WESTERN
AREA POWER
ADMINISTRATION

FISCAL YEARS 2009 – 2013

Parker-Davis Project

Rate Brochure

Proposed Firm Electric & Transmission Service Formula Rates

April 2008

Table of Contents

I. Introduction

The Western Area Power Administration (Western) has initiated a public process to modify the rate methodology used to develop Parker-Davis Project (P-DP) firm electric and transmission service formula rates. A copy of the *Federal Register* notice announcing this public process is included in this brochure as Appendix A. This brochure explains the modifications to the rate methodology and provides detailed information about the proposed firm electric and transmission service formula rates.

II. Project Description

The P-DP was formed by consolidating two projects, Parker Dam and Davis Dam, under the terms of the Act of May 28, 1954. All facilities of the P-DP were operated and maintained by the Bureau of Reclamation (Reclamation) until the formation of the Department of Energy pursuant to the Department of Energy Organization Act (DOE Act). Pursuant to the DOE Act, responsibility for the power marketing functions of Reclamation, including the construction, operation, and maintenance of substations, transmission lines and attendant facilities, was transferred to the Department of Energy. The responsibility for operation and maintenance of the dams and powerplants remains with Reclamation.

Parker Dam, which created Lake Havasu 155 miles below Hoover Dam on the Colorado River, was authorized by the Rivers and Harbors Act of August 30, 1935. Construction of Parker Dam began in 1934 and was completed in 1942. Reclamation constructed the project partly with funds advanced by the Metropolitan Water District of Southern California (MWD). MWD receives half of the capacity and energy from the four generating units at Parker Dam.

Davis Dam, which created Lake Mohave 67 miles below Hoover Dam on the Colorado River, was authorized under the Reclamation Project Act of 1939. Construction began in 1941 but due to construction delays caused by World War II, it was not completed until 1953. Davis Dam has five generating units.

Power generated from the P-DP is marketed to customers in Arizona, Nevada, and California. Excluding project use, the marketing period effective fiscal year 2009 provides for 198,337 kW of capacity in the winter season and 259,206 kW of capacity in the summer season. Customers receive 1,703 kWh per kW in the winter season and 3,441 kWh per kW in the summer season.

The P-DP transmission system includes 48 substations and over 1,500 circuit miles of transmission lines in Arizona, southern Nevada and along the Colorado River in California.

III. Rate Adjustment Procedure

The published procedures for rate adjustments, as amended, are included in this brochure as Appendix B. These procedures adopted by the Department of Energy, give interested parties an opportunity to participate in the development of both power and transmission rates.

The proposed action described in Section I of this brochure, constitutes a minor rate adjustment as defined by 10 CFR 903. As such, Western has determined it is not necessary to hold a public information or public comment forum.

The consultation and comment period for the proposed action began April 29, 2008, and will end May 29, 2008. Western will accept written comments any time during the consultation and comment period. Western will post official comments received via letter, fax, and e-mail to its Web site after the close of the comment period. Western must receive written comments by the end of the consultation and comment period to ensure they are considered in Western's decision process. Send written comments to: J. Tyler Carlson, Regional Manager, Desert Southwest Customer Service Region, Western Area Power Administration, P.O. Box 6457, Phoenix, AZ 85005-6457, e-mail carlson@wapa.gov. Written comments may also be faxed to (602) 605-2490, attention: Jack Murray.

After review of public comments, Western will take further action on the proposed formula rates consistent with 10 CFR part 903. The decision, and an explanation of the principal factors leading to this decision, will be announced in a *Federal Register* notice.

The Deputy Secretary of Energy will submit all information concerning the provisional formula rates to the Federal Energy Regulatory Commission (FERC) and request approval of the provisional rates for a 5-year period beginning October 1, 2008 through September 30, 2013. FERC will then confirm, approve, and place the provisional rates into effect on a final basis, remand the provisional rates to Western, or disapprove the provisional rates.

IV. Rate Methodology

A. Project Repayment

Repayment criteria are based on law and policies established by Department of Energy Order R.A. 6120.2 (RA 6120.2). A copy of RA 6120.2 is included in this brochure as Appendix C. According to RA 6120.2, project revenues are required to repay project investment costs including interest. Generally, the repayment criteria formula is total annual revenues equal total annual expenses plus debt repayment. First, annual revenues are used to pay the annual expenses. These annual expenses include all costs for operation, maintenance, and interest on capitalized investments and deficits. Second, all required payments due on capitalized investments are paid. The hierarchy of repayment requires that the highest interest-bearing investments are repaid first.

Power Repayment Studies (PRS) are conducted and analyzed to ensure that revenues are sufficient to pay all project costs within the prescribed period. PRS report historic and future project revenues, costs including interest, and status of investment repayment. A copy of the most recent PRS is included in this brochure as Appendix D.

B. Revenue Requirements

The P-DP uses the Compound Interest Amortization methodology. Under this methodology, revenue requirements are determined for a future five year cost evaluation period. Revenues collected in excess of the annual revenue requirement are carried forward and used to cover revenue shortfalls in the cost evaluation period. Each year, new revenue requirements for the following five year cost evaluation period will be determined and implemented.

The annual revenue requirements are based on a Cost Apportionment Study (CAS). The CAS allocates P-DP costs and other revenues between generation and transmission revenue requirements. There is a separate CAS for each year of the cost evaluation period. A copy of the CAS in included in this brochure as Appendix E. The CAS can be described in the following steps:

1. All costs including Western's operation and maintenance expenses, Reclamation's expenses, purchase power, multi-project costs associated with Mead Service Center, CME, interest expense, and scheduled principal payments are allocated to either generation or transmission revenue requirements. Costs that are readily identifiable as supporting either generation or transmission functions are directly

allocated to generation or transmission revenue requirements. All other costs are apportioned between generation and transmission revenue requirements based on cost allocation factors.

2. All other sources of revenue including nonfirm transmission service, nonfirm energy sales, ancillary services, facility use charges, multi-project revenues associated with SCADA and the Phoenix Service Center, are allocated to either generation or transmission revenue requirements. Each source of other revenue is allocated based on whether it is directly related to generation or transmission. If a source of other revenue is related to both, an appropriate allocation factor is used to apportion the revenue between generation and transmission revenue requirements.

C. Rate Design

Firm electric and transmission service rates are calculated annually for the five years of the cost evaluation period. A copy of the rate calculations for fiscal years 2009 through 2013 is included in this brochure as Appendix F.

Firm Transmission Rate Formula: The firm transmission rate is equal to the transmission revenue requirement divided by the estimated transmission delivery commitments, rounded to the nearest 12 cent increment. The formula is illustrated below.

$$\frac{\text{Tran Revenue Req}}{\text{Estimated Deliveries}} = \$ \text{ /kW-Year Rate}$$

Firm Transmission Rate Formula (Salt Lake): The firm transmission rate for existing Salt Lake City Area Integrated Projects (SLCA/IP) customers is equal to the firm transmission rate divided by two, rounded to the nearest six cent increment. The formula is illustrated below.

$$\frac{\text{Firm Tran Rate}}{2} = \$ \text{ /kW- Season Rate}$$

Nonfirm Transmission Rate Formula: The nonfirm transmission rate formula is equal to the firm transmission rate divided by 8,760 multiplied by 0.60, multiplied by 1,000, rounded to two decimal places. The formula is illustrated below.

$$\left[\frac{\text{Firm Tran Rate}}{(8{,}760 \times 0.60)}\right] \times 1000 \;=\; \text{mills/kWh Rate}$$

Firm Electric Service – Formula Energy Rate: The firm electric service energy rate is equal to 50% of the generation revenue requirement divided by the estimated generation delivery commitments for firm electric service, rounded to two decimal places. The formula is illustrated below.

$$\left[\frac{(50\% \times \text{Gen Rev Req})}{\text{Estimated Deliveries}}\right] = \text{mills/kWh Rate}$$

Firm Electric Service – Formula Capacity Rate: The firm electric service capacity rate is equal to 50% of the generation revenue requirement divided by the estimated transmission delivery commitments for firm electric service, rounded to two decimal places. The formula is illustrated below.

$$\left[\frac{(50\% \times \text{Gen Rev Req})}{\text{Estimated Deliveries}}\right] = \$\,/\text{kW-Year Rate}$$

V. Proposed Firm Electric and Transmission Service Rates

The proposed firm electric and transmission service rates resulting from the rate methodology are equal to the existing rates and will provide sufficient revenue to pay all annual costs, including interest expense, and repayment of required investment within the allowable period.

The firm electric and transmission service rates are scheduled to become effective on October 1, 2008, and will remain in effect through September 30, 2013. The following table summarizes the rates.

Service	Existing Rates	Proposed Rates	Change
Firm Transmission	$12.96/kW-Year	$12.96/kW-Year	-
Firm Transmission of SLCA/IP	$6.48/kW-Season	$6.48/kW-Season	-
Nonfirm Transmission	2.47 mills/kWh	2.47 mills/kWh	-
Firm Electric (capacity rate)	$17.45/kW-Year	$17.45/kW-Year	-
Firm Electric (energy rate)	3.32 mills/kWh	3.32 mills/kWh	-

VI. Proposed Changes

A. Cost Allocation Factors

Under the current rate methodology, formula rates for P-DP firm electric and transmission service are calculated annually and designed to recover annual project costs, including interest expense, and make repayment of required investment within the allowable period. Costs that are readily identifiable as supporting either generation or transmission functions are directly allocated to generation or transmission revenue requirements. All other costs are apportioned between generation and transmission revenue requirements based on cost allocation factors.

Current cost allocation factors include Supervisory Control and Data Acquisition (SCADA), Capitalized Movable Equipment (CME), labor hours devoted to billing, historic project investment, and percentage of allocated Western operation and maintenance expenses. Western is proposing to modify the current rate methodology by eliminating the CME, labor hours devoted to billing, and historic project investment cost allocation factors. Western also proposes implementing a cost allocation factor that is the ratio of the number of customers receiving firm electric or transmission service to the total number of customers. The following table summarizes the proposed changes to the cost allocation factors.

Cost Category	Current Factor	Proposed Factor
Systemwide (Billing, Finance)	Time Study	Customer Count
Ops/Dispatch	SCADA/Time Study	SCADA
CME	CME Calculation	Percent Allocation of Western O&M
Western P&I	Historic Investment	None (Transmission Only)

At this time, the firm electric and transmission service rates resulting from the proposed modifications to the rate methodology are equal to current rates. Western prepared a detailed impact analysis that determined that over the last seven years, the proposed changes would have resulted in an average annual change to either the transmission or generation revenue requirements of $388,000 or 0.96%. The impact analysis is available on Western's Web site at http://www.wapa.gov/dsw/pwrmkt/RateAdjust/Main.htm.

B. Transmission Prepayment

During informal discussions prior to the commencement of the rate adjustment process, Western received a request from customers to modify the billing practices for P-DP long-term firm transmission service.

In the request, the customers noted that payments for firm electric service are required one month in advance of service and suggested that all parties be subject to the same billing terms and conditions. Current billing practices for P-DP long-term firm transmission service allow customers to pay after the fact, usually one month after service is provided.

Additionally, P-DP rate calculations assume the full and timely collection of revenues. To the extent that customer payments are late or uncollectible, rates may be insufficient to recover revenue requirements. This could result in a rate increase, adversely affecting all P-DP customers.

In response to the customer's request and to mitigate payment risk exposure, Western is proposing changes to billing practices so that customers will be required to pay for P-DP long-term firm transmission service one month in advance of service. This change will be incorporated in the rate schedule for firm point-to-point transmission service. Long-term firm transmission customers will be notified of the change in billing practice before the initial prepayment due date and will be provided with information to illustrate the timing of initial prepayments.

VII. Supporting Data

Information sources for the rate calculations are discussed below. Additional, detail about revenues, expenses, and investments is available in the PRS included in this brochure as Appendix D.

A. Revenues

1. Firm Transmission Sales

Historic revenues from firm transmission sales are based on actual sales reported in the Annual Report of Deliveries and Income. Projections for future sales are based on estimates of transmission deliveries from current and anticipated contractual obligations. For fiscal years 2009 through 2013, the cost evaluation period, average firm transmission sales are estimated at 2,802,689 kW or approximately $36.3 million per year.

2. Firm Energy & Capacity Sales

Historic revenues from firm energy and capacity sales are based on actual sales reported in the Annual Report of Deliveries and Income. Projections for future sales are based on estimates of deliveries from current and anticipated contractual obligations. For fiscal years 2009 through 2013, capacity and energy sales are estimated at $9.5 million per year.

3. Other Revenues

Other revenues include nonfirm transmission service, nonfirm energy sales, ancillary services, facility use charges, and multi-project revenues associated with SCADA and the Phoenix Service Center. Historic other revenues are based on actual amounts reported in financial reports and the Annual Report of Deliveries and Income. Projections for future other revenues are based on trends of historic revenues adjusted for certain known transactions. For fiscal years 2009 through 2013, other revenues are estimated at $4.9 million per year.

B. Expenses

1. Operation and Maintenance (O&M)

Historic O&M expenses are based on actual expenses reported in financial reports of both Western and Reclamation. Projections for future O&M expenses are based on budget and planning data to the extent possible as well as trends of historic expenses. For fiscal years 2009 through 2013, the cost evaluation period, average O&M expenses are estimated at $32.3 million per year.

2. Purchased Power

Historic expenses for purchased power are based on actual expenses reported in financial reports of Western. Projections for future purchase power expenses are based on hydrologic and market pricing analyses conducted by Western and Reclamation. For fiscal years 2009 through 2013, annual purchase power expenses are estimated at $4.2 million.

3. Other Expenses

Other expenses include the unfunded portion of the Civil Service System and Post-Retirement Health and Life Insurance Benefits and Multi-Project Costs. Multi-Project Costs represent expenses to reimburse other Western power systems for investment in shared capital projects. Projections for future other costs are based on actual expenses from the previous year. For fiscal years 2009 through 2013, other expenses are estimated at $1.5 million per year.

4. Interest

Historic interest expenses are based on actual expenses reported in financial reports of Western and the Reclamation. Projections of future interest expenses are calculated annually in the PRS based on unpaid investment, undepreciated capital moveable equipment and warehouse stores. For fiscal years 2009 through 2013, interest is estimated at $17.3 million per year.

C. Investments

Investments include original project investment and additions, replacements, capitalized deficits, and amounts of additions and replacements that are classified as aid to irrigation. Interest rates on the unpaid portion of investment range from 0% to 9.25%. Repayment periods vary based on the type of investment but range from 1 to 50 years. Currently P-DP has no unpaid capitalized deficits and under the Compound Interest Amortization methodology will not incur future capitalized deficits. The table below summarizes investment information during the cost evaluation period.

Fiscal Year	Annual Investment	Cumulative Balance	Principal Payment	Unpaid Balance
2009	$ 16,667,000	$ 502,732,934	$ 4,739,534	$ 245,221,588
2010	11,166,000	513,898,934	3,301,196	253,086,392
2011	9,596,000	523,494,934	3,193,400	259,488,992
2012	22,322,000	545,816,934	3,442,238	278,368,754
2013	$ 40,328,000	$ 586,144,934	$ 4,287,441	$ 314,409,313

Appendix A

Federal Register Notice – Notice of Proposed Formula Rates

Administration's Kansas City Plant Project is not a major federal action significantly affecting the quality of the human environment within the meaning of the National Environmental Policy Act of 1969. Therefore, the preparation of an Environmental Impact Statement is not required and GSA and NNSA are issuing this FONSI for the Proposed Action.

Key stipulations set forth in the Environmental Assessment include the following measures that will be implemented to reduce any impacts the selected alternative may have on the quality of the human environment: Adherence to commitments outlined in the Mitigation Action Plan. The Mitigation Action Plan contains mitigation and monitoring commitments for the project, including commitments set (or that would be set) in any permits. As details of specific mitigation actions are developed, or as additional mitigation measures necessary to produce the results committed to by GSA or NNSA are identified, the Mitigation Action Plan will be updated.

General Services Adminstration:

APPROVED BY:

Dated: April 21, 2008.

Bradley M. Scott,

Regional Administrator, GSA Region 6.

and

Dated: April 21, 2008.

Steve C. Taylor,

Manager, NNSA, Kansas City Site Office.

[FR Doc. E8–9322 Filed 4–28–08; 8:45 am]

BILLING CODE 6820–CG–S

DEPARTMENT OF ENERGY

Western Area Power Administration

Parker-Davis Project-Rate Order No. WAPA–138

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of Proposed Formula Rates for Firm Electric and Transmission Service.

SUMMARY: The Western Area Power Administration (Western) is proposing modifications to the rate methodology used to develop Parker-Davis Project (P–DP) firm electric and transmission service formula rates. The modifications to the rate methodology will change the allocation factors used to apportion certain expenses between generation and transmission revenue requirements. The firm electric and transmission service rates resulting from the rate methodology modifications are equal to current rates and will provide sufficient revenue to pay all annual costs, including interest expense, and repayment of required investment within the allowable period. Western is also proposing changes to the current billing practices for P–DP long-term firm transmission service. Under the proposed billing changes, customers will be required to pay for long-term firm transmission service one month in advance of service. Western will prepare a brochure that provides detailed information on the modifications and proposed firm electric and transmission service formula rates. Current formula rates under Rate Schedules PD–F6, PD–FT6, PD–FCT6, and PD–NFT6 expire September 30, 2008. The proposed formula rates under Rate Schedules PD–F7, PD–FT7, PD–FCT7, and PD–NFT7 are scheduled to become effective on October 1, 2008, and will remain in effect through September 30, 2013. Publication of this **Federal Register** notice begins the formal process for the proposed formula rates.

DATES: The consultation and comment period will begin today and will end May 29, 2008. Western will accept written comments any time during the consultation and comment period. The proposed action constitutes a minor rate adjustment as defined by 10 CFR part 903. As such, Western has determined it is not necessary to hold a public information or public comment forum.

ADDRESSES: Send written comments to: J. Tyler Carlson, Regional Manager, Desert Southwest Customer Service Region, Western Area Power Administration, P.O. Box 6457, Phoenix, AZ 85005–6457, e-mail *carlson@wapa.gov.* Written comments may also be faxed to (602) 605–2490, attention: Jack Murray. Western will post information about the rate process on its Web site at *http://www.wapa.gov/dsw/pwrmkt/RateAdjust/Main.htm.* Western will post official comments received via letter, fax, and e-mail to its Web site after the close of the comment period. Western must receive written comments by the end of the consultation and comment period to ensure they are considered in Western's decision process.

FOR FURTHER INFORMATION CONTACT: Mr. Jack Murray, Rates Manager, Desert Southwest Customer Service Region, Western Area Power Administration, P.O. Box 6457, Phoenix, AZ 85005–6457, telephone (602) 605–2442, e-mail *jmurray@wapa.gov.*

SUPPLEMENTARY INFORMATION: Under the current rate methodology, formula rates for P–DP firm electric and transmission service are recalculated annually and designed to recover annual project costs, including interest expense, and make repayment of required investment within the allowable period. Costs that are readily identifiable as supporting either generation or transmission functions are directly allocated to generation or transmission revenue requirements. All other costs are apportioned between generation and transmission revenue requirements based on cost allocation factors. Current cost allocation factors include Supervisory Control and Data Acquisition, Capitalized Movable Equipment (CME), labor hours devoted to billing, and historic project investment. Western is proposing to modify the current rate methodology by eliminating the CME, labor hours devoted to billing, and historic project investment cost allocation factors. Western also proposes implementing a cost allocation factor that is the ratio of the number of customers receiving firm electric or transmission service to the total number of customers. At this time, the firm electric and transmission service rates resulting from the proposed modifications to the rate methodology are equal to current rates and will provide sufficient revenue to recover generation and transmission revenue requirements.

During informal discussions prior to the commencement of this rate adjustment process, Western received a request from customers to modify the billing practices for P–DP long-term firm transmission service. In the request, the customers noted that payments for firm electric service are required one month in advance of service and suggested that all parties be subject to the same billing terms and conditions. Current billing practices for P–DP long-term firm transmission service allow customers to pay after the fact, usually one month after service is provided. In response to this request, Western is proposing changes to billing practices so that customers will be required to pay for P–DP long-term firm transmission service one month in advance of service. This requirement is incorporated into Rate Schedule PD–FT7.

Rate Schedules PD–F6, PD–FT6, PD–FCT6, and PD–NFT6 were approved under Rate Order No. WAPA–75 for the period beginning November 1, 1997, and ending September 30, 2002.[1] These rate schedules were extended through September 30, 2004, by the approval of Rate Order No. WAPA–98 on September

[1] WAPA–75 was approved by the Deputy Secretary of Energy on November 18, 1997 (62 FR 63150), and confirmed and approved by FERC on a final basis on March 10, 1998, in Docket No. EF98–5041–000 (82 FERC 62164).

13, 2002.[2] These rate schedules were extended again through September 30, 2006, by the approval of Rate Order No. WAPA–113 approved on September 2, 2004.[3] These rate schedules were extended again through September 30, 2008, by Rate Order No. WAPA–131 approved on September 22, 2006.[4]

Legal Authority

The proposed modifications to the rate methodology described above constitutes a minor rate adjustment. Western has determined that it is not necessary to hold a public information or public comment forum for this proposed minor rate adjustment as defined by 10 CFR part 903. After review of public comments and possible amendments or adjustments, Western will recommend the Deputy Secretary of Energy approve the proposed formula rates on an interim basis.

Western is establishing firm electric and transmission service rates for P–DP under the Department of Energy Organization Act (42 U.S.C. 7152); the Reclamation Act of 1902 (ch. 1093, 32 Stat. 388), as amended and supplemented by subsequent laws, particularly section 9(c) of the Reclamation Project Act of 1939 (43 U.S.C. 485h(c)); and other acts that specifically apply to the project involved.

By Delegation Order No. 00–037.00, effective December 6, 2001, the Secretary of Energy delegated: (1) The authority to develop power and transmission rates to Western's Administrator; (2) the authority to confirm, approve, and place such rates into effect on an interim basis to the Deputy Secretary of Energy; and (3) the authority to confirm, approve, and place into effect on a final basis, to remand or to disapprove such rates to the Federal Energy Regulatory Commission. Existing Department of Energy (DOE) procedures for public participation in power rate adjustments (10 CFR part 903) were published on September 18, 1985.

Availability of Information

All brochures, studies, comments, letters, memorandums, or other documents that Western initiates or uses to develop the proposed rates are available for inspection and copying at the Desert Southwest Customer Service Regional Office located at 615 South 43rd Avenue, Phoenix, AZ. Many of these documents and supporting information are also available on Western's Web site at *http://www.wapa.gov/dsw/pwrmkt/RateAdjust/Main.htm.*

Ratemaking Procedure Requirements

Environmental Compliance

In compliance with the National Environmental Policy Act of 1969 (NEPA) (42 U.S.C. 4321, *et seq.*); the Council on Environmental Quality Regulations for implementing NEPA (40 CFR parts 1500–1508); and DOE NEPA Implementing Procedures and Guidelines (10 CFR part 1021), Western has determined this action is categorically excluded from preparing an environmental assessment or an environmental impact statement.

Determination Under Executive Order 12866

Western has an exemption from centralized regulatory review under Executive Order 12866; accordingly, no clearance of this notice by the Office of Management and Budget is required.

Timothy J. Meeks,
Administrator.

[FR Doc. E8–9332 Filed 4–28–08; 8:45 am]

BILLING CODE 6450–01–P

[2] WAPA–98 was approved by the Secretary of Energy on September 13, 2002 (67 FR 60655), and filed with FERC for informational purposes only, and docketed by FERC on September 24, 2002, in Docket No. EF02–5041–000.

[3] WAPA–113 was approved by the Deputy Secretary of Energy on September 2, 2004 (69 FR 55429), and filed with FERC for informational purposes only, and docketed by FERC on September 3, 2004, in Docket No. EF04–5042–000.

[4] WAPA–131 was approved by the Deputy Secretary of Energy on September 22, 2006 (71 FR 57941), and filed with FERC for informational purposes only, and docketed by FERC on September 22, 2006, in Docket No. EF06–5042–000.

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–QAR–2008–0222; FRL–8558–1]

Agency Information Collection Activities: Submissions for OMB Review; Comment Request; Proposed Collection and Comment Request for the Outer Continental Shelf Air Regulation; EPA ICR No. 1601.07; OMB Control No. 2060–0249

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (PRA) (44 U.S.C. 3501 *et seq.*), this document announces that EPA is planning to submit a request to renew an Information Collection Request (ICR) to the Office of Management and Budget (OMB). This ICR is scheduled to expire on January 31, 2009. Before submitting the ICR to OMB for review and approval, EPA is soliciting comments on specific aspects of the proposed information collection as described below.

DATES: Comments must be submitted on or before June 30, 2008.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2008–0222, by one of the following methods:*http://www.regulations.gov:* Follow the on-line instructions for submitting comments.

- *E-mail: a-and-r-docket@epa.gov.*
- *Fax:* (202) 566–9744.
- *Mail:* Agency Information Collection Request Activities: Proposed Collection and Comment Request for the Outer Continental Shelf Air Regulations Docket, Environmental Protection Agency, Air and Radiation Docket and Information Center, Mailcode: 2822T, 1200 Pennsylvania Ave., NW., Washington, DC 20460. Please include a total of two copies.
- *Hand Delivery:* EPA Docket Center, Public Reading Room, EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC 20460. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA–HQ–OAR–2008–0222. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or e-mail. The *http://www.regulations.gov* Web site is an anonymous access system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *http://www.regulations.gov,* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment.

Appendix B

Procedures for Public Participation in Power and Transmission Rate Adjustments (10 CFR 903)

Rules and Regulations

Federal Register
Vol. 50, No. 225
Thursday, November 21, 1985

DEPARTMENT OF AGRICULTURE

Food Safety and Inspection Service

9 CFR Part 318

[Docket No. 80-054C]

Additional Methods for Destruction of Trichinae in Pork Products; Correction

AGENCY: Food Safety and Inspection Service, USDA.

ACTION: Final rule with request for comments; correction.

SUMMARY: This document corrects a final rule on trichina destruction by adding a parenthetical phrase for clarification and by revising the calculation given as an example in a footnote.

FOR FURTHER INFORMATION CONTACT: Mr. Bill F. Dennis, Director, Processed Products Inspection Division, Meat and Poultry Inspection Technical Services, Food Safety and Inspection Service, U.S. Department of Agriculture, Washington, DC 20250, (202) 447-3840.

SUPPLEMENTARY INFORMATION: On February 7, 1985, the Food Safety and Inspection Service (FSIS) published a final rule with request for comments in the **Federal Register** (50 FR 5226) which permits additional treatment methods for trichina destruction in pork products. Under Method No. 6 (9 CFR 318.10(c)(3)(i)(C)), the reference to dry ingredients was intended to be clarified with a parenthetical phrase giving examples of such ingredients. This phrase was inadvertently omitted in the final version of the rule. Also, under that same paragraph, the calculation in Footnote 1 of Table 4 is in error and is being corrected.

§ 318.10 [Corrected]

Accordingly, FSIS amends § 318.10(c)(3)(i)(C) of the Federal meat inspection regulations as follows:

1. The first sentence is amended by adding the following parenthetical phrase directly after the word "ingredients": "(such as salts, sugars, and spices),".

2. Footnote 1 of Table 4 is amended by correcting the calculation given as the example to read as follows:

Example: 120 lbs. pork, 3.56 lbs. salt, 2 lbs. spices, 0.5 lbs. wine, 1 lb. water and starter culture, 0.8 lbs. sugar, .012 lbs. sodium nitrite total weight is 127.872 lbs.

$(3.56\times100)/(127.872-3.56-2-.8-.012)=356/121.5=2.93$

Therefore, the sausage drying time must be increased by 13 percent.

FSIS is reviewing the comments received in response to the final rule and will publish its response to those comments in the near future.

Done at Washington, DC on November 15, 1985.

Donald L. Houston,
Administrator, Food Safety and Inspection Service.

[FR Doc. 85-27750 Filed 11-20-85; 8:45 am]

BILLING CODE 3410-DM-M

DEPARTMENT OF ENERGY

10 CFR Part 903

Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions

Correction

In FR Doc. 85-22365, beginning on page 37835 in the issue of Wednesday, September 18, 1985, make the following corrections:

1. On page 37837, third column, the section heading for § 903.1 should have read:

§ 903.1 Purpose and scope; application.

2. On page 37838, second column, in § 903.2(m), the second sentence should have read as follows: "It does not include a change in rate schedule provisions or in contract terms, other than changes in the price per unit of service, nor does it include changes in the monetary charge pursuant to a formula stated in a rate schedule or a contract."

BILLING CODE 1505-01-M

NATIONAL CREDIT UNION ADMINISTRATION

12 CFR Part 701

Loan Interest Rates

AGENCY: National Credit Union Administration.

ACTION: Final rule.

SUMMARY: This rule continues the 21 percent Federal credit union loan rate ceiling through May 14, 1987. The 21 percent ceiling was scheduled to expire on January 25, 1986. This rule will provide the continued flexibility necessary for each Federal credit union's member-elected board of directors to set loan rates consistent with changing market conditions and in a manner that represents the best interest of the credit union's members.

EFFECTIVE DATE: November 14, 1985.

ADDRESS: National Credit Union Administration, 1776 G Street, NW., Washington, DC 20456.

FOR FURTHER INFORMATION CONTACT: D. Michael Riley, Director, or Martin Kushner, Financial Analyst, Office of Examination and Insurance, or Robert M. Fenner, General Counsel, at the above address. Telephone numbers: (202) 357-1065 (Mr. Riley or Mr. Kushner); (202) 357-1030 (Mr. Fenner).

SUPPLEMENTARY INFORMATION:

Background

Pub. L. 96-221 raised the loan interest rate ceiling for Federal credit unions from 1 percent per month (12 percent per year) to 15 percent per year. It also authorized the NCUA Board to set a higher limit, after consultation with Congress and other Federal financial agencies, for a period not to exceed 18 months, if the Board should determine that (i) money market interest rates have risen over the preceding six months and (ii) prevailing interest rate levels threaten the safety and soundness of individual credit unions as evidenced by adverse trends in liquidity, capital, earnings, and growth.

On December 3, 1980, the NCUA Board determined that these conditions had been met. The Board therefore raised the interest rate ceiling to 21 percent for a nine-month period. In subsequent actions, the Board extended the period covered by the 21 percent attested by an officer so authorized. This attested copy in turn may but need not be certified by any authorized foreign officer both as to the genuineness of the signature of the attesting officer and as to his/her official position. The signature and official position of this certifying foreign officer may then likewise be certified by any other foreign officer so authorized, thereby creating a chain of certificates.

(2) The attested copy, with the additional foreign certificates if any, must be certified by an officer in the Foreign Service of the United States, stationed in the foreign country where the record is kept. This officer must certify the genuineness of the signature and the official position either of (i) the attesting officer; or (ii) any foreign officer whose certification of genuineness of signature and official position relates directly to the attestation or is in a chain of certificates of genuineness of signature and official position relating to the attestation.

(c) *Foreign: Countries Signatory to Convention Abolishing the Requirement of Legalization for Foreign Public Documents.* (1) In any proceeding under this chapter, a public document or entry therein, when admissible for any purpose, may be evidenced by an official publication, or by a copy properly certified under the Convention. To be properly certified, the copy must be accompanied by a certificate in the form dictated by the Convention. This certificate must be signed by a foreign officer so authorized by the signatory country, and it must certify (i) the authenticity of the signature of the person signing the document; (ii) the capacity in which that person acted, and (iii) where appropriate, the identity of the seal or stamp which the document bears.

(2) No certification is needed from an officer in the Foreign Service of public documents.

(3) In accordance with the Convention, the following are deemed to be public documents:

(i) Documents emanating from an authority or an official connected with the courts of tribunals of the state, including those emanating from a public prosecutor, a clerk of a court or a process server;

(ii) Administrative documents;

(iii) Notarial acts; and

(iv) Official certificates which are placed on documents signed by persons in their private capacity, such as official certificates recording the registration of a document or the fact that it was in existence on a certain date, and official and notarial authentication of signatures.

(4) In accordance with the Convention, the following are deemed not to be public documents, and thus are subject to the more stringent requirements of § 287.6(b) above:

(i) Documents executed by diplomatic or consular agents; and

(ii) Administrative documents dealing directly with commercial or customs operations.

Dated: September 13, 1985.

Alan C. Nelson,

Commissioner, Immigration and Naturalization Service.

[FR Doc. 85-22345 Filed 9-17-85; 8:45 am]

BILLING CODE 4410-10-M

DEPARTMENT OF ENERGY

10 CFR Part 903

Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions

AGENCY: Department of Energy.

ACTION: Amendment to final regulations.

SUMMARY: Notice is given that the Deputy Secretary has adopted regulations establishing common public participation procedures for power and transmission rate adjustments and extensions for four Power Marketing Administrations (PMAs) of the Department of Energy: Alaska Power Administration, Southeastern Power Administration, Southwestern Power Administration, and Western Area Power Administration. The Bonneville Power Administration is not included because the Pacific-Northwest Electric Power Planning and Conservation Act, Pub. L. 96-501 (December 5, 1980) (16 U.S.C. 839), establishes unique procedural requirements for Bonneville rate adjustments. The regulations govern the development of rate proposals by the administrators of the four PMAs and the confirmation and approval of rates on an interim basis, subject to refund, by the Deputy Secretary pursuant to the authority delegated by the Secretary of Energy in Delegation Order No. 0204-108 (48 FR 55664, December 14, 1983).

Proposed procedures were published in the **Federal Register** on January 2, 1985 appearing at 50 FR 206. Opportunity for written comments was provided and comments were received from 7 individuals and entities.

EFFECTIVE DATE: The regulations are effective September 18, 1985.

FOR FURTHER INFORMATION CONTACT:
Leon Jourolmon, Jr., Director of Fiscal Operations, Southeastern Power Administration, Samuel Elbert Building, Elberton, Georgia 30635 (404) 283-3261
Richard K. Pelz, Office of the General Counsel, Forrestal Building, U.S. Department of Energy, Washington, DC 20585 (202) 252-2918

SUPPLEMENTARY INFORMATION:

I. Introduction

The existing regulations in 10 CFR Part 903, Subpart A, set forth the procedures for public participation in the development of power and transmission rates for the Alaska, Southeastern, Southwestern, and Western Area Power Administrations. The Bonneville Power Administration is not included because section 7 of the Pacific Northwest Electric Power Planning and Conservation Act, Pub. L. 96-501 (December 5, 1980) (16 U.S.C. 839), establishes unique procedural requirements for Bonneville rate adjustments.

The existing regulations were published in the **Federal Register** on December 31, 1980 (44 FR 86983). They supplement Delegation Order No. 0204-33, which became effective January 1, 1979. That delegation order, among other things, authorized Assistant Secretary for Conservation and Renewable Energy (originally the Assistant Secretary for Resource Applications) to develop power and transmission rates, acting by and through the Administrators of the PMAs, and to confirm, approve and place such rates into effect on an interim basis. The Federal Energy Regulatory Commission (FERC) was given the authority to confirm and approve such rates on a final basis or to disapprove them.

Delegation Order No. 0204-108, which became effective on December 14, 1983 (48 FR 55664), replaced Delegation Order No. 0204-33. Among other changes the new delegation order gave the authority to confirm and approve rates on an interim basis to the Deputy Secretary rather than the Assistant Secretary; provided that rates would be developed by the Administrators; authorized the Administrators to submit rates to the FERC for confirmation and approval on a final basis without prior confirmation and approval on an interim basis; gave the Administrators the authority to put rates for short-term sales into effect on a final basis; and required a certification by the Administrator that the rate is consistent with applicable law and is the lowest possible rate to customers consistent with sound business principles. The revisions to Part 903 incorporate these changes.

The regulations also make several changes, based on four years of experience with the existing procedures, primarily for the purpose of simplifying the regulations and providing more flexibility in their application. The following are the principal changes: Paragraph (c) has been added to both §§ 903.15 and 903.16 authorizing the Administrator to dispense with public information forums and public comment forums if he or she determines that there is no interest in holding them. A provision for informal public meetings for minor rate adjustments has been added. Rates for short term sales are exempted from the regulations at the discretion of the Administrator. The defined terms "Minor new service," "New service," "Revised Proposed Rates" and "Proposed Substitute Rates" have been deleted. The definition of "Rate" has been revised to delete the reference to surcharges and discounts. A sentence has been added explaining that FERC confirmation of a higher Substitute Rate on a final basis constitutes final confirmation of the lower Provisional Rate during the interim period that it was in effect. The provisions relating to refunds have been simplified. The authority of the Deputy Secretary to extend rates on a temporary basis pending further proceedings has been recognized.

A draft of the proposed regulations was published in the Federal Register of January 2, 1985 (50 FR 206). Written comments were invited to be submitted by March 4, 1985. In response to this opportunity, written comments were received from 7 individuals or groups, a list of which is included in the notice.

These procedures shall become effective September 18, 1985.

II. Major Issues

1. Reduction in comment period from 90 days to 45 days on major rate adjustments (§ 903.14(a))

Four commenters objected to the reduction in the comment period on major rate adjustments from 90 days to 45 days. They stated that due process requires that sufficient time be allowed to make meaningful comment.

After further consideration the 90-day provision of the previous procedures has been retained.

2. Elimination of requirement to have a comment period on minor rate adjustments (§ 903.14(a))

Three commenters objected to the elimination of the 30-day comment period for a minor rate adjustment. It is thought that even though a minor rate adjustment may have little economic impact for the PMA, it might have significant impact in the view of a customer.

After further consideration the 30-day provision of the previous procedures has been retained.

3. Elimination of public informtion and comment forums at the discretion of the Administrator (§ 903.15(c) and 903.16(c))

Two commenters objected to the elmination of the requirement to have a public information and public comment forum if the Administrator determines that there is no significant interest in holding one. One commenter states that the potential loss of these forums could significantly hurt the interests of the customers. One other commenter did not object to the elimination of the forums, but suggested that the public forum needed to be scheduled and noticed, and may be cancelled if no person indicates in writing by a prescribed date an intention to appear at such public forum.

After due consideration, the suggestion to schedule public forums suject to cancellation if no person indicates in writing by a prescribed date, an intent to appear, has been adopted.

4. Elimination of "discounts and surcharges" in the definition of a rate (§903.2(1))

One commenter objects to the elimination of "discounts and surcharges" in the definition of a rate. The commenter states that it creates a wide-open loophole in PMA determination of power and transmission rates.

Although "discounts and surcharges" have been deleted from the definition of rates, the definition of rates does not specifically exclude "discounts and surcharges" as it does leasing fees, service facility charges, or other types of facility use charges. The reason is that it sometimes is appropriate to consider "discounts and surcharges" as rates or elements of rates which should be subject to public review and comment, and other times it is not necessary, or appropriate, that they be subjected to public review and comment. There are other terms which are commonly used in rates, or rate schedules, which are similarly neither automatically included or excluded from public review and comment. The elimination of "discounts and surcharges" in the definition of a rate does not create a wide open loophole as suggested because where discounts, surcharges, credits, addons, etc., are appropriately a part of the rate they will be included in the rate review process. Therefore, "discounts and surcharges" have been eliminated from the definition of a rate.

5. Allowing Administrator to make "other procedural changes" (§ 903.14)

One commenter objected to allowing the Administrator to make other procedural changes. The commenter stated that the Administrator could change the proposed rulemaking itself. The commenter recommended that the statement be appended by saying that the Administrator could make a procedural change "not inconsistent with these rules."

After reviewing the proposed change and evaluating the comment received, the language of the existing procedures, which had been shortened for simplification and not for the purpose of eliminating a showing of good cause, was reinstated.

6. Deputy Secretary setting the effective date of a provisional rate (§ 903.21(b))

One commenter objected to allowing the Deputy Secretary to set an effective date that was retroactive. The commenter recommended that the effective date be prospective only.

After evaluating the comment received, the language of the existing procedures was reinstated, amended as follows: replace "Assistant Secretary" with "Deputy Secretary." The intention was simplification, not confusion, of the process.

7. Applicability of procedures to rates for short-term sales (§ 903.1(c))

One commenter noted that the statement that these procedures are not applicable to short term sales of capacity, energy, or transmission is misleading because there are procedural requirements of the DOE Organization Act and the Administrative Procedure Act which do apply.

It is agreed that the provision of the Acts are applicable and the Administrator will comply with them. The misleading statement in § 903.1(c) has been amended for clarification.

8. Applicability of procedures to substitute rates (§ 903.22(c))

One commenter stated that not providing an opportunity to make comments regarding substitute rates, which could be major rate adjustments, if not fair to the consumer.

Substitute rates are prepared in response to the Federal Energy Regulatory Commission (FERC) action. If a customer or interested party is not in agreement with FERC, then any comments or any action should be directed to FERC, which customarily provides the opportunity for comment. This is the same recourse available to the PMA. The provision of an opportunity to comment by the Administrator remains discretionary, as in the language of the existing procedures.

Entities who commented—Listed below are the parties that submitted comments in response to the proposed procedures published in the Federal Register on January 2, 1985 (50 FR 206).

1. American Public Power Association (APPA).
2. Northeast Texas Electric Cooperative, Inc. and Tex-La Electric Cooperative of Texas, Inc.
3. Western Area Power Administration.
4. Arizona Public Service Company.
5. Southeastern Power Resources Committee.
6. Sacramento Municipal Utility District.
7. DOE, Albuquerque Operations Office.

Executive Order 12291

Under the provisions of section 3 of Executive Order 12291, dated February 17, 1981, a Regulatory Impact Analysis must be made prior to the publication of a major rule. The proposed revision of the regulations are of technical nature and simplify procedural requirements applicable to the development of rates. They are considered to be non-major rules within the meaning of the Executive Order. Regulations relating to the sale of electrical power by the various power marketing administrations have been exempted by the Office of Management and Budget (OMB) from prepromulgation review by that agency. Accordingly, no clearance of these proposed regulations by OMB is required.

Regulatory Flexibility Act

Pursuant to sections 601 and 603 of the Regulatory Flexibility Act of 1980 (5 U.S.C. 601, *et seq.*) each agency when required to publish a general notice of proposed rulemaking for any proposed rule shall prepare for public comment an initial Regulatory Flexibility Analysis to describe the impact of the proposed rule on small entities. Under section 601(2) of this Act, "rates," "prices" or "practices," "relating to rates and prices," as used in this Act, are not considered rules for purposes of the Act. The proposed regulations established revised procedures and practices for the development of rates at which power is sold by the power marketing administrations. It follows that the regulations are exempt from the Act. Accordingly, no regulatory flexibility analysis is required.

Paperwork Reduction Act

The Paperwork Reduction Act (44 U.S.C. 3501–3520 (1982)) requires that certain information collection requirements be approved by the Office of Management and Budget before information is demanded of the public. OMB has issued a final rule controlling Paperwork Burdens on the Public (48 FR 13666, March 31, 1983). Ample opportunity is provided in the proposed rules for the interested public to participate with the power marketing administrations in the development of rates. Nevertheless, this is at their sole election. There is no requirement that members of the public participating in the development of rates supply information about themselves to the Government. It follows that the proposed regulations are exempt from the Paperwork Reduction Act.

List of Subjects in 10 CFR Part 903

Electric power rates.

In view of the foregoing, the Department of Energy hereby revises Part 903 to Title 10, Code of Federal Regulations entitled "Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions" as set forth below:

Issued in Washington, DC, September 4, 1984.

Danny J. Boggs,
Deputy Secretary.

10 CFR Part 903 is revised to read as follows:

PART 903—POWER AND TRANSMISSION RATES

Subpart A—Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions for the Alaska, Southeastern, Southwestern, and Western Area Power Administrations

Authority: Secs. 301(b), 302(a), and 644 of Department of Energy Organization Act, Pub. L. 95–91 (42 U.S.C. 7101 *et seq.*); sec. 5 of the Flood Control Act of 1944 (16 U.S.C. 825s); the Reclamation Act of 1902 (43 U.S.C. 372 *et seq.*), as amended and supplemented by subsequent enactments, particularly sec. 9(c) of the Reclamation Project Act of 1939 (43 U.S.C. 485h(c)); and the Acts specifically applicable to individual projects or power systems.

Subpart A—Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions for the Alaska, Southeastern, Southwestern, and Western Area Power Administrations

§ 903.1 Propose and scope; application.

(a) Except as otherwise provided herein, these regulations establish procedures for the development of power and transmission rates by the Administrators of the Alaska, Southeastern, Southwestern, and Western Area Power Administrations; for the providing of opportunities for interested members of the public to participate in the development of such rates; for the confirmation, approval, and placement in effect on an interim basis by the Deputy Secretary of the Department of Energy of such rates; and for the submission of such rates to the Federal Energy Regulatory Commission with or without prior interim approval. These regulations supplement Delegation Order No. 0204–108 of the Secretary of Energy, which was published in the Federal Register and became effective on December 14, 1983 (48 FR 55664), with respect to the activities of the Deputy Secretary and the Administrators.

(b) These procedures shall apply to all power and transmission rate adjustment proceedings for the Power Marketing Administrations (PMAs) which are commenced after these regulations become effective or were in process on the effective date of these regulations, but for which the FERC had not issued any substantive orders on or before December 14, 1983. These procedures supersede "Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions for the Alaska, Southeastern, Southwestern, and Western Area Power Administrations" published in 45 FR 86983 (December 31, 1980) and amended at 46 FR 6864 (January 22, 1981) and 46 FR 25427 (May 7, 1981).

(c) Except to the extent deemed appropriate by the Administrator in accordance with applicable law, these procedures do not apply to rates for short term sales of capacity, energy, or transmission service.

§ 903.2 Definitions.

As used herein—

(a) "Administrator" means the Administrator of the PMA whose rate is involved in the rate adjustment, or anyone acting in such capacity.

(b) "Department" means the Department of Energy, including the PMAs but excluding the Federal Energy Regulatory Commission.

(c) "Deputy Secretary" means the Deputy Secretary of the Department of Energy, or anyone acting in such capacity.

(d) "FERC" means the Federal Energy Regulatory Commission.

(e) "Major rate adjustment" means a rate adjustment other than a minor rate adjustment.

(f) "Minor rate adjustment" means a rate adjustment which (1) will produce less than 1 percent change in the annual revenues of the power system or (2) is for a power system which has either annual sales normally less than 100 million kilowatt hours or an installed capacity of less than 20,000 kilowatts.

(g) "Notice" means the statement which informs customers and the general public of Proposed Rates or proposed rate extensions, opportunities for consultation and comment, and public forums. The Notice shall be by and effective on the date of publication in the **Federal Register**. Whenever a time period is provided, the date of publication in the **Federal Register** shall determine the commencement of the time period, unless otherwise provided in the Notice. The Notice shall include the name, address, and telephone number of the person to contact if participation or further information is sought.

(h) "Power Marketing Administration" or "PMA" means the Alaska Power Administration, Southeastern Power Administration, Southwestern Power Administration, or Western Area Power Administration.

(i) "Power system" means a powerplant or a group of powerplants and related facilities, including transmission facilities, or a transmission system, that the PMA treats as one unit for the purposes of establishing rates and demonstrating repayment.

(j) "Proposed Rate" means a rate revision or a rate for a new service which is under consideration by the Department on which public comment is invited.

(k) "Provisional Rate" means a rate which has been confirmed, approved, and placed in effect on an interim basis by the Deputy Secretary.

(l) "Rate" means the monetary charge or the formula for computing such a charge for any electric service provided by the PMA, including but not limited to charges for capacity (or demand), energy, or transmission service; however, it does not include leasing fees, service facility charges, or other types of facility use charges. A rate may be set forth in a rate schedule or in a contract.

(m) "Rate adjustment" means a change in an existing rate or rates, or the establishment of a rate or rates for a new service. It does not include a change in rate schedule provisions or in contract terms, other than charges in the price per unit of service, nor does it include changes in the monetary change pursuant to a formula stated in a rate schedule or a contract.

(n) "Rate schedule" means a document identified as a "rate schedule," "schedule of rates," or "schedule rate" which designates the rate or rates applicable to a class of service specified therein and may contain other terms and conditions relating to the service.

(o) "Short term sales" means sales that last for no longer than one year.

(p) "Substitute Rate" means a rate which has been developed in place of the rate that was disapproved by the FERC.

§ 903.11 Advance announcement of rate adjustment.

The Administrator may announce that the development of rates for a new service or revised rates for an existing service is under consideration. The announcement shall contain pertinent information relevant to the rate adjustment. The announcement may be through direct contact with customers, at public meetings, by press release, by newspaper advertisement, and/or by **Federal Register** publication. Written comments relevant to rate policy and design and to the rate adjustment process may be submitted by interested parties in response to the announcement. Any comments received shall be considered in the development of Proposed Rates.

§ 903.13 Notice of proposed rates.

(a) The Administrator shall give Notice tht Proposed Rates have been prepared and are under consideration. The Notice shall include:

(1) The Proposed Rates;

(2) An explanation of the need for and derivation of the Proposed Rates;

(3) The locations at which data, studies, reports, or other documents used in developing the Proposed Rates are available for inspection and/or copying;

(4) The dates, times, and locations of any initially scheduled public forums: and

(5) Address to which written comments relative to the Proposed Rates and requests to be informed of FERC actions concerning the rates may be submitted.

(b) Upon request, customers of the power system and other interested persons will be provided with copies of the principal documents used in developing the Proposed Rates.

§ 903.14 Consultation and comment period.

All interested persons will have the opportunity to consult with and obtain information from the PMA, to examine backup data, and to make suggestions for modification of the Proposed Rates for a period ending (a) 90 days in the case of major rate adjustments, or 30 days in the case of minor rate adjustments, after the Notice of Proposed Rates is published in the **Federal Register**, except that such periods may be shortened for good cause shown; (b) 15 days after any answer which may be provided pursuant to § 903.15(b) hereof; (c) 15 days after the close of the last public forum; or (d) such other time as the Administrator may designate; whichever is later. At anytime during this period, interested persons may submit written comments to the PMA regarding the Proposed Rates. The Administrator may also provide additional time for the submission of written rebuttal comments. All written comments shall be available at a designated location for inspection, and copies also will be furnished on request for which the Administrator may assess a fee. Prior to the action described in § 903.21, the Administrator may, by appropriate announcement postpone any procedural date or make other procedural changes for good cause shown at the request of any party or on the Administrator's own motion. The Administrator shall maintain, and distribute on request, a list of interested persons.

§ 903.15 Public information forums.

(a) One or more public information forums shall be held for major rate adjustments, except as otherwise provided in paragraph (c) of this section, and may be held for minor adjustments, to explain, and to answer questions concerning, the Proposed Rates and the basis of and justification for proposing such rates. The number, dates, and locations of such forums will be determined by the Administrator in accordance with the anticipated or demonstrated interest in the Proposed Rates. Notice shall be given in advance of such forums. A public information forum may be combined with a public comment forum held in accordance with § 903.16.

(b) The Administrator shall appoint a forum chairperson. Questions raised at the forum concerning the Proposed Rates and the studies shall be answered by PMA representatives at the forum, at a subsequent forum, or in writing at least 15 days before the end of the consultation and comment period. However, questions that involve voluminous data contained in the PMA records may be answered by providing an opprotunity for consultation and for a review of the records at the PMA offices. As a minimum, the proceedings of the forum held at the principal location shall be transcribed. Copies of all documents introduced, and of questions and written answers shall be available at a designated location for inspection and copies will be furnished by the Administrator on request, for which a fee may be assessed. Copies of the transcript may be obtained from the transcribing service.

(c) No public information forum need be held for major rate adjustments if, after the Administrator has given Notice of a scheduled forum, no person indicates in writing by a prescribed date an intent to appear at such public forum.

§ 903.16 Public comment forums.

(a) One or more public comment forums shall be held for major rate adjustments, except as otherwise provided in paragraph (c) of this section, and may be held for minor rate adjustments, to provide interested persons an opportunity for oral presentation of views, data, and arguments regarding the Proposed Rates. The number, dates, and locations of such forums will be determined by the Administrator in accordance with the anticipated or demonstrated interest in the Proposed Rates. Notice shall be given at least 30 days in advance of the first public comment forum at each location and shall include the purpose, date, time, place, and other information relative to the forum, as well as the locations where pertinent documents are available for examination and/or copying.

(b) The Administrator shall designate a forum chairperson. At the forum, PMA representatives may question those persons making oral statements and comments. The chairperson shall have discretion to establish the sequence of, and the time limits for, oral presentations and to determine if the comments are relevant and noncumulative. Forum proceedings shall be transcribed. Copies of all documents introduced shall be available at a designated location for inspection, and copies shall be furnished on request for which the Administrator may assess a fee. Copies of the transcript may be obtained from the transcribing service.

(c) No public comment forum need be held for major rate adjustments if, after the Administrator has given notice of a scheduled forum, no person indicates in writing by a prescribed date an intent to appear at such public forum.

§ 903.17 Informal public meetings for minor rate adjustments.

In lieu of public information or comment forums in conjunction with a minor rate adjustment, informal public meetings may be held if deemed appropriate by the Administrator. Such informal meetings will not require a Notice or a transcription.

§ 903.18 Revision of proposed rates.

During or after the consultation and comment period and review of the oral and written comments on the Proposed Rates, the Administrator may revise the Proposed Rates. If the Administrator determines that further public comment should be invited, the Administrator shall afford interested persons an appropriate period to submit further written comments to the PMA regarding the revised Proposed Rates. The Administrator may convene one or more additional public information and/or public comment forums. The Administrator shall give Notice of any such additional forums.

§ 903.21 Completion of rate development; provisional rates.

(a) Following completion of the consultation and comment period and review of any oral and written comments on the Proposed Rates, the Administrator may: (1) Withdraw the proposal; (2) develop rates which in the Administrator's and the Deputy Secretary's judgment should be confirmed, approved, and placed into effect on an interim basis (Provisional Rates); or (3) develop rates which in the Administrator's judgment should be confirmed, approved, and placed into effect by the FERC on a final basis without being placed into effect on an interim basis. A statement shall be prepared and made available to the public setting forth the principal factors on which the Deputy Secretary's or the Administrator's decision was based. The statement shall include an explanation responding to the major comments, criticisms, and alternatives offered during the comment period. The Administrator shall certify that the rates are consistent with applicable law and that they are the lowest possible rates to customers consistent with sound business principles. The rates shall be submitted promptly to the FERC for confirmation and approval on a final basis.

(b) The Deputy Secretary shall set the effective date for Provisional Rates. The effective date shall be at least 30 days after the Deputy Secretary's decision except that the effective date may be sooner when appropriate to meet a contract deadline, to avoid financial difficulties, to provide a rate for a new service, or to make a minor rate adjustment.

(c) The effective date may be adjusted by the Administrator to coincide with the beginning of the next billing period following the effective date set by the Deputy Secretary for the Provisional Rates.

(d) Provisional Rates shall remain in effect on an interim basis until: (1) They are confirmed and approved on a final basis by the FERC, (2) they are disapproved and the rates last previously confirmed and approved on a final basis become effective, (3) they are disapproved and higher Substitute Rates are confirmed and approved on a final basis and placed in effect by the FERC, (4) they are disapproved and lower Substitute Rates are confirmed and approved on a final basis by the FERC, or (5) they are superseded by other Provisional Rates placed in effect by the Deputy Secretary, whichever occurs first.

§ 903.22 Final rate approval.

(a) Any rate submitted to the FERC for confirmation and approval on a final basis shall be accompanied with such supporting data, studies, and documents as the FERC may require, and also with the transcripts of forums, written answers to questions, written comments, the Administrator's certification, and the statement of principal factors leading to the decision. The FERC shall also be furnished a listing of those customers and other participants in the rate proceeding who have requested they be informed of FERC action concerning the rates.

(b) If the FERC confirms and approves Provisional Rates on a final basis, such confirmation and approval shall be effective as of the date such rates were placed in effect by the Deputy Secretary, as such date may have been adjusted by the Administrator. If the FERC confirms and approves on a final basis rates submitted by the Administrator without interim approval, such confirmation and approval shall be effective on a date set by the FERC.

(c) If the FERC disapproves Provisional Rates or other submitted rates, the Administrator shall develop Substitute Rates which take into consideration the reasons given by the FERC for its disapproval. If, in the Administrator's judgment, public comment should be invited upon proposed Substitute Rates, the Administrator may provide for a public consultation and comment period before submitting the Substitute Rates. Whether or not such public consultation and comment periods are provided, the Administrator will, upon request, provide customers of the power system and other interested persons with copies of the principal documents used in the development of the Substitute Rates. Within 120 days of the date of FERC disapproval of submitted rates, including Substitute Rates, or such additional time periods as the FERC may provide, the Administrator will submit the Substitute Rates to the FERC. A statement explaining the Administrator's decision shall accompany the submission.

(d) A Provisional Rate that is disapproved by the FERC shall remain in effect until higher or lower rates are confirmed and approved by the FERC on a final basis or are superseded by other rates placed into effect by the Deputy Secretary on an interim basis: Provided, That if the Administrator does not file a Substitute Rate within 120 days of the disapproval or such greater time as the FERC may provide, and if the rate has been disapproved because the FERC determined that it would result in total revenues in excess of those required by law, the rate last previously confirmed and approved on a final basis will become effective on a date and for a period determined by the FERC and revenues collected in excess of such rate during such period will be refunded in accordance with paragraph (g) of this section.

(e) If a Substitute Rate confirmed and approved on a final basis by the FERC is higher than the provisional rate which was disapproved, the Substitute Rate shall become effective on a subsequent date set by the FERC, unless a subsequent Provisional Rate even higher than the Substitute Rate has been put into effect. FERC confirmation and approval of the higher Substitute Rate shall constitute final confirmation and approval of the lower disapproved Provisional Rate during the interim period that it was in effect.

(f) If a Substitute Rate confirmed and approved by the FERC on a final basis is lower than the disapproved provisional rate, such lower rate shall be effective as of the date the higher disapproved rate was placed in effect.

(g) Any overpayment shall be refunded with interest unless the FERC determines that the administrative cost of a refund would exceed the amount to be refunded, in which case no refund will be required. The interest rate applicable to any refund will be determined by the FERC.

(h) A rate confirmed and approved by the FERC on a final basis shall remain in effect for such period or periods as the FERC may provide or until a different rate is confirmed, approved and placed in effect on an interim or final basis: *Provided*, That the Deputy Secretary may extend a rate on an interim basis beyond the period specified by the FERC.

§ 903.23 Rate extensions.

(a) The following regulations shall apply to the extension of rates which were previously confirmed and approved by the FERC or the Federal Power Commission, or established by the Secretary of the Interior, and for which no adjustment is comtemplated:

(1) The Administrator shall give Notice of the proposed extension at least 30 days before the expiration of the prior confirmation and approval, except that such period may be shortened for good cause shown.

(2) The Administrator may allow for consultation and comment, as provided in these procedures, for such period as the Administrator may provide. One or more public information and comment forums may be held, as provided in these procedures, at such times and locations and with such advance Notice as the Administrator may provide.

(3) Following notice of the proposed extension and the conclusion of any consultation and comment period, the Deputy Secretary may extend the rates on an interim basis.

(b) Provisional Rates and other existing rates may be extended on a temporary basis by the Deputy Secretary without advance notice or comment pending further action pursuant to these regulations or by the FERC. The Deputy Secretary shall publish notice in the **Federal Register** of such extension and shall promptly advise the FERC of the extension.

[FR Doc. 85-22365 Filed 9-17-85; 8:45 am]

BILLING CODE 6450-01-M

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Airspace Docket No. 85-AWP-6]

Revocation and Establishment of Compulsory Reporting Points, Hawaii; Correction

AGENCY: Federal Aviation (FAA), DOT.

ACTION: Correction to final rule.

SUMMARY: This action revokes the SEIZE, SQUAT and VILET Compulsory Reporting Points west and southwest of the state of Hawaii. Revocation of these reporting points was inadvertently overlooked in Airspace Docket 85-AWP-6 which revoked and established several compulsory reporting points due to relocation of the Honolulu, HI, air navigation facility.

EFFECTIVE DATE: 0901 GMT, September 26, 1985.

FOR FURTHER INFORMATION CONTACT: Gene Falsetti, Airspace and Air Traffic Rules Branch (ATO-230), Airspace-Rules and Aeronautical Information Division, Air Traffic Operations Service, Federal Aviation Administration, 800 Independence Avenue, SW., Washington, D.C. 20591; telephone: (202) 426-8783.

SUPPLEMENTARY INFORMATION:

History

Federal Register Document 85-18286 was published on August 1, 1985. In that document, the FAA published an amendment to FAR Part 71 that revoked seven and established seven other compulsory reporting points in the state of Hawaii (50 FR 31157). The locations of three of the new reporting points are such that they are approximate to the former SEIZE, SQUAT and VILET Reporting Points. Inadvertently, no action was taken to revoke the replaced reporting points. This action corrects that oversight.

The FAA has determined that this regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. It, therefore—(1) is not a "major rule" under Executive Order 12291; (2) is not a "significant rule" under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a regulatory evaluation as the anticipated impact is so minimal. Since this is a routine matter that will only affect air traffic procedures and air navigation, it is certified that this rule will not have a

Appendix C

Department of Energy Order RA 6120.2

U.S. Department of Energy
Washington, D.C.

ORDER

RA 6120.2

9-20-79

SUBJECT: POWER MARKETING ADMINISTRATION FINANCIAL REPORTING

1. PURPOSE. To establish financial reporting policies, procedures, and methodology for all Department of Energy (DOE) power marketing administrations (PMAs) except where deviations, therefrom are specifically approved by the Secretary, authorized by statute, or identified and explained in a transmittal memorandum or in the footnotes to the reports.

2. CANCELLATION. Paragraph IV. F of INTERIM MANAGEMENT DIRECTIVE 1701, PRICING OF DEPARTMENTAL SERVICES AND PRODUCTS, OF 9-28-77.

3. SCOPE. The provisions of this order apply to the PMAs reporting to the Assistant Secretary for Resource Applications.

4. REFERENCES. Proposed procedures for adjustments in power and transmission rates of the PMAs, 44 F.R. 39184 (July 5, 1979), or such finally adopted procedures.

5. AUTHORITY. This order is issued pursuant to the authority of the Secretary of Energy under the Department of Energy Organization Act, Public Law 95-91, 42 U.S.C. 7101; the Reclamation laws, particularly Section 9(c) of the Reclamation Project Act of 1939, 53 Stat. 1194, 43 U.S.C. 485h(c); Section 5 of the Flood Control Act of 1944, 58 Stat. 890, 16 U.S.C. 825s; the Bonneville Project Act, 50 Stat. 731, as amended, 16 U.S.C. 832 et seq.; the Federal Columbia River Transmission System Act, Public Law 93-454, 16 U.S.C. 838 et seq.; the Eklutna Project Act, 64 Stat. 382, as amended; Section 204 of the Flood Control Act of 1962, 76 Stat. 1193 (Snettisham Project); Reorganization Plan No. 3 of 1950, 64 Stat. 1262; Section 2 of the Act of June 14, 1966, Public Law 89-448, 80 Stat. 200, as amended; Section 303 of the Federal Power Act, 49 Stat. 855, 16 U.S.C. 825b; and related laws.

6. POLICY.

   a. It is DOE policy to encourage sound businesslike financial management and accounting practices in routine accounting and the preparation of power system financial statements. Power system financial statements will be prepared in

DISTRIBUTION:
Power Marketing Administrations

INITIATED BY:
Office of Power Marketing Coordination

accordance with generally accepted accounting principles as prescribed by the American Institute of Certified Public Accountants, the Financial Accounting Standards Board, the General Accounting Office, and the Office of Management and Budget, as appropriate. To the extent practicable, the PMAs will maintain their accounts in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission for public utilities.

b. It is also DOE policy that power repayment studies will be prepared annually using sound and consistent financial forecasting techniques. These forecasts should be designed to approximate as closely as possible the results expected to be achieved in the historical power system financial statements.

7. DEFINITIONS.

a. Assisted Irrigation Investment. "Assisted irrigation investment" means the portion of construction costs of Federal Reclamation projects which are allocated to the irrigation purpose and are assigned pursuant to legal authorization for repayment from the revenues of the power system.

b. Cost Evaluation Period. "Cost evaluation period" means a period of time during which estimates of future costs and revenues may be modified to reflect changing conditions, normally 5 years.

c. Cost Recovery Criteria. "Cost recovery criteria" means the criteria set forth in paragraph 12, beginning on page 13.

d. Investment or Power Investment. "Investment" or "power investment" means unless otherwise indicated in the context, investment allocated to be repaid from power revenues.

e. Power Marketing Administration. "Power marketing administration" means the Alaska Power Administration, the Bonneville Power Administration, the Southeastern Power Administration, the Southwestern Power Administration, or the Western Area Power Administration.

f. Power Repayment Study. "Power repayment study" means a study (previously referred to as an average rate and repayment study or repayment study) portraying the annual repayment of power production and transmission costs of a power system through the application of revenues over the repayment period of the power system. The study shows, among other items, estimated revenues and expenses, year by year, over the remainder of the power system's repayment period (based upon conditions prevailing over the cost evaluation period), the estimated amount of Federal investment amortized during each year, and the total estimated amount of Federal investment remaining to be amortized. The study does not deal with rate design. Power repayment studies may take two forms as described below:

(1) Current Power Repayment Study. A power repayment study that utilizes currently established rates for estimating future revenues. The study reflects the same basic power system included at the time rates were approved.

(2) Revised Power Repayment Study. A study that utilizes, in whole or in part, proposed or assumed rates for estimating future revenues. Typically, it is designed to demonstrate that potential revenue levels will satisfy the cost recovery criteria over the remainder of the power system's repayment period.

g. Power System. A system comprised of one project or more than one project hydraulically and/or electrically integrated and therefore treated as one unit for the purpose of establishing rates.

h. Power System's Repayment Period. A period extending to the final year allowed under the cost recovery criteria for amortization of the original investment in all projects included in the power repayment study.

i. Secretary. The Secretary of Energy.

8. THE ACCOUNTING SYSTEM.

a. The Books of Account. The books of account of all the PMAs will be kept in accordance with accounting systems that are approved by the General Accounting Office and any additional guidelines promulgated by the Secretary. The PMAs shall maintain their power systems accounts in accordance with the uniform system of accounts prescribed by the Federal Energy Regulatory Commission for public utilities and licensees to the extent practicable. Supporting detailed information shall be maintained in a manner that facilitates a ready retrieval, analysis, and verification of pertinent facts. Books of account shall be kept on a monthly basis and closed at the end of each fiscal year.

b. Accounting Concepts. Accounting concepts for PMAs shall be developed around, but not limited to, the following generally accepted principles:

(1) Period Cutoff Accounting. There must be proper cutoff accounting at the beginning and end of the period to ensure that revenues and expenses are not overstated or understated.

(2) Expenses Matched to Period Revenues. Expenses shall be appropriately matched against the periodic revenues.

(3) Current and Fixed Assets. Assets shall be accounted for in a meaningful manner to assure fair presentation of the financial position. Current assets are to be carried at cost or market value, whichever is less; fixed assets are to be carried at cost of acquisition or construction; appropriate charges shall be made for depreciation of fixed assets.

(4) Liabilities. All known liabilities shall be recorded.

c. Specific Power System Accounting Matters. Specific accounting matters which are pertinent to PMA practices include, but are not necessarily limited to, the following:

(1) Interest Rates. Interest expense on the power investment shall be a required portion of the costs to be recovered by power revenues. Rates to be used in computing interest shall be those rates officially established by law, or for all investment with no rate established by law made through 1-29-70, the rate established administratively for such investment, or for all investment made after 1-29-70, the rate established pursuant to paragraph 11, beginning at page 12, and related implementation guidelines.

(2) Unpaid or Deferred Annual Expense. Deficits (or unrecovered expenses) which occur in any year in which revenues fail to recover operation and maintenance, purchased and exchanged power, transmission service and other expenses, and interest expense shall be accrued on the balance sheet as a liability with interest at the rate prescribed in paragraph 11, beginning at page 12, for investment made in the fiscal year in which the loss was incurred.

(3) Priority of Revenue Application. Annual revenues will be first applied to the following recovery of costs during the year in which they are incurred: operation and maintenance (O&M), purchased and exchange power, transmission service and other, and interest expense and any appropriation amortization of revenue bonds. Remaining revenues are available for amortization and shall be applied first to unpaid or deferred annual expense, if any, and then to the Federal investment. To the extent possible, while still complying with the repayment periods established for each increment of investment and unless otherwise indicated by legislation, amortization of the investment will be accompanied by application to the highest interest-bearing investment first.

9. FINANCIAL STATEMENTS.

a. Power System Financial Statements. Power system financial statements shall, to the extent practical, be prepared in accordance with generally accepted accounting principles and concepts. Power system financial results shall be disclosed in a clear, concise, and complete manner. Annual financial statements, accompanied by explanatory footnotes and supporting schedules, shall fairly present the financial position for each PMA power system. Power system reporting requirements shall generally conform to any appropriate standards promulgated by the American Institute of Certified Public Accountants, the Financial Accounting Standards Board, the Federal Energy Regulatory Commission, and the General Accounting Office and shall include, but not necessarily be limited to (1) Statement of Revenues and Expenses or Income Statement; (2) Statement of Assets and Liabilities or Balance Sheet; (3) Statement of Source and Application of Funds or Statement of Changes in Financial Position; (4) Statement of Changes in Proprietary Capital (this statement may be incorporated in either the Statement of Revenues and Expenses or the Statement of Assets and Liabilities); and (5) the appropriate notes to financial statements.

b. Statement of Revenues and Expenses (Income Statement). The results of operations shall be clearly and fairly reported on a comparative basis for the current and preceding fiscal periods. Net Revenues (or Deficit) presents the results of power system operations on a normal accrual accounting basis for the reporting period, after depreciation expense and interest on the unpaid Federal investment.

c. Statement of Assets and Liabilities (Balance Sheet). The financial position of the power system for the current and preceding periods shall present the Federal investment in the power system on a cumulative basis and include a schedule of accumulated net revenues.

d. Statement of Changes in Financial Position (Statement of Source and Application of Funds). A statement of changes in financial position shall be prepared on a comparative basis for the current and preceding fiscal periods to clearly describe the flow of funds of the power system for the reporting period. All power system funds shall be reported according to major source and disposition in a format which is appropriate to conventional regulated-company financial reporting.

e. Notes to the Financial Statements and Supporting Tables. Power system financial statements shall satisfy professional requirements for adequate, informative disclosure. Notes to the financial statements for each power system shall address, as a minimum, the following reporting matters (unless this information is provided elsewhere):

(1) Summary of Significant Accounting Policies. A description of all significant accounting policies of the power system. Policy disclosures shall include, at a minimum: (a) the basis of consolidation, (b) depreciation methods employed, (c) status of allocation of cost varying purposes on multi-purpose projects, and (d) amortization and repayment ; requirements related to the Federal power investment.

(2) Subsequent Events. Disclosure of material events and transactions occurring subsequent to the financial reporting period shall be included if necessary for proper interpretation of the financial statements.

(3) Interest Rates. Current policy regarding interest rates applicable to the reporting power system.

(4) Non-depreciable Assets. The amortization and reporting treatment of the Federal investment in land and other non-depreciable assets.

(5) Contingent Liabilities. A discussion of known major contingent liabilities.

f. Auditor's Opinion. The financial statements and accompanying notes to the financial statements of each power system shall be examined periodically, with the period not to exceed 2 years, by independent auditors, the General Accounting Office, Inspector General, or other acceptable audit organization. The results of this examination shall be reported in a letter which describes the scope of the examination and expresses an opinion on the financial statements.

10. POWER REPAYMENT STUDIES.

a. General Requirements. Each PMA will prepare and publish annually a power repayment study for each power system. Each power repayment study consists of two parts, historical data and future data (forecasts). The development of future data requires the forecast of revenues, expenses and investment. The annual power repayment study will use sound and consistent forecasting techniques. Those forecasting techniques will be explained in a memorandum included with each forecast. The forecasts will utilize, to the extent possible, the accounting concepts set forth on page 4, paragraph 8. The power repayment study is updated annually to test the continuing adequacy of the existing rates. The annual study is called a Current Power Repayment Study. It reflects the same basic power system included at the time rates were approved, but forecasts current operating results and updated estimates of revenues and costs for the remaining years of the repayment study.

b. Rate Adjustment Plan. Whenever the current power repayment study shows that repayment requirements are not being met, action will be taken by the PMA to prepare and recommend a plan to be implemented at the next practicable time to satisfy the repayment requirements (or to explain why such requirements cannot be met). Such plan may include increasing rates, decreasing costs, changing contracts, or any other viable means for meeting cost recovery criteria. This plan will be supported by a Revised Power Repayment Study which will meet the cost recovery criteria. The plan will be submitted to the Assistant Secretary for Resource Applications through the Office of Power Marketing Coordination for review and further action. In certain situations the plan could recommend that no action be taken to meet repayment requirements. While a revised power repayment study must be prepared at a minimum when a current power repayment study shows that repayment requirements are not being met, preparation is not limited to that situation.

c. Cost Evaluation Period. A period of time during which future estimates of costs and revenues may be modified to reflect changing conditions, such as additions to the power systems or inflation. This period of time is normally 5 years. Revenue and cost estimates for the remaining years of the power system's repayment period should reflect price levels, rate levels, and contractual commitments consistent with conditions anticipated during the cost evaluation period.

d. Allowable Unamortized Investment. Each increment of investment shall be carried as allowable unamortized investment for its repayment period in accordance with the following principles:

(1) Duration of Repayment Period. Unless otherwise prescribed by law, each dollar of investment is to be repaid with interest within a period not-to-exceed 50 years. Repayment periods of less than 50 years may be established when the facilities involved have useful life expectancies of less than 50 years. Such shorter repayment periods are appropriate for (a) replacement of power facilities and (b) transmission facilities which are developed and managed as transmission systems rather than as adjuncts to generating projects. In such cases, the expected useful life of the facility involved generally will be used as the repayment period. Such repayment periods may be adjusted from time to time, within the 50-year maximum, if changed conditions indicate a different estimated useful life expectancy.

(2) Start of the Repayment Period. The first year of the repayment period for both specific and joint investment cost shall be the fiscal year following the fiscal year in which the investment goes into commercial service. After each portion of allocated repayable power investment goes into commercial service, the total joint investment costs for a power generating facility shall,

on a pro rata basis, be associated with the specific investment costs incurred in the initial stage of project development (the initial stage of development includes all power units which are initially constructed in a continuous sequence without a time lag or more than 5 years between generating units).

e. Revenues.

(1) Power revenues shall be those expected through the power system's repayment period, based on contractual commitments for sales of power and energy that are expected to exist during the cost evaluation period.

(2) In the absence of specific contractual provisions for increased power sales, the revenue forecast will rely heavily on the past trends of actual customer load growth rates. Where contractual payments for power and/or quantities of such power and energy sales are defined, these shall form the basis for revenue determination.

(3) Power quantities for forecasting future revenues shall also include purchased and exchange power quantities which are consistent with contractual commitments that are estimated to exist during the cost evaluation period, and only to the extent that related costs are also projected. The revenue forecast shall also consider capacity increases resulting from facility additions which are projected to be commercially operational within the cost evaluation period. A schedule comparing revenue estimates for the previous period with actual revenue realized should be included with the annual submission. Miscellaneous revenues shall be included where appropriate, as well as headwater benefit payments to be made to the Treasury for power benefits to non-Federally owned utility hydroplants.

(4) Power quantities used for estimating revenues, unless defined by contract, are determined by theoretical reservoir operation studies based on historical stream flows. In preparing these operational studies, hydrological data, current to within 5 years if possible, and available engineering data will be used, recognizing restrictions imposed by other project functions. Input data will be revised and updated whenever new information indicates that a significant change in the forecast can be expected in the future where there is a significant variance between the forecasted and actual results, but in any event not less frequently than once every 5 years unless an accepted explanation is provided concerning why this is not necessary.

f. Operation and Maintenance Costs. Estimates of O&M costs shall be developed with heavy reliance placed on historical cost trends and actual project costs in the past. The use of various cost indices, developed from and supported by project history is recommended in developing the forecast and testing its reliability. In preparing the estimate, actual costs will be compared to past forecasts to identify sources of variance and previous projection errors. A schedule showing these comparisons will be included with the annual power repayment update. The forecast shall take into account known factors which are expected to affect the future level of such costs during the cost evaluation period.

g. Purchase and Exchange Power Costs. All costs of planned purchased power during the cost evaluation period shall be included in the power repayment study.

h. Transmission Service and Other Costs. These costs, to be estimated for the cost evaluation period, include payments to others required by legislation, "wheeling" payments for use of transmission capacity, rental payments for the use of electrical facilities, payments for detriment caused by project facilities or operation, payments for increased benefits furnished by others, credit payments under certain contracts, and interconnection costs for which a payment is made based on contractual commitments.

i. Interest Rates. Interest rates shall be established as set forth on page 4, paragraph 8c(1) for historical and current rates. Forecasts will utilize the rate established in paragraph 11, beginning on page 12, and related implementation guidelines for the latest available year for all future years.

j. Interest Expense. Interest expense for each of the years of the study will be the sum of the amounts determined by: (1) applying the applicable interest rate to each estimated unamortized power investment at the beginning of the year; plus (2) applying one-half the applicable interest rate to power investments (i.e., additions and replacements) expected to be added and in service during the year; plus (3) applying the applicable interest rate to capitalized unpaid or deferred annual expense, if any. If the interest credit concept is utilized by the PMA, the interest credit should be offset against interest expense.

k. Investment Costs. The power repayment studies will include all investment cost allocated to power for the existing systems. Additionally, the allocated power investment costs of all authorized power system facilities for which Congress has appropriated funds for construction and which will be in service within the cost evaluation period will be included. The investment cost will include construction cost of the project as well as interest during construction, computed using the same rate as determined in paragraph 10i.

l. Replacements. Future replacement costs will be included in repayment studies by adding the estimated capital cost of replacement to the unpaid Federal investment in the year each replacement is estimated to go into service, and adding it to the allowable unamortized investment. The capital costs of each replacement is determined by estimating the cost at current price levels of the new unit of property, less salvage, if any, at the end of the service life of the unit replaced. The allowable unamortized investment is developed by adding each year's investment as it goes into service and then deducting each increment of investment at the end of its allowable repayment period. Replacements should be accounted for separately from the original investment.

m. Status of Repayment. For any year of a power system study, the status of repayment can be determined by comparing the allowable unamortized investment with the unamortized investment. For every year that the unamortized investment is equal to or less than the allowable unamortized investment, repayment is on or ahead of schedule. If for any year the unamortized investment exceeds the allowable, the cost recovery criteria are not being met.

n. Content and Format of Power Repayment Study. Power repayment studies for all power systems shall be accompanied by a statement of pertinent assumptions used in preparing the studies. Further, there should be submitted a schedule which will show significant changes as compared with the previous study and a comparison of the previous forecast to actual performance for the same period. The format of the power repayment studies prepared by the PMAs will be expected to vary to some extent due to differences in conditions among PMAs, e.g., some have transmission systems, while others do not.

11. INTEREST RATE FORMULA.

a. Except as otherwise provided by law, the interest rate to be used for computing interest during construction and interest on the unpaid balance of the costs of Federal power facilities, the construction of which is initiated after September 30, 1983, which are financed with appropriations and the cost of which is properly allocated to commercial power development, shall be the yield rate, as hereinafter provided in subparagraph "b" of this paragraph, during the fiscal year in which construction is initiated. For purposes of this paragraph, the facilities for which a separate interest rate is established may be any of the following so long as repayment periods are established for them:

(1) A Federal reservoir or canal project which includes the generation of electric power that is marketed by a PMA and which may also include transmission facilities constructed during the same stage of construction;

(2) Any unit or separable power feature or groups of such units of features of such Federal reservoir or canal project;

(3) Any separable features or groups of features of a Federal transmission system, including transmission lines, substations, and appurtenant facilities, which are under the administration of a PMA that are not considered a part of a Federal reservoir or canal project;

(4) Annual increments of investment in separable features or groups of features of a Federal transmission system that are placed in service during the same year; or

(5) Replacements of or additions or betterments to power facilities.

b. Each fiscal year the Assistant Secretary for Conservation and Renewable Energy will request the Secretary of the Treasury to provide the computations made as of October 1 of the yield rate for the preceding fiscal year. For purposes of this paragraph, the yield rate is the average yield during the preceding fiscal year on interest-bearing marketable securities of the United States which, at the time the computation is made, have terms of 15 years or more remaining to maturity. The average yield shall be computed as the average during the fiscal year of the daily bid prices. Where the average yield so computed is not a multiple of one-eighth of one percent, the yield rate shall be the multiple of one-eighth of one percent nearest to such average yield.

c. The Assistant Secretary shall annually notify the PMAs of the yield rate for the current fiscal year.

12. COST RECOVERY CRITERIA. The current rates for a power system will be adequate if, and only if, a power repayment study indicates that:

a. The expected revenues are at least sufficient to recover annually, except for a possible initial short transition period:

(1) All costs of operating and maintaining the power system during the year in which such costs are incurred; plus,

(2) The cost of acquiring power through purchase and/or exchange agreements, the costs for transmission services, and other costs during the year in which such costs are incurred; plus,

(3) Expensed interest on the unamortized investment in Federal power facilities in the year for which the interest charges are assessed, except that recovery of the annual interest expense may be deferred in unusual circumstances for short periods of time; plus,

(4) Interest and amortization of revenue bonds where PMAs are authorized to issue such bonds.

b. In addition to the recovery of the above costs on a year-by-year basis, the expected revenues are at least sufficient to recover:

(1) Each dollar of power investment at Federal hydroelectric generating plants within 50 years after they become revenue producing, except as otherwise provided by law: plus,

(2) Each annual increment of Federal transmission investment within the average service life of such transmission facilities or within a maximum of 50 years, whichever is less; plus,

(3) The cost of each replacement of a unit of property of a Federal power system within its expected service life up to a maximum of 50 years; plus,

(4) Each dollar of assisted irrigation investment within the period established for the irrigation water users to repay their share of construction costs; plus,

(5) Other costs such as payments to basin funds, participating projects or States.

13. SUBMISSION. Power system financial statements and power repayment studies will be forwarded to the Assistant Secretary for Resource Applications and shall be accompanied by a statement from the PMA Administrator that the financial statements and power repayment studies are in compliance with this order. Any deviation therefrom shall be disclosed and justified. Copies of power system financial statements and power repayment studies will be provided for policy guidance, evaluation of methodology, and compliance review, and shall be delivered within 180 days of the close of the applicable fiscal year.

FOR THE SECRETARY OF ENERGY:

George S. McIsaac
Assistant Secretary for
Resource Applications

Appendix D

Power Repayment Study

PARKER-DAVIS PROJECT
POWER REPAYMENT STUDY

		EXPENSES											CAPITALIZED DEFICITS			
Fiscal Year	Total Revenue	Operations & Maintenance	Purchased Power/Wheeling	Other	Provision for Depreciation	Interest	Total	Prior Year Adjustments	Revenue After Annual Expenses	Total Principal Payments	Incremental Change to Carryover Start FY 1996	Cumulative Carryover Start FY 1996	Principal Payment	Unpaid Balance	Allowable Unpaid Balance	Cumulative Balance
1943	438,272	56,595	0	118,955	118,137	242,465	536,152	34,124	(132,004)	(59,567)			0	0	0	0
1944	2,018,279	276,100	158,629	347,700	142,587	244,252	1,169,268	328	848,683	883,136			0	0	0	0
1945	2,039,093	293,197	39,936	346,750	143,410	225,479	1,048,772	208	990,113	990,649			0	0	0	0
	~~ 1946-1990 ommitted to condense reporting - Full information available at http://www.wapa.gov/dsw/pwrmkt/RateAdjust/Main.htm ~~~~~															
1991	25,907,615	20,181,577	1,064,568	(1,401,828)	0	2,934,571	22,778,888	0	3,128,727	3,012,868			0	0	0	0
1992	27,268,369	21,204,063	2,276,734	0	0	3,555,804	27,036,601	0	231,768	0			0	1,206,171	1,206,171	1,206,171
1993	27,936,119	24,425,486	5,277,611	0	0	4,983,758	34,686,855	0	(6,750,736)	0			0	7,956,907	7,956,907	7,956,907
1994	31,907,458	18,580,336	1,305,714	0	0	7,879,227	27,765,277	0	4,142,181	3,452,569			3,452,569	4,504,338	7,956,907	7,956,907
1995	31,511,845	20,459,235	575,093	0	0	9,410,857	30,445,185	0	1,066,660	1,066,661			1,066,661	3,437,677	7,956,907	7,956,907
1996	30,672,693	21,539,162	277,426	153,855	0	8,224,697	30,195,140	0	477,553	477,553	0.00	0.00	477,553	2,960,124	7,956,907	7,956,907
1997	37,209,769	19,052,880	177,778	153,855	0	12,072,066	31,456,579	0	5,753,190	2,960,124	2,793,066	2,793,066	2,960,124	0	7,956,907	7,956,907
1998	30,930,885	19,284,517	581,769	1,345,226	0	11,777,599	32,989,111	0	(2,058,226)	506,876	(2,565,102)	227,964	0	0	7,956,907	7,956,907
1999	37,476,820	19,359,015	104,931	292,646	0	12,007,179	31,763,771	0	5,713,049	636,572	5,076,478	5,304,441	0	0	7,956,907	7,956,907
2000	40,262,024	19,639,343	244,946	814,196	0	12,431,534	33,130,019	0	7,132,005	3,027,547	4,104,458	9,408,899	0	0	7,956,907	7,956,907
2001	44,245,434	19,317,486	548,639	997,529	0	12,667,221	33,530,874	0	10,714,559	1,679,247	9,035,313	18,444,212	0	0	7,956,907	7,956,907
2002	41,640,841	22,801,697	255,325	1,130,433	0	13,989,667	38,177,123	0	3,463,718	2,602,030	861,687	19,305,899	0	0	6,750,736	7,956,907
2003	48,086,660	23,950,851	2,346,948	1,461,638	0	14,575,955	42,335,392	0	5,751,267	3,257,639	2,493,628	21,799,528	0	0	0	7,956,907
2004	51,746,896	26,149,241	3,447,691	1,567,270	0	14,941,902	46,106,104	0	5,640,792	1,475,966	4,164,826	25,964,354	0	0	0	7,956,907
2005	50,933,486	26,223,595	8,639,471	1,673,277	0	14,652,379	51,188,722	0	(255,236)	1,614,578	(1,869,814)	24,094,540	0	0	0	7,956,907
2006	54,278,690	25,526,225	1,332,541	1,495,277	0	8,181,217	36,535,260	0	17,743,430	4,880,084	12,863,346	36,957,886	0	0	0	7,956,907
2007	55,419,611	30,451,404	0	674,033	0	14,598,034	45,723,471	0	9,696,140	3,839,596	5,856,544	42,814,430	0	0	0	7,956,907
Prior Year Adj.	8,992,676	3,742,419	0	(1,401,828)	(19,939,118)	(9,661,872)	(27,260,399)	(9,744,498)	45,997,573	7,615,883			0	0	0	0
HISTORICAL SUBTOTAL	1,195,783,502	600,813,300	39,657,516	21,719,036	0	255,218,924	917,408,775	(142,462)	55,693,713	248,313,790			7,956,907	0	0	7,956,907
2008	51,611,857	31,351,664	700,000	633,795	0	15,664,452	48,349,911	0	3,261,946	4,451,992	(1,190,046)	41,624,384	0	0	0	7,956,907
2009	50,734,270	30,159,829	4,208,635	1,456,361	0	16,101,724	51,926,549	0	(1,192,278)	4,739,534	(5,931,812)	35,692,572	0	0	0	7,956,907
2010	50,730,238	31,752,775	4,208,635	1,456,361	0	16,747,031	54,164,802	0	(3,434,564)	3,301,196	(6,735,760)	28,956,812	0	0	0	7,956,907
2011	50,725,925	33,204,356	4,208,635	1,456,361	0	17,210,678	56,080,030	0	(5,354,105)	3,193,400	(8,547,505)	20,409,306	0	0	0	7,956,907
2012	50,722,318	33,397,198	4,208,635	1,456,361	0	17,603,081	56,665,275	0	(5,942,957)	3,442,238	(9,385,195)	11,024,111	0	0	0	7,956,907
2013	50,718,250	33,186,932	4,208,635	1,456,361	0	18,602,992	57,454,920	0	(6,736,670)	4,287,441	(11,024,111)	0	0	0	0	7,956,907
FUTURE YR SUBTOTAL	253,631,001	161,701,090	21,043,175	7,281,805	0	86,265,506	276,291,576	0	(6,736,670)	18,963,809	(11,024,111)	0	0	0	0	7,956,907
2014	66,856,513	33,186,932	4,208,635	1,456,361	0	20,068,709	58,920,637	0	7,935,876	7,806,251	129,625	129,625	0	0	0	7,956,907
2015	67,859,935	33,186,932	4,208,635	1,456,361	0	20,383,388	59,235,316	0	8,624,619	8,344,355	280,264	409,889	0	0	0	7,956,907
2016	69,199,356	33,186,932	4,208,635	1,456,361	0	21,309,928	60,161,856	0	9,037,500	9,103,591	(66,091)	343,798	0	0	0	7,956,907
2017	69,865,808	33,186,932	4,208,635	1,456,361	0	21,568,940	60,420,868	0	9,444,940	9,733,929	(288,989)	54,809	0	0	0	7,956,907
2018	69,187,407	33,186,932	4,208,635	1,456,361	0	21,323,056	60,174,984	0	9,012,423	7,268,006	1,744,417	1,799,226	0	0	0	7,956,907
2019	69,198,599	33,186,932	4,208,635	1,456,361	0	20,738,719	59,590,647	0	9,607,952	7,770,191	1,837,761	3,636,987	0	0	0	7,956,907
2020	65,499,049	33,186,932	4,208,635	1,456,361	0	20,094,496	58,946,424	0	6,552,626	8,280,665	(1,728,039)	1,908,948	0	0	0	7,956,907
2021	66,171,695	33,186,932	4,208,635	1,456,361	0	19,385,312	58,237,240	0	7,934,455	8,827,285	(892,831)	1,016,117	0	0	0	7,956,907
2022	66,171,695	33,186,932	4,208,635	1,456,361	0	18,625,302	57,477,230	0	8,694,464	9,412,769	(718,305)	297,812	0	0	0	7,956,907
2023	66,508,017	33,186,932	4,208,635	1,456,361	0	17,810,996	56,662,924	0	9,845,093	10,040,051	(194,958)	102,854	0	0	0	7,956,907
2024	66,844,340	33,186,932	4,208,635	1,456,361	0	16,929,141	55,781,069	0	11,063,271	10,860,325	202,945	305,800	0	0	0	7,956,907
2025	66,844,340	33,186,932	4,208,635	1,456,361	0	15,983,097	54,835,025	0	12,009,315	11,953,750	55,564	361,364	0	0	0	7,956,907
2026	66,171,695	33,186,932	4,208,635	1,456,361	0	15,019,462	53,871,390	0	12,300,304	11,872,929	427,375	788,739	0	0	0	7,956,907
2027	66,171,695	33,186,932	4,208,635	1,456,361	0	14,134,411	52,986,339	0	13,185,355	12,235,053	950,302	1,739,041	0	0	0	7,956,907
2028	66,171,695	33,186,932	4,208,635	1,456,361	0	13,231,845	52,083,773	0	14,087,921	12,926,515	1,161,407	2,900,447	0	0	0	7,956,907
2029	66,171,695	33,186,932	4,208,635	1,456,361	0	12,311,690	51,163,618	0	15,008,077	11,559,089	3,448,988	6,349,435	0	0	0	7,956,907
2030	64,153,758	33,186,932	4,208,635	1,456,361	0	11,482,120	50,334,048	0	13,819,710	11,651,818	2,167,892	8,517,328	0	0	0	7,956,907
	~~ 2031-2062 ommitted to condense reporting - Full information available at http://www.wapa.gov/dsw/pwrmkt/RateAdjust/Main.htm ~~~~~															
2063	62,110,164	33,186,932	4,208,635	1,302,246	0	0	38,697,813	0	23,412,351	0	23,412,351	498,563,065	0	0	0	7,956,907
2064	62,110,164	33,186,932	4,208,635	1,302,246	0	0	38,697,813	0	23,412,351	0	23,412,351	521,975,416	0	0	0	7,956,907
2065	62,110,164	33,186,932	4,208,635	1,302,246	0	0	38,697,813	0	23,412,351	0	23,412,351	545,387,767	0	0	0	7,956,907
STUDY TOTAL	4,846,163,555	2,519,586,518	280,249,711	102,283,132	0	741,834,016	3,643,953,376	(142,462)	23,412,351	669,575,905	23,412,351		7,956,907	0	0	7,956,907

PARKER-DAVIS PROJECT
POWER REPAYMENT STUDY

Fiscal Year	Incremental Annual Investment	REPLACEMENTS Principal Payment	REPLACEMENTS Unpaid Balance	REPLACEMENTS Allowable Unpaid Balance	REPLACEMENTS Cumulative Balance	REPLACEMENTS Incremental Annual Investment	PROJECT & ADDITIONS Principal Payment	PROJECT & ADDITIONS Unpaid Balance	PROJECT & ADDITIONS Allowable Unpaid Balance	PROJECT & ADDITIONS Cumulative Balance	PROJECT & ADDITIONS Incremental Annual Investment	AID TO IRRIGATION Principal Payment	AID TO IRRIGATION Unpaid Balance	AID TO IRRIGATION Allowable Unpaid Balance	AID TO IRRIGATION Cumulative Balance	AID TO IRRIGATION Incremental Annual Investment
1943	0	0	0	0	0	0	(59,567)	8,141,743	8,082,176	8,082,176	8,082,176	0	0	0	0	0
1944	0	0	0	0	0	0	883,136	7,515,983	8,339,552	8,339,552	257,376	0	698,564	698,564	698,564	698,564
1945	0	0	0	0	0	0	990,649	6,907,382	8,721,600	8,721,600	382,048	0	700,475	700,475	700,475	1,911
	~~ 1946-1990 ommitted to condense reporting - Full information available at http://www.wapa.gov/dsw/pwrmkt/RateAdjust/Main.htm ~~~															
1991	0	0	3,473,422	29,425,276	29,425,276	0	3,012,868	16,199,000	180,320,048	180,320,048	(2,273,158)	0	0	26,769,876	26,769,876	0
1992	1,206,171	0	1,716,717	27,668,571	27,668,571	(1,756,705)	0	35,274,580	199,395,628	199,395,628	19,075,580	0	0	26,769,876	26,769,876	0
1993	6,750,736	0	7,319,375	33,271,229	33,271,229	5,602,658	0	60,838,305	224,959,353	224,959,353	25,563,725	0	0	26,769,876	26,769,876	0
1994	0	0	18,212,456	44,164,310	44,164,310	10,893,081	0	79,551,686	235,333,182	243,672,734	18,713,381	0	0	26,071,312	26,769,876	0
1995	0	0	16,911,326	42,863,180	42,863,180	(1,301,130)	0	77,625,521	233,024,969	241,746,569	(1,926,165)	0	0	26,069,401	26,769,876	0
1996	0	0	37,740,172	63,692,026	63,692,026	20,828,846	0	81,299,829	236,417,192	245,420,877	3,674,308	0	0	26,060,007	26,769,876	0
1997	0	0	43,856,455	69,808,309	69,808,309	6,116,283	0	91,367,734	242,940,496	255,488,782	10,067,905	0	0	26,060,813	26,769,876	0
1998	0	0	48,548,992	74,500,846	74,500,846	4,692,537	506,876	91,345,634	241,906,480	255,973,558	484,776	0	0	25,674,853	26,769,876	0
1999	0	159,865	50,072,258	76,183,977	76,183,977	1,683,131	471,309	95,850,800	246,094,338	260,950,034	4,976,475	5,398	90,691	25,683,261	26,865,965	96,089
2000	0	2,068,095	53,150,168	81,303,251	81,329,982	5,146,005	561,885	96,750,852	244,475,173	262,411,970	1,461,937	397,567	399,728	26,136,326	27,572,568	706,603
2001	0	755,532	63,577,525	90,517,238	92,512,871	11,182,889	771,155	103,417,223	179,265,021	269,849,496	7,437,526	152,559	3,974,169	19,237,250	31,299,569	3,727,001
2002	0	1,749,041	75,041,020	102,974,241	105,725,407	13,212,536	586,211	102,871,746	176,538,930	269,890,230	40,734	266,779	5,751,690	10,069,192	33,343,869	2,044,300
2003	0	2,918,957	81,512,941	111,043,927	115,116,284	9,390,877	0	104,155,347	173,493,768	271,173,831	1,283,601	338,682	6,454,588	9,372,215	34,385,449	1,041,580
2004	0	1,475,966	82,602,443	111,932,112	117,681,752	2,565,468	0	109,508,821	175,692,677	276,527,306	5,353,474	0	6,403,711	9,654,857	34,334,572	(50,877)
2005	0	1,612,974	83,200,189	108,122,384	119,892,472	2,210,721	0	112,607,433	176,829,291	279,625,917	3,098,611	1,604	6,403,711	9,457,818	34,336,176	1,604
2006	0	984,208	105,376,532	131,067,664	143,053,023	23,160,551	1,895,462	110,973,976	175,134,104	279,887,922	262,005	2,000,414	1,909,182	8,369,594	31,842,061	(2,494,115)
2007	0	1,457,406	115,594,541	138,127,924	154,728,438	11,675,415	2,382,190	109,033,786	175,798,781	280,329,922	442,000	0	1,433,789	7,338,913	31,366,668	(475,393)
Prior Year Adj.	0	(2,295,858)	0	0	0	18,498,250	8,456,205	0	0	0	(12,420,801)	1,455,536	0	0	0	(4,228,410)
HISTORICAL SUBTOTAL	7,956,907	39,133,897	115,594,541	138,127,924	154,728,438	154,728,438	171,290,106	109,033,786	175,798,781	280,329,922	280,329,922	29,932,879	1,433,789	7,338,913	31,366,668	31,366,668
2008	0	3,143,018	124,135,523	146,331,373	166,412,438	11,684,000	1,308,974	107,724,812	175,499,921	280,329,922	0	0	1,433,789	7,414,312	31,366,668	0
2009	0	4,629,857	133,576,666	156,964,102	180,483,438	14,071,000	109,677	110,211,135	178,103,037	282,925,922	2,596,000	0	1,433,789	7,393,380	31,366,668	0
2010	0	3,301,196	141,441,470	164,996,320	191,649,438	11,166,000	0	110,211,135	178,104,904	282,925,922	0	0	1,433,789	7,499,113	31,366,668	0
2011	0	3,193,400	147,844,070	173,455,889	201,245,438	9,596,000	0	110,211,135	177,709,998	282,925,922	0	0	1,433,789	7,501,696	31,366,668	0
2012	0	3,442,238	166,723,832	195,571,157	223,567,438	22,322,000	0	110,211,135	181,170,544	282,925,922	0	0	1,433,789	3,646,969	31,366,668	0
2013	0	4,237,041	202,764,391	234,391,912	263,845,038	40,277,600	0	110,211,135	181,032,178	282,925,922	0	50,400	1,433,789	3,689,251	31,417,068	50,400
FUTURE YR SUBTOTAL	0	18,803,732	202,764,391	234,391,912	263,845,038	97,432,600	109,677	110,211,135	181,032,178	282,925,922	2,596,000	50,400	1,433,789	3,689,251	31,417,068	50,400
2014	0	7,302,251	213,888,140	252,394,150	282,271,038	18,426,000	0	110,211,135	181,007,322	282,925,922	0	504,000	1,433,789	4,137,613	31,921,068	504,000
2015	0	7,840,355	238,261,785	279,000,301	314,485,038	32,214,000	0	110,211,135	179,938,627	282,925,922	0	504,000	1,433,789	4,141,173	32,425,068	504,000
2016	0	8,599,591	249,071,194	295,227,539	333,894,038	19,409,000	0	110,211,135	178,822,410	282,925,922	0	504,000	1,433,789	4,136,374	32,929,068	504,000
2017	0	9,229,929	249,258,265	302,134,280	343,311,038	9,417,000	0	110,211,135	178,376,142	282,925,922	0	504,000	1,433,789	4,121,522	33,433,068	504,000
2018	0	3,631,814	247,581,451	300,054,544	345,266,038	1,955,000	3,636,192	106,574,943	177,820,447	282,925,922	0	0	1,433,789	3,598,397	33,433,068	0
2019	0	0	247,581,451	299,576,411	345,266,038	0	7,770,191	98,804,752	176,380,497	282,925,922	0	0	1,433,789	3,581,536	33,433,068	0
2020	0	0	247,581,451	297,218,911	345,266,038	0	8,280,665	90,524,087	174,821,462	282,925,922	0	0	1,433,789	3,054,006	33,433,068	0
2021	0	1,319,485	246,261,966	292,136,747	345,266,038	0	7,507,800	83,016,286	174,821,462	282,925,922	0	0	1,433,789	3,005,621	33,433,068	0
2022	0	9,412,769	236,849,197	288,774,971	345,266,038	0	0	83,016,286	174,821,462	282,925,922	0	0	1,433,789	2,977,538	33,433,068	0
2023	0	3,303,545	233,545,652	288,774,971	345,266,038	0	6,736,506	76,279,780	173,436,276	282,925,922	0	0	1,433,789	2,693,877	33,433,068	0
2024	0	155,045	233,390,607	290,689,381	345,266,038	0	10,705,280	65,574,500	173,391,420	282,925,922	0	0	1,433,789	2,691,335	33,433,068	0
2025	0	3,246,755	230,143,852	285,086,723	345,266,038	0	8,706,995	56,867,505	173,153,035	282,925,922	0	0	1,433,789	2,529,934	33,433,068	0
2026	0	3,002,181	227,141,671	281,102,943	345,266,038	0	8,870,748	47,996,757	173,155,731	282,925,922	0	0	1,433,789	2,470,766	33,433,068	0
2027	0	1,339,886	225,801,784	280,501,253	345,266,038	0	10,895,167	37,101,590	173,155,731	282,925,922	0	0	1,433,789	2,470,766	33,433,068	0
2028	0	11,667,168	214,134,616	259,443,526	345,266,038	0	1,259,347	35,842,243	173,155,731	282,925,922	0	0	1,433,789	2,470,766	33,433,068	0
2029	0	11,559,089	202,575,527	253,216,945	345,266,038	0	0	35,842,243	173,111,956	282,925,922	0	0	1,433,789	2,377,114	33,433,068	0
2030	0	5,712,045	196,863,482	248,524,408	345,266,038	0	5,939,772	29,902,471	173,034,138	282,925,922	0	0	1,433,789	2,377,114	33,433,068	0
	~~ 2031-2062 ommitted to condense reporting - Full information available at http://www.wapa.gov/dsw/pwrmkt/RateAdjust/Main.htm ~~~															
2063	0	0	0	0	345,266,038	0	0	0	0	282,925,922	0	0	0	0	33,433,068	0
2064	0	0	0	0	345,266,038	0	0	0	0	282,925,922	0	0	0	0	33,433,068	0
2065	0	0	0	0	345,266,038	0	0	0	0	282,925,922	0	0	0	0	33,433,068	0
STUDY TOTAL	7,956,907	345,266,038	0	0	345,266,038	345,266,038	282,919,892	0	0	282,925,922	282,925,922	33,433,068	0	0	33,433,068	33,433,068

Appendix E

Cost Apportionment Study

PARKER-DAVIS PROJECT
COST APPORTIONMENT STUDY

	FY 2009			
	Total	Allocation Factor	Generation	Transmission
Annual Expenses				
Western O&M				
Systemwide Expenses	4,339,890	Customers/Gen/Tran	1,415,450	2,924,440
Substation & Transmission Lines	9,032,430	Transmission	0	9,032,430
Communication & Control Equipment	1,426,432	SCADA	14,174	1,412,258
System Operation & Load Dispatch	3,724,565	SCADA/Tran	32,527	3,692,038
Subtotal Western O&M	18,523,317		1,462,151	17,061,166
	100%		7.9%	92.1%
Western General Expenses	5,722,061	% of Subtotal	451,675	5,270,386
Bureau of Reclamation O&M	6,114,000	Generation	6,114,000	0
Purchase Power	4,208,635	Generation	4,208,635	0
Capitalized Movable Equipment	1,377,569	% of Subtotal	108,739	1,268,830
Mead Service Center (Multi-Project)	142,458	Transmission	0	142,458
Bureau of Reclamation Replacements	2,340,000	Generation	2,340,000	0
Principal/Interest Payments - Reclamation	81,048	Generation	81,048	0
Principal/Interest Payments - Western	18,156,994	Transmission	0	18,156,994
Total Annual Gross Expenses	56,666,084		14,766,248	41,899,835
	100%		26.1%	73.9%
Other Revenues				
Nonfirm Transmission				
OASIS	1,758,000	Transmission	0	1,758,000
Losses	300,000	Transmission	0	300,000
Nonfirm Energy				
Other	0	Generation	0	0
Surplus / Excess	0	Generation	0	0
Ancillary Services				
Voltage Support, Reserves	45,000	Generation	45,000	0
Scheduling Service	0	Transmission	0	0
Miscellaneous				
Facilities Use Charges	755,321	Transmission	0	755,321
Western Miscellaneous	11,947	Transmission	0	11,947
Reclamation Miscellaneous	0	Generation	0	0
Transfer - Other Western Projects	298,637	Transmission	0	298,637
Multi-Project Revenue				
SCADA	44,562	SCADA	443	44,119
Phoenix Service Center	1,735,658	Transmission	0	1,735,658
Total Annual Other Revenues	4,949,125		45,443	4,903,682
	100%		0.9%	99.1%
Net Expenses Before Carryover	51,716,959		14,720,805	36,996,153
Carryover Application To Maintain Level Gen Rate	(5,258,509)		(5,258,509)	
Carryover Application To Maintain Level Tran Rate	(673,303)			(673,303)
Net Expenses After Carryover	45,785,146		9,462,296	36,322,849

Cost Allocation Factors & Rate Design Loads

SCADA Points	Number	Percentage
Generation	74	0.994%
Transmission	7,373	99.006%
	7,447	100%

Customers	Count	Percentage
Transmission	57	60.00%
Generation	38	40.00%
	95	100%

Rate Design Loads	Avg CROD kW	Energy MWh
Firm Electric Service - AOF	203,481	1,071,533
Firm Electric Service - Non-AOF	30,363	158,245
Firm Electric Service - Project Use	37,303	195,267
Firm Transmission	2,531,542	0
	2,802,689	1,425,045

PARKER-DAVIS PROJECT
COST APPORTIONMENT STUDY

	FY 2010			
	Total	Allocation Factor	Generation	Transmission
Annual Expenses				
Western O&M				
Systemwide Expenses	4,470,087	Customers/Gen/Tran	1,457,913	3,012,174
Substation & Transmission Lines	9,303,404	Transmission	0	9,303,404
Communication & Control Equipment	1,469,225	SCADA	14,600	1,454,625
System Operation & Load Dispatch	3,836,302	SCADA/Tran	33,502	3,802,800
Subtotal Western O&M	19,079,018		1,506,015	17,573,003
	100%		7.9%	92.1%
Western General Expenses	5,854,306	% of Subtotal	462,114	5,392,192
Bureau of Reclamation O&M	7,019,000	Generation	7,019,000	0
Purchase Power	4,208,635	Generation	4,208,635	0
Capitalized Movable Equipment	1,377,569	% of Subtotal	108,739	1,268,830
Mead Service Center (Multi-Project)	142,458	Transmission	0	142,458
Bureau of Reclamation Replacements	550,000	Generation	550,000	0
Principal/Interest Payments - Reclamation	82,175	Generation	82,175	0
Principal/Interest Payments - Western	19,152,837	Transmission	0	19,152,837
Total Annual Gross Expenses	57,465,999		13,936,678	43,529,321
	100%		24.3%	75.7%
Other Revenues				
Nonfirm Transmission				
OASIS	1,758,000	Transmission	0	1,758,000
Losses	300,000	Transmission	0	300,000
Nonfirm Energy				
Other	0	Generation	0	0
Surplus / Excess	0	Generation	0	0
Ancillary Services				
Voltage Support, Reserves	45,000	Generation	45,000	0
Scheduling Service	0	Transmission	0	0
Miscellaneous				
Facilities Use Charges	755,321	Transmission	0	755,321
Western Miscellaneous	11,947	Transmission	0	11,947
Reclamation Miscellaneous	0	Generation	0	0
Transfer - Other Western Projects	294,605	Transmission	0	294,605
Multi-Project Revenue				
SCADA	44,562	SCADA	443	44,119
Phoenix Service Center	1,735,658	Transmission	0	1,735,658
Total Annual Other Revenues	4,945,093		45,443	4,899,650
	100%		0.9%	99.1%
Net Expenses Before Carryover	52,520,906		13,891,235	38,629,670
Carryover Application To Maintain Level Gen Rate	(4,428,939)		(4,428,939)	
Carryover Application To Maintain Level Tran Rate	(2,306,821)			(2,306,821)
Net Expenses After Carryover	45,785,146		9,462,296	36,322,849

PARKER-DAVIS PROJECT
COST APPORTIONMENT STUDY

Cost Allocation Factors & Rate Design Loads

SCADA Points

	Number	Percentage
Generation	74	0.994%
Transmission	7,373	99.006%
	7,447	100%

Customers

	Count	Percentage
Transmission	57	60.00%
Generation	38	40.00%
	95	100%

Rate Design Loads

	Avg CROD kW	Energy MWh
Firm Electric Service - AOF	203,481	1,071,533
Firm Electric Service - Non-AOF	30,363	158,245
Firm Electric Service - Project Use	37,303	195,267
Firm Transmission	2,531,542	0
	2,802,689	1,425,045

PARKER-DAVIS PROJECT
COST APPORTIONMENT STUDY

	FY 2011			
	Total	Allocation Factor	Generation	Transmission
Annual Expenses				
Western O&M				
Systemwide Expenses	4,604,188	Customers/Gen/Tran	1,501,649	3,102,539
Substation & Transmission Lines	9,582,507	Transmission	0	9,582,507
Communication & Control Equipment	1,513,302	SCADA	15,038	1,498,264
System Operation & Load Dispatch	3,951,390	SCADA/Tran	34,507	3,916,883
Subtotal Western O&M	19,651,387		1,551,194	18,100,193
	100%		7.9%	92.1%
Western General Expenses	5,990,518	% of Subtotal	472,865	5,517,653
Bureau of Reclamation O&M	7,762,000	Generation	7,762,000	0
Purchase Power	4,208,635	Generation	4,208,635	0
Capitalized Movable Equipment	1,377,569	% of Subtotal	108,739	1,268,830
Mead Service Center (Multi-Project)	142,458	Transmission	0	142,458
Bureau of Reclamation Replacements	100,000	Generation	100,000	0
Principal/Interest Payments - Reclamation	83,270	Generation	83,270	(0)
Principal/Interest Payments - Western	19,957,593	Transmission	0	19,957,593
Total Annual Gross Expenses	59,273,431		14,286,703	44,986,727
	100%		24.1%	75.9%
Other Revenues				
Nonfirm Transmission				
OASIS	1,758,000	Transmission	0	1,758,000
Losses	300,000	Transmission	0	300,000
Nonfirm Energy				
Other	0	Generation	0	0
Surplus / Excess	0	Generation	0	0
Ancillary Services				
Voltage Support, Reserves	45,000	Generation	45,000	0
Scheduling Service	0	Transmission	0	0
Miscellaneous				
Facilities Use Charges	755,321	Transmission	0	755,321
Western Miscellaneous	11,947	Transmission	0	11,947
Reclamation Miscellaneous	0	Generation	0	0
Transfer - Other Western Projects	290,292	Transmission	0	290,292
Multi-Project Revenue				
SCADA	44,562	SCADA	443	44,119
Phoenix Service Center	1,735,658	Transmission	0	1,735,658
Total Annual Other Revenues	4,940,780		45,443	4,895,337
	100%		0.9%	99.1%
Net Expenses Before Carryover	54,332,651		14,241,260	40,091,390
Carryover Application To Maintain Level Gen Rate	(4,778,964)		(4,778,964)	
Carryover Application To Maintain Level Tran Rate	(3,768,541)			(3,768,541)
Net Expenses After Carryover	45,785,146		9,462,296	36,322,849

Cost Allocation Factors & Rate Design Loads

SCADA Points	Number	Percentage
Generation	74	0.994%
Transmission	7,373	99.006%
	7,447	100%

Customers	Count	Percentage
Transmission	57	60.00%
Generation	38	40.00%
	95	100%

Rate Design Loads	Avg CROD kW	Energy MWh
Firm Electric Service - AOF	203,481	1,071,533
Firm Electric Service - Non-AOF	30,363	158,245
Firm Electric Service - Project Use	37,303	195,267
Firm Transmission	2,531,542	0
	2,802,689	1,425,045

PARKER-DAVIS PROJECT
COST APPORTIONMENT STUDY

	FY 2012			
	Total	Allocation Factor	Generation	Transmission
Annual Expenses				
Western O&M				
Systemwide Expenses	4,742,316	Customers/Gen/Tran	1,546,701	3,195,615
Substation & Transmission Lines	9,869,982	Transmission	0	9,869,982
Communication & Control Equipment	1,558,701	SCADA	15,489	1,543,212
System Operation & Load Dispatch	4,069,932	SCADA/Tran	35,544	4,034,388
Subtotal Western O&M	20,240,931		1,597,734	18,643,197
	100%		7.9%	92.1%
Western General Expenses	6,130,816	% of Subtotal	483,941	5,646,875
Bureau of Reclamation O&M	7,225,000	Generation	7,225,000	0
Purchase Power	4,208,635	Generation	4,208,635	0
Capitalized Movable Equipment	1,377,569	% of Subtotal	108,739	1,268,830
Mead Service Center (Multi-Project)	142,458	Transmission	0	142,458
Bureau of Reclamation Replacements	0	Generation	0	0
Principal/Interest Payments - Reclamation	84,380	Generation	84,380	(0)
Principal/Interest Payments - Western	20,697,724	Transmission	0	20,697,724
Total Annual Gross Expenses	60,107,514		13,708,429	46,399,084
	100%		22.8%	77.2%
Other Revenues				
Nonfirm Transmission				
OASIS	1,759,000	Transmission	0	1,759,000
Losses	300,000	Transmission	0	300,000
Nonfirm Energy				
Other	0	Generation	0	0
Surplus / Excess	0	Generation	0	0
Ancillary Services				
Voltage Support, Reserves	45,000	Generation	45,000	0
Scheduling Service	0	Transmission	0	0
Miscellaneous				
Facilities Use Charges	755,321	Transmission	0	755,321
Western Miscellaneous	11,947	Transmission	0	11,947
Reclamation Miscellaneous	0	Generation	0	0
Transfer - Other Western Projects	285,685	Transmission	0	285,685
Multi-Project Revenue				
SCADA	44,562	SCADA	443	44,119
Phoenix Service Center	1,735,658	Transmission	0	1,735,658
Total Annual Other Revenues	4,937,173		45,443	4,891,730
	100%		0.9%	99.1%
Net Expenses Before Carryover	55,170,341		13,662,986	41,507,355
Carryover Application To Maintain Level Gen Rate	(4,200,690)		(4,200,690)	
Carryover Application To Maintain Level Tran Rate	(5,184,505)			(5,184,505)
Net Expenses After Carryover	45,785,146		9,462,296	36,322,849

Cost Allocation Factors & Rate Design Loads

SCADA Points

	Number	Percentage
Generation	74	0.994%
Transmission	7,373	99.006%
	7,447	100%

Customers

	Count	Percentage
Transmission	57	60.00%
Generation	38	40.00%
	95	100%

Rate Design Loads

	Avg CROD kW	Energy MWh
Firm Electric Service - AOF	203,481	1,071,533
Firm Electric Service - Non-AOF	30,363	158,245
Firm Electric Service - Project Use	37,303	195,267
Firm Transmission	2,531,542	0
	2,802,689	1,425,045

PARKER-DAVIS PROJECT
COST APPORTIONMENT STUDY

	FY 2013			
	Total	Allocation Factor	Generation	Transmission
Annual Expenses				
Western O&M				
Systemwide Expenses	4,884,586	Customers/Gen/Tran	1,593,103	3,291,483
Substation & Transmission Lines	10,166,080	Transmission	0	10,166,080
Communication & Control Equipment	1,605,462	SCADA	15,953	1,589,509
System Operation & Load Dispatch	4,192,030	SCADA/Tran	36,608	4,155,422
Subtotal Western O&M	20,848,158		1,645,664	19,202,494
	100%		7.9%	92.1%
Western General Expenses	6,275,323	% of Subtotal	495,348	5,779,975
Bureau of Reclamation O&M	6,263,000	Generation	6,263,000	0
Purchase Power	4,208,635	Generation	4,208,635	0
Capitalized Movable Equipment	1,377,569	% of Subtotal	108,739	1,268,830
Mead Service Center (Multi-Project)	142,458	Transmission	0	142,458
Bureau of Reclamation Replacements	300,000	Generation	300,000	0
Principal/Interest Payments - Reclamation	85,596	Generation	85,596	(0)
Principal/Interest Payments - Western	22,241,622	Transmission	0	22,241,622
Total Annual Gross Expenses	61,742,362		13,106,982	48,635,379
	100%		21.2%	78.8%
Other Revenues				
Nonfirm Transmission				
OASIS	1,760,000	Transmission	0	1,760,000
Losses	300,000	Transmission	0	300,000
Nonfirm Energy				
Other	0	Generation	0	0
Surplus / Excess	0	Generation	0	0
Ancillary Services				
Voltage Support, Reserves	45,000	Generation	45,000	0
Scheduling Service	0	Transmission	0	0
Miscellaneous				
Facilities Use Charges	755,321	Transmission	0	755,321
Western Miscellaneous	11,947	Transmission	0	11,947
Reclamation Miscellaneous	0	Generation	0	0
Transfer - Other Western Projects	280,617	Transmission	0	280,617
Multi-Project Revenue				
SCADA	44,562	SCADA	443	44,119
Phoenix Service Center	1,735,658	Transmission	0	1,735,658
Total Annual Other Revenues	4,933,105		45,443	4,887,662
	100%		0.9%	99.1%
Net Expenses Before Carryover	56,809,257		13,061,539	43,747,717
Carryover Application To Maintain Level Gen Rate	(3,599,243)		(3,599,243)	
Carryover Application To Maintain Level Tran Rate	(7,424,868)			(7,424,868)
Net Expenses After Carryover	45,785,146		9,462,296	36,322,849

Cost Allocation Factors & Rate Design Loads

SCADA Points	Number	Percentage
Generation	74	0.994%
Transmission	7,373	99.006%
	7,447	100%

Customers	Count	Percentage
Transmission	57	60.00%
Generation	38	40.00%
	95	100%

Rate Design Loads	Avg CROD kW	Energy MWh
Firm Electric Service - AOF	203,481	1,071,533
Firm Electric Service - Non-AOF	30,363	158,245
Firm Electric Service - Project Use	37,303	195,267
Firm Transmission	2,531,542	0
	2,802,689	1,425,045

Appendix F

Rate Calculations

PARKER-DAVIS PROJECT RATE DESIGN
FY 2009

Generation Delivery Commitments		
Firm Electric Service	233,844 kW	1,229,778 MWH
Priority Use Power	37,303 kW	195,267 MWH
Total	271,147 kW	1,425,045 MWH

Transmission Delivery Commitments		
Firm Electric Service	233,844	kW
Priority Use Power	37,303	kW
Firm Transmission Service	2,531,542	kW
Total	2,802,689	kW

Generation Revenue Requirement	
Firm Electric Service	$8,160,522
*Aggregate Power Managers	$1,301,774
Total	$9,462,296

Transmission Revenue Requirement	
Firm Electric Service	$3,030,618
*Aggregate Power Managers	$483,447
Firm Transmission Service	$32,808,784
Total	$36,322,849

Aggregate Power Managers		
Generation Revenue Requirement		$1,301,774
Transmission Revenue Requirement		$483,447
Total		$1,785,221
**Priority Use Power Revenue	8.25 mills/kWh	$1,610,949
APM Contributory Payment		$174,272

* Aggregate Power Managers (APMs) have the financial responsibility for Priority Use Power (PUP).

**The Bureau of Reclamation determines the PUP revenue requirement, which the PUP customers are obligated to pay through a power rate. The current PUP power rate is 8.25 mills/kWh. The APMs agreed via contract to make contributory payment to make up the difference, if any , between the PUP rate set by BOR and total funding Parties' obligation.

STEP ONE								
Firm Transmission Rate		$36,322,849	/	2,802,689	kWs	=	$12.96 /1	kW-YR
							$1.08 /2	kW-MO
							$0.25	kW-WK
							$0.04	kW-DAY
							$0.00148	kWh
STEP TWO								
Calculated Capacity Rate		$4,731,148	/	271,147	kWs		$17.45 /3	kW-YR
							$1.45 /2	kW-MO
Calculated Energy Rate		$4,731,148	/	1,425,045	MWHs		3.32 /4	Mills/kWh
Calculated Composite Rate without Transmission		$9,462,296	/	1,425,045	MWHs		6.64 /5	Mills/kWh
Calculated Composite Rate with Transmission								
	Generation	$9,462,296						
	Transmission	$3,514,065						
		$12,976,361	/	1,425,045	MWHs		9.11	Mills/kWh
STEP THREE								
Nonfirm Transmission Rate							2.47 /6	Mills/kWh
STEP FOUR								
Firm Transmission Rate for SLCA/IP Power							$6.48 /7	kW-SEASON
							$1.08 /8	kW-MO
LOWER COLORADO RIVER DEVELOPMENT FUND CHARGE - Effective June 1, 2005								
Arizona							4.5 /9	Mills/kWh
California & Nevada							2.5 /9	Mills/kWh

/1 Annual Net Expenses Allocated to Transmission DIVIDED BY the sum of the Total transmission delivery commitments.
/2 $/kW-YR DIVIDED BY 12, rounded up to the penny.
/3 (Annual Net Expenses Allocated to Generation MULTIPLIED BY .50) DIVIDED BY the sum of the Total Generation Delivery Commitment
/4 (Annual Net Expenses Allocated to Generation MULTIPLIED BY .50) DIVIDED BY the sum of the Total Generation Delivery commitment.
/5 Annual Net Expenses Allocated to Generation DIVIDED BY the sum of the Total Generation Delivery Commitment
/6 (Firm Transmission Rate $/kW-YR DIVIDED BY (8,760 MULTIPLIED BY 0.6)) MULTIPLIED BY 1,000, rounded two decimal places.
/7 Firm Transmission Rate $/kW-YR DIVIDED BY 2, rounded up to the penny.
/8 Firm Transmission Rate $/kW-SEASON DIVIDED BY 6, rounded up to the penny.
/9 Lower Colorado River Development Fund Surcharge - For the Parker-Davis Project, this charge is to be assessed commencing June 1, 2005, per Section 102(c) of the Hoover Power Plant Act of 1984 (Public Law 98-381)

PARKER-DAVIS PROJECT RATE DESIGN
FY 2010

Generation Delivery Commitments		
Firm Electric Service	233,844 kW	1,229,778 MWH
Priority Use Power	37,303 kW	195,267 MWH
Total	271,147 kW	1,425,045 MWH

Transmission Delivery Commitments		
Firm Electric Service	233,844	kW
Priority Use Power	37,303	kW
Firm Transmission Service	2,531,542	kW
Total	2,802,689	kW

Generation Revenue Requirement	
Firm Electric Service	$8,160,522
*Aggregate Power Managers	$1,301,774
Total	$9,462,296

Transmission Revenue Requirement	
Firm Electric Service	$3,030,618
*Aggregate Power Managers	$483,447
Firm Transmission Service	$32,808,784
Total	$36,322,849

Aggregate Power Managers		
Generation Revenue Requirement		$1,301,774
Transmission Revenue Requirement		$483,447
Total		$1,785,221
**Priority Use Power Revenue	8.25 mills/kWh	$1,610,949
APM Contributory Payment		$174,272

* Aggregate Power Managers (APMs) have the financial responsibility for Priority Use Power (PUP).

**The Bureau of Reclamation determines the PUP revenue requirement, which the PUP customers are obligated to pay through a power rate. The current PUP power rate is 8.25 mills/kWh. The APMs agreed via contract to make contributory payment to make up the difference, if any , between the PUP rate set by BOR and total funding Parties' obligation.

STEP ONE									
Firm Transmission Rate		$36,322,849	/	2,802,689	kWs	=	$12.96	/1	kW-YR
							$1.08	/2	kW-MO
							$0.25		kW-WK
							$0.04		kW-DAY
							$0.00148		kWh
STEP TWO									
Calculated Capacity Rate		$4,731,148	/	271,147	kWs		$17.45	/3	kW-YR
							$1.45	/2	kW-MO
Calculated Energy Rate		$4,731,148	/	1,425,045	MWHs		3.32	/4	Mills/kWh
Calculated Composite Rate without Transmission		$9,462,296	/	1,425,045	MWHs		6.64	/5	Mills/kWh
Calculated Composite Rate with Transmission									
	Generation	$9,462,296							
	Transmission	$3,514,065							
		$12,976,361	/	1,425,045	MWHs		9.11		Mills/kWh
STEP THREE									
Nonfirm Transmission Rate							2.47	/6	Mills/kWh
STEP FOUR									
Firm Transmission Rate for SLCA/IP Power							$6.48	/7	kW-SEASON
							$1.08	/8	kW-MO
LOWER COLORADO RIVER DEVELOPMENT FUND CHARGE - Effective June 1, 2005									
Arizona							4.5	/9	Mills/kWh
California & Nevada							2.5	/9	Mills/kWh

/1 Annual Net Expenses Allocated to Transmission DIVIDED BY the sum of the Total transmission delivery commitments.
/2 $/kW-YR DIVIDED BY 12, rounded up to the penny.
/3 (Annual Net Expenses Allocated to Generation MULTIPLIED BY .50) DIVIDED BY the sum of the Total Generation Delivery Commitment
/4 (Annual Net Expenses Allocated to Generation MULTIPLIED BY .50) DIVIDED BY the sum of the Total Generation Delivery commitment.
/5 Annual Net Expenses Allocated to Generation DIVIDED BY the sum of the Total Generation Delivery Commitment
/6 (Firm Transmission Rate $/kW-YR DIVIDED BY (8,760 MULTIPLIED BY 0.6)) MULTIPLIED BY 1,000, rounded two decimal places.
/7 Firm Transmission Rate $/kW-YR DIVIDED BY 2, rounded up to the penny.
/8 Firm Transmission Rate $/kW-SEASON DIVIDED BY 6, rounded up to the penny.
/9 Lower Colorado River Development Fund Surcharge - For the Parker-Davis Project, this charge is to be assessed commencing June 1, 2005, per Section 102(c) of the Hoover Power Plant Act of 1984 (Public Law 98-381)

PARKER-DAVIS PROJECT RATE DESIGN
FY 2011

Generation Delivery Commitments		
Firm Electric Service	233,844 kW	1,229,778 MWH
Priority Use Power	37,303 kW	195,267 MWH
Total	271,147 kW	1,425,045 MWH

Transmission Delivery Commitments		
Firm Electric Service	233,844	kW
Priority Use Power	37,303	kW
Firm Transmission Service	2,531,542	kW
Total	2,802,689	kW

Generation Revenue Requirement	
Firm Electric Service	$8,160,522
*Aggregate Power Managers	$1,301,774
Total	$9,462,296

Transmission Revenue Requirement	
Firm Electric Service	$3,030,618
*Aggregate Power Managers	$483,447
Firm Transmission Service	$32,808,784
Total	$36,322,849

Aggregate Power Managers		
Generation Revenue Requirement		$1,301,774
Transmission Revenue Requirement		$483,447
Total		$1,785,221
**Priority Use Power Revenue	8.25 mills/kWh	$1,610,949
APM Contributory Payment		$174,272

* Aggregate Power Managers (APMs) have the financial responsibility for Priority Use Power (PUP).

**The Bureau of Reclamation determines the PUP revenue requirement, which the PUP customers are obligated to pay through a power rate. The current PUP power rate is 8.25 mills/kWh. The APMs agreed via contract to make contributory payment to make up the difference, if any, between the PUP rate set by BOR and total funding Parties' obligation.

STEP ONE

Firm Transmission Rate	$36,322,849	/	2,802,689	kWs	=	$12.96 /1	kW-YR
						$1.08 /2	kW-MO
						$0.25	kW-WK
						$0.04	kW-DAY
						$0.00148	kWh

STEP TWO

Calculated Capacity Rate		$4,731,148	/	271,147	kWs	$17.45 /3	kW-YR
						$1.45 /2	kW-MO
Calculated Energy Rate		$4,731,148	/	1,425,045	MWHs	3.32 /4	Mills/kWh
Calculated Composite Rate without Transmission		$9,462,296	/	1,425,045	MWHs	6.64	Mills/kWh
Calculated Composite Rate with Transmission							
	Generation	$9,462,296					
	Transmission	$3,514,065					
		$12,976,361	/	1,425,045	MWHs	9.11	Mills/kWh

STEP THREE

Nonfirm Transmission Rate	2.47 /6	Mills/kWh

STEP FOUR

Firm Transmission Rate for SLCA/IP Power	$6.48 /7	kW-SEASON
	$1.08 /8	kW-MO

LOWER COLORADO RIVER DEVELOPMENT FUND CHARGE - Effective June 1, 2005

Arizona	4.5 /9	Mills/kWh
California & Nevada	2.5 /9	Mills/kWh

/1 Annual Net Expenses Allocated to Transmission DIVIDED BY the sum of the Total transmission delivery commitments.

/2 $/kW-YR DIVIDED BY 12, rounded up to the penny.

/3 (Annual Net Expenses Allocated to Generation MULTIPLIED BY .50) DIVIDED BY the sum of the Total Generation Delivery Commitment

/4 (Annual Net Expenses Allocated to Generation MULTIPLIED BY .50) DIVIDED BY the sum of the Total Generation Delivery commitment.

/5 Annual Net Expenses Allocated to Generation DIVIDED BY the sum of the Total Generation Delivery Commitment

/6 (Firm Transmission Rate $/kW-YR DIVIDED BY (8,760 MULTIPLIED BY 0.6)) MULTIPLIED BY 1,000, rounded two decimal places.

/7 Firm Transmission Rate $/kW-YR DIVIDED BY 2, rounded up to the penny.

/8 Firm Transmission Rate $/kW-SEASON DIVIDED BY 6, rounded up to the penny.

/9 Lower Colorado River Development Fund Surcharge - For the Parker-Davis Project, this charge is to be assessed commencing June 1, 2005, per Section 102(c) of the Hoover Power Plant Act of 1984 (Public Law 98-381)

PARKER-DAVIS PROJECT RATE DESIGN
FY 2012

Generation Delivery Commitments		
Firm Electric Service	233,844 kW	1,229,778 MWH
Priority Use Power	37,303 kW	195,267 MWH
Total	271,147 kW	1,425,045 MWH

Transmission Delivery Commitments		
Firm Electric Service	233,844	kW
Priority Use Power	37,303	kW
Firm Transmission Service	2,531,542	kW
Total	2,802,689	kW

Generation Revenue Requirement	
Firm Electric Service	$8,160,522
*Aggregate Power Managers	$1,301,774
Total	$9,462,296

Transmission Revenue Requirement	
Firm Electric Service	$3,030,618
*Aggregate Power Managers	$483,447
Firm Transmission Service	$32,808,784
Total	$36,322,849

Aggregate Power Managers		
Generation Revenue Requirement		$1,301,774
Transmission Revenue Requirement		$483,447
Total		$1,785,221
**Priority Use Power Revenue	8.25 mills/kWh	$1,610,949
APM Contributory Payment		$174,272

* Aggregate Power Managers (APMs) have the financial responsibility for Priority Use Power (PUP).

**The Bureau of Reclamation determines the PUP revenue requirement, which the PUP customers are obligated to pay through a power rate. The current PUP power rate is 8.25 mills/kWh. The APMs agreed via contract to make contributory payment to make up the difference, if any , between the PUP rate set by BOR and total funding Parties' obligation.

STEP ONE								
Firm Transmission Rate		$36,322,849	/	2,802,689	kWs	=	$12.96 /1	kW-YR
							$1.08 /2	kW-MO
							$0.25	kW-WK
							$0.04	kW-DAY
							$0.00148	kWh
STEP TWO								
Calculated Capacity Rate		$4,731,148	/	271,147	kWs		$17.45 /3	kW-YR
							$1.45 /2	kW-MO
Calculated Energy Rate		$4,731,148	/	1,425,045	MWHs		3.32 /4	Mills/kWh
Calculated Composite Rate without Transmission		$9,462,296	/	1,425,045	MWHs		6.64	Mills/kWh
Calculated Composite Rate with Transmission								
	Generation	$9,462,296						
	Transmission	$3,514,065						
		$12,976,361	/	1,425,045	MWHs		9.11	Mills/kWh
STEP THREE								
Nonfirm Transmission Rate							2.47 /6	Mills/kWh
STEP FOUR								
Firm Transmission Rate for SLCA/IP Power							$6.48 /7	kW-SEASON
							$1.08 /8	kW-MO
LOWER COLORADO RIVER DEVELOPMENT FUND CHARGE - Effective June 1, 2005								
Arizona							4.5 /9	Mills/kWh
California & Nevada							2.5 /9	Mills/kWh

/1 Annual Net Expenses Allocated to Transmission DIVIDED BY the sum of the Total transmission delivery commitments.
/2 $/kW-YR DIVIDED BY 12, rounded up to the penny.
/3 (Annual Net Expenses Allocated to Generation MULTIPLIED BY .50) DIVIDED BY the sum of the Total Generation Delivery Commitment
/4 (Annual Net Expenses Allocated to Generation MULTIPLIED BY .50) DIVIDED BY the sum of the Total Generation Delivery commitment.
/5 Annual Net Expenses Allocated to Generation DIVIDED BY the sum of the Total Generation Delivery Commitment
/6 (Firm Transmission Rate $/kW-YR DIVIDED BY (8,760 MULTIPLIED BY 0.6)) MULTIPLIED BY 1,000, rounded two decimal places.
/7 Firm Transmission Rate $/kW-YR DIVIDED BY 2, rounded up to the penny.
/8 Firm Transmission Rate $/kW-SEASON DIVIDED BY 6, rounded up to the penny.
/9 Lower Colorado River Development Fund Surcharge - For the Parker-Davis Project, this charge is to be assessed commencing June 1, 2005, per Section 102(c) of the Hoover Power Plant Act of 1984 (Public Law 98-381)

PARKER-DAVIS PROJECT RATE DESIGN
FY 2013

Generation Delivery Commitments		
Firm Electric Service	233,844 kW	1,229,778 MWH
Priority Use Power	37,303 kW	195,267 MWH
Total	271,147 kW	1,425,045 MWH

Transmission Delivery Commitments	
Firm Electric Service	233,844 kW
Priority Use Power	37,303 kW
Firm Transmission Service	2,531,542 kW
Total	2,802,689 kW

Generation Revenue Requirement	
Firm Electric Service	$8,160,522
*Aggregate Power Managers	$1,301,774
Total	$9,462,296

Transmission Revenue Requirement	
Firm Electric Service	$3,030,618
*Aggregate Power Managers	$483,447
Firm Transmission Service	$32,808,784
Total	$36,322,849

Aggregate Power Managers		
Generation Revenue Requirement		$1,301,774
Transmission Revenue Requirement		$483,447
Total		$1,785,221
**Priority Use Power Revenue	8.25 mills/kWh	$1,610,949
APM Contributory Payment		$174,272

* Aggregate Power Managers (APMs) have the financial responsibility for Priority Use Power (PUP).

**The Bureau of Reclamation determines the PUP revenue requirement, which the PUP customers are obligated to pay through a power rate. The current PUP power rate is 8.25 mills/kWh. The APMs agreed via contract to make contributory payment to make up the difference, if any , between the PUP rate set by BOR and total funding Parties' obligation.

STEP ONE								
Firm Transmission Rate		$36,322,849	/	2,802,689	kWs	=	$12.96 /1	kW-YR
							$1.08 /2	kW-MO
							$0.25	kW-WK
							$0.04	kW-DAY
							$0.00148	kWh
STEP TWO								
Calculated Capacity Rate		$4,731,148	/	271,147	kWs		$17.45 /3	kW-YR
							$1.45 /2	kW-MO
Calculated Energy Rate		$4,731,148	/	1,425,045	MWHs		3.32 /4	Mills/kWh
Calculated Composite Rate without Transmission		$9,462,296	/	1,425,045	MWHs		6.64 /5	Mills/kWh
Calculated Composite Rate with Transmission								
	Generation	$9,462,296						
	Transmission	$3,514,065						
		$12,976,361	/	1,425,045	MWHs		9.11	Mills/kWh
STEP THREE								
Nonfirm Transmission Rate							2.47 /6	Mills/kWh
STEP FOUR								
Firm Transmission Rate for SLCA/IP Power							$6.48 /7	kW-SEASON
							$1.08 /8	kW-MO
LOWER COLORADO RIVER DEVELOPMENT FUND CHARGE - Effective June 1, 2005								
Arizona							4.5 /9	Mills/kWh
California & Nevada							2.5 /9	Mills/kWh

/1 Annual Net Expenses Allocated to Transmission DIVIDED BY the sum of the Total transmission delivery commitments.
/2 $/kW-YR DIVIDED BY 12, rounded up to the penny.
/3 (Annual Net Expenses Allocated to Generation MULTIPLIED BY .50) DIVIDED BY the sum of the Total Generation Delivery Commitment
/4 (Annual Net Expenses Allocated to Generation MULTIPLIED BY .50) DIVIDED BY the sum of the Total Generation Delivery commitment.
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/8 Firm Transmission Rate $/kW-SEASON DIVIDED BY 6, rounded up to the penny.
/9 Lower Colorado River Development Fund Surcharge - For the Parker-Davis Project, this charge is to be assessed commencing June 1, 2005, per Section 102(c) of the Hoover Power Plant Act of 1984 (Public Law 98-381)