheim requested Edison integrate 25 megawatts of capacity and associated energy from July 1, 1983 through June 30, 1990 and 15 megawatts of capacity and associated energy from July 1, 1990 through June 30, 1992 as a City Capacity Resource, and supply the necessary firm transmission from the 500 kv bus at Four Corners to Lewis Substation. Anaheim would purchase this capacity and energy from the City of Farmington, New Mexico from its entitlement in the San Juan Power Plant, Unit 4, of Public Service of New Mexico. In a letter dated October 27, 1980, Edison stated because of significant loop flow and line rating uncertainties, Edison had no assurance that it would have any excess transmission capacity

from Four Corners to the Edison system from which it could provide firm transmission service to Anaheim during the requested time frame. As a result, Edison stated it could not integrate the purchase as a City Capacity Resource. However, in the same letter Edison did offer to provide interruptible transmission service to Anaheim from Four Corners to Lewis and to integrate the purchase as non-firm energy beginning July 1, 1983.

(7) Pursuant to the Integrated Operations Agreement between Riverside and Edison executed November 11, 1977, Riverside has requested integration of non-firm energy it might purchase form third parties. Supplemental agreements have been executed by Edison and Riverside integrating non-firm energy from the following third parties:

Nevada Power Company	Executed 1-27-81
Western Area Power Administration	Executed 1-27-81
Salt River Project	Executed 2-2-82
Arizona Public Service Company	Executed 2-2-82
Arizona Electric Power Co-op.	Executed 2-2-82
Public Service Company of New Mexico	Executed 1-11-83
Plains Electric Generation and	Executed 1-10-83
Transmission Cooperative, Inc.	Executed 8-6-84
Utah Power & Light Company	Executed 5-6-83
Montana Power Company	Executed 5-6-83
Glendale	Executed 5-25-83
Burbank	Executed 5-25-83
Pasadena	Executed 5-25-83
Los Angeles Department of Water & Power	Executed 11-22-83
San Diego Gas & Electric	Executed 11-16-83
City of Farmington, New Mexico	Executed 12-14-83
Bonneville Power Administration	Executed 12-29-83

California Department of Water Resources	Executed 11-7-83 Executed 11-12-84
El Paso Electric Company	Executed 4-2-85

(8) Edison has received letters from Riverside requesting integration of non-firm energy from various third parties. Edison has acknowledged the requests and is in the process of providing agreements to Riverside for execution.

Deseret G & T Co-op.	Request received	7-11-85	Letter of acceptance	9-16-85
Washington Water Power	Request received	9-11-85	Letter of acceptance	10-2-85
Portland General Electric	Request received	9-11-85	Letter of acceptance	9-27-85
Pacific Power & Light	Request received	10-31-85	Letter of acceptance	11-27-85
Idaho	Request received	11-25-85	Letter of acceptance	12-13-85
Western Area Power Admin.	Request received	3-10-86	Letter of acceptance	3-17-86
Public Utility District of Chelan County	Request received	1-28-86	Letter of acceptance	2-11-86
Seattle	Request received	1-10-86	Letter of acceptance	1-17-86

(9) By letter dated January 15, 1982, Riverside requested integration of its share of the Palo Verde Nuclear Generating Station and associated transmission arrangements. Edison accepted Riverside's entitlement share and the associated energy of the Palo Verde Nuclear Generating Station for integration in a letter dated August 24, 1982. A supplemental agreement for this integration was executed between Edison and Riverside March 14, 1986, as was a firm transmission service agreement.

(10) By letter dated January 11, 1980, Riverside requested integration of its share of the Intermountain Power Project and the related transmission facilities. Edison accepted Riverside's capacity entitlement and associated energy in the Intermountain Power Project for integration for planning purposes in a letter dated March 13, 1980. Supplemental and firm transmission service agreements are in the process of execution.

(11) By letters dated July 23, 1984, September 24, 1984, and December 17, 1984, Riverside requested Edison integrate 35 megawatts of capacity and associated energy from Public Service of New Mexico, and give Riverside capacity credit for such pursuant to the Integrated Operations Agreement between Edison and Riverside. In letters dated August 27, 1984, and December 19, 1984 responding to Riverside's request, Edison stated that the proposed 35 MW capacity resource did not meet the qualifications for integration under the Integrated Operations Agreement, and declined to integrate such resource.

(12) In letters from the cities of Anaheim and Riverside, dated March 21, 1985, and February 11, 1985, respectively, requests were made for the integration of replacement capacity to be purchased by the cities from San Diego and to be used for each city's San Onofre Generating Station (Units 2 and 3) obligation. In letters dated March 7, 1985, and April 2, 1985, Edison accepted for integration the replacement capacity to be purchased from San Diego. Edison then indicated to the cities of Anaheim and Riverside on an oral basis that Edison would be willing to provide them with replacement capacity at a charge of 10 cents a kw-day, unless otherwise agreed. Edison then executed Letter Agreements with Anaheim and Riverside, dated April 15, 1985, providing for Anaheim and Riverside's purchase of replacement capacity from Edison at 10 cents a kw-day for obligations incurred at San Onofre Generating Station Units 2 and 3. This Letter Agreement was extended twice through December 31, 1985. On December 6, 1985 the FERC accepted the original April 19, 1985 Letter Agreement and the two extensions for filing.

Currently, Anaheim, Riverside, Azusa, Banning, Colton, and Vernon have executed letter agreements with Edison providing for the purchase of replacement capacity from Edison at 10 cents kw-day for the year 1986. These letter agreements cover all city capacity resources integrated through December 31, 1986.

(13) The City of Vernon requested integration and interruptible transmission service for non-firm energy they might purchase from Nevada Power Company and the State of California Department of Water Resources. Agreements integrating this non-firm energy into the Edison system and providing interruptible transmission service were executed between Edison and Vernon on January 5, 1982 and December 23, 1983, for each of the third party resources, respectively.

(14) By letter dated May 8, 1981, Vernon requested integration of its share of the Palo Verde Nuclear Generating Station and associated transmission arrangements. Edison accepted Vernon's entitlement share and the associated energy of the Palo Verde Nuclear Generating Station for integration for planning purposes in a letter dated August 24, 1982. Because Edison and Vernon could not reach agreement, Edison unilaterally

filed a supplemental agreement and a firm transmission service agreement with FERC February 24, 1986, for the integration of Vernon's share of the Palo Verde Nuclear Generating Station.

(15) Pursuant to the Integrated Operations Agreement between Banning and Edison executed September 10, 1981, Banning requested integration of the non-firm energy it might purchase from the Nevada Power Company. Edison and Banning executed a supplemental agreement for the Nevada Power Company non-firm energy on April 9, 1985.

(16) Edison received letters from Banning requesting integration of non-firm energy from various third parties. Edison has acknowledged the requests and is in the process of providing agreements to Banning for execution, integrating non-firm energy from the following third parties:

Glendale	Request received	1-15-86	Letter of acceptance	1-23-86
Utah Power & Light	Request received	1-13-86	Letter of acceptance	1-22-86

(17) By letter dated January 4, 1982, Banning requested integration of its share of the Palo Verde Nuclear Generating Station and associated transmission arrangements. Edison accepted Banning's entitlement share and the associated energy of Palo Verde Nuclear Generating Station for integration for planning purposes in a letter dated August 24, 1982. A supplemental agreement for this integration was executed between Edison and Banning February 26, 1986. A firm transmission service agreement, signed by Edison, has been sent to Banning for execution.

(18) By letter dated February 22, 1982, Azusa requested integration of its share of the Palo Verde Nuclear Generating Station and associated transmission arrangements. Edison accepted Azusa's entitlement share and the associated energy of Palo Verde Nuclear Generating Station for integration for planning purposes in a letter dated August 24, 1982. A supplemental agreement for this integration was executed between Edison and Azusa February 18, 1986. A firm transmission service agreement, signed by Edison, has been sent to Azusa for execution.

(19) In a letter dated January 15, 1986, Azusa requested integration of non-firm energy it would acquire from Western Area Power Administration, City of Glendale, City of Farmington, New Mexico, and Arizona Electric Power Co-op. Edison accepted the non-firm energy for integration from these third parties in letters to Azusa dated January 24, 1986 and January 27, 1986.

(20) In letters dated January 31, 1986 and March 6, 1986, Azusa requested integration of non-firm energy purchased from El Paso Electric Company and Salt River Project, respectively. Edison accepted the non-firm energy for integration for Azusa in letters dated February 21, 1986 and March 17, 1986.

(21) By letter dated February 18, 1982, Colton rquested integration of its share of the Palo Verde Nuclear Generating Station and associated transmission arrangements. Edison accepted Colton's entitlement share and the associated energy of Palo Verde Nuclear Generating Station for integration for planning purposes in a letter dated August 24, 1982. A supplemental agreement for this integration was executed between Edison and Colton February 18, 1986. A firm transmission service agreement, signed by Edison, has been sent to Colton for execution.

(22) Edison received letters from Colton requesting integration of non-firm energy from various third parties. Edison has acknowledged the requests and is in the process of providing agreements to Colton, for execution, integrating non-firm energy from the following third parties:

Arizona Electric Power Co-op.	Request received	1-13-86	Letter of acceptance	1-22-86
Glendale	Request received	1-13-86	Letter of acceptance	1-22-86
El Paso Electric	Request received	2-24-86	Letter of acceptance	3-4-86
Western Area Power Administration	Request received	2-24-86	Letter of acceptance	3-4-86

(23) In response to requests for interruptible transmission service, Edison executed interruptible transmission service agreements with the entities listed below. In these agreements Edison provides interruptible transmission service throughout the Edison transmission network.

Riverside	Executed 1-27-81	FERC No. 129
Anaheim	Executed 1-30-81	FERC No. 130
Azusa	Executed 12-22-82	FERC No. 160
Banning	Executed 12-22-82	FERC No. 159
Colton	Executed 12-22-82	FERC No. 162

Burbank	Executed 1-18-83	FERC No. 166
Pasadena	Executed 11-2-82	FERC No. 158
Glendale	Executed 9-2-81	FERC No. 143
Calif. Dept. of Water Resources	Executed 12-19-84	FERC No. 181
Western Area Power Admin.	Executed 10-10-80	FERC No. 120
San Diego Gas & Electric	Executed 2-18-82	FERC No. 151
Pacific Gas & Electric	Executed 10-14-81	FERC No. 147
Los Angeles Dept. of Water & Power	Executed 3-6-80	FERC No. 118
Los Angeles Dept. of Water & Power	Executed 6-11-81	FERC No. 140
Arizona Electric Power Co-op.	Executed 12-28-82	FERC No. 161
M-S-R Public Power Agency	Executed 8-24-82	FERC No. 153

(24) In response to requests for firm transmission service over Edison's transmission paths, Edison has executed firm transmission service agreements with the entities listed below to provide such service to them.

Burbank	Executed 4-20-84	FERC No. 177
Pasadena	Executed 4-25-84	FERC No. 175
Glendale	Executed 5-1-84	FERC No. 176
Riverside	Executed 3-14-86	
Azusa	Executed 2-18-86	
Banning	Executed 2-25-86	
Colton	Executed 2-18-86	
Calif. Dept. of Water Resources	Executed 10-11-79	FERC No. 113
Burbank	Executed 3-13-81	FERC No. 135
Glendale	Executed 3-13-81	FERC No. 136

Pasadena	Executed 4-14-81	FERC No. 137
Imperial Irrigation District	Executed 4-14-81	FERC No. 138
Pacific Gas & Electric	Executed 5-1-80	FERC No. 117
San Diego Gas & Electric	Executed 11-13-81	FERC No. 139
Arizona Electric Power Co-op.	Executed 5-8-81	FERC No. 131
Los Angeles Dept. of Water & Power	Executed 5-28-81	FERC No. 141
Western Area Power Admin.	Executed 8-31-84	

(25) Edison entered into a letter agreement dated January 30, 1980, whereby Edison is willing to resell surplus non-firm energy to Portland General Electric Company.

(26) Edison and Washington Water Power Company entered into a Capacity Exchange Agreement dated June 1, 1980. Washington Water Power will make available to Edison 60,000 KW of capacity and associated energy during the months of June, July, August, and September. In return Edison will make available to Washington Water Power 80,000 KW of capacity and associated energy during the months of December, January, and February.

(27) Edison and Puget Sound Power & Light Company ("Puget") entered into an exchange of energy agreement dated April 1, 1981. Edison and Puget will exchange energy made available by Puget to Edison during the summer for energy made available by Edison to Puget during the winter.

(28) The State of California Department of Water Resources and Edison executed a Capacity Exchange Agreement dated September 17, 1981. This agreement provides for the exchange of specified amounts of generation capacity, exchange energy, and a reduction of transmission service charges for the service provided under the Edison CDWR Firm Transmission Service Agreement.

(29) The State of California Department of Water Resources and Edison executed an agreement dated December 31, 1982 modifying the terms of the State EHV Contract with respect to CDWR's use of interstate and intrastate EHV transmission service.

(30) In a letter dated April 24, 1980, the City of Boulder City requested to purchase from Edison capacity beginning in 1981 and continuing through 1990. Edison responded in a letter dated July 17, 1980, that it was unwilling, at this time, to undertake any new obligations of the type Boulder City had

requested due to numerous uncertainties Edison was encountering in acquiring new capacity to meet its future requirements.

(31) Upon receipt of an allocation in the Hoover Dam and Parker-Davis Project, the cities of Anaheim, Azusa, Banning, Colton and Riverside orally negotiated with Edison a means by which they could best utilize this resource. It was determined Edison would integrate the Hoover Dam and Parker-Davis Project as a city capacity resource for Anaheim, Azusa, Banning, Colton, and Riverside and provide firm transmission service for the resources from Mead substation to each city's point of delivery. Vernon is also a recipient of an allocation from the Hoover Dam and Parker-Davis Project. Vernon has elected not to integrate this resource, but to operate it as a non-integrated resource. Disagreement exists between Edison and Vernon concerning the terms of firm transmission service which Edison has offered to Vernon. The issues are in litigation before FERC in Docket No.ER-75-000 (Phase II).

(32) In 1981 and again in 1982 Vernon requested to purchase a portion of the San Onofre Nuclear Generating Station from Edison. Edison responded that it was not actively trying to sell a portion of SONGS, but might consider a written request for such a purchase. Edison suggested Vernon pursue an acquisition from San Diego Gas & Electric, who had distributed proposals to sell a portion of its share of SONGS. On February 8, 1983 Vernon sent a written request to Edison. However, since they could not agree on the terms, a sale of an interest in SONGS from Edison was never realized.

With respect to the San Diego interest, because it was not feasible for Edison to give Vernon early capacity credit for the resource, Vernon elected not to purchase San Diego's interest. On April 19, 1983 Edison reiterated its offer to provide firm transmission service to Vernon should it reconsider and purchase an interest in San Diego's share of the plant. Edison also indicated that its proposal to sell a portion of its interest in SONGS was still open to a countr offer from Vernon.

(33) During 1980, Arizona Public Service Company and the Salt River Project offered to sell a 5.5% and 5.91% interest, respectively, in Palo Verde Units 1, 2, and 3. Since several California entities expressed interest in purchasing all or part of such Palo Verde interests, by letters dated October 27, 1980, Edison sent a statement to such entitites regarding the availability of firm transmission service. The entities receiving the statement were: City of Anaheim, City of Azusa, City of Banning, City of Burbank, City of Colton, City of Glendale, City of Pasadena, City of Vernon, Department of Water and Power of the City of Los Angeles, Imperial Irrigation District (all members of Southern California Public Power Authority), Modesto-Santa Clara-Redding Public Power Agency (M-S-R), and Turlock Irrigation District. In the statement,

Edison indicated that firm transmission service for such Palo Verde power could be provided only upon construction of new transmission facilities, which may be completed by 1987. Prior to such time, Edison offered interruptible transmission service, or perhaps short-term firm transmission service, over the Palo Verde-Devers No. 1 line (under construction for 1982 operation).

Subsequent to Edison's statement, the Southern California Public Power Authority members purchased Salt River Project's 5.91% interest in Palo Verde and made transmission arrangements which did not include Edison's offered services. Neither M-S-R nor Turlock obtained any share of Palo Verde due to either rejections by their respective cities or by the sellers.

(34) A consortium of nearly all publicly and privately-owned utilities in California have joined together to build a third 500 kV transmission line linking California and the Pacific Northwest. Fifteen northern California public agencies, the federal Western Area Power Administration, the California Department of Water Resources, the southern California cities of Anaheim, Azusa, Banning, Colton, Riverside and Vernon, several irrigation districts, most in the central valley, along with Pacific Gas and Electric Company, Edison and San Diego Gas & Electric are planning to build the new 1600 MW line from the California-Oregon border to central California where it will connect with existing extra-high voltage facilities. A Memorandum of Understanding was executed between the participants on December 19, 1984, and the new line is scheduled to be completed in 1991.

An issue has arisen between Edison and San Diego as to whether or not Edison was responsible for providing to San Diego firm south to north transmission service through Edison's system to enable San Diego to deliver power from San Diego's system over the new line. Edison contends that it does not have sufficient south to north transmission capability to provide such service. However, by a February 25, 1986 letter agreement executed by Edison and San Diego, joint efforts will be made to increase transmission capability or through a contractual arrangement whereby Edison would provide capacity and/or energy from its system to the Pacific Northwest entities on behalf of San Diego.

(35) By letter dated July 12, 1982, Edison provided Commission Federal de Electricidad (CFE) with the initial draft of a power exchange agreement which the parties had agreed to develop. On January 23, 1984, Edison and CFE culminated negotiations by executing the CFE-Edison Capacity and Electric Energy Exchange Agreement. This agreement enables CFE and Edison to purchase and sell economy energy, economy capacity, and short-term firm service.

(36) On April 23, 1985, Edison solicited expressions of interest in a proposed Palo Verde-Devers No.2 Transmission Line, which will provide transmission capacity between the Palo Verde Nuclear Generating Station and the Devers Substation located in California. Twenty entities responded requesting 2910 MW of capacity. Since the line capability is expected to be 1200 MW, capacity was allocated to eleven entities based upon their existing commitment to firm resources in the Southwest. The following entities received an allocation: Los Angeles Department of Water & Power, M-S-R, Imperial Irrigation District, and the cities of Riverside, Vernon, Burbank, Glendale, Pasadena, Azusa, Banning and Colton. Due to the excessive requests, the following entities were unable to participate in the line: the City of Anaheim, Arizona Electric Power Co-op., Arizona Public Service Co., California Dept. of Water Resources, Colorado River Commission of Nevada, Pacific Gas & Electric, Salt River Project, San Diego Gas & Electric and Western Area Power Administration. Edison and each of the participants have executed a letter agreement dated January 29, 1986, under which the participants will share the cost of the regulatory filing activities.

Since the allocation was made, Edison has received comments from Vernon, Arizona Electric Power Co-op., Imperial Irrigation District, Riverside and San Diego Gas & Electric expressing their disappointment in either not receiving an allocation or a larger allocation. Edison reiterated its original response that the allocations are based upon commitments to firm resources, but would reconsider the allocations if additional capacity in the line should become available.

(37) By letter dated July 19, 1985, Pasadena requested that Edison provide 200 MW of firm transmission service, in addition to that already provided under the 1970 Pasadena-Edison 230 kV Interconnection and Transmission Service Agreement. Negotiations are continuing and an agreement is expected in 1986.

(38) On December 20, 1983, Edison and the Imperial Irrigation District executed the Edison-IID Power Exchange Agreement whereby Edison is to exchange energy generated by its existing geothermal resources in the Imperial Valley for a like amount of capacity and energy purchased by IID from El Paso Electric for delivery to Edison at Palo Verde.

(39) On June 10, 1980, the City of Burbank requested Edison to provide transmission service for energy purchased from the Metropolitan Water District of Southern California (MWD). Edison and Burbank executed the Edison-Burbank MWD Hydro Electric Energy Delivery Agreement on January 7, 1982. The contract terminated on March 31, 1983, at which time the energy was no longer available to Burbank.

(40) On November 29, 1982, Burbank requested firm transmission service for a possible layoff or sale to the Southern California Public Power Authority of SONGS Units 2 & 3 from San Diego Gas & Electric. The service would be for the term of the SONGS project. Since no contract between San Diego and the city was ever executed, a transmission service agreement was not necessary.

(41) In a letter dated October 22, 1980, Pacific Gas & Electric requested firm transmission service from Mead substation to Midway substation during the period 1981 through 1988 in various amounts for the purchase of capacity and energy from Arizona Electric Power Co-op.'s Apache Plant. Edison's response dated November 19, 1980, stated Edison had no surplus transmission capacity in the transmission facilities between Mead and Lugo Substations which could be used to provide such service. Edison would be able to provide interruptible transmission service from Mead substation to Midway substation, and possibly firm transmission service between its points of interconnection on the Victorville-Lugo transmission line and Number 3 Vincent-Midway line.

(42) By letter dated January 16, 1981, Pacific Gas & Electric requested transmission service from either Four Corners 345/500 kv switchyards or possibly the Palo Verde High Voltage Switchyard for purchase of contingent capacity and energy from Public Service Company of New Mexico's San Juan Generating Station during the period 1983 through 1987. Edison responded to this request in a letter dated February 6, 1981. It appeared at the time Edison could provide firm transmission service on the Palo Verde-Devers 500 kv line for the period requested, if it was completed. But once Palo Verde Unit 2 went commercial, which was scheduled for May 1984, only interruptible transmission service would be available. Because of significant loop flow and line rating uncertainties, Edison had no assurance it would have any excess transmission capacity from Four Corners to the Edison system. Consequently, Edison was in no position to provide firm transmission, in any amount, to PG&E. Edison could, however, provide interruptible transmission service to PG&E from Four Corners to Midway Substation.

(43) In a letter dated March 4, 1982, Pacific Gas & Electric requested firm transmission service from Palo Verde to Midway for 300 MW of capacity and energy from the Southwest for the summer, or an exchange of Southwest power for Northwest power, and the addition of Palo Verde and Four Corners as points of delivery in the Edison-PG&E Interruptible Transmission Service to Midway Agreement. By letter dated April 1, 1982, Edison stated it could not provide firm transmission service from Palo Verde-Devers to Midway, but Edison would be willing to explore possible power exchanges. Palo Verde and Four Corners would be added to the SCE-PG&E Interruptible Transmission Service to Midway Agreement by amendment.

(44) Edison received letters from Anaheim, Riverside, Azusa, Banning, Colton, and the Northern California Power Agency in January and February of 1984 concerning the Pacific Intertie DC Transmission Line upgrades. The entities requested they be given the opportunity to participate in the uprating of the DC Line. In Edison's letter dated July 10, 1984, to each of the five cities, Edison reviewed the contractual framework within which the upgrades would occur. Edison's ownership right to, and obligations for, DC line upgrades are governed by the Edison-City of Los Angeles DC Line Agreement ("DC Line Agreement"). Edison's rights to utilize the transmission capacity of the DC line and its upgrades are governed by the DC Line Agreement and the California Companies Pacific Intertie Agreement ("CCPIA"). With respect to transmission service that may be offered to third parties, the DC Line Agreement and the CCPIA contain rights of first refusal that may be exercised by signators to those agreements. Several years ago, Edison announced it would not exercise these rights as they relate to transmission service, and it does not intend to exercise such rights. That waiver was expressed before the FERC Docket No. E-7777 (Phase II) hearings commenced, and was confirmed in the recent decision in that proceeding. Edison evaluated the requests made by the five cities and others in light of Edison's contractual commitments and the limited increases to which Edison would be entitled. Edison determined it would be unable to offer firm transmission service over, or an ownership participation in, its share of the upgrades because it expects to fully utilize its share of the upgrades for the benefit of all of Edison's customers including its resale cities. Edison will continue to make available interruptible transmission service over Edison's allocation of the capacity of the Pacific Intertie, including Edison's share of the existing DC line and any upgrades to it, in accordance with prior agreements and commitments.

(45) As a result of development of the Colorado River Indian Irrigation Project ("CRIIP"), the Bureau of Indian Affairs ("BIA") agreed to supply electrical power to off-reservation customers in the vicinity of the CRIIP lines. Since it was not an integral part of CRIIP, the BIA elected to sell such off-reservation portion of its system. On June 15, 1984 Edison and the U.S. Department of the Interior executed an agreement under which Edison agreed to purchase CRIIP's off-reservation distribution system located on the California side of the Colorado River.

(46) On April 4, 1983 San Diego Gas & Electric and Edison entered into the Service Area Reciprocal Power Supply Agreement. San Diego has agreed to serve a small number of Edison's retail customers adjacent to the San Diego Gas & Electric system and Edison has agreed to serve a small number of San Diego's retail customers adjacent to Edison's territory. This agreement allows the parties to accept and deliver energy to serve each other's customers.

(47) Edison, along with participation from the Los Angeles Department of Water & Power, developed the 10 MW (gross) Brawley Geothemal Unit 1 in the Brawley Known Geothermal Resource Area (KGRA). The Unit commenced operations as an experimental unit in mid-1980 and operations were terminated in mid-1985. The Unit was never declared to be in commercial status. The Unit is now being decommissioned and at the present time there are no future plans for further geothermal development in the Brawley KGRA.

(48) By letter dated October 8, 1981, the consultant for Modesto-Santa Clara-Redding Public Power Agency (M-S-R) requested firm and interruptible transmission service from Palo Verde Nuclear Generating Station to Midway Substation (near Bakersfield, CA) for a potential 150 MW purchase from El Paso Electric Company's (EPE) share of PVNGS. By letter dated April 21, 1982, Edison indicated that it was willing to provide interruptible and short-term firm transmission service for such PVNGS purchase. In addition, Edison indicated that long-term firm service would require a new transmission facility. By letter dated June 28, 1982, Edison withdrew its prior offer for firm transmission service upon the understanding that M-S-R had terminated its discussions with EPE.

(49) By letter dated February 4, 1981, the consultant for Modesto-Santa Clara-Redding Public Power Agency (M-S-R) indicated an interest in exploring the possibility of joint ownership of the Palo Verde-Devers No. 2 line to deliver power to M-S-R from its planned acquisition of a share in San Juan Unit No. 4. In addition, by letter dated May 16, 1983, the consultant for M-S-R reiterated an interest in the new line as well as transmission service from Devers to Lugo and from Lugo to Midway Substations.

By letter dated June 20, 1983, Edison stated that Edison could not commit itself to participate in any specific transmission project nor determine transmission service needs until certain studies are completed and the needs are defined to justify the necessary transmission facilities.

By letter dated September 29, 1984, M-S-R requested 150 MW of firm transmission service from Palo Verde to Midway for its San Juan Project power upon completion of the Palo Verde-Devers No. 2 Line. By letter dated November 8, 1984, Edison responded that, although no decision had been made on constructing a line, Edison was willing to discuss mutually beneficial arrangements under which Edison would construct and own the Palo Verde-Devers No. 2 Line and provide transmission service for M-S-R's San Juan Project power.

Item 2

Licensees whose construction permits include conditions pertaining to antitrust aspects should list and discuss those actions or policies which have been implemented in accordance with such conditions.

Response

No antitrust conditions were imposed on Southern California Edison with respect to the construction permit for Palo Verde 1, 2 & 3.

ER 81-177

EXHIBIT 1

Southern California Edison Company

P. O. BOX 800
2244 WALNUT GROVE AVENUE
ROSEMEAD, CALIFORNIA 91770

RONALD DANIELS
MANAGER OF REVENUE REQUIREMENTS

TELEPHONE
(213) 572-1701

December 16, 1980

Federal Energy Regulatory Commission
Office of the Secretary
Union Center Plaza
825 North Capitol, N.E.
Washington, D.C. 20426

Gentlemen:

Pursuant to Section 205(d) of the Federal Power Act and to Sections 35.13 and 35.14 of the Commission's Regulations, there are transmitted herewith for filing, as a change in Southern California Edison Company's (Edison) resale rates, six copies of the following listed documents relating to electric service to resale customers. Volumes 1 and 4, marked "Executed Copies", contain the executed copies of the attestation and witness verifications, respectively.

Volume 1

1. Transmittal letter, including list of schedules to be superseded, including customer name and mailing address.

2. Federal Register Notice.

3. Attestation.

4. Sales and Revenue Comparisons - Period 1 - 12 months Ended June 30, 1980 - Recorded.

5. Supporting Cost Statements, A through P, Period 1 - 12 Months Ended June 30, 1980 - Recorded.

Volume 2 (Excluding SONGS Unit 2)

6. Proposed Rates, Special Conditions, Rules.

7. Wage-Price Statement, Period II.

8. Sales and Revenue Comparisons, Period II - 1981 - Estimated.

9. Sales and Revenue Comparisons - 12 months preceding and succeeding the proposed date the rates are to become effective.

10. Supporting Cost Statements, A through P, Period II - 1981 - Estimated.

Volume 3 (Including SONGS Unit 2)

11. Proposed Rates, Special Conditions, Rules.

12. Wage-Price Statement, Period II.

13. Sales and Revenue Comparisons, Period II -1981 - Estimated.

14. Supporting Cost Statements, A through P, Period II - 1981 - Estimated.

Volume 4

15. Prepared testimony of witnesses, John B. Adams, Larry O. Chubb, Robert P. Haub, Lawrence J. Hedrick, Richard L. Jensen, Finn B. Jespersen, Ray W. Scofield and James R. Simmons.

16. Exhibits entitled:

   a. JBA-1, "Financial Requirements, Characteristics, and the Required Rate of Return."

   b. LJH-1, "Development of Proposed Resale Rate of Return for Test Year 1981."

   c. LJH-2, "Calculation of Attrition Allowance Using Historical Trends."

   d. LJH-3, "Calculation of Attrition Allowance Using Anticipated Changes in 1981 Test Year Resale Costs."

   e. RLJ-1, "Comparison of Present and Proposed Resale Rates for 1981."

   f. FBJ-1, "Administrative and General Labor Dollars as a Percent of Total Labor Dollars By

Organization."

g. FBJ-2, "Detailed Analysis for the Functionalization of Administrative and General Expense."

h. FBJ-3, "Direct Allocation of Account 928 (Regulatory Commission Expense) to FERC Jurisdictional Customers."

i. FBJ-4, "Detailed Analysis for the Functionalization of General Plant."

Volume 5

17. Workpapers supporting rate increase filing.

Separate Documents

18. Voucher to cover the filing fees.

19. A proposed notice, in triplicate, suitable for publication in the Federal Register.

There are no agreements between Edison and its resale customers in effect that preclude unilateral rate change filings by Edison of the type here involved. Therefore, no agreement of resale customers to this filing is required.

With this filing, Edison initially increases the base rates for resale service and revises the base rates and the fuel cost adjustment billing factor to reflect the estimated test year 1981 system average cost of fuel as the base cost of fuel and the loss factors estimated for 1981. The rates filed herein, including the fuel cost adjustment provision, are estimated to produce a return of 11.36% overall on rate base for resale service based on Period II - 1981 estimated. This includes an attrition allowance of 0.4% intended to afford the Company the opportunity to earn an average of 14% on common equity during the years 1981 and 1982, if the increased rates were to be effective at the beginning of 1981. The overall increase in resale revenues for the test year is estimated at about $18.6 million without San Onofre Nuclear Unit No. 2 (SONGS 2). The increase is proposed to be made effective 60 days after filing or February 14, 1981, whichever is later, pursuant to Section 205 of the Federal Power Act.

The fuel clause contained in the filing complies with Section 35.14 of the Regulations both in form and content. A copy of the clause is shown on Sheet 1 of Statement 0 for Period II (Volumes 2 and 3, as applicable). Billing factors will be revised monthly, to be effective from the 1st of the month.

The initial fuel clause billing for each billing period will be an estimated amount based on data recorded for the calendar month just prior to the month in which the billing factor is to become effective. Such estimated fuel clause billing will be adjusted in the following billing for any difference between recorded and estimated fuel and purchased power costs. The base cost has been derived by utilizing estimated 1981 system fuel and purchased power costs and sales data which were used in developing the new resale base rates. The calculation of the fuel cost adjustment billing factor used to adjust the fuel clause billing previously made on an estimated basis will serve to precisely match the fuel and purchased power component of the new resale rates with the fuel and purchased power costs actually incurred and allocated to resale service on a monthly basis. Development of the base fuel expense is shown on Sheet 3 of Statement O for Period II (Volumes 2 and 3, as applicable).

Rates proposed to be made effective concurrently with the operation of SONGS 2 reflect the additional costs allocable to resale operations as a result of SONGS 2 becoming operational. It is extremely important that the base rate increase proposed to be made effective with the SONGS 2 addition be timed with its becoming operational since the SONGS 2 investment will be removed from the AFUDC base at the time it becomes operational. Any delay in adjusting Edison's base rates to reflect the capital and operating costs associated with SONGS 2 will result in serious revenue and earnings deficiencies for the Company and result in deterioration of its financial position and ability to attract capital on reasonable terms. At the same time, however, the fuel clause will promptly reflect in charges to customers the reduced fuel costs resulting from the displacement of high cost fuel oil with low cost fuel in Edison's fuel mix.

An additional revenue increase resulting from the step resale rate increase proposed to be made effective concurrently with the operation of SONGS 2 is estimated to be about $23.7 million, if SONGS 2 were to become operational January 1, 1981. The resale rate proposed to be made effective with the operation of SONGS 2 contains an adjustment formula, designated the "SONGS 2 Adjustment", which is designed to reflect the escalation in costs associated with SONGS 2 that will occur as a result of delays in SONGS 2 becoming operational beyond January 1, 1981. These additional costs reflect the additional accumulation of AFUDC on the SONGS 2 investment beyond January 1, 1981, and expected escalation in operating costs resulting from such delay offset in part by additional investment tax credits.

The rates filed herein (Volumes 2 and 3 as applicable) are embodied in rate schedule (TOU-R) which will be applicable to all resale customers. By serving all resale customers under a TOU-R rate design, the Company believes the resale customers will be encouraged to implement time-of-use rate design in their

retail operations and to encourage other conservation and load management measures by their retail customers. Since the revenues estimated under the new filed rates are based on present usage and load patterns of the customers, to the extent that conservation and load management objectives are enhanced, the revenues produced under such rates may be expected to become increasingly deficient. Thus, it is important that any regulatory lag resulting from delay in implementing the proposed new rates be kept to a minimum.

When it is considered that the rates presently in effect are based on a test year 1979 cost of service and under Edison's showings contained in the filing (e.g., Statement M, Period II, Sheet 1, Excluding SONGS 2) would produce only about 7.44% return on rate base allocated to resale for test year 1981 (a return on common equity of less than 6%), it is doubly important that any delay in the effective date of the increase be kept at a minimum. Such low level of earnings in the test year at present rates would be further reduced by any ordered reductions in those rates (filed in Docket No. ER79-150) that might result from the Commission's decision in that docket, a result that we believe would be totally unjust but must be considered a distinct possibility where those rates are being tested on the basis of a test year 1979 cost of service and the Commission staff and intervenors have recommended substantial disallowances.

Edison has already delayed this resale rate increase filing based on test year 1981 cost of service beyond the time it would be required to be filed to become effective at the beginning of the test year 1981 without suspension. It has done this in part in order to track the system cost of service used in developing the resale rates in this filing as nearly as possible with the system cost of service which it expects to be the primary determinant of retail rates also based on test year 1981 which it contemplates will be approved by the California Public Utilities Commission (CPUC) and be made effective on or about January 1, 1981.

Since the Commission's objective of tracking the timing of resale rate changes and retail rate changes as closely as possible to minimize potential "price squeeze" problems will be most nearly achieved if the resale rates filed herein are made effective as soon after the beginning of test year 1981 as possible, Edison respectfully requests that the increased rates be made effective as soon as possible after the required 60-day notice period and that, if the rate filing is to be set down for hearing, the suspension in their effectiveness pursuant to Section 205(e) of the Federal Power Act, be kept to a minimum period, namely one day. Edison's present resale rates are shown in this filing to be wholly inadequate to recover its cost of service on its resale operations based on test year 1981.

Given a minimum delay in making the new resale rates effective, Edison will be prepared to make a supplemental or amended filing, after the CPUC

decision on Edison's 1981 test year retail rate increase filing is issued if the combined effect of such modifications is to reduce costs to resale. Such revision would include adjustments for any differences between the system cost of service (including rate of return allowance exclusive of attrition) which the CPUC adopts in fixing the retail rates and which Edison has used as a basis for developing the resale rates involved in this filing. Such a procedure would accordingly adjust the filed resale rates and would further reduce the potential for any "price squeeze" problem to arise from this filing.

Any delay in making this rate increase filing effective will simply contribute to regulatory lag and earnings deficiencies at a time when the utilities, and Edison in particular, are plagued by cash flow problems and the serious disenchantment of investors with utility securities, as evidenced by market price performance (Edison's common stock sells at less than 80% of book value). The need for investor favor to attract the vast amounts of new capital to finance new construction to meet load growth and comply with government imposed environmental requirements continues to be at an all time high.

Continued subsidy of utility rates by stockholders not only jeopardizes the utilities' ability to continue to provide adequate and reliable service but actually aggravates the problem by underpricing the service, thus tending to encourage wasteful use of energy at a time when the national interest and objective is to motivate energy users to conserve and to avoid or minimize wasteful use. The policy of our new national energy legislation is to price energy service at its full cost and thus communicate the proper signal to energy users to encourage the most efficient use of energy resources. Underpricing of energy service by delay in effecting rate increases designed to cover increased costs is clearly contrary to the national interest and the national energy policy.

Because of the serious inadequacy of existing rates to cover test year 1981 cost of service and the possibility that even those rates, based on test year 1979, may be reduced by Commission decision to be rendered in Docket No. ER79-150, and those rates would produce even lower returns than the 7.44% on rate base and 5.2% return on common equity in 1981 that the Docket No. ER79-150 filed rates subject to refund would produce, it is imperative that the Company's resale rates be promptly brought up to a level that is more adequate to cover the resale cost of service. A minimum suspension period (one day) is therefore, we submit, clearly justified if the new rates are to be made the subject of an evidentiary hearing, and Edison respectfully requests that any suspension ordered be limited to one day.

Copies of this letter and all enclosures have been mailed this date to the customers on the attached list; to the Public Utilities Commission of the State of California, 350 McAllister Street, San Francisco, California 94102; and to the Arizona Corporation Commission, 250 Capital Annex, 1700 West Washington, Phoenix, Arizona 85007.

Copies of the rate schedules herewith tendered for filing are now open and available for public inspection in a convenient form and place during ordinary business hours at Edison's principal office in Rosemead and at its district offices in Blythe, Bishop, Vernon, Santa Ana, Covina, San Bernardino, Hemet, Redlands, and Victorville.

Please direct requests for additional copies of these enclosures or further information to the undersigned.

Very truly yours,

SOUTHERN CALIFORNIA EDISON COMPANY

Ronald Daniels

RONALD DANIELS
Manager of Revenue Requirements

RD:rcj
Enclosures

SOUTHERN CALIFORNIA EDISON COMPANY

SCHEDULES TO BE SUPERSEDED

Rate* Schedule	FERC No. As Supplemented	Customer Name and Mailing Address
R	15	City of Anaheim Attention: City Manager City Hall 204 East Lincoln Avenue Anaheim, California 92805
R	19	Anza Electric Cooperative, Inc. Attention: General Manager P. O. Box 96 Anza, California 92306
R	6	Arizona Public Service Company, Cibola Attention: Manager, Rates & Property Valuation Department P. O. Box 21666 Phoenix, Arizona 85036
R	29	Arizona Public Service Company, Ehrenberg Attention: Manager, Rates & Property Valuation Department P. O. Box 21666 Phoenix, Arizona 85036
R	16	City of Azusa Attention: City Administrator 213 East Foothill Boulevard Azusa, California 91702
R	21	City of Banning Attention: City Manager Post Office Box 998 Banning, California 92220

* Presently, the resale customers have the option of either being served on an R or TOU-R rate schedule.

Rate* Schedule	FERC No. As Supplemented	Customer Name and Mailing Address
R	31	City of Colton Attention: City Manager City Hall 650 North La Cadena Drive Colton, California 92324
R	17	City of Riverside Board of Public Utilities and City Counsel Attention: City Clerk 3900 Main Street Riverside, California 92522
TOU-R	33	Southern California Water Company, Gold Hill 3625 West Sixth Street Los Angeles, California 90020
TOU-R	33	Southern California Water Company, Harnish 3625 West Sixth Street Los Angeles, California 90020
TOU-R	13	City of Vernon 4305 Santa Fe Avenue Vernon, California 90058

* Presently, the resale customers have the option of either being served on a schedule R or TOU-R rate schedule.

EXHIBIT 1A

Southern California Edison Company

P. O. BOX 800
2244 WALNUT GROVE AVENUE
ROSEMEAD, CALIFORNIA 91770

RONALD DANIELS
MANAGER OF REVENUE REQUIREMENTS

TELEPHONE

March 13, 1981

Federal Energy Regulatory Commission
Office of the Secretary
Union Center Plaza
825 North Capitol, N.E.
Washington, D.C. 20426

Re: Southern California Edison Company
Docket No. ER 81-177-000

Gentlemen:

Pursuant to the Commission's Order titled, "Order Accepting For Filing And Suspending Proposed Rates, Granting Summary Disposition In Part, Denying Motions To Reject, Granting Interventions, And Establishing Procedures," issued on February 13, 1981, there are transmitted herewith for filing six copies of the following listed documents revising the subject filing made herein relating to electric service to resale customers with respect to the volume numbers contained in the original filing as follows:

<u>Volume 1:</u>

1. Revised Sales and Revenue Comparisons - Period I - 12 months ended June 30, 1980 - Recorded

2. Revised Statement N, Period I, Sheet 1 of 1.

<u>Volume 2:</u> (Excluding SONGS Unit 2)

3. Revised Summary of Proposed Changes, Proposed Rates, Special Conditions, Rules.

4. Revised Sales and Revenue Comparisons, Period II, 1981 - Estimated

5. Revised Sales and Revenue Comparisons - 12 months preceding and succeeding the proposed date the rates are to become effective.

6. Revised Statement N, Period II, Sheet 1 of 1

7. Revised Statement O, Period II, Sheets 1 and 2 of 4

8. Revised Statement P, Period II, Sheet 1 of 1

<u>Volume 3:</u> (Including SONGS Unit 2)

9. Revised Proposed Rates, Special Conditions, Rules

10. Revised Statement O, Period II, Sheet 1 of 4

11. Revised Statement P, Period II, Sheet 1 of 1

<u>Volume 4:</u>

12. Supplemental Prepared testimony of Lawrence J. Hedrick

13. Supplemental Prepared testimony of Finn B. Jespersen

14. Prepared Testimony of Warren E. Ferguson

15. Exhibit entitled:

    a. WEF-1, "Comparison of Present and Proposed Resale Rates for 1981." (Revision of RLJ-1)

<u>Volume 5:</u>

16. Revised workpaper page P2.

These revisions in the filing, pursuant to the Commission's Order issued on February 13, 1981, reduce the annual revenue increase in base rates for resale service based on a 1981 test year from approximately $18.6 million to $16.7 million or a decrease of approximately $1.9 million. The revised rates are estimated to produce a rate of return of 10.96% overall on rate base for resale service.

The Company also revised its SONGS Adjustment clause appearing in the Phase 2 part of the filing (Volume 3). Such clause was revised to include only a component for AFUDC; however, the clause still includes

the ITC offset. The ITC offset was retained because, as Mr. Hedrick points out in his Supplemental Prepared Testimony, without such inclusion the resale customers would not receive the benefit of these investment tax credits.

Certain "housecleaning" revisions were also made in the filing. Those revisions consisted of the following:

1) Proposed Rates, Special Condition 8(8): Closed parenthesis in base period fuel cost formula.

2) Proposed Rates, Special Condition 11: Changed Special Condition 11 to conform to CPUC summer and winter periods and to delete reference to Pacific Standard Time.

3) Statement O, Period II, Sheet 1 of 4 (Volume 2 and 3): Closed parenthesis in formula.

The revisions ordered by the Commission to its February 13, 1981 suspension order, that is, the summary rejection of the Company's proposed attrition allowance and the five-month suspension in the effective date of the resale rate increases therein, in Edison's view, are not supported by sufficient reasoning of rationale to comport with recent court rulings and may contribute a denial of due process. Consequently, the Company has filed with the Commission a petition for rehearing on such rulings.

Under the Commission's Order, the revised rate schedules are to be made effective July 16, 1981, subject to refund.

Copies of this letter and all enclosures have been mailed this date to the customers on the attached list to the Public Utilities Commission of the State of California, State Building, San Francisco, California 94102; and to the Arizona Corporation Commission, 250 Capital Annex, 1700 West Washington, Phoenix, Arizona 85007.

Copies of the rate schedules herewith tendered for filing are now open and available for public inspection in a convenient form and place during ordinary business hours at Edison's principal office in Rosemead and at its district offices in Blythe, Bishop, Vernon, Santa Ana, Covina, San Bernardino, Hemet, Redlands, and Victorville.

Please direct requests for additional copies of these enclosures or further information to the undersigned.

Very truly yours,

SOUTHERN CALIFORNIA EDISON COMPANY

Ronald Daniels

RONALD DANIELS
Manager of Revenue Requirements

LJH:dcc
1F80065

SOUTHERN CALIFORNIA EDISON COMPANY

SCHEDULES TO BE SUPERSEDED

Rate* Schedule	FERC No. As Supplemented	Customer Name and Mailing Address
R	15	City of Anaheim Attention: City Manager City Hall 204 East Lincoln Avenue Anaheim, California 92805
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R	29	Arizona Public Service Company, Ehrenberg Attention: Manager, Rates & Property Valuation Department P. O. Box 21666 Phoenix, Arizona 85036
R	16	City of Azusa Attention: City Administrator 213 East Foothill Boulevard Azusa, California 91702
R	21	City of Banning Attention: City Manager Post Office Box 998 Banning, California 92220

* Presently, the resale customers have the option of either being served on an R or TOU-R rate schedule.

Rate* Schedule	FERC No. As Supplemented	Customer Name and Mailing Address
R	31	City of Colton Attention: City Manager City Hall 650 North La Cadena Drive Colton, California 92324
R	17	City of Riverside Board of Public Utilities and City Counsel Attention: City Clerk 3900 Main Street Riverside, California 92522
TOU-R	33	Southern California Water Company, Gold Hill 3625 West Sixth Street Los Angeles, California 90020
TOU-R	33	Southern California Water Company, Harnish 3625 West Sixth Street Los Angeles, California 90020
TOU-R	13	City of Vernon 4305 Santa Fe Avenue Vernon, California 90058

* Presently, the resale customers have the option of either being served on a schedule R or TOU-R rate schedule.

ER 82-427

EXHIBIT 2

Southern California Edison Company

P. O. BOX 800
2244 WALNUT GROVE AVENUE
ROSEMEAD, CALIFORNIA 91770

RONALD DANIELS
MANAGER OF REVENUE REQUIREMENTS

TELEPHONE
(213) 572-1701

March 31, 1982

Federal Energy Regulatory Commission
Office of the Secretary
Union Center Plaza
825 North Capitol, N.E.
Washington, D.C. 20426

Gentlemen:

Pursuant to Section 205(d) of the Federal Power Act and to Sections 35.13 and 35.14 of the Commission's Regulations, there are transmitted herewith for filing, as a change in Southern California Edison Company's (Edison) resale rates, six copies of the following listed documents relating to electric service to resale customers. Volumes 1 and 2, marked "Executed Copies", contain the executed copies of the attestation and witness verifications, respectively.

<u>Volume 1 - General Information</u>

- o Introduction.
- o Transmittal letter, including list of schedules to be superseded, including customer name and mailing address.
- o Federal Register Notice.
- o Attestation.
- o Present Rate Schedules, Special Conditions, Rules.
- o Proposed Rate Schedules, Special Conditions, Rules.
- o Sales and Revenue Comparisons - Period I - Recorded Calendar Year 1980.
- o Sales and Revenue Comparisons - Period II - Estimated 12 months ending August 31, 1983.

Volume 2 - Prepared Testimony and Exhibits

- Prepared Testimony As Follows:

Line No.	Chapter	Title	Sponsoring Witness
1.	1	Introduction	-----
2.	2	Financial	-----
3.	A.	Financial Policy	J. B. Adams
4.	B.	Financial Statements	L. G. Geiger
5.	3	O & M Expense	-----
6.	A.	General O & M	C. H. Silsbee
7.	B.	Mono Power Company	F. T. Clisby
8.	4	Taxes	A. L. Smith
9.	5	Rate Base	L. O. Chubb
10.	6	Cost of Service	A. R. Escamilla
11.	7	Rate Design	W. E. Ferguson
12.	8	Acronyms and Definitions	-----

Volume 3 - Period I Statements

- Supporting Cost Statements, AA through BL, Period I - Recorded Calendar Year 1980.

Volume 4 - Period II Statements

- Supporting Cost Statements, AA through BL, Period II - Estimated 12 Months Ending August 1983.

Volume 5 - Cost and Controls Study of San Onofre Units 2 and 3

Volume 6 - Cross-Referenced Prepared Testimony and Work Papers

Volume 7 - Recent Rate Decisions and Application Transmittal Letters (Statement AX Work Papers)

Volume 8 - Cross-Referenced Period II Statements

Volume 9 - Work Papers Cost and Controls Study of SONGS 2 and 3

Separate Documents

- Voucher to cover the filing fees.

- A proposed notice, in triplicate, suitable for publication in the Federal Register.

There are no agreements between Edison and its resale customers in effect which preclude unilateral rate change filings by Edison of the type here involved. Therefore, no agreement of resale customers to this filing is required.

With this filing, Edison initially increases the base rates for resale service and revises the base rates and the fuel cost adjustment billing factors to reflect the estimated test year 12 months ending August 1983 system average cost of fuel as the base cost of fuel and the loss factors estimated for that same period. The rates filed herein, including the fuel cost adjustment provision, are estimated to produce a return of 11.73% overall on rate base for resale service based on Period II. The overall increase in resale revenues for the test year is estimated at about $60.4 million. The increase is proposed to be made effective in two steps. Step 1 reflects Period II costs excluding costs (other than fuel) associated with San Onofre Nuclear Generating Station Unit No. 2 (SONGS 2). The overall increase in resale revenues for Step 1 rates for the test year is estimated at about $38.4 million. The increase is proposed to be made effective June 1, 1982. Step 2, which amounts to an additional increase in resale revenues of approximately $22.0 million, includes the costs (other than fuel) associated with SONGS 2 and is proposed to be made effective on June 2, 1982. These dates are within the sixty to one hundred and twenty day period after filing, pursuant to Section 205 of the Federal Power Act.

As discussed in Chapter 1 of Volume 2, "Introduction", of the prepared. testimony, Edison has designed these rates to be in conformance with the Commission's standard for permitting no longer than a one day suspension. Said introduction to the prepared testimony is by this reference incorporated herein and made a part of this transmittal letter. As indicated above, Edison requests that Step 1 rates be permitted to become effective, subject to refund, on June 1, 1982 without suspension. This is justified by the fact that Edison's projected earned rate of return on resale operations at present rates (3.09%) is already far below the level found to be just and reasonable (10.09%) in FERC Docket No. ER 79-150 by the administrative law judge.

SONGS 2 is estimated to commence commercial operation on August 15, 1982, which is after the proposed effective date of Step 2 rates but two weeks prior to the beginning of Period II. FERC's new regulations permit a proposed effective date as early as three months prior to the beginning of Period II. Edison proposes an effective date for Step 2 rates of June 2, 1982, and believes that no suspension from that date is warranted. However, Edison will not oppose a Commission suspension order which provides that the Step 2 rates will become effective no later than the date on which SONGS 2 commences commercial operation (now estimated to be August 15, 1982), or five months after the June 2, 1982, proposed effective date (November 2, 1982), whichever occurs first. Such a suspension order would protect both Edison and the resale customers from variances up to two and one-half months in the commercial operation date of SONGS 2 and would more closely match rates producing revenues which reflect the costs of SONGS 2 with the commercial operation date of that unit.

SOUTHERN CALIFORNIA EDISON COMPANY

SCHEDULES TO BE SUPERSEDED

Rate Schedule	FERC No. As Supplemented	Customer Name and Mailing Address
TOU-R	15	City of Anaheim Attention: City Manager City Hall Post Office Box 3222 Anaheim, California 92805
TOU-R	6	Arizona Public Service Company, Cibola Attention: Manager, Rates and Property Valuation Department Post Office Box 21666 Phoenix, Arizona 85036
TOU-R	29	Arizona Public Service Company, Ehrenberg Attention: Manager, Rates and Property Valuation Department Post Office Box 21666 Phoenix, Arizona 85036
TOU-R	16	City of Azusa Attention: City Administrator 777 North Alameda Avenue Azusa, California 91702
TOU-R	21	City of Banning Attention: City Manager Post Office Box 998 Banning, California 92220
TOU-R	31	City of Colton Attention: City Manager City Hall 650 North La Cadena Drive Colton, California 92324
TOU-R	17	City of Riverside Board of Public Utilities and City Counsel Attention: City Clerk 3900 Main Street Riverside, California 92522

SOUTHERN CALIFORNIA EDISON COMPANY

SCHEDULES TO BE SUPERSEDED

(Continued)

Rate Schedule	FERC No. As Supplemented	Customer Name and Mailing Address
TOU-R	33	Southern California Water Company, Gold Hill 3625 West Sixth Street Post Office Box 76893 Los Angeles, California 90076-0893
TOU-R	33	Southern California Water Company, Harnish 3625 West Sixth Street Post Office Box 76893 Los Angeles, California 90076-0893
TOU-R	13	City of Vernon 4305 Santa Fe Avenue Vernon, California 90058

ER 84-75

EXHIBIT 3

Southern California Edison Company

P. O. BOX 800
2244 WALNUT GROVE AVENUE
ROSEMEAD, CALIFORNIA 91770

RONALD DANIELS
MANAGER OF REVENUE REQUIREMENTS

TELEPHONE
(213) 572-1701

November 8, 1983

Federal Energy Regulatory Commission
Office of the Secretary
Union Center Plaza
825 North Capitol, N.E.
Washington, D.C. 20426

Gentlemen:

Pursuant to Section 205(d) of the Federal Power Act and to Sections 35.13 and 35.14 of the Commission's Regulations, there are transmitted herewith for filing, as a change in Southern California Edison Company's (Edison) resale rates, six copies of the following listed documents relating to electric service to resale customers. Volumes 1 and 2 of one set, marked "Original", contain the original executed attestation and witness verifications, respectively.

This filing contains eleven volumes marked as follows:

<u>Volume 1 - General Information</u>

- o Table of Contents
- o Letter of Transmittal
- o Federal Register Notice
- o Attestation
- o Present Rate Schedules
- o Proposed Rate Schedules for Step I
- o Proposed Rate Schedules for Step II
- o Revenue Comparison - Period I
- o Revenue Comparison - Period II

Volume 2 - Prepared Testimony and Discussion of Statements

- Table of Contents
- Index to Discussion of Statements
- Prepared Testimony and Discussion of Statements (Includes witness verifications)

Volume 3 - Period I Statements

- Supporting Cost Statements, AA through BL, Period I - Recorded Calendar Year 1982.

Volume 4 - Period II Statements With 50 Percent of CWIP

- Supporting Cost Statements, AA through BM, Period II - Estimated 12 Months Ending December 1984, with 50 percent of CWIP, included in Rate Base.

Volume 5 - Period II Statements Without 50 Percent of CWIP

- Supporting Cost Statements, AA through BM, Period II - Estimated 12 Months Ending December 1984, without 50 percent of CWIP, included in Rate Base.

Volume 6 - Work Papers for O&M Expense, Taxes and Sales and Peak Demand Forecast - Period II, With and Without 50 Percent CWIP.

Volume 7 - Work Papers for Depreciation and Financial Policy and Statements - Period II, With and Without 50 Percent CWIP.

Volume 8 - Work Papers for Rate Base - Period II, With and Without 50 Percent CWIP.

Volume 9 - Cost and Controls Study for San Onofre Units 2 and 3 and Work Papers.

Volume 10 - Work Papers for Cost of Service and Rate Design - Period II, With and Without 50 Percent CWIP.

Volume 11 - Statement AX

In addition, there are transmitted a voucher to cover the filing fee and a proposed notice, in triplicate, suitable for publication in the Federal Register.

There are no agreements between Edison and its resale customers in effect which preclude unilateral rate change filings by Edison of the type here involved. Therefore, no agreement of resale customers to this filing is required.

With this filing, Edison initially increases the base rates for resale service and revises the base rates and the fuel cost adjustment billing factors to reflect the estimated test year twelve months ending December 1984. None of the costs included as part of the revenue requirement in this

filing have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices. The rates filed herein, including the fuel cost adjustment provision, are estimated to produce a return of 12.63 percent overall on rate base for resale service.

The overall increase in resale revenues for the test year is estimated to be $42.6 million, which represents a 17.1 percent increase over current revenues, to bring the resale revenue forecast for 1984 to $290.8 million.

This increase is justified by the fact that Edison's projected earned rate of return on resale operations at present rates is 7.77 percent, well below the level found to be just and reasonable (10.09 percent) in FERC Docket No. ER79-150-000.

The requested increase includes costs associated with inclusion of 50 percent of Construction Work in Progress (CWIP) in rate base, as permitted by the Federal Energy Regulatory Commission (FERC), Order No. 298, and costs associated with San Onofre Nuclear Generating Station (SONGS) Units 2 and 3. The impact of including 50 percent of CWIP in rate base represents a 4.2 percent increase in current revenues, which is significantly less than the 6 percent limitation contained in FERC Order No. 298.

As discussed in Chapter 1 of Volume 2, "Introduction", Edison has designed its rates to be in conformance with the Commission's standard for permitting no longer than a one-day suspension. The increase is proposed to be made effective in two steps: Step 1, which is based on a 13.25 percent return on common equity (11.50 percent return on rate base) will increase current revenues by 13.1 percent, or $32.6 million. Edison is proposing an effective date of January 7, 1984, for Step 1. Step 2, which is based on a 16.0 percent return on common equity (12.63 percent return on rate base), will increase current revenues an additional 4.0 percent, or $9.9 million. Edison is proposing an effective date of January 8, 1984, for Step 2 rates.

The fuel clause contained in the filing complies with Section 35.14 of the Commission's Regulations both in form and content. A copy of the clause is included in this filing with the present and proposed rate schedules. Billing factors are proposed to be revised monthly, and are to be effective from the first of the month. The initial fuel clause billing for each billing period will be an estimated amount based on data recorded for the calendar month just prior to the month in which the billing factor is to become effective. Such estimated fuel clause billing will be adjusted in the following billing for any difference between recorded and estimated fuel and purchased power costs. The base cost has been derived by utilizing estimated Period II system fuel and purchased power costs and sales data which were used in developing the new resale base rates. The calculation of the fuel cost adjustment billing factor used to adjust the fuel clause billing previously made on an estimated basis will serve to precisely match the fuel and purchased power component of the new resale rates with the fuel and

purchased power costs actually incurred and allocated to resale service on a monthly basis. Development of the base fuel expense is shown on Sheet 2 of Statement BI for Period II.

The rates filed herein are embodied in rate schedule R-3, which is proposed to be applicable to all resale customers. By serving all resale customers under an R-3, time-of-use rate design, the Company believes that these rates will track the costs of serving its resale customers.

When it is considered that the resale rates presently in effect would result in a revenue deficiency in the test year, it is important that any delay in the effective date of the proposed rate increase be kept to a minimum. Such a revenue deficiency would be further exacerbated by any ordered reductions in those rates (filed in FERC Docket No. ER82-427-000) which might result from the FERC's decision in that docket, a result that Edison believes would be totally unjust, but must be considered a distinct possibility where intervenors have recommended substantial disallowances. While Edison believes it can support a cost of equity capital at 17.5 percent, the rate increases tendered in the filing for Step 1 and Step 2 are based on reduced return levels of 13.25 percent and 16 percent, respectively. This was done to further two objectives: (1) to eliminate a suspension of the proposed rates; and (2) to request an equity rate of return no higher than that allowed by the California Public Utilities Commission on retail rates.

Because of the inadequacy of existing rates to cover the test year twelve months ending December 1984 cost of service, including a return component commensurate with present and projected cost of capital, a minimum suspension period is therefore, Edison submits, clearly justified. If the new rates are to be made the subject of an evidentiary hearing, Edison respectfully requests that any suspension period be minimized.

Copies of this letter and all enclosures have been mailed this date to the customers on the attached list; to the Public Utilities Commission of the State of California, 350 McAllister Street, San Francisco, California 94102; and to the Arizona Corporation Commission, 250 Capital Annex, 1700 West Washington, Phoenix, Arizona 85007.

Copies of the rate schedules herewith tendered for filing are now open and available for public inspection in a convenient form and place during ordinary business hours at Edison's principal office in Rosemead and at its district offices in Blythe, Vernon, Santa Ana, Covina, San Bernardino, Redlands, and Victorville.

Please direct requests for additional copies of these enclosures or further information to the undersigned.

Very truly yours,

SOUTHERN CALIFORNIA EDISON COMPANY

Ronald Daniels

RONALD DANIELS
Manager of Revenue Requirements

MW:jah
5F83154
Enclosures

SOUTHERN CALIFORNIA EDISON COMPANY

SCHEDULES TO BE SUPERSEDED

Rate Schedule	FERC No. As Supplemented	Customer Name and Mailing Address
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TOU-R	29	Arizona Public Service Company, Ehrenberg Attention: Manager, Rates and Property Valuation Department Post Office Box 21666 Phoenix, Arizona 85036
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TOU-R	31	City of Colton Attention: City Manager City Hall 650 North La Cadena Drive Colton, California 92324
TOU-R	17	City of Riverside Board of Public Utilities and City Counsel Attention: City Clerk 3900 Main Street Riverside, California 92522

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SOUTHERN CALIFORNIA EDISON COMPANY

SCHEDULES TO BE SUPERSEDED

(Continued)

Rate Schedule	FERC No. As Supplemented	Customer Name and Mailing Address
TOU-R	33	Southern California Water Company, Gold Hill 3625 West Sixth Street Post Office Box 76893 Los Angeles, California 90076-0893
TOU-R	33	Southern California Water Company, Harnish 3625 West Sixth Street Post Office Box 76893 Los Angeles, California 90076-0893
TOU-R	13	City of Vernon 4305 Santa Fe Avenue Vernon, California 90058

EXHIBIT 3A

Southern California Edison Company

SCE

P. O. BOX 800
2244 WALNUT GROVE AVENUE
ROSEMEAD, CALIFORNIA 91770

RONALD DANIELS
MANAGER OF REVENUE REQUIREMENTS

TELEPHONE
(818) 572-1701

June 18, 1984

ALL PARTICIPANTS OF RECORD

Subject: Southern California Edison Company Motion for Order Allowing the Collection of Interim Rates FERC Docket No. ER84-75-000

Gentlemen:

Attached please find the detailed cost support for the Southern California Edison Company's (Edison) Motion for Order Allowing the Collection of Interim Rates (Motion) discussed with FERC Staff and Intervenors on June 11, 1984 in Washington, D.C. The interim rates contained herein are embodied in rate Schedule R-3.1, which is proposed to be applicable to all resale customers.

The interim rates represent a reduction of the compliance rates (filed February 6, 1984) which became effective on June 8, 1984. The basis for the motion to voluntarily reduce rates is Edison's review and acceptance of certain adjustments to the initial filing identified by the participants during two technical conferences.

Edison proposes that the interim rates become effective on July 1, 1984. The motion is made without prejudice to Edison's right to collect any higher rates following issuance of the initial decision of the presiding Administrative Law Judge (ALJ). Any such increase would be prospective only, subject to refund pending final Commission approval, and limited to the full amount of the increase reflected in the rates filed on February 6, 1984, in compliance with the Commission's suspension order in this docket.

The reduction in resale revenue requirement resulting from the cost of service changes is $3,323,000. The compliance filing resale revenue requirement of $289,946,000 has been reduced to $286,623,000. This represents a 1.2 percent decrease from compliance rate revenues.

The following paragraphs summarize the changes incorporated in the revised cost of service.

Cool Water Coal Gasification Project Removed from Rate Base

To be consistent with the treatment of the Cool Water Coal Gasification Project set forth in Edison's retail rate filing (Application No. 83-12-53), Edison has removed from the resale jurisdictional rate base all costs, including Construction Work in Progress (CWIP), associated with the Cool Water Project. Revised Statements AG, AL, AM, AE, AJ, BK, AK, AQ, AS, AF, and AR, contained herein, reflect the changes outlined above.

Functionalization of Current Year's Deferred Tax Expense

Edison has refunctionalized the current year's deferred tax expense exhibited in the initial filing to be consistent with the functionalization of tax deductions. Revised Statements AF, AR, AQ, and BK incorporate the refunctionalized amounts.

South Georgia Adjustment to Reflect Previous Rate Filing

Edison has recalculated the South Georgia adjustment presented in the initial filing to reflect the joint stipulation in the prior proceeding, FERC Docket No. ER82-427-000 (Exhibit 190). Revised Statements AF, AR, and BK reflect the recalculated South Georgia Adjustment.

Correction of SONGS 3 In-Service Date for Tax Purposes

In the initial filing, Edison used a January 1, 1984, in-service date for the calculation of SONGS 3 property and payroll taxes. Edison has recalculated property and payroll taxes based on an in-service date of April 1, 1984. Revised Statements AK, AQ, and BK reflect the above changes.

Reduction in System Peak Demand for Anaheim and Riverside Ownership Interest in SONGS 2 and 3

Demand allocation factors presented in Statement BB in the initial filing were revised to reflect the capacity credits for Anaheim and Riverside's ownership interest in SONGS 2 and 3. Revised Statement BB and work paper reference WP-CAM-1 (Rev.) contained herein support the revised demand allocation factors.

Adjusted Return Levels

The original filing utilized a 16.00 percent return on common equity (ROCE), although testimony contained therein supported a 17.50 percent ROCE. The revised cost of service included utilizes an equity rate of return of 16.31 percent, which reflects synchronization with the ROCE allowed by, or requested from, the CPUC on retail rates for a 12-month period beginning June 8, 1984, (effective date for rates in FERC Docket No. ER84-75-000).

Working Cash Adjustments

The required adjustments to working cash accompanying the above changes have been incorporated in the revised cost of service (Statement BK); however, because of the recursive nature of the working cash calculation, the necessary changes, which are of a minor amount, have not been reflected in the revised statements.

The information contained herein includes only the Period II Statements and Tariff sheets (or portions thereof) affected by the above adjustments. The affected statements are shown with 50 percent CWIP as allowed by the FERC Order No. 298. The cost information also includes work papers which support the individual adjustments to the previous filings. Edison submits that any discovery related to the motion and supplemental cost support be incorporated in the procedural schedule adopted by the ALJ. Henceforth, all data requests to Edison on the motion are due by the date of submitting follow-up data requests, or July 13, 1984.

Copies of this letter and all enclosures have been mailed this date to the interested parties on the attached list.

Please direct requests for additional copies of these enclosures or future information to the undersigned.

Very truly yours,

SOUTHERN CALIFORNIA EDISON COMPANY

Ronald Daniels

RONALD DANIELS
Manager of Revenue Requirements

RD:mlt
840605b03

cc: Attached List

SERVICE LIST

ER84-75-000

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El Monte, CA 91734

Bruce V. Malkenhorst
City Administrator/City Clerk
City Hall
4305 Santa Fe Avenue
Vernon, CA 90058

Sandra S. Strebel, Esq.
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John M. Adragna, Esq.
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Spiegel & McDiarmid
2600 Virginia Avenue, N.W.
Washington, D.C. 20037

Eldridge Sinclair
City of Banning, Electric Division
P.O. Box 998
176 East Lincoln Street
Banning, CA 92220

Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

Docket Office
California Public Utilities
Commission
350 McAllister Street
San Francisco, CA 94102

Utilities Director
City of Colton
650 North La Cadena
Colton, CA 92324

John Hsu
Utilities Director
777 North Alameda Avenue
Azusa, CA 91702

G. W. Hoyt
Utilities Director
P.O. Box 3222
Anaheim, CA 92803

Fred Kray
Director of Public Utilities
City Hall
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Riverside, CA 92522

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Manager, Rates & Property
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City Manager
City of Banning
161 W. Ramsey
Banning, CA 92220

ER 86-XXX

EXHIBIT 4

Southern California Edison Company
P. O. BOX 800
2244 WALNUT GROVE AVENUE
ROSEMEAD, CALIFORNIA 91770

J. S. PIGNATELLI
DIRECTOR OF REVENUE REQUIREMENTS

TELEPHONE
(818) 302-3956

January 30, 1986

Federal Energy Regulatory Commission
Office of the Secretary
Union Center Plaza
825 North Capitol Street, N.E.
Washington, D.C. 20426

Gentlemen:

Pursuant to Section 205(d) of the Federal Power Act and to Section 35.13 of the Commission's Regulations, there are transmitted herewith for filing, in order to effectuate a change in Southern California Edison Company's ("Edison") resale rates to reflect a settlement between Edison and all of its resale customers, six copies of the following listed documents relating to electric service to resale customers. Volumes 1 and 2 of one set, marked "Original", contain the original executed attestation and witness verifications, respectively.

This filing contains eight volumes marked as follows:

Volume 1 - General Information
Volume 2 - Prepared Testimony and Discussion of Statements
Volume 3 - Period I Statements
Volume 4 - Period II Statements
Volume 5 - Documents, Statement AX
Volume 6 - Settlement Agreement
Volume 7 - Work Papers for Operation and Maintenance Expenses, Depreciation, Taxes, Cost of Capital and Financial Statements, Cost of Service, and Rates and Tariff Provisions
Volume 8 - Work Papers for Rate Base

There are also transmitted with this filing, a voucher to cover the filing fee and a proposed notice, in triplicate, suitable for publication in the Federal Register.

The level of the rate change requested in this filing reflects a settlement agreement between Edison and its resale customers which was executed as of January 13, 1986, ("Settlement Agreement"). Subject to Commission approval, current resale rates are to be increased to reflect a $5 million increase in resale revenue requirement based on the billing determinants proposed by Edison in Docket No. ER84-75-000. Due to lower sales projections for 1986 than proposed in Docket No. ER84-75-000, the estimated increase in resale revenues

for Test Year 1986 has been computed to be $4,920,000. This increase in resale revenues is subject to various adjustments as specified in the Settlement Agreement.

Pursuant to Rule 602 of the Commission's Rules of Practice and Procedure, the Settlement Agreement, an explanatory statement, and a proposed Commission order accepting the Settlement Agreement are included in Volume 6 of this filing. The explanatory statement outlines the terms and conditions of the Settlement Agreement and includes a discussion of each of the adjustments to resale rates. Edison's resale customers have agreed to, within five days of this filing, file letters in support of this filing and the rates established pursuant thereto. Edison requests that the Commission approve the settlement contained in Volume 6 of this filing, and the settlement rates attendant thereto, and find that the Settlement Agreement appears to be fair and reasonable and in the public interest.

Concurrent with this filing, Edison is filing, in Docket ER84-75-000, the Motion of Southern California Edison Company for Authorization to Collect Lower Resale Rates on an Interim Basis, Request for Expedited Consideration, and for Waiver of Notice Requirements ("Motion") 1/. Both the rate level and the effective date of the proposed rate schedules contained in this filing are dependent upon the Commission's action on the Motion. Therefore, for the Commission to have flexibility in implementing the appropriate resale rates under the Settlement Agreement, Edison has included with this filing two different sets of rate schedules, Schedules R-4.0 and R-4.1.

The Settlement Agreement specifies that settlement rates will become effective on the date the Commission issues its order approving the Motion or May 1, 1986, whichever is earlier. The chart below shows the appropriate rate schedule and effective date depending on the Commission's actions on the Motion. It should be noted that depending on the timing of the Commission's action on the Motion, it is possible that both Rate Schedules R-4.0 and R-4.1 will become effective.

1/ In the Motion, Edison, with the support of the active participants in Docket No. ER84-75-000, including the trial staff, is seeking to lower resale rates to reflect several stipulations and agreements. Edison is filing the Motion in order that its customers receive the benefit of the lower rate and Edison minimize its future refund obligation. Edison is requesting that the Commission authorize these interim lower rates effective June 8, 1984. If the Motion is granted and the settlement approved, the effect would be to allow Edison to make refunds based on the rate schedules contained in the Motion and charge prospectively based on alternate proposed Rate Schedule R-4.1 included in this filing. The net effect would be a rate reduction from rates currently in effect in Docket No. ER84-75-000, Rate Schedule R-3.2.

APPROPRIATE RATE SCHEDULE AND EFFECTIVE DATE

Action on Motion	Rate Schedule	Effective Date of Rate Schedule
Motion Approved		
Prior to May 2, 1986	R-4.1	Issuance Date of Order on Motion
May 2, 1986 or later	R-4.0	May 1, 1986
	R-4.1	Issuance Date of Order on Motion
Motion Denied	R-4.0	May 1, 1986

To the extent necessary to allow rates to become effective as of the appropriate date shown above, Edison, pursuant to Section 35.11 of the Commission's Regulations, requests waiver of the notice requirements.

Proposed Rate Schedule R-4.0, is based upon an increase in the presently effective Rate, Schedule R-3.2, which provides for an increase in annual resale revenues of $5 million based on the billing determinants proposed in Docket No. ER84-75-000 in accordance with provisions of the Settlement Agreement. The demand rates have been increased to provide for 50 percent of the proposed revenue increase and the energy rates have been increased to provide for the remaining 50 percent as agreed among the parties to the Settlement Agreement. A comparison of present and proposed rates is as follows:

	Per Meter Per Month		
	Present Rates, Schedule R-3.2	Proposed Rates, Schedule R-4.0	Increase
CUSTOMER CHARGE:	$400.00	$400.00	0
Demand Charge (to be added to Customer Charge):			
All kW of on-peak billing demand, per kW	$15.08	$15.35	$0.27
Plus all kW of mid-peak billing demand, per kW	$ 1.51	$ 1.54	$0.03
Plus all kW of off-peak billing demand, per kW	No Charge	No Charge	0
Energy Charge (to be added to Customer and Demand Charges):			
All on-peak kWh, per kWh	4.790¢	4.860¢	0.070¢
Plus all mid-peak kWh, per kWh	4.492¢	4.561¢	0.069¢
Plus all off-peak kWh, per kWh	4.040¢	4.111¢	0.071¢

Alternate proposed Rate Schedule R-4.1, is computed by applying the same increase computed above to Rate Schedule R-3.3, proposed in the Motion. A comparison of rates proposed in the Motion and alternate proposed rates is as follows:

	Per Meter Per Month		
	Rates Proposed in Motion, Schedule R-3.3	Alternate Proposed Rates, Schedule R-4.1	Increase
CUSTOMER CHARGE:	$400.00	$400.00	0
Demand Charge (to be added to Customer Charge):			
All kW of on-peak billing demand, per kW	$14.33	$14.60	$0.27
Plus all kW of mid-peak billing demand, per kW	$ 1.43	$ 1.46	$0.03
Plus all kW of off-peak billing demand, per kW	No Charge	No Charge	0
Energy Charge (to be added to Customer and Demand Charges):			
All on-peak kWh, per kWh	4.790¢	4.860¢	0.070¢
Plus all mid-peak kWh, per kWh	4.492¢	4.561¢	0.069¢
Plus all off-peak kWh, per kWh	4.040¢	4.111¢	0.071¢

No changes are proposed in any other tariff provisions.

There are no agreements between Edison and its resale customers in effect which preclude unilateral rate change filings by Edison of the type here involved other than the Settlement Agreement enclosed. The effectiveness of a vast majority of operative features of the Settlement Agreement, including a limited prohibition against filings for a period of time, is subject to Commission approval of the Settlement Agreement without change or condition unacceptable to any party.

The principal increases in costs incurred by Edison, which give rise to the need for this proposed increase in base rates over base rates established in Docket No. ER84-75-000, are as follows:

1. San Onofre Nuclear Generating Station Unit 3 was considered to be in service for only nine months in Test year 1984, which was used in Docket No. ER84-75-000. This unit will be in service for the entire year in 1986.

2. Palo Verde Nuclear Generating Station Units 1 and 2 are scheduled to be in service during January 1986 and August 1986, respectively. Neither of these units was considered to be in service in Test Year 1984.

3. Operation and maintenance expense levels are projected to increase over amounts included in Test Year 1984.

4. Edison has responded to changed energy market conditions by terminating several fuel contracts and is amortizing the costs of the terminations over a 4-year period.

5. There has been a significant increase in the demand component of purchased power as the result of increased purchases from the Cholla Generating Station, owned by the Arizona Public Service Company, and increased purchases from cogeneration facilities which have been placed in service during 1985 and projected to be placed in service during 1986.

The increases in costs associated with the new nuclear units being placed in service are offset in part by reduced amounts of construction work in progress included in rate base and increased amounts of deferred income taxes. The net increase in costs resulting from the nuclear units being placed in service, the costs of fuel contract terminations, and the increase in demand costs for Cholla purchased power are offset in whole or in part by reduced energy costs. The resale customers will be recovering the benefit of these reduced energy costs through operation of the Fuel Cost Adjusment Clause.

The Settlement Agreement contains a specific assumption relative to the amount of Other CWIP in rate base. It is Edison's intention to compute avoided AFUDC as required by FERC Order No. 298 on the assumed amount as of the effective date of the settlement rates.

None of the costs included as part of the cost of service have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

Copies of this letter and all enclosures have been mailed this date to the customers on the enclosed list; to the Public Utilities Commission of the State of California, 350 McAllister Street, San Francisco, California 94102; and to the Arizona Corporation Commission, 250 Capital Annex, 1700 West Washington, Phoenix, Arizona 85007.

Copies of the rate schedules herewith tendered for filing are now open and available for public inspection in a convenient form and place during ordinary business hours at Edison's principal office in Rosemead and at its district offices in Blythe, Vernon, Santa Ana, Covina, San Bernardino, Redlands, and Victorville.

Please direct requests for additional copies of these enclosures or further information to the undersigned.

Very truly yours,

SOUTHERN CALIFORNIA EDISON COMPANY

J. S. PIGNATELLI
Director of Revenue Requirements

DMC:ns
86FERC.TL
Enclosures

SOUTHERN CALIFORNIA EDISON COMPANY

SCHEDULES TO BE SUPERSEDED

Rate Schedule	FERC No. As Supplemented	Customer Name and Mailing Address
R-3.2	15	City of Anaheim Attention: Mr. Gordon Hoyt, Utilities Director Post Office Box 3222 Anaheim, California 92805
R-3.2	180	Arizona Public Service Company, Buckskin Attention: Mr. Alan Propper Manager, Rate Services Post Office Box 53999 Phoenix, Arizona 85072-3999
R-3.2	6	Arizona Public Service Company, Cibola Attention: Mr. Alan Propper Manager, Rate Services Post Office Box 53999 Phoenix, Arizona 85072-3999
R-3.2	29	Arizona Public Service Company, Ehrenberg Attention: Mr. Alan Propper Manager, Rate Services Post Office Box 53999 Phoenix, Arizona 85072-3999
R-3.2	180	Arizona Public Service Company, Moonridge Attention: Mr. Alan Propper Manager, Rate Services Post Office Box 53999 Phoenix, Arizona 85072-3999
R-3.2	16	City of Azusa Attention: Mr. Joseph F. Hsu Utilities Director 777 North Alameda Avenue Azusa, California 91702
R-3.2	21	City of Banning Attention: Mr. Eldridge W. Sinclair Public Utilities Director Post Office Box 998 Banning, California 92220

SOUTHERN CALIFORNIA EDISON COMPANY

SCHEDULES TO BE SUPERSEDED

(Continued)

Rate Schedule	FERC No. As Supplemented	Customer Name and Mailing Address
R-3.2	31	City of Colton Attention: Mr. Gale Drews Utility Director 650 North La Cadena Drive Colton, California 92324
R-3.2	17	City of Riverside Attention: Mr. Everett Ross Director of Public Utilities 3900 Main Street Riverside, California 92501
R-3.2	33	Southern California Water Company, Gold Hill Attention: Mr. W. V. Caveney, President 3625 West Sixth Street Los Angeles, California 90005
R-3.2	33	Southern California Water Company, Harnish Attention: Mr. W. V. Caveney, President 3625 West Sixth Street Los Angeles, California 90005
R-3.2	13	City of Vernon Attention: Mr. Bruce V. Malkenhorst City Administrator/City Clerk 4305 Santa Fe Avenue Vernon, California 90058

8604160028

INFORMATION REQUESTED BY
THE NRC FOR ANTITRUST REVIEW

LOS ANGELES DEPARTMENT OF
WATER AND POWER

REGULATORY GUIDE 9.3 RESPONSES

2.

[illegible]

Item 1a

Anticipated excess or shortage in generating capacity resources not expected at the construction permit stage. Reasons for the excess or shortage along with data on how the excess will be allocated, distributed, or otherwise utilized or how the shortage will be obtained.

Response

The Los Angeles Department of Water and Power (Department) was not a participant in the Palo Verde Nuclear Generating Station (Palo Verde) at the time the construction permit was issued. The Department's reserve margin in 1979 and the planned reserves for the period through the year 2005 are as follows:

	1979	1986	1990	1995	2000	2005
LADWP Resources	6559	6414	6928	7477	8133	8556
LADWP Loads	4090	4922	5348	5829	6286	6734
Required Reserves (MW)	525	1480	1599	1671	1784	1808
Required Reserves (%)	12.8	30.1	29.9	28.7	28.4	26.8
Excess Reserves (MW)	1944	12	-19	-23	63	14

The 1979 reserve margin of 525 MW was the required operational reserve determined by the Department's spinning reserve requirements at that time. The Department's future required reserves shown above are the planning reserves required to meet the loss-of-load-probability criterion of one-day-in-ten years. Because the Department plans reserve margins sufficient to provide a reliable electric system, no shortages or excesses in generating resources are anticipated assuming that future resources are available as required.

Item 1b

New power pools or coordinating groups or changes in structure, activities, policies, practices, or membership of power pools or coordinating groups in which the licensee was, is, or will be a participant.

Response

In July 1982, the Department, along with the following entities, established the Southern California Utility Power Pool (SCUPP):

- o The City of Burbank, California
- o The City of Glendale, California
- o The City of Pasadena, California

SCUPP was originally oriented toward coordination of operations but was expanded in December 1985 to include coordination of load forecasting and resource planning. SCUPP provides for the sharing of operating reserves, brokering of economy energy, joint energy and capacity purchases, and joint studies for load forecasting and resource planning.

Item 1c

Changes in transmission with respect to: (1) the nuclear plant, (2) interconnections, or (3) connections to wholesale customers.

Response

(1) The Department has a transmission arrangement with Salt River Project Agricultural Improvement and Power District (SRP) for delivery between Palo Verde and the Western Area Power Administration (Western) system in Arizona. The Department has contracted with Western to wheel the Palo Verde power over Western's system to the Boulder City, Nevada area where it interconnects with the Department's system.

(2) The Intermountain Power Project Southern Transmission System, which extends from Delta, Utah, to Southern California, was placed in service in 1985 and provides interconnection with the Department's system at the Adelanto Switching Station near Adelanto, California.

(3) The Department has no wholesale customers.

Item 1d

Changes in the ownership or contractual allocation of the output of the nuclear facility. Reasons and basis for such changes should be included.

Response

In October 1977, the Department contracted for the purchase of a 30-percent ownership interest in the Coronado Generating Station (Coronado) from SRP. The contractual arrangements provided that upon the Date of Firm Operation of Unit 1 of Palo Verde, the Department would exchange the Coronado ownership for a 5.7-percent ownership in Palo Verde. The Date of Firm Operation of Palo Verde Unit 1 occurred on January 27, 1986; and the ownership was exchanged on January 29, 1986. The resulting ownership interests are shown below:

Arizona Public Service Company	29.10%
Salt River Project Agricultural Improvement and Power District	17.49
Southern California Edison Company	15.80
Public Service Company of New Mexico	10.20
El Paso Electric Company	15.80
Southern California Public Power Authority	5.91
Los Angeles Department of Water and Power	5.70
	100.00%

Item 1e

Changes in design, provisions, or conditions of rate schedules and reasons for such changes. Rate increases or decreases are not necessary.

Response

In December 1978, the Department adopted restructured retail electric rates eliminating declining blocks, reducing demand charges to only 25¢ per kilowatt per month, and basing rates on the short-run marginal energy cost. These charges are consistent with the Public Utility Regulatory Policies Act rate standards.

Item 1f

List of all: (1) new wholesale customers; (2) transfers from one rate schedule to another, including copies of schedules not previously furnished; (3) changes in licensee's service area; and (4) licensee's acquisitions or mergers.

Response

(1) The Department does not have any full requirements or partial requirements wholesale customers. Sales to other electric utilities are governed by the terms and conditions of individual contracts which usually provide for a cost plus or split savings basis. See the response to Item 1h for a list of the utilities the Department has contracted with.

(2) See response to (1).

(3) There have been no changes in the Department's service area boundaries.

(4) The Department has not been involved in any acquisitions or mergers.

Item 1g

List of those generating capacity additions committed for operation after the nuclear facility, including ownership rights or power output allocations.

Response

The Department's June 1985 Resource Plan shows no specific resource additions committed to construction after the commercial operation date of Palo Verde Unit 3. However, the Department's Resource Plan shows the need for 2503 MW of generating capability from March 1988, when Palo Verde Unit 3 is put into service through the year 2005. Although 203 MW of this is presently identified as small hydro or geothermal generation, 2300 MW is generic, which is assumed to be a future energy source of an unspecified type. Included in the need are 655 MW of Los Angeles basin gas- or oil-fueled generation which is scheduled to be retired and the Department's 5.7-percent ownership (217 MW) in Palo Verde which is subject to recall by SRP.

Item 1h

Summary of requests or indications of interest by other electric power wholesale or retail distributors, and licensee's response, for any type of electric service or cooperative venture or study.

Response

Over the past several years, the Department has received inquiries and requests from various entities for electric services which resulted in the agreements shown in attachment #1h-1.

The Department is involved in the following cooperative ventures or studies:

- White Pine Power Project - The Department, in cooperation with White Pine County, Nevada, the California cities of Anaheim, Burbank, Glendale, Pasadena, Riverside and the Nevada entities of Boulder city, Lincoln County Power District No. 1, Mt. Wheeler Power, Inc., Nevada Power Company, Overton Power District No. 5, Sierra Pacific Power Company, Valley Electric Association, Wells Rural Electric Company, has undertaken studies to determine the feasibility of constructing a 1500 megawatt, coal-fired generation station near Ely, Nevada. If built, the commercial operation would be in the mid-1990's.

- Mead-Phoenix DC Intertie Project - The Department is participating as a member of the Southern California Public Power Authority (SCPPA) in the Mead-Phoenix DC Intertie Project. SCPPA, Salt River Project Agricultural Improvement and Power District, M-S-R Public Power Agency, and the Western Area Power Administration are studying the feasibility of constructing, owning and operating the Mead-Phoenix DC Intertie Project which is a proposed 240 mile ±500 kv DC transmission line to be constructed between Mead Substation near Boulder City, Nevada and the Phoenix, Arizona area. If built, the facility would be in service in 1990.

- Geothermal - In 1981, the Department entered into an agreement with Union Oil Company which gives the Department and others the right of first refusal for up to 450 megawatts of geothermal generation from a geothermal field north of Brawley, California. Because of unsolved technical problems associated with the highly saline geothermal fluids, the various parties have mutually agreed to terminate the project. Termination negotiations are currently taking place.

- Spring Canyon Pumped Storage Project - The Department and the entities of Ak-Chin Indian Community, Arizona Electric Power Cooperative, Arizona Public Service Company, Citizens Utilities Company, Colorado River Commission of Nevada, Escanada Company, Imperial Irrigation District, Nevada Power Company, Public Service Company of New Mexico, Salt River Project Agricultural Improvement and Power District, San Diego Gas and Electric Company, Southern California Edison Company, Wellton-Mohawk Irrigation and Drainage District and the California cities of Burbank, Colton, Glendale, Pasadena and Riverside are engaged in a cooperative study to determine the feasibility of constructing the Spring Canyon Pumped Storage Project. If built, the Project would provide a generating capacity from 1000 to 4000 megawatts. The study is presently scheduled to be completed in late 1988.

Item 2

Licensees whose construction permits include conditions pertaining to antitrust aspects should list and discuss those actions or policies which have been implemented in accordance with such conditions.

Response

The Department was not a participant in the project when the construction permit was issued for Palo Verde.

100-011-10103. B.C. HYDRO-LOS ANGELES ENERGY SALES AGREEMENT
DEPARTMENT OF WATER AND POWER
BRITISH COLUMBIA HYDRO AND POWER AUTHORITY
BURBANK, CITY OF
GLENDALE, CITY OF
PASADENA, CITY OF
10/31/1986 01/84

100-011-10161 LETTER AGREEMENT BETWEEN THE BONNEVILLE POWER ADMINISTRATION AND THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES FOR THE SALE OF NORTHWEST CUSTOMERS' ENERGY
DEPARTMENT OF WATER AND POWER
BONNEVILLE POWER ADMINISTRATION
EVERGREEN 02/78

100-011-10205 AGREEMENT BETWEEN DEPARTMENT OF WATER & POWER OF THE CITY OF LOS ANGELES AND PACIFIC POWER & LIGHT COMPANY
DEPARTMENT OF WATER AND POWER
PACIFIC POWER & LIGHT COMPANY
MUTUALLY AGREED 07/78

100-011-10239 (SUPERCEDES 100-011-90112) AGREEMENT FOR SALE AND INTERCHANGE OF ENERGY BETWEEN THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES AND PUBLIC UTILITY DISTRICT NO. 2 OF GRANT COUNTY
DEPARTMENT OF WATER AND POWER
PUBLIC UTILITY DISTRICT #2 OF GRANT COUNTY
EVERGREEN 09/78

100-011-10244 (SUPERCEDES DRAFT NO. 90115) RESALE OF NONFIRM ENERGY BETWEEN THE IDAHO POWER COMPANY AND THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES
DEPARTMENT OF WATER AND POWER
IDAHO POWER COMPANY
EVERGREEN 10/78

100-011-10245 AGREEMENT FOR SALE AND INTERCHANGE OF ENERGY BETWEEN THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES AND PUBLIC UTILITY DISTRICT NO. 1 OF COWLITZ COUNTY, WASHINGTON
DEPARTMENT OF WATER AND POWER
PUBLIC UTILITY DISTRICT #1 OF COWLITZ COUNTY
EVERGREEN 09/78

100-011-10256 (SUPERCEDES CONTRACT NO. 10241) AGREEMENT FOR SALE AND INTERCHANGE OF ENERGY BETWEEN THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES AND PUBLIC UTILITY DISTRICT NO. 1 OF DOUGLAS COUNTY, WASHINGTON
DEPARTMENT OF WATER AND POWER
PUBLIC UTILITY DISTRICT #1 OF DOUGLAS COUNTY
EVERGREEN 07/78

100-011-10257	AGREEMENT FOR SALE AND INTERCHANGE OF ENERGY BETWEEN THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES AND PUBLIC UTILITY DISTRICT NO. 1 OF CHELAN COUNTY, WASHINGTON DEPARTMENT OF WATER AND POWER PUBLIC UTILITY DISTRICT #1 OF CHELAN COUNTY EVERGREEN	09/78
100-011-10298	(SUPERCEDES CONTRACT NO. 10707) AN AGREEMENT BETWEEN THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES AND WASHOE COUNTY, NEVADA DEPARTMENT OF WATER AND POWER WASHOE COUNTY, NEVADA EVERGREEN	07/79
100-011-10302	(SUPRECEDES CONTRACT NO. 10980) SERVICE AGREEMENT BETWEEN PUGET SOUND POWER & LIGHT COMPANY AND THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES PROVIDING FOR THE SALE OF SURPLUS THERMAL ENERGY DEPARTMENT OF WATER AND POWER PUGET SOUND POWER & LIGHT COMPANY EVERGREEN	05/79
100-011-10304	CONSULTING SERVICES IN CONNECTION WITH POWER SUPPLY RELATED MATTERS DEPARTMENT OF WATER AND POWER R.W. BECK AND ASSOCIATES AUGUST 2, 1982	08/79
100-011-10376	CITY - MONTANA 1971 SALES AGREEMENT MONTANA POWER COMPANY, THE DEPARTMENT OF WATER AND POWER EVERGREEN	01/71
100-011-10377	CITY - PACIFIC POWER 1971 SALES AGREEMENT DEPARTMENT OF WATER AND POWER PACIFIC POWER & LIGHT COMPANY EVERGREEN	12/73
100-011-10398	NONFIRM ENERGY PURCHASE FROM MONTANA DEPARTMENT OF WATER AND POWER MONTANA POWER COMPANY, THE EVERGREEN	11/79
100-011-10468	NONFIRM THERMAL ENERGY BETWEEN DEPARTMENT OF WATER & POWER OF CITY OF LOS ANGELES AND PACIFIC POWER & LIGHT COMPANY DEPARTMENT OF WATER AND POWER PACIFIC POWER & LIGHT COMPANY EVERGREEN OR MUTUALLY AGREED	04/80

100-011-10582	LOS ANGELES _ WASHINGTON RECALLABLE SURPLUS ENERGY LETTER AGREEMENT DEPARTMENT OF WATER AND POWER WASHINGTON WATER POWER COMPANY, THE EVERGREEN	05/81
100-011-10583	LOS ANGELES _ WASHINGTON SURPLUS ENERGY AGREEMENT DEPARTMENT OF WATER AND POWER WASHINGTON WATER POWER COMPANY, THE BY AT LEAST 30 DAY'S ADVANCED NOTICE	04/81
100-011-10566	EUGENE - LOS ANGELES 1972 SALES AGREEMENT EUGENE, CITY OF, OREGON DEPARTMENT OF WATER AND POWER EVERGREEN	06/72
100-011-10608	(SUPERCEDES AGREEMENT NO. 10540) LOS ANGELES _ MONTANA EXCESS FIRM ENERGY AGREEMENT DEPARTMENT OF WATER AND POWER MONTANA POWER COMPANY, THE BY MUTUAL AGREEMENT	04/81
100-011-10609	BONNEVILLE _ LOS ANGELES REPLACEMENT MASTER CONTROL SYSTEM FOR THE PACIFIC HVDC INTERTIE AGREEMENT DEPARTMENT OF WATER AND POWER BONNEVILLE POWER ADMINISTRATION JANUARY 1, 1984	08/81
100-011-10613	LOS ANGELES _ BONNEVILLE INTERIM ARRANGEMENTS DURING THE PACIFIC HVDC INTERTIE UPGRADE LETTER AGREEMENT DEPARTMENT OF WATER AND POWER BONNEVILLE POWER ADMINISTRATION JANUARY 1,1985	08/81
100-011-10687	TRUST AGREEMENT EXECUTED BY AND THROUGH THE UNITED STATES OF AMERICA DEPARTMENT OF THE INTERIOR ACTING BY AND THROUGH THE BONNEVILLE POWER ADMINISTRATOR AND THE CALIFORNIA UTILITY CUSTOMERS PROVIDING FOR NONFEDERAL ENERGY UNITED STATES OF AMERICA DEPARTMENT OF THE INTERIOR BONNEVILLE POWER ADMINISTRATION BURBANK, CITY OF GLENDALE, CITY OF DEPARTMENT OF WATER AND POWER PACIFIC GAS AND ELECTRIC COMPANY PASADENA, CITY OF SAN DIEGO GAS & ELECTRIC COMPANY SOUTHERN CALIFORNIA EDISON CO. CALIFORNIA,DEPARTMENT OF WATER RESOURCES, THE STATE OF EVERGREEN	08/73

100-011-10797 CITY OF LOS ANGELES-EUGENE WATER & ELECTRIC BOARD POWER INTERCHANGE AND SALES AGREEMENT CITIES OF EUGENE AND LOS ANGELES
DEPARTMENT OF WATER AND POWER
EUGENE WATER & ELECTRIC BOARD
EVERGREEN 07/74

100-011-10816 ENABLING AGREEMENT BETWEEN BRITISH COLUMBIA HYDRO AND POWER AUTHORITY AND LOS ANGELES DEPARTMENT OF WATER AND POWER
DEPARTMENT OF WATER AND POWER
BRITISH COLUMBIA HYDRO AND POWER AUTHORITY
EVERGREEN 08/74

100-011-10818 ENABLING AGREEMENT BETWEEN WEST KOOTENAY POWER LTD. AND LOS ANGELES DEPARTMENT OF WATER AND POWER
DEPARTMENT OF WATER AND POWER
WEST KOOTENAY POWER LTD.
EVERGREEN 08/74

100-011-10823 (AMENDED BY AMENDMENT NO.3 , 12-31-81) ENABLING AGREEMENT BETWEEN CITY OF SEATTLE, DEPARTMENT OF LIGHTING AND THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES
DEPARTMENT OF WATER AND POWER
SEATTLE, CITY OF, DEPARTMENT OF LIGHTING
EVERGREEN 08/74

100-011-10876 CITY OF TACOMA AND DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES INTERCHANGE AGREEMENT
DEPARTMENT OF WATER AND POWER
TACOMA, CITY OF,SWPT. OF PUBLIC UTILITIES, LIGHT DIV.
EVERGREEN 01/75

100-011-10935 PACIFIC POWER & LIGHT SERVICE AGREEMENT UNDER FPC ELECTRIC TARIFF ORIGINAL VOLUME NO. 2
DEPARTMENT OF WATER AND POWER
PACIFIC POWER & LIGHT COMPANY
EVERGREEN 09/75

100-011-90131 SEATTLE - LOS ANGELES SALE AND INTERCHANGE OF ENERGY AGREEMENT
DEPARTMENT OF WATER AND POWER
SEATTLE, CITY OF, DEPARTMENT OF LIGHTING
DRAFT 07/79

100-012-10225 NEVADA - LOS ANGELES INTERRUPTIBLE TRANSMISSION SERVICE LETTER AGREEMENT
NEVADA POWER COMPANY
DEPARTMENT OF WATER AND POWER
EVERGREEN 06/78

100-012-10285 (AMENDED BY AMENDMENT NO.2,DEC:22,1980) LOS ANGELES - NEVADA CAPACITY AGREEMENT
DEPARTMENT OF WATER AND POWER
NEVADA POWER COMPANY
DECEMBER 31, 1981 06/79

100-012-10594 (SUPERCEDES CONTRACT NO. 10909) MCCULLOUGH 287 & 230KV SWITCHYARD AGREEMENT
DEPARTMENT OF WATER AND POWER
NEVADA POWER COMPANY
UNITED STATES OF AMERICA DEPARTMENT OF THE INTERIOR
FIFTY YEARS 06/81

100-012-10660 NEVADA-LOS ANGELES 1982 NONFIRM TRANSMISSION SERVICE AGREEMENT
NEVADA POWER COMPANY
DEPARTMENT OF WATER AND POWER
STATE OF NEVADA DIVISION OF COLORADO RIVER RESORCES
WESTERN AREA POWER ADMINISTRATION
DECEMBER 31,1982 07/82

100-012-10722 AN INTERCHANGE AGREEMENT BETWEEN DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES AND NEVADA POWER COMPANY
DEPARTMENT OF WATER AND POWER
NEVADA POWER COMPANY
EVERGREEN 11/73

100-012-90002 LOS ANGELES-NEVADA SURPLUS ENERGY AGREEMENT BETWEEN DEPARTMENT OF WATER & POWER OF THE CITY OF LOS ANGELES AND NEVADA POWER COMPANY
DEPARTMENT OF WATER AND POWER
NEVADA POWER COMPANY
DRAFT 06/77

100-012-90160 (SUPERCEDES, UPON EXECUTION, 100-012-10722) INTERCHANGE AGREEMENT BETWEEN THE DEPARTMENT OF WATER & POWER OF CITY OF LOS ANGELES AND NEVADA POWER COMPANY
DEPARTMENT OF WATER AND POWER
NEVADA POWER COMPANY
DRAFT 02/80

100-012-90161 NEVADA _ LOS ANGELES INTERRUPTIBLE TRANSMISSION SERVICE AGREEMENT
DEPARTMENT OF WATER AND POWER
NEVADA POWER COMPANY
DRAFT 02/80

100-013-10011 AGREEMENT FOR EDISON-LOS ANGELES PARTICULATE EMISSIONS INVESTIGATION BETWEEN DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES AND SOUTHERN CALIFORNIA EDISON COMPANY
SOUTHERN CALIFORNIA EDISON CO.
DEPARTMENT OF WATER AND POWER
30 MO. OR MUTUAL AGREEMENT 01/77

100-013-10036	EDISON-LOS ANGELES SEPULVEDA CANYON POWER PLANT TRANSMISSION SERVICE AGREEMENT DEPARTMENT OF WATER AND POWER SOUTHERN CALIFORNIA EDISON CO. COTERMINOUS W/SEPULVEDA CYN PWR PLT INTERCONNECTION AGREEMENT	04/83
100-013-10078P	CITY-EDISON PACIFIC INTERTIE D-C TRANSMISSION FACILITIES AGREEMENT DEPARTMENT OF WATER AND POWER SOUTHERN CALIFORNIA EDISON CO. MARCH 31,2041	04/66
100-013-10079	CITY - EDISON SYLMAR INTERCONNECTION AGREEMENT DEPARTMENT OF WATER AND POWER SOUTHERN CALIFORNIA EDISON CO. EVERGREEN	04/66
100-013-10098	EDISON - LOS ANGELES TOWER(2-32) SERVICE AT ATWATER AGREEMENT DEPARTMENT OF WATER AND POWER SOUTHERN CALIFORNIA EDISON CO. EVERGREEN	09/66
100-013-10265	EDISON - LOS ANGELES MIDWAY - SYLMAR INTERRUPTIBLE TRANSMISSION SERVICE AGREEMENT SOUTHERN CALIFORNIA EDISON CO. DEPARTMENT OF WATER AND POWER EVERGREEN	03/79
100-013-10292	LOS ANGELES - EDISON GREG AVENUE NONFIRM TRANSMISSION SERVICE AGREEMENT DEPARTMENT OF WATER AND POWER SOUTHERN CALIFORNIA EDISON CO. APRIL 1, 1983	01/79
100-013-10332	CITY - EDISON OWENS VALLEY INTERCONNECTION AND INTERCHANGE AGREEMENT BETWEEN DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES AND SOUTHERN CALIFORNIA EDISON COMPANY SOUTHERN CALIFORNIA EDISON CO. DEPARTMENT OF WATER AND POWER NOV.29,2019	09/69
100-013-10343	(AMENDMENT NO.1 PROPOSED FOR EXECUTION) VICTORVILLE - LUGO INTERCONNECTION AGREEMENT BETWEEN DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES AND SOUTHERN CALIFORNIA EDISON COMPANY SOUTHERN CALIFORNIA EDISON CO. DEPARTMENT OF WATER AND POWER NOV.29,2019	11/69

100-013-10351	AGREEMENT WITH SOUTHERN CALIFORNIA EDISON COMPANY AND DEPARTMENT OF WATER &POWER OF CITY OF LOS ANGELES TO PERMIT THE DEPARTMENT REBUILD CERTAIN EDISON DISTRIBUTION FACILITIES IN INYO COUNTY DEPARTMENT OF WATER AND POWER SOUTHERN CALIFORNIA EDISON CO. UNTIL SUPERSEDED BY OTHER CONTRACT		1 1/79
100-013-10417	INTERRUPTIBLE TRANSMISSION SERVICE AGREEMENT BETWEEN SOUTHERN CALIFORNIA EDISON COMPANY AND DEPARTMENT OF WATER & POWER OF CITY OF LOS ANGELES DEPARTMENT OF WATER AND POWER SOUTHERN CALIFORNIA EDISON CO. EVERGREEN UNTIL TERM. BY 30 DAY'S NOTICE		03/80
100-013-10436	CITY - EDISON 1951 INTERCHANGE AGREEMENT DEPARTMENT OF WATER AND POWER SOUTHERN CALIFORNIA EDISON CO. EVERGREEN		01/51
100-013-10462	LETTER AGREEMENT BETWEEN SOUTHERN CALIFORNIA EDISON COMPANY , DEPARTMENT OF WATER AND POWER , CITY OF BURBANK , CITY OF GLENDALE AND CITY OF PASADENA PROVIDING THE TERMS AND CONDITIONS FOR THE USE OF EDISON'S LITTLE LAKE MICROWAVE EQUIPMENT IN CONNECTION WITH THE 800-KV DC TRANSMISSION LINE SOUTHERN CALIFORNIA EDISON CO. DEPARTMENT OF WATER AND POWER GLENDALE, CITY OF PASADENA, CITY OF BURBANK, CITY OF JANUARY 18,2017		09/71
100-013-10532	LOS ANGELES _ EDISON INTERRUPTIBLE TRANSMISSION SERVICE OF VICTORVILLE _ ELDORADO AGREEMENT DEPARTMENT OF WATER AND POWER SOUTHERN CALIFORNIA EDISON CO. BY 30 DAY'S ADVANCED NOTICE		06/81
100-013-10542	LETTER AGREEMENT BETWEEN SOUTHERN CALIFORNIA EDISON COMPANY AND DEPARTMENT OF WATER AND POWER TO PROVIDE SHORT TERM FIRM SERVICE SOUTHERN CALIFORNIA EDISON CO. DEPARTMENT OF WATER AND POWER EVERGREEN		07/72
100-013-10546	(SUPERCEDES DRAFT NO. 90154) NORTH BRAWLEY GEOTHERMAL UNIT 1 AGREEMENT BETWEEN LOS ANGELES AND EDISON COMPANY DEPARTMENT OF WATER AND POWER SOUTHERN CALIFORNIA EDISON CO. CONCURRANT WITH THE GEOTHRMAL SALES CONTRACTS		05/81

100-013-10572	LOS ANGELES - EDISON MIDWAY-SYLMAR FIRM-EMERGENCY-TRANSMISSION SERVICE AGREEMENT DEPARTMENT OF WATER AND POWER SOUTHERN CALIFORNIA EDISON CO. BY 30 DAY'S ADVANCED NOTICE	05/81
100-013-10723	(SUPERCEDES DRAFTS # 90177 AND 90190) EDISON-LOS ANGELES ECONOMY ENERGY AGREEMENT SOUTHERN CALIFORNIA-EDISON CO. DEPARTMENT OF WATER AND POWER 30 DAYS ADVANCE NOTICE	09/82
100-013-10738	(AMENDED BY AMENDMENT NO.1,NOV.6,-1980) CITY-EDISON EXCESS ENERGY SALES AGREEMENT DEPARTMENT OF WATER AND POWER SOUTHERN CALIFORNIA EDISON CO. EVERGREEN	12/73
100-013-10745	SOUTHERN CALIFORNIA EDISON COMPANY TO STORE FUEL OIL FOR DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES SOUTHERN CALIFORNIA EDISON CO. DEPARTMENT OF WATER AND POWER EVERGREEN	01/74
100-013-10754	(SUPERCEDES DRAFT # 90195) SOLAR POWER PILOT PLANT DELIVERY OF ENERGY AGREEMENT BETWEEN EDISON AND THE DEPARTMENT OF WATER & POWER SOUTHERN CALIFORNIA EDISON CO. DEPARTMENT OF WATER AND POWER COTERMINOUS WITH SOLAR PWR.PLT AGREEMENT (DWP 10988)	12/82
100-013-10805	EDISON-DWP DDSMS EQUIPMENT FOR SYLMAR DEPARTMENT OF WATER AND POWER SOUTHERN CALIFORNIA EDISON CO. JAN.1,1980 MIN.-OTHERWISE EVERGREEN	08/74
100-013-10812	EDISON-DEPARTMENT OF WATER AND POWER MASTER FRINGE AGREEMENT DEPARTMENT OF WATER AND POWER SOUTHERN CALIFORNIA EDISON CO. EVERGREEN	10/74
100-013-10817	DWP-EDISON 1974 TRANSMISSION SERVICE AGREEMENT FOR WHEELING FROM VICTORVILLE-LUGO TO D.W.P. DEPARTMENT OF WATER AND POWER SOUTHERN CALIFORNIA EDISON CO. EVERGREEN	01/74

100-013-10898	AGREEMENT FOR EDISON-DWP TELEMETERING EQUIPMENT AT MCCULLOUGH AND ELDORADO SUBSTATIONS DEPARTMENT OF WATER AND POWER SOUTHERN CALIFORNIA EDISON CO. EVERGREEN	05/75
100-013-10915	CITY - EDISON 400,000 KVA INTERCONNECTION AGREEMENT SOUTHERN CALIFORNIA EDISON CO. DEPARTMENT OF WATER AND POWER EVERGREEN	07/62
100-013-10987	EDISON-LOS ANGELES INYO INTERCONNECTION AGREEMENT SOUTHERN CALIFORNIA EDISON CO. DEPARTMENT OF WATER AND POWER FIVE YEARS ADVANCE NOTICE OR MUTUAL AGREEMENT	08/76
100-013-90187	LOS ANGELES - EDISON EASTERN DESERT TRANSMISSION ALLOCATION AGREEMENT DEPARTMENT OF WATER AND POWER SOUTHERN CALIFORNIA EDISON CO. DRAFT	11/81
100-013-90194	(WILL SUPERCED 10812,UPON EXECUTION) EDISON - LOS ANGELES MASTER FRINGE AGREEMENT SOUTHERN CALIFORNIA EDISON CO. DEPARTMENT OF WATER AND POWER DRAFT	
100-014-10037	DWR-LOS ANGELES GREG AVENUE POWER PLANT ENERGY EXCHANGE AGREEMENT DEPARTMENT OF WATER AND POWER CALIFORNIA,DEPARTMENT OF WATER RESOURCES, THE STATE OF 2 YEARS ADVANCE NOTICE OR COTERMINOUS W/TRANS. SERV. AGREEMENT	04/83
100-014-10056	DWR-LOS ANGELES ECONOMY ENERGY AGREEMENT DEPARTMENT OF WATER AND POWER CALIFORNIA,DEPARTMENT OF WATER RESOURCES, THE STATE OF 30 DAYS' ADVANCE WRITTEN NOTICE	09/83
100-014-10099	CONTRACT FOR COOPERATIVE DEVELOPMENT WEST BRANCH, CALIFORNIA AQUEDUCT BETWEEN THE DEPARTMENT OF WATER RESOURCES, RESOURCES AGENCY, STATE OF CALIFORNIA AND THE DEPARTMENT OF WATER AND POWER, CITY OF LOS ANGELES, CALIFORNIA CALIFORNIA,DEPARTMENT OF WATER RESOURCES, THE STATE OF DEPARTMENT OF WATER AND POWER FEB. 9, 2042	09/66

100-014-10101	CONTRACT BETWEEN CALIFORNIA SUPPLIERS AND THE STATE OF CALIFORNIA FOR THE SALE , EXCHANGE AND TRANSMISSION OF ELECTRIC CAPACITY AND ENERGY FOR THE OPERATING OF STATE WATER PROJECT PUMPING PLANTS CALIFORNIA,DEPARTMENT OF WATER RESOURCES, THE STATE OF PACIFIC GAS AND ELECTRIC COMPANY SOUTHERN CALIFORNIA EDISON CO. SAN DIEGO GAS & ELECTRIC COMPANY DEPARTMENT OF WATER AND POWER EVERGREEN	11/66
100-014-10102	CONTRACT AMONG THE CALIFORNIA SUPPLIERS PACIFIC GAS AND ELECTRIC COMPANY SOUTHERN CALIFORNIA EDISON CO. SAN DIEGO GAS & ELECTRIC COMPANY DEPARTMENT OF WATER AND POWER EVERGREEN	11/66
100-014-10626	CASTAIC POWER PROJECT AGREEMENT WITH THE DEPARTMENT OF WATER RESOURCES OF THE STATE OF CALIFORNIA FOR RELOCATION OF THE STATES COMMUNICATIONS INTERFACE EQUIPMENT AT THE CASTAIC POWER PROJECT DEPARTMENT OF WATER AND POWER CALIFORNIA,DEPARTMENT OF WATER RESOURCES, THE STATE OF 2025	04/73
100-014-10681	STATE - LOS ANGELES SETTLEMENT AGREEMENT AND AGREEMENT ON PRINCIPALES FOR THE AMENDMENT OF THE CONTRACT FOR COOPERATIVE DEVELOPMENT WEST BRANCH CALIFORNIA AQUEDUCT DEPARTMENT OF WATER AND POWER CALIFORNIA,DEPARTMENT OF WATER RESOURCES, THE STATE OF NOTSPECIFIED	05/82
100-014-90117	STATE-LOS ANGELES INTERRUPTIBLE TRANSMISSION SERVICE AGREEMENT CALIFORNIA,DEPARTMENT OF WATER RESOURCES, THE STATE OF DEPARTMENT OF WATER AND POWER DRAFT	05/79
100-015-10128	CITY - GLENDALE PACIFIC INTERTIE D-C TRANSMISSION FACILITIES AGREEMENT GLENDALE, CITY OF DEPARTMENT OF WATER AND POWER APRIL 14 , 2041	08/66
100-015-10129	CITY - BURBANK PACIFIC INTERTIE D-C TRANSMISSION FACILITIES AGREEMENT BURBANK, CITY OF DEPARTMENT OF WATER AND POWER APRIL 14 , 2041	04/67

100-015-10130	CITY - PASADENA PACIFIC-INTERTIE D-C TRANSMISSION FACILITIES AGREEMENT PASADENA, CITY OF DEPARTMENT OF WATER AND POWER APRIL 14,2041	10/66
100-015-10131	CITY - GLENDALE INTERCONNECTION AGREEMENT GLENDALE, CITY OF DEPARTMENT OF WATER AND POWER EVERGREEN	12/66
100-015-10132	CITY - BURBANK INTERCONNECTION AGREEMENT BURBANK, CITY OF DEPARTMENT OF WATER AND POWER EVERGREEN	08/67
100-015-10133	CITY - PASADENA 1968 INTERCHANGE AGREEMENT PASADENA, CITY OF DEPARTMENT OF WATER AND POWER EVERGREEN	10/68
100-015-10134	CITY - BURBANK 1968 INTERCHANGE AGREEMENT BURBANK, CITY OF DEPARTMENT OF WATER AND POWER EVERGREEN	10/68
100-015-10135	CITY - GLENDALE 1968 INTERCHANGE AGREEMENT GLENDALE, CITY OF DEPARTMENT OF WATER AND POWER EVERGREEN	10/68
100-015-10143	CONTRACT SUPPLEMENTAL TO SUPPLEMENTAL CONTRACT OF JUNE 18,1935 AND AMENDATORY TO CONTRACT OF SEPTEMBER 24,1931 BETWEEN THE CITY OF LOS ANGELES A MUNICIPAL CORPORATION AND DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES AND CITY OF PASADENA DEPARTMENT OF WATER AND POWER PASADENA, CITY OF EVERGREEN	04/41
100-015-10226	LOS ANGELES - BURBANK, GLENDALE, PASADENA TRANSMISSION SERVICE AGREEMENT DEPARTMENT OF WATER AND POWER BURBANK, CITY OF GLENDALE, CITY OF PASADENA, CITY OF EVERGREEN	12/78

100-015-10366	CITY - GLENDALE EMERGENCY TRANSMISSION SERVICE AGREEMENT GLENDALE, CITY OF DEPARTMENT OF WATER AND POWER EVERGREEN	12/70
100-015-10444	(AMENDED BY AMENDMENT NO. 1, JUNE 8, 1982, ALSO CONTRACT SUPERCEDES CONTRACT NO. 10067) INTERRUPTIBLE TRANSMISSION SERVICE AGREEMENT BETWEEN LOS ANGELES AND CITY OF BURBANK DEPARTMENT OF WATER AND POWER BURBANK, CITY OF 30 DAYS ADVANCED NOTICE BY EITHER PARTY	06/82
100-015-10445	(AMENDED BY AMENDMENT NO. 1, JUNE 8, 1982, ALSO CONTRACT SUPERCEDES CONTRACT NO. 10068) INTERRUPTIBLE TRANSMISSION SERVICE AGREEMENT BETWEEN LOS ANGELES AND CITY OF GLENDALE DEPARTMENT OF WATER AND POWER GLENDALE, CITY OF 30 DAYS ADVANCED NOTICE BY EITHER PARTY	06/82
100-015-10447	(AMENDED BY AMENDMENT NO. 1, JUNE 8, 1982, ALSO CONTRACT SUPERCEDES CONTRACT NO. 10155) INTERRUPTIBLE TRANSMISSION SERVICE AGREEMENT BETWEEN LOS ANGELES AND CITY OF PASADENA DEPARTMENT OF WATER AND POWER PASADENA, CITY OF 30 DAYS ADVANCED NOTICE	06/82
100-015-10463	MCCULLOUGH - VICTORVILLE LINE 2 TRANSMISSION AGREEMENT WITH THE MUNICIPALITIES DEPARTMENT OF WATER AND POWER BURBANK, CITY OF GLENDALE, CITY OF PASADENA, CITY OF MAY 31, 2030	06/80
100-015-10464	LETTER AGREEMENT OF UNDERSTANDING OF THE CONVERSION OF MCCULLOUGH _ VICTORVILLE LINE NO. 2 DEPARTMENT OF WATER AND POWER BURBANK, CITY OF GLENDALE, CITY OF PASADENA, CITY OF MAY 31, 1987	06/80
100-015-10465	(AMENDED BY AMENDMENT NO.1 ,5-20-82) LOSANGELES - BURBANK VICTORVILLE TO RECEIVING STATION E TRANSMISSION SERVICE AGREEMENT DEPARTMENT OF WATER AND POWER BURBANK, CITY OF EVERGREEN UNLESS TERMINATED BY 5 YEAR'S ADVANCED NOTICE	06/80

100-015-10466	(AMENDED BY AMENDMENT NO.1 ,5-20-82) LOS ANGELES - GLENDALE VICTORVILLE TO RECEIVING STATION E TRANSMISSION SERVICE AGREEMENT DEPARTMENT OF WATER AND POWER GLENDALE, CITY OF EVERGREEN UNLESS TERMINATED BY 5 YEAR'S ADVANCED NOTICE	06/80
100-015-10467	(AMENDED BY AMENDMENT NO.1 ,5-20-82) LOS ANGELES - PASADENA VICTORVILLE TO SYLMAR TRANSMISSION SERVICE AGREEMENT DEPARTMENT OF WATER AND POWER PASADENA, CITY OF MAY 31, 2030	06/80
100-015-10657	(SUPERCEDES, DRAFT #-90182 AND UPON EXECUTION ,CONTRACT NOS.-10133,10134,AND 10135) LOS ANGELES _ MUNICIPALITIES POWER COORDINATION AGREEMENT DEPARTMENT OF WATER AND POWER BURBANK, CITY OF GLENDALE, CITY OF PASADENA, CITY OF 3 YEARS ADVANCE NOTICE	07/82
100-015-10659	EXPIRED 3/31/1983 (SUPERCEDES DRAFT NO. 100-015-90180) LOS ANGELES _ BURBANK SEPULVEDA CANYON POWER PLANT FIRM TRANSMISSION SERVICE AGREEMENT DEPARTMENT OF WATER AND POWER BURBANK, CITY OF MARCH 31, 1983	04/82
100-015-90120	BURBANK - LOS ANGELES INTERRUPTIBLE TRANSMISSION SERVICE AGREEMENT AMENDMENT NO. 1 BURBANK, CITY OF DEPARTMENT OF WATER AND POWER DRAFT	12/78
100-015-90132	LOS ANGELES - BURBANK 1979 PEAKING CAPACITY AGREEMENT DEPARTMENT OF WATER AND POWER BURBANK, CITY OF DRAFT	07/79
100-015-90186 10669	AIR WAY RECEIVING STATION CONSTRUCTION AGREEMENT BETWEEN GELANDALE AND LOS ANGELES DEPARTMENT OF WATER AND POWER GLENDALE, CITY OF DRAFT	

100-015-90197 VICTORVILLE-ADELANTO-RINALDI TRANSMISSION AGREEMENT BETWEEN PASADENA AND LOS ANGELES
PASADENA, CITY OF
DEPARTMENT OF WATER AND POWER
DRAFT

100-015-90198 VICTORVILLE-ADELANTO-RINALDI TRANSMISSION AGREEMENT BETWEEN GLENDALE AND LOS ANGELES
GLENDALE, CITY OF
DEPARTMENT OF WATER AND POWER
DRAFT

100-015-90199 VICTORVILLE-ADELANTO-RINALDI-TRANSMISSION AGREEMENT BETWEEN BURBANK AND LOS ANGELES
BURBANK, CITY OF
DEPARTMENT OF WATER AND POWER
DRAFT

100-016-10038 AGREEMENT FOR SALE AND INTERCHANGE OF ENERGY BETWEEN THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES AND ARIZONA PUBLIC SERVICE COMPANY
ARIZONA PUBLIC SERVICE COMPANY
DEPARTMENT OF WATER AND POWER
EVERGREEN 12/76

100-016-10096 ALTERNATE DELIVERY POINT AT MCCULLOUGH SWITCHYARD FOR NEVADA-ARIZONA ENTITLEMENT ENERGY FROM SECTION C-3, HOOVER P.P.
DEPARTMENT OF WATER AND POWER
COLORADO RIVER COMMISSION OF NEVADA
NEVADA POWER COMPANY
WESTERN AREA POWER ADMINISTRATION
12/31/84 01/84

100-016-10110 (REVISION 3, EXIBIT B, 3/28/83) (AMENDED BY AMENDMENT NO.1,7/30/81) CONTRACT WITH THE CITY OF LOS ANGELES AND ITS DEPARTMENT OF WATER AND POWER FOR TRANSMISSION SERVICE OVER THE MEAD-LIBERTY-PINNACLE PEAK TRANSMISSION FACILITIES (AMENDED ,BY AMENDMENT NO. 1, ON OCTOBER OF 1979)
UNITED STATES BUREAU OF RECLAMATION LOWER COLORADO REGION
DEPARTMENT OF WATER AND POWER
MARCH 31,1988 OR 3 YEARS' NOTICE OR MUTUAL AGR. 04/78

100-016-10112 MEMORANDUM OF AGREEMENT PROVIDING FOR PURCHASE AND RELATED CORONADO / PALOVERDE AGREEMENTS (SEE 10595 FOR MEMORANDUM PROVIDING THE EXTENTION)
DEPARTMENT OF WATER AND POWER
SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST.
RECEIPT OF FINAL PAYMENT 08/77

100-016-10198	(SUPERCEDES CONTRACT NO.-100-040-10204) AGREEMENT FOR INTERCONNECTION AT HEAD STATION DEPARTMENT OF WATER AND POWER UNITED STATES BUREAU OF RECLAMATION LOWER COLORADO REGION DECEMBER 31, 2018	07/78
100-016-10219	ECONOMY ENERGY AGREEMENT DEPARTMENT OF WATER AND POWER SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. EVERGREEN	08/78
100-016-10333	LOS ANGELES - AEPCO NON-FIRM ENERGY AGREEMENT DEPARTMENT OF WATER AND POWER ARIZONA ELECTRIC POWER COOPERATIVE EVERGREEN	09/79
100-016-10345	(AMENDED BY AMENDMENT #4, 12/08/83) (AMENDED BY AMENDMENT #3, 10/21/82) ARIZONA - LOS ANGELES INTERRUPTIBLE TRANSMISSION SERVICE AGREEMENT DEPARTMENT OF WATER AND POWER ARIZONA PUBLIC SERVICE COMPANY 30 DAYS ADVANCE NOTICE	10/82
100-016-10357	AGREEMENT FOR ELECTRIC SERVICE BETWEEN THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES AND SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. DEPARTMENT OF WATER AND POWER EVERGREEN	11/70
100-016-10358	(SUPERCEDES DRAFT NO. 90105) AGREEMENT FOR SALE AND INTERCHANGE OF ENERGY BETWEEN THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES AND TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION INCORPORATED DEPARTMENT OF WATER AND POWER TRI-STATE GENERATION AND TRANSMISSION ASSCIATION INC. EVERGREEN	11/79
100-016-10405	(SUPERCEDES DRAFT NO. 90144) LETTER AGREEMENT WITH CITY OF COLORADO SPRINGS FOR GENERAL PURPOSE POWER SALES DEPARTMENT OF WATER AND POWER COLORADO SPRINGS,CITY OF EVERGREEN	01/80
100-016-10415	(SUPERCEDES CONTRACT NO.10943 BY LETTER DATED 1/16/81) TUCSON _ LOS ANGELES INTERCHANGE AGREEMENT DEPARTMENT OF WATER AND POWER TUCSON GAS & ELECTRIC COMPANY APRIL 30, 1982	01/80

100-016-10461	LOS ANGELES _ SALT RIVER PROJECT ENERGY SALE AGREEMENT NO. 2 DEPARTMENT OF WATER AND POWER SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. DECEMBER 31, 1982	11/80
100-016-10476	EL PASO _ LOS ANGELES SALE & INTERCHANGE AGREEMENT DEPARTMENT OF WATER AND POWER EL PASO ELECTRIC COMPANY 30 DAY'S ADVANCED NOTICE BY EITHER PARTY	07/80
100-016-10528	(SUPERCEDES 100-016-10712 , REVISION NO. 3 TO EXHIBIT B, 3/28/83, EXHIBIT B HAS BEEN REVISED ON JULY 30, 1981) NONFIRM TRANSMISSION SERVICE (COLORADO RIVER STORAGE PROJECT) AGREEMENT WITH WESTHERN DEPARTMENT OF WATER AND POWER WESTERN AREA POWER ADMINISTRATION MARCH 31, 1986	10/80
100-016-10536	WESTERN SYSTEM COORDINATING COUNCIL(WSCC) BROKER AGREEMENT BETWEEN THE DEPARTMENT OF WATER & POWER AND COLORADO PUBLIC SERVICE COMPANY DEPARTMENT OF WATER AND POWER WESTERN SYSTEMS COORDINATING COUNCIL BY ADVANCED NOTICE	
100-016-10593	TUCSON _ LOS ANGELES 1982-84 POWER SALE AGREEMENT DEPARTMENT OF WATER AND POWER TUCSON GAS & ELECTRIC COMPANY APRIL 30, 1984	06/81
100-016-10595	MEMORANDUM OF PROVIDING FOR EXTENTION OF CORNADO _ PALO VERDE PROJECT BETWEEN LOS ANGELES AND SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT DEPARTMENT OF WATER AND POWER SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. AS THE SAME AS ORIGINAL COTRACT(10112)	08/81
100-016-10703	NEW MEXICO-ARIZONA-SO. CALIFORNIA TRANSMISSION PRELIMINARY WORK AGREEMENT OF MULTIPARTY ARIZONA ELECTRIC POWER COOPERATIVE ARIZONA PUBLIC SERVICE COMPANY DEPARTMENT OF WATER AND POWER EL PASO ELECTRIC COMPANY PACIFIC GAS AND ELECTRIC COMPANY SAN DIEGO GAS & ELECTRIC COMPANY SOUTHERN CALIFORNIA EDISON CO. SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. TUCSON GAS & ELECTRIC COMPANY WESTERN AREA POWER ADMINISTRATION NEW MEXICO,PUBLIC SERVICE COMPANY OF 30 DAYS ADVANCED NOTICE	03/82

100-016-90045	PRINCIPLES FOR LOS ANGELES ENTITLEMENT PURCHASE FROM ST. GEORGE AND LOS ANGELES' SALE OF RESERVE CAPACITY TO ST. GEORGE DEPARTMENT OF WATER AND POWER ST. GEORGE DRAFT	11/75
100-016-90049	LETTER AGREEMENT TO FORMALIZE INTERCONNECTION COMMITTEE UNDER THE PRINCIPLES OF INTERCONNECTED OPERATION FOR THE FOUR CORNERS , MOHAVE AND NAVAJO PROJECTS ARIZONA PUBLIC SERVICE COMPANY DEPARTMENT OF WATER AND POWER EL PASO ELECTRIC COMPANY NEVADA POWER COMPANY NEW MEXICO,PUBLIC SERVICE COMPANY OF SOUTHERN CALIFORNIA EDISON CO. TUCSON GAS & ELECTRIC COMPANY UNITED STATES BUREAU OF RECLAMATION LOWER COLORADO REGION DRAFT	12/75
100-016-90060	FOUR CORNERS-MOHAVE-NAVAJO UNIT TRIPPING AGREEMENT ARIZONA PUBLIC SERVICE COMPANY EL PASO ELECTRIC COMPANY DEPARTMENT OF WATER AND POWER NEVADA POWER COMPANY NEW MEXICO,PUBLIC SERVICE COMPANY OF SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. SOUTHERN CALIFORNIA EDISON CO. UNITED STATES OF AMERICA, THE DRAFT	06/76
100-016-90088	LOS ANGELES - ARIZONA 1978 - 1979 APACHE POWER SALES AGREEMENT DEPARTMENT OF WATER AND POWER ARIZONA ELECTRIC POWER COOPERATIVE DRAFT	06/77
100-016-90191	NEW MEXICO-LOS ANGELES ECONOMY ENERGY AGREEMENT DEPARTMENT OF WATER AND POWER NEW MEXICO,PUBLIC SERVICE COMPANY OF DRAFT	
100-016-90193	INTERCONNECTION AGREEMENT BETWEEN PLAINS ELECTRIC GENERATION & TRANSMISSION COOPRATIVE INC. AND THE DEPARTMENT OF WATER & POWER OF THE CITY OF LOS ANGELES DEPARTMENT OF WATER AND POWER PLAINS ELECTRIC GENERATION & TRANSMISSION COOPERATIVE INC. DRAFT	

100-017-10033	AGREEMENT FOR INSTALLATION & TESTING OF A THYRISTOR VALVE AT THE SYLMAR SWITCHING STATION ASEA DEPARTMENT OF WATER AND POWER NOT IN FILE	02/76
100-017-10052	AGREEMENT FOR SALE AND INTERCHANGE OF ENERGY BETWEEN THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES AND PACIFIC GAS & ELECTRIC COMPANY DEPARTMENT OF WATER AND POWER PACIFIC GAS AND ELECTRIC COMPANY EVERGREEN	01/77
100-017-10057	ANAHEIM-LOS ANGELES-ECONOMY-ENERGY AGREEMENT DEPARTMENT OF WATER AND POWER ANAHEIM,CITY OF 30 DAYS' ADVANCE WRITTEN NOTICE	09/83
100-017-10058	RIVERSIDE-LOS ANGELES ECONOMY ENERGY AGREEMENT DEPARTMENT OF WATER AND POWER RIVERSIDE, CITY OF 30 DAYS' ADVANCE WRITTEN NOTICE	09/83
100-017-10059	VERNON-LOS ANGELES ECONOMY ENERGY AGREEMENT DEPARTMENT OF WATER AND POWER VERNON, CITY OF 30 DAYS' ADVANCE WRITTEN NOTICE	02/84
100-017-10061	SHELDON-ARLETA LANDFILL GAS AGREEMENT DEPARTMENT OF WATER AND POWER DEPARTMENT OF PUBLIC WORKS OF THE CITY OF L.A. MUTUAL AGREEMENT	06/77
100-017-10095	VERNON-LOS ANGELES INTERRUPTIBLE-TRANSMISSION SERVICE AGREEMENT DEPARTMENT OF WATER AND POWER VERNON, CITY OF 30 DAYS' ADVANCE WRITTEN NOTICE	09/83
100-017-10193	AGREEMENT - WESTERN SYSTEMS COORDINATING COUNCIL WESTERN SYSTEMS COORDINATING COUNCIL DEPARTMENT OF WATER AND POWER EVERGREEN	08/67
100-017-10235	CONTRACT OF INDEMNITY RELATING TO AGREEMENT FOR SALE OF SAN LUIS GENERATING CAPACITY (BECAUSE OF CONFLICT WITH DWP CONTRACT NO. 10101) DEPARTMENT OF WATER AND POWER PACIFIC GAS AND ELECTRIC COMPANY EVERGREEN	11/78

100-017-10291	SAN DIEGO - LOS ANGELES INTERRUPTIBLE TRANSMISSION SERVICE AGREEMENT DEPARTMENT OF WATER AND POWER SAN DIEGO GAS & ELECTRIC COMPANY EVERGREEN	02/79
100-017-10375	LOS ANGELES _ PACIFIC GAS & ELECTRIC SALE AND PURCHASE OF FIRM SERVICE FOR LIMITED PERIODS AGREEMENT DEPARTMENT OF WATER AND POWER PACIFIC GAS AND ELECTRIC COMPANY JUNE 1, 1983 OR SUPERCEDED BY LONG TERM CONTRACT	0 5/80
100-017-10409	ECONOMY ENERGY AGREEMENT WITH SAN DIEGO GAS & ELECTRIC COMPANY DEPARTMENT OF WATER AND POWER SAN DIEGO GAS & ELECTRIC COMPANY EVERGREEN	02/80
100-017-10443	INTERRUPTIBLE TRANSMISSION SERVICE AGREEMENT BTWEEN LOS ANGELES AND CITY OF RIVERSIDE DEPARTMENT OF WATER AND POWER RIVERSIDE, CITY OF BY MUTUAL AGREEMENT	05/80
100-017-10448	ANAHEIM - LOS ANGELES INTERRUPTIBLE TRANSMISSION SERVICE AGREEMENT DEPARTMENT OF WATER AND POWER ANAHEIM, CITY OF BY 30 DAY'S ADVANCED NOTICE	05/80
100-017-10481	AGREEMENT FOR INTERCONNECTION AND COOPERATIVE USE OF CERTAIN PACIFIC INTERTIE MICROWAVE FACILITIES PACIFIC GAS AND ELECTRIC COMPANY SOUTHERN CALIFORNIA EDISON CO. SAN DIEGO GAS & ELECTRIC COMPANY DEPARTMENT OF WATER AND POWER JULY 31, 2007	08/72
100-017-10522	BRADLEY LANDFILL GAS SALES AGREEMENT BETWEEN DEPT. OF WATER AND POWER OF CITY OF LOS ANGELES AND RELIANCE LAND COMPANY DEPARTMENT OF WATER AND POWER RELIANCE LAND COMPANY AUGUST 21,1990	08/80
100-017-10545	(SUPERCEDES DRAFT NO.90128) GEOTHERMAL ENERGY CONTRACTS WITH UNION OIL COMPANY OF CALIFORNIA REGARDING 10 MW GEOTHERMAL GENERATING PLANT - NORTH BRAWLEY GEOTHERMAL FIELD UNION OIL COMPANY OF CALIFORNIA DEPARTMENT OF WATER AND POWER 6 MO. AFTER FIRM OPS OR, ALL WORK COMPLETED	05/81

100-017-10547 PUBLIC UTILITIES(PARTIES) NORTH BRAWLY GEOTHERMAL UNIT 1 PARTICIPATION AGREEMENT
DEPARTMENT OF WATER AND POWER
ANAHEIM,CITY OF
BURBANK, CITY OF
GLENDALE, CITY OF
PASADENA, CITY OF
RIVERSIDE, CITY OF
IMPERIAL IRRIGATION DISTRICT
CONCURRENT WITH DWP_EDISON UNIT 1 PARTICIPATION AGREEMENT 05/81

100-017-10548 NORTH BRAWLY GEOTHRMAL ENERGY AGREEMENT BETWEEN LOS ANGELES AND UNION OIL COMPANY
DEPARTMENT OF WATER AND POWER
UNION OIL COMPANY OF CALIFORNIA
35 YEARS FROM COMPLITION OF CONSTRUCTION OF LAST UNIT 05/81

100-017-10549 LOS ANGELES _ UNION REIMBURSMENT OF GEOTHERMAL ENERGY AGREEMENT
DEPARTMENT OF WATER AND POWER
UNION OIL COMPANY OF CALIFORNIA
NOT-SPESIFIED 05/81

100-017-10550 (SUPERCEDES DRAFT NO.90155) NORTH BRAWLEY GEOTHERMAL PATICIPATION AGREEMENT
DEPARTMENT OF WATER AND POWER
ANAHEIM,CITY OF
BURBANK, CITY OF
GLENDALE, CITY OF
PASADENA, CITY OF
RIVERSIDE, CITY OF
IMPERIAL IRRIGATION DISTRICT
BY TERMINATION OF ALL GEOTHERMAL SALES COTRACT 05/81

100-017-10551 NORTH BRAWLY GEOTHERMAL PROJECT CALIFORNIA ENVIRONMENTAL, FEASABILITY AND LICENSING AGREEMENT
DEPARTMENT OF WATER AND POWER
ANAHEIM,CITY OF
BURBANK, CITY OF
GLENDALE, CITY OF
PASADENA, CITY OF
RIVERSIDE, CITY OF
IMPERIAL IRRIGATION DISTRICT
BY COMPL.OF CEQA OR,AGREE. OF MANAGEMENT 05/81

100-017-10574	(AMENDED BY AMENDMENT NO. 1, 8/12/1982) LOS ANGELES _ PACIFIC GAS & ELECTRIC CO. INTERCHANGE AGREEMENT DEPARTMENT OF WATER AND POWER PACIFIC GAS AND ELECTRIC COMPANY ONE YEAR ADVANCED NOTICE	04/81
100-017-10646	LAW OFFICES OF NORTHCUTT ELY AND LOS ANGELES AGREEMENT NOTE: THIS AGREEMENT (DWP 10646) IS "EXHIBIT A" TO (DWP 10647) AND IS ATTACHED TO THE AGREEMENT (SEE 100-017-10647) DEPARTMENT OF WATER AND POWER LAW OFFICES OF NORTHCUTT ELY 30 DAYS' ADVANCE WRITTEN NOTICE	09/81
100-017-10647	AGREEMENT BETWEEN DWP, BURBANK, GLENDALE, PASADENA, AND SCE (HOOVER POWER SALES CONTRACT EXPIRES ON 5/31/87 AND WESTERN IS TO DEVELOPE MARKETING PLAN FOR HOOVER ENERGY - LAW OFFICE OF NORTHCUTT ELY TO REPRESENT ON RELATED HOOVER ENERGY LEGAL MATTERS FOR L.A. AND PARTICIPANTS OF THIS AGREEMENT) DEPARTMENT OF WATER AND POWER BURBANK, CITY OF GLENDALE, CITY OF PASADENA, CITY OF SOUTHERN CALIFORNIA EDISON CO. 30 DAYS' ADVANCE WRITTEN NOTICE	05/82
100-017-10771	WESTERN SYSTEM COORDINATING COUNCIL LOOP FLOW AGREEMENT DEPARTMENT OF WATER AND POWER WESTERN SYSTEMS COORDINATING COUNCIL 12 MONTHS; OPTION EXTENDS 12 MORE MONTHS	12/82
100-017-10940	AGREEMENT FOR CONSULTANT SERVICES FOR ELECTRIC POWER CONTROL SYSTEMS COMPUTER SCIENCES CORPORATION DEPARTMENT OF WATER AND POWER EVERGREEN	12/75
100-017-10988	AGREEMENT FOR SOLAR POWER PILOT PLANT SOUTHERN CALIFORNIA EDISON CO. DEPARTMENT OF WATER AND POWER CALIFORNIA,DEPARTMENT OF WATER RESOURCES, THE STATE OF CALIFORNIA ENERGY RESOURCES CONSERVATION AND DEV. COMM. AUGUST 5,1978,DEF. AGREE,OR MUTUAL AGREE	08/76
100-017-90046	LOS ANGELES-SAN DIEGO PRINCIPLES FOR AN INTERCHANGE AGREEMENT DEPARTMENT OF WATER AND POWER SAN DIEGO GAS & ELECTRIC COMPANY DRAFT	02/76

100-017-90056 ALAMEDA COGENERATION PROJECT ,POWER SALE AGREEMENT BETWEEN GREAT LAKES CARBON CORPORATION AND THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES
GREAT LAKES CARBON CORPORATION
DEPARTMENT OF WATER AND POWER
DRAFT 04/76

100-017-90071 GENERAL PROVISIONS OF TEN MEGAWATTS ELECTRIC CENTRAL RECEIVER SOLAR PILOT PLANT(COOPRATIVE SOLAR, EXHIBITS) AGREEMENT
ENERGY R. & D. ADMIN. OF U.S.A.
DEPARTMENT OF WATER AND POWER
DRAFT 01/77

100-017-90073 DWP-PG&E ENABLING AGREEMENT FOR THE SALE AND EXCHANGE OF SURPLUS ENERGY
DEPARTMENT OF WATER AND POWER
PACIFIC GAS AND ELECTRIC COMPANY
DRAFT 01/77

100-017-90080 OPERATING AGREEMENT BETWEEN PACIFIC GAS & ELECTRIC COMPANY AND DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES
PACIFIC GAS AND ELECTRIC COMPANY
DEPARTMENT OF WATER AND POWER
DRAFT 07/77

100-017-90084 HEBER GEOTHERMAL DEMONSTRATION PLANT BETWEEN THE DEPARTMENT AND SAN DIEGO GAS AND ELECTRIC COMPANY
DEPARTMENT OF WATER AND POWER
SAN DIEGO GAS & ELECTRIC COMPANY
DRAFT 07/77

100-017-90130 ECONOMY ENERGY AGREEMENT WITH SAN DIEGO ELECTRIC COMPANY
DEPARTMENT OF WATER AND POWER
SAN DIEGO GAS & ELECTRIC COMPANY
DRAFT 06/79

100-017-90166 PENROSE STANITARY LANDFILL GAS PURCHASE & SALE AGREEMENT
DEPARTMENT OF WATER AND POWER
BY PRODUCT COMPANY
DRAFT 07/80

100-017-90176 PRELIMINARY DRAFT FORM OF ECONOMY ENERGY AGREEMENT
PACIFIC GAS AND ELECTRIC COMPANY
DRAFT

ACTIVE CONTRACT LIST BY CONTRACT NO.

100-017-90183	LOS ANGELES _ WSCC BROKER IDENTIFIED ENERGY AGREEMENT DEPARTMENT OF WATER AND POWER WESTERN SYSTEMS COORDINATING COUNCIL DRAFT	
100-017-90184	ECONOMY ENERGY AGREEMENT BETWEEN LOS ANGELES AND PACIFIC GAS & ELECTRIC COMPANY DEPARTMENT OF WATER AND POWER PACIFIC GAS AND ELECTRIC COMPANY DRAFT	
100-018-00000	THE CAPACITY EMERGENCY CURTILMENT PLAN OF THE CITY OF LOS ANGELES. APPROVED BY CITY COUNCIL OF LOS ANGELES - 10/79 DEPARTMENT OF WATER AND POWER DEPARTMENT OF WATER AND POWER UNTIL CAPACITY EMERGENCY LASTS	10/79
100-018-01267	HARBOR DEPARTMENT OF THE CITY OF LOS ANGELES AND DWP, AGREEMENT BETWEEN THE DEPARTMENT OF WATER AND POWER HARBOR DEPARTMENT OF THE CITY OF LOS ANGELES EVERGREEN	09/83
100-018-10044	STERN-ROGER ENGINEERING CORP. AGREEMENT DEPARTMENT OF WATER AND POWER STERN-ROGER ENGINEERING CORPORATION 30 DAYS' ADVANCE WRITTEN NOTICE	10/83
100-018-10045	AGREEMENT TO REDUCE FLOODING AND TO FORGO USE OF COLORADO RIVER WATER DEPARTMENT OF WATER AND POWER CALIFORNIA,DEPARTMENT OF WATER RESOURCES, THE STATE OF AUGUST 31, 1983 OR SEVEN (7) DAYS ADVANCE NOTICE	05/83
100-018-10147	ELECTRONIC CURRENT TRANSDUCER TEST PROGRAM DEPARTMENT OF WATER AND POWER ELECTRIC POWER RESEARCH INSTITUTE TWO YEARS AFTER INSTALLATION	05/78
100-018-10154	AGREEMENT FOR THE PURCHASE, SALE AND DELIVERY OF NATURAL GAS FUEL FOR ELECTRIC GENERATION UNDER SCHEDULE NO. G-58 SOUTHERN CALIFORNIA GAS COMPANY SOUTHERN COUNTIES GAS COMPANY OF CALIFORNIA DEPARTMENT OF WATER AND POWER EVERGREEN	05/67

100-018-10180	FIRST AMENDMENT TO AGREEMENT NO. 10180 - NATIONAL ECONOMIC RESEARCH ASSOCIATES DEPARTMENT OF WATER AND POWER NATIONAL ECONOMIC RESEARCH ASSOCIATES DRAFT	07/79
100-018-10249	EXXON THERMAL DENOX PROCESS --- LETTER OF INTENT - HAYNES GENERATING STATION UNIT 4 DEPARTMENT OF WATER AND POWER EXXON RESEARCH AND ENGINEERING COMPANY END OF PROCESS	12/78
100-018-10266	GREG AVENUE POWER PLANT INTERCONNECTION AGREEMENT WITH METRPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA DEPARTMENT OF WATER AND POWER METROPOLITAN WATER DISTRICT TWO YEARS' WRITTEN NOTICE	07/79
100-018-10273	FEASIBILITY STUDY AGREEMENT FOR SAN GABREIL HYDROELECTRIC BETWEEN DEPARTMENT OF WATER & POWER AND COUNTY FLOOD CONTROL DISTRICT DEPARTMENT OF WATER AND POWER LOS ANGELES COUNTY FLOOD CONTROL DISTRICT UPON EXECUTION OF THE LEASE CONT. OR, MUTUAL AGREEMENT	05/79
100-018-10276	PRELIMINARY DESIGN FOR SEPULVEDA CANYON POWER PLANT INTERCONNECTION AGREEMENT DEPARTMENT OF WATER AND POWER METROPOLITAN WATER DISTRICT UNTIL A DEFINITIVE AGREEMENT IS SIGNED	04/79
100-018-10396	AGREEMENT WITH ELECTRIC POWER RESEARCH INSTITUTE LETTING EPRI INSTALL REVENUE METERING SYSTEM ON DC TRANSMISSION LINE DEPARTMENT OF WATER AND POWER ELECTRIC POWER RESEARCH INSTITUTE TWO YEARS AFTER INSTLATION	01/80
100-018-10410	SEPULVEDA CANYON POWER PLANT INTERCONNECTION AGREEMENT DEPARTMENT OF WATER AND POWER METROPOLITAN WATER DISTRICT BY 5 YEAR'S ADVANCED NOTICE	05/80
100-018-10473	LOS ANGELES-TEXACO COGENERATION INTERCONNECTION AGREEMENT DEPARTMENT OF WATER AND POWER TEXACO INCORPORATED 5 YEARS; 1 YEAR ADV. NOTICE THEREAFTER	

100-018-10474	LOS ANGELES _ RAND CORPORATION AGREEMENT DEPARTMENT OF WATER AND POWER RAND CORPORATION AUGUST 7, 1982	08/80
100-018-10487	(AMENDED BY AMENDMENT NO.2, 4/1/83) (AMENDED BY AMENDMENT NO.1, 7/27/81) SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY JOINT POWERS AGREEMENT ENABLING MUNICIPALITIES FROM SOUTHERN CALIF. & IMPERIAL IRRIGATION DISTRICT TO CREATE A SEPERATE PUBLIC ENTITY DEPARTMENT OF WATER AND POWER ANAHEIM,CITY OF AZUZA, CITY OF BANNING,CITY OF BURBANK, CITY OF COLTON,CITY OF SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY GLENDALE, CITY OF PASADENA, CITY OF RIVERSIDE, CITY OF IMPERIAL IRRIGATION DISTRICT JULY 17, 2030	07/80
100-018-10489	(SUPERCEDES CONTRACT NO.10288) CALIFORNIA COAL PROJECT LETTER AGREEMENT DEPARTMENT OF WATER AND POWER CALIFORNIA,DEPARTMENT OF WATER RESOURCES, THE STATE OF NEVADA POWER COMPANY ANAHEIM,CITY OF IMPERIAL IRRIGATION DISTRICT RIVERSIDE, CITY OF GLENDALE, CITY OF BURBANK, CITY OF PASADENA, CITY OF BANNING,CITY OF SOUTHERN CALIFORNIA EDISON CO. 30 DAY'S ADVANCED NOTICE	07/80
100-018-10544	USAGE OF VEHICLE WEIGHING SCALES AT VALLEY STEAM PLANT DEPARTMENT OF WATER AND POWER CALIFORNIA, STATE OF EVERGREEN	11/72
100-018-10560	(AMENDED BY AMENDMENT NO.2) LOS ANGELES _ BOOZ ALLEN & HAMILTON MANAGEMENT AND SYSTEM ENGINEERING CONSULTANT AGREEMENT DEPARTMENT OF WATER AND POWER BOOZ ALLEN & HAMILTON MANAGEMENT FEB. 11, 1982 (AMENDED TO BE EVERGREEN UNTIL TERM.BY NOTICE)	02/81

100-018-10606	AN AGREEMENT FOR USE OF ENERGY BROKER COMPUTER PROGRAMS BETWEEN LOS ANGELES AND FLORIDA ELECTRIC POWER COORDINATING GROUP INC. DEPARTMENT OF WATER AND POWER FLORIDA ELECTRIC POWER COORDINATING GROUP INC. BY 30 DAY'S ADVANCE NOTICE	07/81
100-018-10661	(SUPERCEDES DRAFT NO. 90171) TIME-MIRROR - LOS ANGELES COGENERATION AGREEMENT DEPARTMENT OF WATER AND POWER TIME MIRROR COMPANY BY TWO YEARS ADVANCED NOTICE	12/81
100-018-10680	SANTA FE _ LOS ANGELES OCCASIONAL AND EMERGENCY REINSTALLATION OF RAIL TRACK SERVICE AGREEMENT DEPARTMENT OF WATER AND POWER SANTA FE RAILWAY COMPANY CONTEGENT TO THE ORIGINAL AGREEMENT	04/82
100-018-22200	RESOLUTION FOR SURPLUS DIGESTER GAS DEVELOPMENT OF THE HYPERION TREATMENT PLANT DEPARTMENT OF WATER AND POWER DEPARTMENT OF PUBLIC WORKS OF THE CITY OF L.A. EVERGREEN	09/63
100-018-90139	WARNER VALLEY POWER PROJECT PLANNING AGREEMENT AND PARTICIPATION AGREEMENT NEVADA POWER COMPANY DEPARTMENT OF WATER AND POWER ST. GEORGE DRAFT	02/78
100-018-90140	DRAFT OF PROJECT PRINCIPLES FOR CALIFORNIA COAL PROJECT DEPARTMENT OF WATER AND POWER SOUTHERN CALIFORNIA EDISON CO. ANAHEIM,CITY OF BURBANK, CITY OF CALIFORNIA,DEPARTMENT OF WATER RESOURCES, THE STATE OF COLTON,CITY OF PASADENA, CITY OF GLENDALE, CITY OF IMPERIAL IRRIGATION DISTRICT NEVADA POWER COMPANY RIVERSIDE, CITY OF 30 DAYS' WRITTEN NOTICE	08/79
100-018-90153	GENERAL DRAFT FORM OF EMERGENCY SERVICE AGREEMENT DEPARTMENT OF WATER AND POWER DRAFT	10/79

100-018-90159	COMPOSITE WHITE PINE PROJECT AGREEMENT DEPARTMENT OF WATER AND POWER LINCOLN COUNTY POWER DISTRICT NO.9 MT. WHEELER POWER INC. OVERTON POWER DISTRICT NO. 5 SIERRA PACIFIC POWER COMPANY VALLEY ELECTRIC ASSOCIATION WELLS RUSAL ELECTRIC COMPANY ANAHEIM, CITY OF BURBANK, CITY OF GLENDALE, CITY OF PASADENA, CITY OF RIVERSIDE, CITY OF DRAFT	01/80
100-018-90164	TEXACO _ LOS ANGELES COGENERATION AGREEMENT DEPARTMENT OF WATER AND POWER TEXACO INCORPORATED DRAFT	05/80
100-018-90168	COMPETITIVE GEOTHERMAL RESOURCES LEASE BIDS-MONO-LONG VALLY KNOWN GEOTHERMAL RESOURCE AREA DEPARTMENT OF WATER AND POWER BUREAU OF LAND MANAGEMENT DRAFT	07/80
100-018-90174	LOS ANGLES _ COUNTY OLIVE VIEW COGENERATION& INTERCONNECTION AGREEMENT DEPARTMENT OF WATER AND POWER LOS ANGELES COUNTY DRAFT	02/81
100-018-90178	SAN GABRIEL POWER PROJECT AGREEMENT BETWEEN DEPARTMENT OF WATER &POWER AND CONTY FLOOD CONTROL DISTRICT DEPARTMENT OF WATER AND POWER LOS ANGELES COUNTY FLOOD CONTROL DISTRICT DRAFT	
100-018-90179	SAN GABRIEL DAM HYDROELECTRIC GENERRATION FEASIBILITY AGREEMENT BETWEEN DEPARTMENT OF WATER & POWER AND COUNTY FLOOD CONTROL DISTRICT DEPARTMENT OF WATER AND POWER LOS ANGELES COUNTY FLOOD CONTROL DISTRICT DRAFT	

100-018-90181	LOS ANGELES ECONOMY ENERGY DRAFT AGREEMENT DEPARTMENT OF WATER AND POWER DRAFT	
100-018-90186	CAL-MAT AND LOS ANGELES LANDFILL GAS PURCHASE AGREEMENT DEPARTMENT OF WATER AND POWER CAL-MET GAS COMPANY DRAFT	
100-018-90188	SMALL HYDRO DEVLOPMETNT INTERCONNECTION AND TRANSMISSION SERVICE MEMORANDUM OF AGREEMENT BETWEEN POWER SYSTEM AND WATER SYSTEM OF THE DEPARTMENT POWER SYSTEM OF THE DEPARTMENT WATER SYSTEM OF THE DEPARTMENT DRAFT	12/81
100-018-90189	WEST COAST BASIN POWER PROJECT AGREEMENT BETWEEN LA.COUNTY FLOOD CONTROL DISTRICT AND LA.-DEPARTMENT OF WATER-&-POWER LOS ANGELES COUNTY FLOOD CONTROL DISTRICT DEPARTMENT OF WATER AND POWER DRAFT	
100-018-90192	HARRY ALLEN PROJECT AGREEMENT DEPARTMENT OF WATER AND POWER ST. GEORGE NEVADA POWER COMPANY TURLOCK IRRIGATION DISTRICT MODESTO IRRIGATION DISTRICT DESERT GENERATION & TRANSMISSION COOPERATIVE NORTHERN CALIFORNIA POWER AGENCY VALLEY ELECTRIC ASSOCIATION LINCOLN COUNTY POWER DISTRICT NO.9 SACRAMENTO MUNICIPAL UTILITY DISTRICT SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY OVERTON POWER DISTRICT NO. 5 DRAFT	
100-018-90196	NGH PROTOTYPE SSR DAMPING DEVICE PARTICIPATION AGREEMENT DEPARTMENT OF WATER AND POWER ARIZONA PUBLIC SERVICE COMPANY SOUTHERN CALIFORNIA EDISON CO. WESTERN AREA POWER ADMINISTRATION TUCSON GAS & ELECTRIC COMPANY NEVADA POWER COMPANY SAN DIEGO GAS & ELECTRIC COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. DRAFT	

100-018-90200	FERC ELECTRIC TARIFF ORIGINAL VOLUME NO. 2 SIERRA PACIFIC POWER CO. SIERRA PACIFIC POWER COMPANY DRAFT	
100-020-10002	AGREEMENT TO WAIVER OF STATUTE OF LIMITATIONS DEFENSES BY ALL PARTIES TO THE ORIGINAL COAL SUPPLY AGREEMENT(DWP10264) UNIIL 2/1/77 PEABODY COAL COMPANY DEPARTMENT OF WATER AND POWER SOUTHERN CALIFORNIA EDISON CO. SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. NONT SPECIFIED	07/76
100-020-10006	MOHAVE PROJECT-INTRA-NEVADA-GAS-DIVERSION-AGREEMENT SOUTHERN CALIFORNIA EDISON CO. DEPARTMENT OF WATER AND POWER NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. SOUTHWEST GAS CORPORATION EVERGREEN	06/74
100-020-10007	MOHAVE PROJECT EMERGENCY-DIVERTED-GAS-TRANSPORTATION AND-FACILITIES-AGREEMENT SOUTHERN CALIFORNIA EDISON CO. DEPARTMENT OF WATER AND POWER SOUTHWEST GAS CORPORATION NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. EVERGREEN	11/69
100-020-10008	MOHAVE PROJECT EXCESS GAS SERVICE AGREEMENT SOUTHERN CALIFORNIA EDISON CO. DEPARTMENT OF WATER AND POWER NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. SOUTHWEST GAS CORPORATION EVERGREEN	11/69
100-020-10009M	MOHAVE PROJECT IGNITION AND INCIDENTAL GAS SERVICE AGREEMENT SOUTHERN CALIFORNIA EDISON CO. DEPARTMENT OF WATER AND POWER NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. SOUTHWEST GAS CORPORATION EVERGREEN	11/69

100-020-10010 AGREEMENT CONCERNING DIVERSION OF NATURAL GAS TO MOHAVE PARTICIPANTS FOR USE IN THE MOHAVE PLANT
SOUTHERN CALIFORNIA GAS COMPANY
SOUTHERN COUNTIES GAS COMPANY OF CALIFORNIA
PACIFIC LIGHTING SERVICE COMPANY
DEPARTMENT OF WATER AND POWER
EVERGREEN 11/69

100-020-10011 MOHAVE PROJECT-EMERGENCY-GAS-SUPPLY-AGREEMENT
SOUTHERN CALIFORNIA EDISON CO.
DEPARTMENT OF WATER AND POWER
NEVADA POWER COMPANY
SALT RIVER PROJECT-AGRICULTURAL-IMPROVEMENT-&-POWER DIST.
TRANSWESTERN PIPELINE COMPANY
SOUTHERN CALIFORNIA GAS COMPANY
SOUTHERN COUNTIES GAS COMPANY OF CALIFORNIA
PACIFIC LIGHTING-SERVICE-COMPANY
EVERGREEN 11/69

100-020-10042 MOHAVE PROJECT OPERATING AGREEMENT AMONG THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT SOUTHERN CALIFORNIA EDISON COMPANY
DEPARTMENT OF WATER AND POWER
NEVADA POWER COMPANY
SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST.
SOUTHERN CALIFORNIA EDISON CO.
JULY 1,2006 05/69

100-020-10074 MOHAVE PROJECT COAL WEIGHING , SAMPLING AND ANALYSIS FACILITIES AGREEMENT
SOUTHERN CALIFORNIA EDISON CO.
DEPARTMENT OF WATER AND POWER
NEVADA POWER COMPANY
SALT RIVER PROJECT AGRICULTURAL-IMPROVEMENT & POWER DIST.
PEABODY COAL COMPANY
2025 01/67

100-020-10075M MOHAVE PROJECT-COAL SUPPLY AGREEMENT-INTERPRETIVE-SUPPLEMENT NO.1
SOUTHERN CALIFORNIA EDISON CO.
DEPARTMENT OF WATER AND POWER
NEVADA POWER COMPANY
SALT RIVER PROJECT AGRICULTURAL-IMPROVEMENT & POWER DIST.
PEABODY COAL COMPANY
2025 01/67

100-020-10076M	MOHAVE PROJECT COAL SUPPLY AGREEMENT INTERPRETIVE SUPPLEMENT NO.2 SOUTHERN CALIFORNIA EDISON CO. DEPARTMENT OF WATER AND POWER NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. PEABODY COAL COMPANY 2025	01/67
100-020-10085	MOHAVE ELDORADO COMMUNICATION FACILITIES AGREEMENT AMONG THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES , NEVADA POWER COMPANY , SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT, SOUTHERN CALIFORNIA EDISON COMPANY DEPARTMENT OF WATER AND POWER NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. SOUTHERN CALIFORNIA EDISON CO. JULY 1,2006	01/67
100-020-10210	MOHAVE PROJECT PRELIMINARY AGREEMENT ASSIGNMENT BETWEEN DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES , SOUTHERN CALIFORNIA EDISON SOUTHERN CALIFORNIA EDISON CO. DEPARTMENT OF WATER AND POWER EVERGREEN	12/66
100-020-10211	PLANT SITE CONVEYANCE-2 AND THE MOHAVE PROJECT PLANT SITE CONVEYANCE AND CO-TENANCY AGREEMENT ASSIGNMENT BETWEEN DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES AND SOUTHERN CALIFORNIA EDISON COMPANY SOUTHERN CALIFORNIA EDISON CO. DEPARTMENT OF WATER AND POWER JULY 1,2006	12/68
100-020-10212	MOHAVE PROJECT CONSTRUCTION AGREEMENT ASSIGNMENT BETWEEN THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES , SOUTHERN CALIFORNIA EDISON COMPANY SOUTHERN CALIFORNIA EDISON CO. DEPARTMENT OF WATER AND POWER 120 DAYS AFTER COMPLETION NOTICE	12/68
100-020-10213	ELDORADO SYSTEM CONVEYANCE 2 AND THE ELDORADO SYSTEM CONVEYANCE AND CO-TENANCY AGREEMENT ASSIGNMENT BETWEEN DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES AND SOUTHERN CALIFORNIA EDISON COMPANY SOUTHERN CALIFORNIA EDISON CO. DEPARTMENT OF WATER AND POWER JULY 1,2006	06/67

100-020-10214	ELDORADO SYSTEM CONSTRUCTION AGREEMENT ASSIGNMENT BETWEEN DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES AND SOUTHERN CALIFORNIA EDISON COMPANY SOUTHERN CALIFORNIA EDISON CO. DEPARTMENT OF WATER AND POWER EVERGREEN	12/68
100-020-10263	WATER USER CONTRACT ASSIGNMENT 2 BETWEEN DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES AND SOUTHERN CALIFORNIA EDISON COMPANY SOUTHERN CALIFORNIA EDISON CO. DEPARTMENT OF WATER AND POWER JULY 1,2006	12/68
100-020-10264	MOHAVE PROJECT COAL SUPPLY AGREEMENT ASSIGNMENT 2 BETWEEN DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES AND SOUTHERN CALIFORNIA EDISON COMPANY DEPARTMENT OF WATER AND POWER SOUTHERN CALIFORNIA EDISON CO. 2005	12/68
100-020-10270	MOHAVE PROJECT CONSTRUCTION AGREEMENT SUBCONTRACTS ASSIGNMENT BETWEEN DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES AND SOUTHERN CALIFORNIA EDISON COMPANY SOUTHERN CALIFORNIA EDISON CO. DEPARTMENT OF WATER AND POWER 120 DAYS AFTER COMPLETION	12/68
100-020-10271	MOHAVE PROJECT AND ELDORADO SYSTEM INDEMNITY AGREEMENT BY DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES DEPARTMENT OF WATER AND POWER 2025	12/68
100-020-10283	MOHAVE GENERAL ASSIGNMENT AGREEMENT SOUTHERN CALIFORNIA EDISON CO. DEPARTMENT OF WATER AND POWER JULY 1,2006	12/68
100-020-10318	MOHAVE PROJECT - PERMANENT WATER INTAKE FACILITIES AGREEMENT RIGHTS-OF-WAY FOR ACCESS ROAD AND ELECTRIC COMMUNICATION CONDUITS COLORADO RIVER COMMISSION OF NEVADA RIO ALTO VISTA PROPERTIES DEPARTMENT OF WATER AND POWER NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. SOUTHERN CALIFORNIA EDISON CO. JULY 1,2006	04/69

100-020-10403 FOUR CORNERS PROJECT AND MOHAVE PROJECT SPARE PARTS AGREEMENT AMONG ARIZONA PUBLIC SERVICE COMPANY , DEPARTMENT OF WATER AND POWER OF THE LOS ANGELES , EL PASO ELECTRIC COMPANY , NEVADA POWER COMPANY , PUBLIC SERVICE COMPANY OF NEW MEXICO , SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT , TUSCON GAS & ELECTRIC COMPANY , AND SOUTHERN CALIFORNIA EDISON COMPANY
ARIZONA PUBLIC SERVICE COMPANY
DEPARTMENT OF WATER AND POWER
EL PASO ELECTRIC COMPANY
NEVADA POWER COMPANY
PUBLIC SERVICE COMPANY OF NEW MEXICO
SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST.
TUCSON GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA EDISON CO.
EVERGREEN 04/71

100-020-10514 AGREEMENT BETWEEN MOHAVE PARTICIPANTS AND ASIC (A WHOLLY-OWNED SUBSIDIARY OF EDISON) FOR THE REMOVAL OF FLY-ASH FROM THE MOHAVE PLANT SITE
DEPARTMENT OF WATER AND POWER
NEVADA POWER COMPANY
SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST.
SOUTHERN CALIFORNIA EDISON CO.
ASSOCIATED SOUTHERN INVESTMENT COMPANY
EVERGREEN 07/72

100-020-10535 ELDORADO SYSTEM OPERATING AGREEMENT BETWEEN DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES , NEVADA POWER COMPANY , SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT , AND SOUTHERN CALIFORNIA EDISON COMPANY
NEVADA POWER COMPANY
SOUTHERN CALIFORNIA EDISON CO.
DEPARTMENT OF WATER AND POWER
SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST.
JULY 1,2006 12/69

100-020-10781 NEVADA GAS DIVERSION LETTER OF UNDERSTANDING
DEPARTMENT OF WATER AND POWER
SOUTHERN CALIFORNIA EDISON CO.
NEVADA POWER COMPANY
SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST.
EVERGREEN 06/74

100-020-10964 AMENDED COAL SLURRY PIPELINE AGREEMENT BETWEEN PEABODY COAL COMPANY AND BLACK MESA PIPELINE,INC.
PEABODY COAL COMPANY
BLACK MESA PIPELINE, INC.
DECEMBER 31, 2005 05/76

100-020-10966 AMENDED MOHAVE PROJECT COAL SUPPLY AGREEMENT BETWEEN PEABODY COAL COMPANY AND SOUTHERN CALIFORNIA EDISON COMPANY, DEPARTMENT OF WATER & POWER OF THE CITY OF LOS ANGELES, NEVADA POWER COMPANY AND SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT
PEABODY COAL COMPANY
SOUTHERN CALIFORNIA EDISON CO.
DEPARTMENT OF WATER AND POWER
NEVADA POWER COMPANY
SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST.
DECEMBER 31, 2005 05/76

100-020-90028 FOUR CORNERS PROJECT CROSS TRIPPING AGREEMENT BETWEEN ARIZONA PUBLIC SERVICE COMPANY , EL PASO ELECTRIC COMPANY , DEPARTMENT OF WATER AND POWER CITY OF LOS ANGELES , NEVADA POWER COMPANY , PUBLIC SERVICE COMPANY OF NEW MEXICO , SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT , SOUTHERN CALIFORNIA EDISON COMPANY AND TUSCON GAS & ELECTRIC COMPANY
ARIZONA PUBLIC SERVICE COMPANY
EL PASO ELECTRIC COMPANY
DEPARTMENT OF WATER AND POWER
NEVADA POWER COMPANY
PUBLIC SERVICE COMPANY OF NEW MEXICO
SOUTHERN CALIFORNIA EDISON CO.
SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST.
TUCSON GAS & ELECTRIC COMPANY
DRAFT 07/71

100-030-10018 AMENDED NAVAJO STATION COAL SUPPLY AGREEMENT
ARIZONA PUBLIC SERVICE COMPANY
DEPARTMENT OF WATER AND POWER
NEVADA POWER COMPANY
SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST.
UNITED STATES OF AMERICA, THE
PEABODY COAL COMPANY
TUCSON GAS & ELECTRIC COMPANY
APRIL 30, 2011 02/77

100-030-10023N WATER SERVICE CONTRACT ASSIGNMENT - NAVAJO PROJECT
ARIZONA PUBLIC SERVICE COMPANY
DEPARTMENT OF WATER AND POWER
NEVADA POWER COMPANY
SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST.
DECEMBER 31, 2016 06/70

100-030-10062 SEE AGREEMENT (DWP 10335) MEMORANDUM OF AGREEMENT PROVIDING FOR EXECUTION ON NAVAJO STATION COAL SUPPLY AGREEMENT

100-030-10077N MEMORANDUM FOR RECORDATION OF NAVAJO STATION COAL SUPPLY AGREEMENT AND IMPOSITION OF EQUITABLE SERVITUDE AND CONVENANT RUNNING WITH THE LAND
PEABODY COAL COMPANY
ARIZONA PUBLIC SERVICE COMPANY
DEPARTMENT OF WATER AND POWER
NEVADA POWER COMPANY
SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST.
TUCSON GAS & ELECTRIC COMPANY
2016 12/70

100-030-10078N MULTI - PARTY AGREEMENT - NAVAJO PROJECT
ARIZONA PUBLIC SERVICE COMPANY
DEPARTMENT OF WATER AND POWER
NEVADA POWER COMPANY
SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST.
TUCSON GAS & ELECTRIC COMPANY
PEABODY COAL COMPANY
GREEN RIVER COAL COMPANY
ST. LOUIS UNION TRUST COMPANY
MORGAN GUARANTY COMPANY OF NEW YORK
EVERGREEN 12/70

100-030-10123 NAVAJO GENERATING STATION OPERATING AGREEMENT
UNITED STATES OF AMERICA, THE
ARIZONA PUBLIC SERVICE COMPANY
DEPARTMENT OF WATER AND POWER
NEVADA POWER COMPANY
SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST.
TUCSON GAS & ELECTRIC COMPANY
DRAFT 08/72

100-030-10124 (AMENDED BY AMENDMENT NO.1 ,2-9-82) NAVAJO PROJECT SOUTHERN TRANSMISSION OPERATING AGREEMENT BETWEEN THE UNITED STATES OF AMERICA, ARIZONA PUBLIC SERVICE COMPANY, DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES, NEVADA POWER COMPANY, SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT, TUCSON GAS AND ELECTRIC COMPANY
UNITED STATES OF AMERICA, THE
ARIZONA PUBLIC SERVICE COMPANY
DEPARTMENT OF WATER AND POWER
NEVADA POWER COMPANY
SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST.
TUCSON GAS & ELECTRIC COMPANY
DRAFT 09/73

100-030-10125	NAVAJO PROJECT WESTERN TRANSMISSION SYSTEM OPERATING AGREEMENT BETWEEN THE UNITED STATES OF AMERICA, ARIZONA PUBLIC SERVICE COMPANY, THE CITY OF LOS ANGELES DEPARTMENT OF WATER AND POWER, NEVADA POWER COMPANY, SALT RIVER PROJECT, TUCSON GAS & ELECTRIC COMPANY UNITED STATES OF AMERICA, THE DEPARTMENT OF WATER AND POWER NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. TUCSON GAS & ELECTRIC COMPANY DRAFT	01/73
100-030-10267	WESTWING SWITCHYARD INTERCONNECTION AGREEMENT UNITED STATES OF AMERICA, THE ARIZONA PUBLIC SERVICE COMPANY DEPARTMENT OF WATER AND POWER EL PASO ELECTRIC COMPANY NEVADA POWER COMPANY PUBLIC SERVICE COMPANY OF NEW MEXICO SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. TUCSON GAS & ELECTRIC COMPANY TERMINATION OF NAVAJO CO-TENANCY OR ARZ. NUCLEAR TRANS. PART.AGR.	05/79
100-030-10334	NAVAJO PROJECT PARTICIPATION AGREEMENT BETWEEN THE UNITED STATES OF AMERICA , ARIZONA PUBLIC SERVICE COMPANY , DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES , NEVADA POWER COMPANY , SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT , AND TUCSON GAS & ELECTRIC COMPANY ARIZONA PUBLIC SERVICE COMPANY UNITED STATES OF AMERICA, THE DEPARTMENT OF WATER AND POWER NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. TUCSON GAS & ELECTRIC COMPANY 2019	11/69
100-030-10335	MEMORANDUM OF AGREEMENT PROVIDING FOR EXECUTION OF NAVAJO STATION COAL SUPPLY AGREEMENT PEABODY COAL COMPANY ARIZONA PUBLIC SERVICE COMPANY DEPARTMENT OF WATER AND POWER NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. TUCSON GAS & ELECTRIC COMPANY EVERGREEN	09/69

100-030-10336	LETTER AGREEMENT TO THE NAVAJO STATION COAL SUPPLY AGREEMENT PEABODY COAL COMPANY ARIZONA PUBLIC SERVICE COMPANY NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. DEPARTMENT OF WATER AND POWER TUCSON GAS & ELECTRIC COMPANY EVERGREEN	09/69
100-030-10337	APPLICATION FOR FEDERAL RIGHTS-OF-WAY AND EASEMENTS ARIZONA PUBLIC SERVICE COMPANY NEVADA POWER COMPANY DEPARTMENT OF WATER AND POWER SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. TUCSON GAS & ELECTRIC COMPANY 2014	11/69
100-030-10338	APPLICATION AND GRANT OF RIGHTS-OF-WAY AND EASEMENTS- NAVAJO PROJECT SECRETARY OF THE INTERIOR ARIZONA PUBLIC SERVICE COMPANY DEPARTMENT OF WATER AND POWER NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. TUCSON GAS & ELECTRIC COMPANY 2014	11/69
100-030-10339	NAVAJO PROJECT POWER COORDINATION AGREEMENT UNITED STATES OF AMERICA, THE ARIZONA PUBLIC SERVICE COMPANY DEPARTMENT OF WATER AND POWER SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. TUCSON GAS & ELECTRIC COMPANY DECEMBER 31, 2026	11/69
100-030-10340	NAVAJO PROJECT - INTERIM ARRANGEMENT FOR INTERCONNECTED OPERATIONS UNITED STATES OF AMERICA, THE ARIZONA PUBLIC SERVICE COMPANY DEPARTMENT OF WATER AND POWER NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. SOUTHERN CALIFORNIA EDISON CO. TUCSON GAS & ELECTRIC COMPANY EVERGREEN	11/69

100-030-10341	CONTRACT WITH DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES FOR INTERIM SALE OF UNITED STATES ENTITLEMENT OF NAVAJO PROJECT UNITED STATES OF AMERICA, THE DEPARTMENT OF WATER AND POWER JULY 1, 1985	
100-030-10342	MEMORANDUM TRANSMISSION AGREEMENT BETWEEN PARTICIPANTS IN THE NAVAJO PROJECT AND SOUTHERN CALIFORNIA EDISON COMPANY UNITED STATES OF AMERICA, THE ARIZONA PUBLIC SERVICE COMPANY DEPARTMENT OF WATER AND POWER NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. TUCSON GAS & ELECTRIC COMPANY SOUTHERN CALIFORNIA EDISON CO. EVERGREEN	09/69
100-030-10344	NAVAJO PROJECT INDENTURE OF LEASE NAVAJO UNITS 1, 2 AND 3 NAVAJO TRIBE OF INDIANS, THE ARIZONA PUBLIC SERVICE COMPANY DEPARTMENT OF WATER AND POWER NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. 2021	12/69
100-030-10350	LETTER AGREEMENT FOR LIABILITIES ON NAVAJO PROJECT MEMORANDUM TRANSMISSION AGREEMENT SOUTHERN CALIFORNIA EDISON CO. ARIZONA PUBLIC SERVICE COMPANY DEPARTMENT OF WATER AND POWER NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. TUCSON GAS & ELECTRIC COMPANY SEPTEMBER 30,2019	11/69
100-030-10384	GRANT OF FEDERAL RIGHTS-OF-WAY AND EASEMENTS SECRETARY OF THE INTERIOR ARIZONA PUBLIC SERVICE COMPANY DEPARTMENT OF WATER AND POWER NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. TUCSON GAS & ELECTRIC COMPANY EVERGREEN	11/69

100-030-10385	APPLICATION FOR FEDERAL RIGHTS-OF-WAY AND EASEMENTS ARIZONA PUBLIC SERVICE COMPANY DEPARTMENT OF WATER AND POWER NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. TUCSON GAS & ELECTRIC COMPANY EVERGREEN	09/70
100-030-10433	MEMORANDUM FOR RECORDATION OF EFFECTIVE DATE OF GRANT OF FEDERAL RIGHTS-OF-WAY AND EASEMENTS UNITED STATES OF AMERICA, THE ARIZONA PUBLIC SERVICE COMPANY DEPARTMENT OF WATER AND POWER NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. TUCSON GAS & ELECTRIC COMPANY EVERGREEN	06/71
100-030-10498	NAVAJO PROJECT CO-TENANCY AGREEMENT BETWEEN ARIZONA PUBLIC SERVICE COMPANY, DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES, NEVADA POWER COMPANY, SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT, TUCSON GAS AND ELECTRIC COMPANY, AND THE UNITED STATES OF AMERICA ARIZONA PUBLIC SERVICE COMPANY DEPARTMENT OF WATER AND POWER NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. TUCSON GAS & ELECTRIC COMPANY UNITED STATES OF AMERICA, THE COTERMINOUS WITH INDENTURE OF LEASE	04/76
100-030-10498S	SUPPLEMENT # 1 TO NAVAJO PROJECT CO-TENANCY AGREEMENT BETWEEN ARIZONA PUBLIC SERVICE COMPANY, DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES, NEVADA POWER COMPANY, SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT, TUCSON GAS AND ELECTRIC COMPANY, AND THE UNITED STATES OF AMERICA ARIZONA PUBLIC SERVICE COMPANY DEPARTMENT OF WATER AND POWER NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. TUCSON GAS & ELECTRIC COMPANY UNITED STATES OF AMERICA, THE COTERMINOUS WITH INDENTURE OF LEASE	04/76

100-030-10499	NAVAJO GENERATING STATION CONSTRUCTION AGREEMENT UNITED STATES OF AMERICA, THE ARIZONA PUBLIC SERVICE COMPANY DEPARTMENT OF WATER AND POWER NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. TUCSON GAS & ELECTRIC COMPANY 120 DAYS AFTER FINAL COMPLETION REPORT OR BINDING ARBITRATION	04/76
100-030-10500	NAVAJO PROJECT WESTERN TRANSMISSION SYSTEM CONSTRUCTION AGREEMENT ARIZONA PUBLIC SERVICE COMPANY DEPARTMENT OF WATER AND POWER NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. TUCSON GAS & ELECTRIC COMPANY UNITED STATES OF AMERICA, THE 120 DAYS AFTER FINAL COMPLETION REPORT OR BINDING ARBITRATION	04/76
100-030-10501	NAVAJO PROJECT SOUTHERN TRANSMISSION SYSTEM CONSTRUCTION AGREEMENT ARIZONA PUBLIC SERVICE COMPANY DEPARTMENT OF WATER AND POWER NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. TUCSON GAS & ELECTRIC COMPANY UNITED STATES OF AMERICA, THE 120 DAYS AFTER FINAL COMPLETION REPORT OR BINDING ARBITRATION	04/76
100-030-10502	EDISON-NAVAJO TRANSMISSION AGREEMENT BETWEEN PARTICIPANTS IN THE NAVAJO PROJECT AND SOUTHERN CALIFORNIA EDISON COMPANY ARIZONA PUBLIC SERVICE COMPANY DEPARTMENT OF WATER AND POWER NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. TUCSON GAS & ELECTRIC COMPANY UNITED STATES OF AMERICA, THE SOUTHERN CALIFORNIA EDISON CO. 2023	04/73
100-030-10624	SULFUR DIOXIDE REMOVAL TEST MODULES PROJECT AGREEMENT BETWEEN THE MOHAVE PROJECT AND THE NAVAJO PROJECT FOR A JOINT DEVELOPMENT OF THE SULFUR REMAVAL SOUTHERN CALIFORNIA EDISON CO. DEPARTMENT OF WATER AND POWER SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. NEVADA POWER COMPANY ARIZONA PUBLIC SERVICE COMPANY TUCSON GAS & ELECTRIC COMPANY UNITED STATES OF AMERICA, THE JANUARY 1, 1976 (EXTENDABLE)	04/73

100-030-10662 (AMENDED BY AMENDMENT NO.1, ON JANUARY 1979) NAVAJO PROJECT PACIFIC NORTHWEST PACIFIC SOUTHWEST INTERTIE PROJECT: CONTRACT FOR INSTALLATION, OPERATION, MAINTENANCE AND REPLACEMENT OF A PHASE SHIFTING TRANSFORMER AT LIBERTY SUBSTATION BETWEEN THE UNITED STATES OF AMERICA, ARIZONA PUBLIC SERVICE COMPANY, DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES, NEVADA POWER COMPANY, SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT, TUCSON GAS & ELECTRIC COMPANY

UNITED STATES OF AMERICA, THE
ARIZONA PUBLIC SERVICE COMPANY
DEPARTMENT OF WATER AND POWER
NEVADA POWER COMPANY
SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST.
2019 02/74

100-030-10759 RED MOUNTAIN RELAY STATION LICENSE AGREEMENT BETWEEN DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES, SOUTHERN CALIFORNIA EDISON COMPANY, AND NEVADA POWER COMPANY

DEPARTMENT OF WATER AND POWER
SOUTHERN CALIFORNIA EDISON CO.
NEVADA POWER COMPANY
JULY 1,2006 04/74

100-030-80077 SETTLEMENT AGREEMENT AND MUTUAL RELEASE "APS VS. PEABODY COAL CO." BREACHED CONTRACT BY FAILING TO DELIVER COAL IN THE AMOUNT REQUIRED

DEPARTMENT OF WATER AND POWER
ARIZONA PUBLIC SERVICE COMPANY
NEVADA POWER COMPANY
TUCSON GAS & ELECTRIC COMPANY
PEABODY COAL COMPANY
KENNECOTT CORPORATION
003/84

100-030-90031 CONTRACT WITH THE NAVAJO PARTICIPANTS FOR INTERMITTENT TRANSMISSION OF EMERGENCY AUXILIARY POWER FOR THE NAVAJO GENERATING STATION

UNITED STATES OF AMERICA, THE
ARIZONA PUBLIC SERVICE COMPANY
DEPARTMENT OF WATER AND POWER
NEVADA POWER COMPANY
SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST.
TUCSON GAS & ELECTRIC COMPANY
DRAFT 01/72

100-030-90034	NAVAJO PROJECT WESTERN TRANSMISSION SYSTEM, MCCULLOUGH SUBSTATION OPERATING AGREEMENT ARIZONA PUBLIC SERVICE COMPANY DEPARTMENT OF WATER AND POWER NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. TUCSON GAS & ELECTRIC COMPANY UNITED STATES OF AMERICA, THE DRAFT	04/73
100-030-90042	AGREEMENT FOR SALE OF POWER AND ENERGY BETWEEN THE DEPARTMENT OF WATER AND POWER OF THE CITY OF LOS ANGELES AND TUCSON GAS & ELECTRIC COMPANY (NAVAJO LAYOFF) TUCSON GAS & ELECTRIC COMPANY DEPARTMENT OF WATER AND POWER DRAFT	10/75
100-030-90048	FOUR CORNERS - MOHAVE - NAVAJO TRANSMISSION STUDY PROGRAM AGREEMENT ARIZONA PUBLIC SERVICE COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. SOUTHERN CALIFORNIA EDISON CO. 30 DAYS AFTER LAST OF REPORT SUBMISSION OR ALL PAYMENT	08/77
100-030-90172	NEVADA _ LOS ANGELES INTERCONNECTION AGREEMENT DEPARTMENT OF WATER AND POWER NEVADA POWER COMPANY DRAFT	11/80
100-035-10627	PALO VERDE NUCLEAR GENERATING STATION POWER SALE AGREEMENT BETWEEN SO. CALIFORNIA PUBLIC POWER AUTHORITY AND THE DEPARTMENT OF WATER & POWER OF THE CITY OF LOS ANGELES SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY DEPARTMENT OF WATER AND POWER OCTOBER 31, 2030	08/81
100-035-10628	PALO VERDE NUCLEAR GENERATING STATION - AGENCY AGREEMENT BETWEEN SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY AND DEPARTMENT OF WATER AND POWER OF CITY OF LOS ANGELES SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY DEPARTMENT OF WATER AND POWER PROJECT NOT FEASIBLE OR INTEREST OF AUTHORITY TERMINATED	08/81
100-035-10630	PALO VERDE NUCLEAR GENERATING STATION - AGENCY AGREEMENT BETWEEN CITY OF AZUSA AND THE DEPARTMENT OF WATER AND POWER OF CITY OF LOS ANGELES AZUZA, CITY OF DEPARTMENT OF WATER AND POWER TERMINATION OF PURCHASER'S PWR SALES CONTR OR BY MUTUAL AGREEMENT	12/81

100-035-10632	PALO VERDE NUCLEAR GENERATING STATION - AGENCY AGREEMENT BETWEEN CITY OF BURBANK AND THE DEPARTMENT OF WATER AND POWER OF CITY OF LOS ANGELES BURBANK, CITY OF DEPARTMENT OF WATER AND POWER TERMINATION OF PURCHASER'S PWR SALES CONTR OR BY MUTUAL AGREEMENT	12/81
100-035-10633	PALO VERDE NUCLEAR GENERATING STATION - AGENCY AGREEMENT BETWEEN CITY OF COLTON AND THE DEPARTMENT OF WATER AND POWER OF CITY OF LOS ANGELES COLTON,CITY OF DEPARTMENT OF WATER AND POWER TERMINATION OF PURCHASER'S PWR SALES CONTR OR BY MUTUAL AGREEMENT	12/81
100-035-10634	PALO VERDE NUCLEAR GENERATING STATION - AGENCY AGREEMENT BETWEEN CITY OF GLENDALE AND THE DEPARTMENT OF WATER AND POWER OF CITY OF LOS ANGELES GLENDALE, CITY OF DEPARTMENT OF WATER AND POWER TERMINATION OF PURCHASER'S PWR SALES CONTR OR BY MUTUAL AGREEMENT	12/81
100-035-10636	PALO VERDE NUCLEAR GENERATING STATION - AGENCY AGREEMENT BETWEEN CITY OF PASADENA AND THE DEPARTMENT OF WATER AND POWER OF CITY OF LOS ANGELES PASADENA, CITY OF DEPARTMENT OF WATER AND POWER TERMINATION OF PURCHASER'S PWR SALES CONTR OR BY MUTUAL AGREEMENT	12/81
100-035-10637	PALO VERDE NUCLEAR GENERATING STATION - AGENCY AGREEMENT BETWEEN CITY OF RIVERSIDE AND THE DEPARTMENT OF WATER AND POWER OF CITY OF LOS ANGELES RIVERSIDE, CITY OF DEPARTMENT OF WATER AND POWER TERMINATION OF PURCHASER'S PWR SALES CONTR OR BY MUTUAL AGREEMENT	12/81
100-035-10638	PALO VERDE NUCLEAR GENERATING STATION - AGENCY AGREEMENT BETWEEN CITY OF VERNON AND THE DEPARTMENT OF WATER AND POWER OF CITY OF LOS ANGELES VERNON, CITY OF DEPARTMENT OF WATER AND POWER TERMINATION OF PURCHASER'S PWR SALES CONTR OR BY MUTUAL AGREEMENT	12/81

100-035-90126	PALO VERDE COMMON FACILITIES AGREEMENT ARIZONA PUBLIC SERVICE COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. NEW MEXICO,PUBLIC SERVICE COMPANY OF EL PASO ELECTRIC COMPANY SOUTHERN CALIFORNIA EDISON CO. SAN DIEGO GAS & ELECTRIC COMPANY NEVADA POWER COMPANY DEPARTMENT OF WATER AND POWER PASADENA, CITY OF ANAHEIM,CITY OF BURBANK, CITY OF GLENDALE, CITY OF RIVERSIDE, CITY OF DRAFT	05/79
100-036-80071	ARIZONA NUCLEAR POWER PROJECT PARTICIPATION AGREEMENT (NON-DWP AGREEMENT) ARIZONA PUBLIC SERVICE COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. TUCSON GAS & ELECTRIC COMPANY PUBLIC SERVICE COMPANY OF NEW MEXICO EL PASO ELECTRIC COMPANY 09/01/2024	09/73
100-036-80076	PALO VERDE NUCLEAR GENERATING STATION ASSIGNMENT AGREEMENT (NON-DWP AGREEMENT) ARIZONA PUBLIC SERVICE COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. TUCSON GAS & ELECTRIC COMPANY PUBLIC SERVICE COMPANY OF NEW MEXICO EL PASO ELECTRIC COMPANY EVERGREEN	08/81
100-040-10004	CITY-NEVADA GENERATING CHARGES COLORADO RIVER COMMISSION OF NEVADA DEPARTMENT OF WATER AND POWER MAY 31,1987	01/70
100-040-10009C	CONTRACT FOR PURCHASE OF ENERGY FROM THE CITY OF LOS ANGELES , CALIFORNIA UNITED STATES OF AMERICA, THE DEPARTMENT OF WATER AND POWER MAY 31,1987	12/64
100-040-10204	UNITED STATES DEPARTMENT OF THE INTERIOR BUREAU OF RECLAMATION PACIFIC NORTHWEST-PACIFIC SOUTHWEST INTERTIE PROJECT CONTRACT FOR INTERCONNECTION AT MEAD SUBSTATION WITH THE CITY OF LOS ANGELES AND ITS DEPARTMENT OF WATER AND POWER BUREAU OF RECLAMATION DEPARTMENT OF WATER AND POWER MAY 31,1987	11/67

100-040-10429 UNITED STATES DEPARTMENT OF THE INTERIOR BUREAU OF RECLAMATION REGION 3
CONTRACT BOULDER CANYON PROJECT AMENDMENT NO.2 TO LEASE OF TELEPHONE LINE
CONTRACT NO. I334-1940
BUREAU OF RECLAMATION
DEPARTMENT OF WATER AND POWER
EVERGREEN 07/71

100-040-10731 CONTRACT FOR THE MODIFICATION OF CERTAIN FACILITIES OF THE DEPARTMENT OF WATER
AND POWER OF THE CITY OF LOS ANGELES, CENTRAL ARIZONA PROJECT GRANITE REEF
AQUEDUCT TRANSMISSION SYSTEM, MCCULLOUGH-DAVIS 230-KV TRANSMISSION LINE
DEPARTMENT OF WATER AND POWER
UNITED STATES OF AMERICA, THE
COTERMINOUS WITH AGREEMENT (DWP-10594)

100-040-10746 BOULDER CANYON - PARKER DAVIS PROJECTS ARIZONA - CALIFORNIA -NEVADA CONTRACT
FOR SALE AND INTERCHANGE OF ENERGY
UNITED STATES OF AMERICA, THE
DEPARTMENT OF WATER AND POWER
SOUTHERN CALIFORNIA EDISON CO.
CALIFORNIA ELECTRIC POWER COMPANY
MAY 31 , 1987 03/58

100-040-10829 BOULDER CANYON PROJECT CONTRACT FOR RESALE OF ELECTRIC ENERGY AT HOOVER DAM
POWER PLANT
UNITED STATES OF AMERICA, THE
DEPARTMENT OF WATER AND POWER
SOUTHERN CALIFORNIA EDISON CO.
METROPOLITAN WATER DISTRICT
MAY 31 , 1987 06/58

100-040-10830 CONTRACT FOR THE PURPOSE OF IMPLEMENTING THE SETTLEMENT MADE BY THE UNITED
STATES WITH CITIZENS UTILITIES COMPANY AND CALIFORNIA-PACIFIC UTILITIES
COMPANY (REPLACEMENT ENERGY CONTRACT)
DEPARTMENT OF WATER AND POWER
METROPOLITAN WATER DISTRICT
SOUTHERN CALIFORNIA EDISON CO.
CALIFORNIA ELECTRIC POWER COMPANY
NO TERMINATION DATE SPECIFIED 06/60

100-040-40002 THE HOOVER DAM POWER AND WATER CONTRACTS AND RELATED DATA (TAN BOOK) BOULDER
CANYON PROJECT ARIZONA - CALIFORNIA - NEVADA CONTRACT FOR THE SALE OF ELECTRIC
ENERGY
UNITED STATES OF AMERICA, THE
DEPARTMENT OF WATER AND POWER
DECEMBER 31 , 1987 05/41

100-040-40003	BOULDER CANYON PROJECT FINAL REPORTS PART I - INTRODUCTORY HOOVER DAM POWER AND WATER CONTRACTS (BLUE BOOK)	
100-050-10815	SAN JOAQUIN NUCLEAR PROJECT PARTICIPATION AGREEMENT DEPARTMENT OF WATER AND POWER SOUTHERN CALIFORNIA EDISON CO. PACIFIC GAS AND ELECTRIC COMPANY CALIFORNIA,DEPARTMENT OF WATER RESOURCES, THE STATE OF ANAHEIM,CITY OF GLENDALE, CITY OF PASADENA, CITY OF RIVERSIDE, CITY OF NORTHERN CALIFORNIA POWER AGENCY DRAFT	11/77
100-060-10000	INTERMOUNTAIN POWER PROJECT---LAY-OFF POWER PURCHASE CONTRACT DEPARTMENT OF WATER AND POWER UTAH POWER & LIGHT COMPANY INTERMOUNTAIN POWER AGENCY CONTINUE FOR TERM OF UP&L PWR SALES CONTR OR 2 OTHER CONTR CONDITION	01/83
100-060-10016	SOUTHERN TRANSMISSION SYSTEM AGREEMENT FOR THE ACQUISITION OF CAPACITY BETWEEN SOUTHERN CALIFORNIA PULIC POWER AUTHORITY AND DWP DEPARTMENT OF WATER AND POWER SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY 06/15/2027	05/83
100-060-10017	TRANSMISSION SERVICE CONTRACT BETWEEN SCPPA AND DWP DEPARTMENT OF WATER AND POWER SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY 06/15/2027	05/83
100-060-10020	AGENCY AGREEMENT BETWEEN SCPPA AND DWP DEPARTMENT OF WATER AND POWER SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY 06/15/2027	05/83
100-060-10437	(SUPERCEDES DRAFT NO. 90079) INTERMOUNTAIN POWER PROJECT - POWER SALE AGREEMENT DEPARTMENT OF WATER AND POWER INTERMOUNTAIN POWER AGENCY JUNE 15, 2027	07/80

100-060-10438 INTERMOUNTAIN POWER PROJECT CONSTRUCTION MANAGEMENT AND OPERATING AGREEMENT
DEPARTMENT OF WATER AND POWER
INTERMOUNTAIN POWER AGENCY
JUNE 15, 2027 07/80

100-060-10552 (AMENDED BY AMENDMENT NO. 1, JAN. 20, 1983) INTERMOUNTAIN POWER PROJECT - EXCESS POWER SALE AGREEMENT RELATING TO THE SALE BY UTAH COOPERATIVES AND MUNICIPALITIES AND TO THE PURCHASE BY THE DEPARTMENT AND CALIFORNIA MUNICIPALITIES
DEPARTMENT OF WATER AND POWER
BURBANK, CITY OF
GLENDALE, CITY OF
PASADENA, CITY OF
UTAH INTERMOUNTAIN POWER PROJECT PARTICIPANT
MARCH ,1999 OR, BY TERMINATION OF ALL RELATED POWER CONTRACTS 12/80

100-099-80001 EXCHANGE AGREEMENT - BONNEVILLE POWER ADMINSTRATION AND GLENDALE
BONNEVILLE POWER ADMINISTRATION
GLENDALE, CITY OF
20 YEARS FROM DATE OF EXECUTION 02/62

100-099-80002 EXCHANGE AGREEMENT EXECUTED BY THE UNITED STATES OF AMERICA DEPARTMENT OF THE INTERIOR ACTING BY AND THROUGH THE BONNEVILLE POWER ADMINISTRATOR AND THE CITY OF BURBANK
UNITED STATES OF AMERICA DEPARTMENT OF THE INTERIOR
BURBANK, CITY OF
DEC 21, 1986 02/66

100-099-80003 POWER SALES CONTRACT EXECUTED BY THE UNITED STATES OF AMERICA DEPARTMENT OF THE INTERIOR ACTING BY AND THROUGH THE BONNEVILLE POWER ADMINISTRATOR AND THE CITY OF GLENDALE
UNITED STATES OF AMERICA DEPARTMENT OF THE INTERIOR
GLENDALE, CITY OF
20 YEARS AFTER DATE OF ACCEPTANCE 02/66

100-099-80004 EXCHANGE AGREEMENT EXECUTED BY THE UNITED STATES OF AMERICA DEPARTMENT OF THE INTERIOR ACTING BY AND THROUGH THE BONNEVILLE POWER ADMINISTRATOR AND THE CITY OF PASADENA
UNITED STATES OF AMERICA DEPARTMENT OF THE INTERIOR
PASADENA, CITY OF
APRIL 1, 1986 03/66

100-099-80005 POWER SALES CONTRACT EXECUTED BY THE UNITED STATES OF AMERICA DEPARTMENT OF THE INTERIOR ACTING BY AND THROUGH THE BONNEVILLE POWER ADMINISTRATOR AND SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT
UNITED STATES OF AMERICA DEPARTMENT OF THE INTERIOR
SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST.
20 YEARS AFTER DATE OF EXECUTION 12/68

100-099-80007 CALIFORNIA POWER POOL AGREEMENT
PACIFIC GAS AND ELECTRIC COMPANY
SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA EDISON CO.
EVERGREEN 07/64

100-099-80008 PACIFIC NORTHWEST - PACIFIC SOUTHWEST INTERTIE PROJECT- CONTRACT FOR INTERCONNECTIONS AT MEAD SUBSTATION WITH SOUTHERN CALIFORNIA EDISON COMPANY
UNITED STATES OF AMERICA, THE
SOUTHERN CALIFORNIA EDISON CO.
MAY 31, 1987 07/67

100-099-80009 DIVERSITY EXCHANGE AGREEMENT EXECUTED BY THE UNITED STATES OF AMERICA DEPARTMENT OF THE INTERIOR ACTING BY AND THROUGH THE BONNEVILLE POWER ADMINISTRATOR AND SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT
UNITED STATES OF AMERICA DEPARTMENT OF THE INTERIOR
SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST.
JULY 21, 1986 03/69

100-099-80011 AGREEMENT EXECUTED BY THE UNITED STATES OF AMERICA DEPARTMENT OF THE INTERIOR ACTING BY AND THROUGH THE BONNEVILLE POWER ADMINISTRATOR AND PORTLAND GENERAL ELECTRIC COMPANY
UNITED STATES OF AMERICA DEPARTMENT OF THE INTERIOR
PORTLAND GENRAL ELECTRIC CO.
20 YEARS AFTER DATE OF ACCEPTANCE 08/65

100-099-80012 BOULDER CANYON PROJECT ARIZONA - CALIFORNIA - NEVADA - CONTRACT FOR REMOVAL OF T-6-A TIE CIRCUIT AT HOOVER POWER PLANT
UNITED STATES OF AMERICA, THE
SOUTHERN CALIFORNIA EDISON CO.
NEVADA, STATE OF
DRAFT 04/73

100-099-80026 GAS SALES AGREEMENT SOUTHWEST GAS CORPORATION TO NEVADA POWER COMPANY
NEVADA POWER COMPANY
SOUTHWEST GAS CORPORATION
EVERGREEN 09/63

100-099-80027 CONTRACT FOR TEMPORARY DELIVERY OF MEXICAN WATER FROM THE COLORADO RIVER TO INTERNATIONAL BOUNDARY IN THE VICINITY OF TIJUANA, BAJA CALIFORNIA, MEXICO AND FOR CONSTRUCTION AND OPERATION OF FACILITIES THEREFOR
UNITED STATES OF AMERICA, THE
METROPOLITAN WATER DISTRICT
EVERGREEN 05/72

100-099-80034	POWER SALES CONTRACT BETWEEN PUGET SOUND POWER AND LIGHT COMPANY AND THE CITY OF PASADENA PUGET SOUND POWER & LIGHT COMPANY PASADENA, CITY OF JUNE 30,1981 OR NOTICE BY 7/1 OF ANY YEAR	08/76
100-099-80036	CALIFORNIA COMPANIES PACIFIC INTERTIE AGREEMENT PACIFIC GAS AND ELECTRIC COMPANY SAN DIEGO GAS & ELECTRIC COMPANY SOUTHERN CALIFORNIA EDISON CO. JULY 31,2007	08/66
100-099-80038	ARIZONA-NEVADA POWER POOL AGREEMENT BETWEEN THE UNITED STATES OF AMERICA, NEVADA POWER COMPANY, SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT UNITED STATES OF AMERICA, THE NEVADA POWER COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. DEC. 31,1982 THEN EVERGREEN W/2 YEAR NOTICE	06/71
100-099-80039	ECONOMY ENERGY AGREEMENT BETWEEN THE CITY OF PASADENA, CALIFORNIA AND SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. PASADENA, CITY OF EVERGREEN	09/76
100-099-80040	INLAND POWER POOL AGREEMENT SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. COLORADO-UTE ELECTRIC ASSOCIATION,INC. PLATTE RIVER POWER AUTHORITY PUBLIC SERVICE COMPANY OF COLORADO TRI-STATE GENERATION AND TRANSMISSION ASSCIATION INC. UNITED STATES BUREAU OF RECL.-MISSORI RIVER PROJECT MAY 2009	05/74
100-099-80042	THE UNITED STATES DEPARTMENT OF THE INTERIOR BUREAU OF RECLAMATION LOWER COLORADO REGION CENTRAL ARIZONA PROJECT CONTRACT WITH SOUTHERN CALIFORNIA EDISON COMPANY FOR INTERIM SALE OF UNITED STATES ENTITLEMENT OF NAVAJO PROJECT UNITED STATES OF AMERICA DEPARTMENT OF THE INTERIOR SOUTHERN CALIFORNIA EDISON CO. 20 YEARS AFTER INITIAL GENERATION DATE	09/69
100-099-80044	PG&E SALES CONTRACT EDISON - PACIFIC 1977 INTERRUPTIBLE TRANSMISSION SERVICE AGREEMENT SOUTHERN CALIFORNIA EDISON CO. PACIFIC GAS AND ELECTRIC COMPANY DECEMBER 31, 1977 OR 30 DAYS NOTICE	08/77

100-099-80047 AGREEMENT FOR THE SALE OF CANADIAN ENTITLEMENT CAPACITY AND SAN LUIS PUMPED STORAGE AND GENERATING CAPABILITY
PACIFIC GAS AND ELECTRIC COMPANY
CALIFORNIA,DEPARTMENT OF WATER RESOURCES, THE STATE OF
SEPTEMBER 30,1977 OR EXTENDED EVERY MONTH THEREAFTER 07/77

100-099-80051 POWER SALES CONTRACT EXECUTED BY THE UNITED STATES OF AMERICA DEPARTMENT OF ENERGY ACTING BY AND THRU THE BONNEVILLE POWER ADMINISTRATOR AND THE CITY OF ANAHEIM, CALIFORNIA(SURPLUS ENERGY)
BONNEVILLE POWER ADMINISTRATION
ANAHEIM,CITY OF
DRAFT 03/78

100-099-80052 AGREEMENT FOR THE SALE OF SURPLUS AND PROVISIONAL ENERGY BY BONNEVILLE TO CITY OF BOUNTIFUL,UTAH
BONNEVILLE POWER ADMINISTRATION
BOUNTIFUL, CITY-OF,UTAH
DRAFT 05/78

100-099-80054 POWER SALES CONTRACT EXCUTED BY THE USA DEPARTMENT OF ENERGY ACTING THROUGH BPA AND THE CITY OF ANAHEIM
BONNEVILLE POWER ADMINISTRATION
ANAHEIM,CITY OF
DRAFT 03/78

100-099-80055 EXCHANGE AND TRANSFER AGREEMENT BETWEEN THE USA DEP EXCHANGE AND TRANSFER AGREEMENT EXECUTED BY THE UNITED STATES OF AMERICA DEPARTMENT OF ENERGY ACTING THROUGH THE BPA AND SIERRA PACIFIC POWER COMPANY
BONNEVILLE POWER ADMINISTRATION
SIERRA PACIFIC POWER COMPANY
DRAFT 03/78

100-099-80058 ANAHEIM _ LOS ANGELES INTEGRATED OPERATION AGREEMENT
DEPARTMENT OF WATER AND POWER
ANAHEIM,CITY OF
EVERGREEN 11/77

100-099-80059 EL-PASO _ PASADENA SALE AND INTERCHANGE OF ENERGY AGREEMENT
EL PASO ELECTRIC COMPANY
PASADENA, CITY OF
30 DAY'S ADVANCED NOTICE 09/81

100-099-80060 SALE AND INTERCHANGE OF ENERGY AGREEMENT BETWEEN EL-PASO AND CITY OF BURBANK
EL PASO ELECTRIC COMPANY
BURBANK, CITY OF
TERMINATED BY 30 DAY'S ADVANCED NOTICE 07/80

100-099-80061	SALE AND INTERCHANGE OF ENERGY AGREEMENT BETWEEN EL-PASO AND CITY OF GLENDALE EL PASO ELECTRIC COMPANY GLENDALE, CITY OF TERMINATED BY 30 DAY'S ADVANCED NOTICE	09/80
100-099-80062	AMENDMENT NO. 2 TO PASADENA _ EDISON 230KV INTERCHANGE AGREEMENT PASADENA, CITY OF SOUTHERN CALIFORNIA EDISON CO. EVREGREEN	11/80
100-099-80063	AMENDMENT NO. 1 TO THE SIX_PARTY ECONOMY ENERGY AGREEMENT ARIZONA PUBLIC SERVICE COMPANY EL PASO ELECTRIC COMPANY NEW MEXICO,PUBLIC SERVICE COMPANY OF SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. TUCSON GAS & ELECTRIC COMPANY SOUTHERN CALIFORNIA EDISON CO. EVERGREEN	11/80
100-099-80064	AMENDMENT NO. 1 TO THE EDISON _ NEVADA ECONOMY ENERGY AGREEMENT SOUTHERN CALIFORNIA EDISON CO. NEVADA POWER COMPANY EVERGREEN	11/80
100-099-80065	AMENDMENT NO. 1 TO THE EDISON _ SIERRA-PACIFIC EMERGENCY SERVICE AGREEMENT SOUTHERN CALIFORNIA EDISON CO. SIERRA PACIFIC POWER COMPANY EVERGREEN	11/80
100-099-80066	AMENDMENT NO. 1 TO THE EDISON _ UTAH ECONOMY ENERGY AGREEMENT SOUTHERN CALIFORNIA EDISON CO. COLORADO-UTE ELECTRIC ASSOCIATION,INC. EVERGREEN	11/80
100-099-80068	AMENDMENT NO. 1 TO SERVICE SCHEDULE K OF CORONADO_ CHOLLA INTERCONNECTION AGREEMENT ARIZONA PUBLIC SERVICE COMPANY SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT & POWER DIST. EVERGREEN	04/80
100-099-80069	BONNEVILLE - MUNICIPALITIES-HOOVER-EXCHANGE AGREEMENT BONNEVILLE POWER ADMINISTRATION BURBANK, CITY OF GLENDALE, CITY OF PASADENA, CITY OF DECEMBER 31, 2001	12/81

100-099-80072 FIRM SURPLUS AGREEMENT PUBLIC SERVICE CO. OF NEW MEXICO BURBANK, CITY OF GLENDALE, CITY OF PASADENA, CITY OF
PUBLIC SERVICE COMPANY OF NEW MEXICO
BURBANK, CITY OF
GLENDALE, CITY OF
PASADENA, CITY OF
APRIL 30, 1984

100-099-80073 PENNSYLVANIA-NEW JERSEY-MARYLAND-INTERCONNECTION AGREEMENT PUBLIC SERVICE ELECTRIC AND GAS CO. PHILADELPHIA ELECTRIC CO. PENNSYLVANIA POWER AND LIGHT CO. BALTIMORE GAS AND ELECTRIC CO. PENNSYLVANIA ELECTRIC CO. METROPOLITAN EDISON CO. NEW JERSEY POWER AND LIGHT CO. JERSEY CENTRAL POWER AND LIGHT CO.
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
PHILADELPHIA ELECTRIC COMPANY
PENNSYLVANIA POWER AND LIGHT COMPANY
BALTIMORE GAS AND ELECTRIC COMPANY
PENNSYLVANIA ELECTRIC COMPANY
METROPOLITAN EDISON COMPANY
NEW JERSEY POWER AND LIGHT COMPANY
JERSEY CENTRAL POWER AND LIGHT COMPANY
CONSENT OF ALL PARTICIPANTS OR 3 YEARS ADVANCE WITHDRAW NOTICE 11/56

100-099-80074 UTAH POWER AND LIGHT SERVICE SCHEDULE RATES FOR SALE OF NON-FIRM ENERGY FOR RESALE
UTAH POWER & LIGHT COMPANY
7 DAYS ADVANCE WRITTEN NOTICE 04/82

100-099-80075 SCE-DWR POWER, ENERGY AND TRANSMISSION SALES AND EXCHANGE AGREEMENT
SOUTHERN CALIFORNIA EDISON CO.
CALIFORNIA,DEPARTMENT OF WATER RESOURCES, THE STATE OF
DECEMBER 31 2004 04/83

100-099-90018 MOHAVE PROJECT LAYOFF AGREEMENT BETWEEN NEVADA POWER COMPANY AND SOUTHERN CALIFORNIA EDISON COMPANY
NEVADA POWER COMPANY
SOUTHERN CALIFORNIA EDISON CO.
EVERGREEN

100-099-90024 CALIFORNIA COMPANIES PACIFIC INTERTIE AGREEMENT BETWEEN PACIFIC GAS AND ELECTRIC COMPANY , SOUTHERN CALIFORNIA EDISON COMPANY AND SAN DIEGO GAS AND ELECTRIC COMPANY
PACIFIC GAS AND ELECTRIC COMPANY
SOUTHERN CALIFORNIA EDISON CO.
SAN DIEGO GAS & ELECTRIC COMPANY
APRIL 1, 2007 08/66

100-099-90025 CENTRAL ARIZONA PROJECT CONTRACT WITH SOUTHERN CALIFORNIA EDISON CO.-FOR INTERIM SALE OF U.S. ENTITTLEMENT OF NAVAJO PROJECT
SOUTHERN CALIFORNIA EDISON CO.
UNITED STATES OF AMERICA DEPARTMENT OF THE INTERIOR
DRAFT

8604160028

INFORMATION REQUESTED BY
THE NRC FOR ANTITRUST REVIEW

SOUTHERN CALIFORNIA PUBLIC
POWER COMPANY

REGULATORY GUIDE 9.3 RESPONSES

Item 1a

Anticipated excess or shortage in generating capacity resources not expected at the construction permit stage. Reasons for the excess or shortage along with data on how the excess will be allocated, distributed, or otherwise utilized or how the shortage will be obtained.

Response

The Southern California Public Power Authority (SCPPA), created in 1980 pursuant to the Joint Exercise of Powers Act, is a public entity organized under the laws of the State of California. Its purpose is to develop and finance power projects for the generation and transmission of electrical energy for its' members. The members of SCPPA are the Imperial Irrigation District located in the Imperial Valley of Southern California and the Southern California cities of Anaheim, Azusa, Banning, Burbank, Colton, Glendale, Los Angeles, Pasadena, Riverside and Vernon. Each member of SCPPA is responsible for its' own resource planning and, therefore, has its own resource plan. SCPPA is not involved in power supply planning for its members.

Item 1b

New power pools or coordinating groups or changes in structure, activities, policies, practices or membership of power pools or coordinating groups in which the licensee was, is, or will be a participant.

Response

See Item 1a.

Item 1c

Changes in transmission with respect to: (1) the nuclear plant, (2) interconnections, or (3) connections to wholesale customers.

Response

(1) SCPPA has a transmission arrangement with the Salt River Project Agricultural Improvement and Power District (SRP) for the transmission of energy from the Palo Verde Nuclear Generating Station (Palo Verde) to the Boulder City, Nevada area where it interconnects with the Los Angeles Department of Water and Power's transmission system for delivery to the Southern California area.

(2) SCPPA did not require any new interconnections or transmission agreements for Palo Verde.

(3) SCPPA has no wholesale customers.

Item 1d

Changes in the ownership or contractual allocation of the output of the nuclear facility. Reasons and basis for such changes should be included.

Response

In 1982, SCPPA purchased from SRP a 5.91-percent interest (225 megawatts) in Palo Verde. The purchase also included certain rights to the high-voltage switchyard as well as certain rights to transmission facilities. The present ownership interests in Palo Verde including the purchase are shown below:

Arizona Public Service Company	29.10%
Salt River Project Agricultural Improvement and Power District	17.49
Southern California Edison Company	15.80
Public Service Company of New Mexico	10.20
El Paso Electric Company	15.80
Southern California Public Power Authority	5.91
Los Angeles Department of Water and Power	5.70
	100.00%

Item 1e

Changes in design, provisions, or conditions of rate schedules and reasons for such changes. Rate increases or decreases are not necessary.

Response

The cost of power to SCPPA members from a particular project financed by SCPPA is based on the cost of such project. The cost to each member is based on its proportionate entitlement to the project output.

Item 1f

List of all: (1) new wholesale customers; (2) transfers from one rate schedule to another, including copies of schedules not previously furnished; (3) changes in licensee's service area; and (4) licensee's acquisitions or mergers.

Response

(1) SCPPA does not have wholesale customers.

(2) See response to (1).

(3) SCPPA itself does not have service area boundaries. Each member in SCPPA has its own individual service area.

(4) SCPPA has not been involved in any acquisition or mergers except as noted in the response to Item 1d.

Item 1g

List of those generating capacity additions committed for operation after the nuclear facility, including ownership rights or power output allocations.

Response

At the present time, SCPPA has no generating capacity additions committed for operation after Palo Verde.

Item 1h

Summary of requests or indications of interest by other electric power wholesale or retail distributors, and licensee's response, for any type of electric service or cooperative venture or study.

Response

Over the past several years, SCPPA has been contacted for potential SCPPA participation in various proposed power projects. At the present time, other projects or studies that SCPPA is involved in are:

The Southern Transmission Project

Direct-current transmission line being constructed between the Intermountain Power Project (IPP) near Delta, Utah, and Adelanto, California. The ±500-kilovolt direct-current transmission line is part of IPP and will transmit the California participants' entitlement from the Intermountain Generating Station as early as 1986.

The Mead-Phoenix DC Intertie Project

A feasibility study for construction and operation of a ±500-kilovolt direct-current transmission line between Phoenix, Arizona, and the Boulder City, Nevada area and the Adelanto, California area in Southern California.

Item 2

Licensees whose construction permits include conditions pertaining to antitrust aspects should list and discuss those actions or policies which have been implemented in accordance with such conditions.

Response

SCPPA was not a participant in the project when the construction permit was issued for Palo Verde.