for assistance. A copy is also available for inspection and reproduction at the address in item h above.

m. Individuals desiring to be included on the Commission's mailing list should so indicate by writing to the Secretary of the Commission.

Comments, Protests, or Motions to Intervene—Anyone may submit comments, a protest, or a motion to intervene in accordance with the requirements of Rules of Practice and Procedure, 18 CFR 385.210, .211, .214. In determining the appropriate action to take, the Commission will consider all protests or other comments filed, but only those who file a motion to intervene in accordance with the Commission's Rules may become a party to the proceeding. Any comments, protests, or motions to intervene must be received on or before the specified comment date for the particular application.

Filing and Service of Responsive Documents—Any filings must bear in all capital letters the title ''COMMENTS'', ''RECOMMENDATIONS FOR TERMS AND CONDITIONS'', ''PROTEST'', OR ''MOTION TO INTERVENE'', as applicable, and the Project Number of the particular application to which the filing refers. Any of the above-named documents must be filed by providing the original and the number of copies provided by the Commission's regulations to: The Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426. A copy of any motion to intervene must also be served upon each representative of the Applicant specified in the particular application.

Agency Comments—Federal, state, and local agencies are invited to file comments on the described application. A copy of the application may be obtained by agencies directly from the Applicant. If an agency does not file comments within the time specified for filing comments, it will be presumed to have no comments. One copy of an agency's comments must also be sent to the Applicant's representatives.

David P. Boergers,

Secretary.

[FR Doc. 00–28631 Filed 11–7–00; 8:45 am]

BILLING CODE 6717–01–M

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Notice of Application for Amendment of License and Soliciting Comments, Motions To Intervene, and Protests

November 2, 2000.

Take notice that the following hydroelectric application has been filed with the Commission and is available for public inspection:

a. *Application:* Amendment of License.

b. *Project No.:* 10228–015.

c. *Date Filed:* July 21, 2000.

d. *Applicant:* Cannelton Hydroelectric Project, L.P.

e. *Name of Project:* Cannelton.

f. *Location:* The project is located on the Ohio River in Hancock County, Kentucky, at the U.S. Army Corps of Engineers' Cannelton Locks and Dam.

g. *Filed Pursuant to:* Federal Power Act, 16 U.S.C. 791(a)–825(r).

h. *Applicant Contact:* Cannelton Hydroelectric Project, L.P., 120 Calumet Ct., Aiken, SC 29803, (803) 642–2749.

i. *FERC Contact:* Any questions on this notice should be addressed to Dave Snyder at (202) 219–2385.

j. *Deadline for filing comments and/or motions:* December 8, 2000. All documents (original and eight copies) should be filed with: David P. Boergers, Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426. Comments and protests may be filed electronically via the internet in lieu of paper. See, 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's web site at http://www.ferc.fed.us/efi/doorbell.htm.

Please include the Project Number (10228–015) on any comments or motions filed.

k. *Description of Filing:* Pursuant to § 4.200(c) and § 4.202(a) of the Commission's Rules of Practice and Procedure (18 CFR), Cannelton Hydroelectric Project, L.P., requests, among other things, an extension of time until December 2005 to complete construction of the Cannelton Project.

l. *Locations of the Application:* A copy of the application is available for inspection and reproduction at the Commission's Public Reference Room, located at 888 First Street, NE., Room 2A, Washington, DC 20426, or by calling (202) 208–1371. The application may be viewed on the web at www.ferc.fed.us/online/rims.htm. Call (202) 208–2222 for assistance. A copy is also available for inspection and reproduction at the address in item h above.

m. Individuals desiring to be included on the Commission's mailing list should so indicate by writing to the Secretary of the Commission.

Comments, Protests, or Motions to Intervene—Anyone may submit comments, a protest, or a motion to intervene in accordance with the requirements of Rules of Practice and Procedure, 18 CFR 385.210, .211, .214. In determining the appropriate action to take, the Commission will consider all protests or other comments filed, but only those who file a motion to intervene in accordance with the Commission's Rules may become a party to the proceeding. Any comments, protests, or motions to intervene must be received on or before the specified comment date for the particular application.

Filing and Service of Responsive Documents—Any filings must bear in all capital letters the title ''COMMENTS'', ''RECOMMENDATIONS FOR TERMS AND CONDITIONS'', ''PROTEST'', OR ''MOTION TO INTERVENE'', as applicable, and the Project Number of the particular application to which the filing refers. Any of the above-named documents must be filed by providing the original and the number of copies provided by the Commission's regulations to: The Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426. A copy of any motion to intervene must also be served upon each representative of the Applicant specified in the particular application.

Agency Comments—Federal, state, and local agencies are invited to file comments on the described application. A copy of the application may be obtained by agencies directly from the Applicant. If an agency does not file comments within the time specified for filing comments, it will be presumed to have no comments. One copy of an agency's comments must also be sent to the Applicant's representatives.

David P. Boergers,

Secretary.

[FR Doc. 00–28632 Filed 11–7–00; 8:45 am]

BILLING CODE 6717–01–M

DEPARTMENT OF ENERGY

Western Area Power Administration

Proposed Rates for the Central Valley and California-Oregon Transmission Projects

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of Proposed Rates.

SUMMARY: The Western Area Power Administration (Western) is proposing new rates for Central Valley Project (CVP) firm power, power scheduling, scheduling coordinator, transmission, California-Oregon Transmission Project (COTP) transmission, and CVP ancillary services. The current rates expire September 30, 2002. The current power rates are insufficient due to significant increases in the prices of energy in the California electric markets. Proposing new rates for all the services listed above extends the rates for these services through the end of the current CVP Power Marketing Plan.

A rate increase will provide sufficient revenue to repay all annual costs, including interest expense, and repay required investment within the allowable period. Rate impacts are detailed in a rate brochure to be provided to all interested parties. The proposed new rates are scheduled to go into effect on April 1, 2001, and will remain in effect through December 31, 2004, which is the end of the current CVP Power Marketing Plan. This **Federal Register** notice initiates the public process to replace the existing approved rates that expire September 30, 2002.

Western previously proposed rates that were published in the **Federal Register**, March 3, 2000. The publication of this **Federal Register** notice rescinds those proposed rates. Western will disregard all public input associated with the rescinded proposed rates.

DATES: The consultation and comment period will begin November 8, 2000 and will end December 29, 2000. Western will present a detailed explanation of these new proposed rates at a public information forum scheduled for November 17, 2000, beginning at 1 p.m. Pacific Standard Time (PST), at the Sierra Nevada Regional Office. Western will receive oral and written comments at a public comment forum scheduled for December 13, 2000, beginning at 1 p.m. PST, at the Sierra Nevada Regional Office. Western must receive all comments by the end of the consultation and comment period to assure consideration of the comments.

ADDRESSES: Send written comments to Mr. Jerry W. Toenyes, Regional Manager, Sierra Nevada Customer Service Region, Western Area Power Administration, 114 Parkshore Drive, Folsom, CA 95630–4710, e-mail toenyes@wapa.gov.

FOR FURTHER INFORMATION CONTACT: Ms. Debbie Dietz, Rates Manager, Sierra Nevada Customer Service Region, Western Area Power Administration, 114 Parkshore Drive, Folsom, CA 95630–4710, (916) 353–4453, e-mail ddietz@wapa.gov.

SUPPLEMENTARY INFORMATION: With the publication of this notice Western is withdrawing the previously proposed rates published on March 3, 2000 (65 FR 11569). Due to significant unexpected increases in the prices of energy in the California electric markets, the rates proposed in the March 3, 2000, **Federal Register** notice would be insufficient to recover the project costs. Therefore, Western rescinds those proposed rates and will disregard all public input associated with the rescinded proposed rates.

This **Federal Register** notice will initiate the public process to replace the existing approved rates that expire September 30, 2002. The proposed new rates for CVP firm power are designed to recover an annual revenue requirement that includes the investment repayment, interest, purchase power costs, transmission, operation and maintenance expense, and any charges or credits associated with the creation, termination, or modification to any tariff, contract, or schedule approved by the Federal Energy Regulatory Commission (FERC). A cost-of-service study allocates the projected annual revenue requirement for firm power between capacity and energy.

The capacity revenue requirement includes: (i) 100 percent of capacity purchase costs; (ii) 50 percent of the investment repayment; (iii) 50 percent of the interest expense; (iv) 50 percent of the operation and maintenance expense allocated to power; and (v) 100 percent of CVP and COTP transmission expense. Projected CVP and COTP transmission revenue and 50 percent of projected CVP project use revenue reduce the annual costs that determine the capacity revenue requirement.

The energy revenue requirement includes: (i) 100 percent of energy purchase costs; (ii) 50 percent of the investment repayment; (iii) 50 percent of the interest expense; and (iv) 50 percent of the operation and maintenance expense allocated to power. Projected surplus power revenue and 50 percent of projected CVP project use revenue reduce annual costs to determine the energy revenue requirement.

The resulting capacity/energy revenue requirement split varies from 30 percent allocated to capacity from April 1, 2001, through September 30, 2001, to 15 percent allocated to capacity from October 1, 2004, through December 31, 2004. The average capacity/energy revenue requirement split for the rate period is 22 percent to capacity and 78 percent to energy. The variation in the capacity/energy revenue requirement split is due to fluctuations in energy purchase costs and seasonal CVP hydro generation.

Western also developed new proposed rates for CVP firm power with the transmission revenue requirement removed from the firm power revenue requirement. These rates would apply if Western joins the California Independent System Operator (CAISO) and if the CAISO uses the transmission revenue requirement to develop a regional transmission rate. Western has not made a decision on joining the CAISO. The decision to join the CAISO is not part of this rate adjustment public process. These new proposed power rates with the transmission revenue requirement removed are designed to recover an annual revenue requirement that includes investment repayment, interest, purchase power, operation and maintenance expense, and any charges or credits associated with the creation, termination, or modification to any tariff, contract, or schedule approved by FERC.

A cost-of-service study allocates projected annual revenue requirement for firm power between capacity and energy. The capacity revenue requirement includes: (i) 100 percent of capacity purchase costs; (ii) 50 percent of the investment repayment; (iii) 50 percent of the interest expense; and (iv) 50 percent of the operation and maintenance expense allocated to power.

Fifty percent of the projected CVP project use revenue reduces the annual cost to determine the capacity revenue requirement. The energy revenue requirement includes: (i) 100 percent of energy purchase costs; (ii) 50 percent of the investment repayment; (iii) 50 percent of the interest expense; and (iv) 50 percent of the operation and maintenance expense allocated to power. Projected surplus power revenue and 50 percent of the projected CVP project use revenue reduce the annual cost to determine the energy revenue requirement.

The resulting capacity/energy revenue requirement split varies from 24 percent allocated to capacity from April 1, 2001, through September 30, 2001, to 11 percent allocated to capacity from October 1, 2004, through December 31, 2004. The average capacity/energy revenue requirement split for the rate period is 17 percent to capacity and 83 percent to energy. The variation in the capacity/energy revenue requirement split is due to fluctuations in energy purchase costs and seasonal CVP hydro generation.

For both sets of firm power rates described above, Western will pass through to its customers any additional costs or credits that may be charged or credited to Western as the result of the creation, termination, or modification of any tariff, contract, schedule or other documents approved by FERC. When possible, Western will pass through directly to each customer FERC approved costs or credits in the same manner Western receives these costs or credits. If the FERC approved costs or credits are charged to Western in such a way that a direct pass through to each customer is not possible, Western will distribute the FERC approved costs or credits to each customer in a manner consistent with the rate design used in developing the proposed rates.

The new proposed rates for CVP firm power and the applicable revenue requirement split between capacity and energy are in Table 1.

TABLE 1.—PROPOSED FIRM POWER RATES

Effective period	Total composite mills/kWh	Capacity $/kWmonth	Energy mills/kWh	Capacity/energy split
04/01/01 to 09/30/01	22.71	3.81	15.99	30/70
10/01/01 to 09/30/02	26.16	3.34	20.64	21/79
10/01/02 to 09/30/03	26.96	3.48	21.24	21/79
10/01/03 to 09/30/04	26.46	3.41	20.85	21/79
10/01/04 to 12/31/04	29.62	2.96	25.06	15/85

The proposed rates for CVP firm power with the transmission revenue requirement removed and applicable revenue requirement split between capacity and energy are in Table 1A.

TABLE 1A.—PROPOSED FIRM POWER RATES WITH THE TRANSMISSION REVENUE REQUIREMENT REMOVED FROM THE FIRM POWER REVENUE REQUIREMENT

Effective period	Total composite mills/kWh	Capacity $/kWmonth	Energy mills/kWh	Capacity/energy split
04/01/01 to 09/30/01	21.04	2.86	15.99	24/76
10/01/01 to 09/30/02	24.74	2.48	20.64	17/83
10/01/02 to 09/30/03	25.57	2.63	21.24	17/83
10/01/03 to 09/30/04	25.08	2.57	20.85	17/83
10/01/04 to 12/31/04	28.22	2.05	25.06	11/89

The Deputy Secretary of the Department of Energy (DOE), approved the existing Rate Schedule CV–F9 for CVP commercial firm power on September 19, 1997 (Rate Order No. WAPA–77, 62 FR 50924, September 29, 1997). FERC confirmed and approved the rate schedule on January 8, 1998, under FERC Docket No. EF97–5011–000 (82 FERC ¶ 62,006). The existing Rate Schedule CV–F9 became effective on October 1, 1997, for the period ending September 30, 2002. Under Rate Schedule CV–F9, the composite rate on October 1, 2000, is 18.56 mills per kilowatthour (mills/kWh), the base energy rate is 10.51 mills/kWh and the capacity rate is $3.81 per kilowattmonth (kWmonth).

The proposed rates for CVP firm power will result in an overall composite rate increase of approximately 22 percent on April 1, 2001, when compared with the current CVP commercial firm power rates under Rate Schedule CV–F9. Table 2 provides a comparison of the current rates in Rate Schedule CV–F9 and the proposed rates along with the percentage change in the rates.

TABLE 2.—COMPARISON OF CURRENT AND PROPOSED RATES

Effective period	Total composite rate	Percent change	Capacity $/kW month	Percent change	Energy mills/kWh	Percent change
Percentage Change in Firm Power Rates						
Current Rate Schedule						
Existing 10/01/00 to 09/30/01	18.56	....	3.81	....	10.51	....

TABLE 2.—COMPARISON OF CURRENT AND PROPOSED RATES—Continued

Effective period	Total composite rate	Percent change	Capacity $/kW month	Percent change	Energy mills/kWh	Percent change
Proposed Rates						
04/01/01 to 09/30/01	22.71	22	3.81	0	15.99	52
10/01/01 to 09/30/02	26.16	41	3.34	−12	20.64	96
10/01/02 to 09/30/03	26.96	45	3.48	−9	21.24	102
10/01/03 to 09/30/04	26.46	43	3.41	−10	20.85	98
10/01/04 to 12/31/04	29.62	60	2.96	−22	25.06	138

The proposed rates for CVP firm power with the transmission revenue requirement removed will result in an overall composite rate increase of approximately 13 percent on April 1, 2001, when compared with the current CVP commercial firm power rates under Rate Schedule CV–F9. Table 2A provides a comparison of the current rates in Rate Schedule CV–F9 and the proposed rates with the Transmission Revenue Requirement removed along with the percentage change in the rates.

TABLE 2A.—COMPARISON OF CURRENT AND PROPOSED RATES WITH THE TRANSMISSION REVENUE REQUIREMENT REMOVED [1]

Effective period	Total composite rate	Percent change	Capacity $/kW month	Percent change	Energy mills/kWh	Percent change
Percentage Change in Firm Power Rates						
Current Rate Schedule						
Existing 10/01/00 to 09/30/01	18.56	....	3.81	....	10.51	....
Proposed Rates With the Transmission Revenue Requirement Removed						
04/01/01 to 09/30/01	21.04	13	2.86	−25	15.99	52
10/01/01 to 09/30/02	24.74	33	2.48	−35	20.64	96
10/01/02 to 09/30/03	25.57	38	2.63	−31	21.24	102
10/01/03 to 09/30/04	25.08	35	2.57	−33	20.85	98
10/01/04 to 12/31/04	28.22	52	2.05	−46	25.06	138

[1] These rates do not include the cost of transmission; therefore, the customer is required to buy transmission at an additional cost.

Adjustment Clauses Associated With the Proposed Rates for CVP Firm Power

Power Factor Adjustment

This provision in Rate Schedule CV–F9 will remain the same under the proposed rates for CVP firm power.

Low Voltage Loss Adjustment

This provision in Rate Schedule CV–F9 will remain the same under the proposed rates for CVP firm power.

Revenue Adjustment

The Revenue Adjustment Clause (RAC) provides for a comparison between the projected net revenues in the rate adjustment power repayment study to the actual net revenues. If the actual net revenue is more than the projected net revenue, CVP preference customers receive a credit. If actual net revenue is less than the projected net revenue, CVP preference customers may pay a surcharge, if needed, to make a minimum investment payment. The limit for the RAC credit or surcharge is $20 million, plus any purchase power contract adjustments during the fiscal year (FY) for which the RAC is being calculated.

The RAC is calculated annually and the associated distribution of the RAC credit or surcharge occurs during a 9-month period on power bills issued January through September. For customers whose RAC credits cannot be fully credited through nine equal monthly amounts, Western has the option to increase the RAC credit during August and September. The FY 2001 RAC calculation will be based on the net revenue for FY 2001, including revenues and expenses for October 2000 to March 2001, which is outside of the rate adjustment period. A RAC will be calculated for October through December 2004. The maximum RAC credit or surcharge for October through December 2004 is $10 million plus purchase power contract adjustments applied to the April to September 2005 bills.

Proposed Rate for Power Scheduling Service

The proposed rate for power scheduling service is $76.65 per hour and is based on costs incurred to provide the service. Power scheduling service provides for scheduling resources to meet load and reserve requirements.

Proposed Rate for Scheduling Coordinator Service

The proposed rate for scheduling coordinator service is $76.65 per hour and is based on costs incurred to provide the service. Scheduling coordinator service provides scheduling, real-time dispatching, and financial settlements with the CAISO and/or power exchanges.

Proposed Formula Rate for CVP Transmission

The proposed formula rate for firm CVP transmission includes two components:

Component 1: Transmission revenue requirement/(CVP capacity + total transmission capacity under long-term contracts). Component 1 is the ratio of Western's transmission revenue requirement to the sum of the maximum operating capacity of the Northern CVP power plants under normal operating conditions (CVP capacity) and the total transmission capacity under long-term contracts between Western and other parties. Northern CVP power plants are J.F. Carr, Folsom, Keswick, Nimbus, Shasta, Spring Creek, and Trinity.

Component 2: Pass through of any transmission-related costs or credits incurred by Western due to electric industry restructuring or other changes in the industry. The costs or credits in component 2, as well as any changes to these costs or credits, will be passed through to each appropriate transmission customer.

Western will revise the rate from component 1 based on updated data as of April 30 of each year. Western will also revise the rate from component 1 if there is a change in component 1 of the CVP firm transmission rate of at least $.05 per kWmonth. The estimated rate resulting from the proposed formula rate for firm CVP transmission for April to September 2001 is $0.70 per kWmonth, a 37-percent increase from the existing rate of $0.51 per kWmonth, under Rate Schedule CV–FT3. Based on a contract agreement to provide transmission service in the future, the estimated rate resulting from the proposed formula rate for firm CVP transmission for FY 2002 is $.56 per kWmonth, a 10-percent increase from the existing rate of $.51 per kWmonth.

The estimated rate resulting from the proposed formula rate for nonfirm CVP transmission service for April to September 2001 is 1.00 mill/kWh. The proposed formula rate for nonfirm CVP transmission is based on the same two components used in the proposed formula rate for firm CVP transmission. A revision to the nonfirm rate resulting from component 1 will occur whenever component 1 of the firm transmission rate is revised. If the rates from the proposed formula rate are higher than other transmission rates in California, firm or nonfirm transmission service for 1 year or less may be sold at lower rates.

The proposed formula rate for CVP transmission service is based on a revenue requirement that recovers: (i) The costs for facilities that support the transfer capability of the CVP transmission system (excluding generation facilities and radial lines); (ii) the nonfacilities costs allocated to transmission; and (iii) any transmission-related costs or credits incurred by Western due to electric industry restructuring or other changes in the industry. The proposed formula rate includes Western's cost for scheduling, system control and dispatch service, and reactive supply and voltage control service associated with the transmission service. The proposed formula rate is applicable to existing CVP firm transmission service and future point-to-point transmission service.

Proposed Rate for Transmission of CVP Power by Others

Western will pass through transmission service costs or credits it incurs for delivering CVP power over a third party's transmission system to the requesting CVP customer. Rates under this schedule will be automatically adjusted as third party transmission costs or credits are adjusted.

Proposed Formula Rate for Network Integration Transmission

If Western offers network integration transmission service, it will be consistent with FERC Order No. 888. The proposed formula rate is the product of the network customer's load ratio share times one-twelfth of the annual network integration transmission revenue requirement. The load ratio share is the network customer's hourly load coincident with Western's monthly CVP transmission system peak minus the coincident peak for all firm CVP (including reserved capacity) point-to-point transmission service, plus the reserved capacity of all firm point-to-point transmission service customers.

The proposed formula rate for network integration transmission service is based on a revenue requirement that recovers: (i) The costs for facilities that support the transfer capability of the CVP transmission system (excluding generation facilities and radial lines); (ii) the nonfacilities costs allocated to transmission; and (iii) any transmission-related costs or credits incurred by Western due to electric industry restructuring or other changes in the industry. The proposed formula rate includes Western's cost for scheduling, system control and dispatch service, and reactive supply and voltage control service needed to provide the transmission service.

Proposed Formula Rate for COTP Transmission

The proposed formula rate for COTP transmission includes two components:

Component 1: Transmission Revenue Requirement/Western's share of COTP Seasonal Capacity. Component 1 is the ratio of the transmission revenue requirement to Western's share of COTP seasonal capacity. Western will update the rate resulting from component 1 at least 15 days before the start of each California-Oregon Intertie rating season. Seasonal definitions for summer, winter, and spring are June through October, November through March, and April through May, respectively.

Component 2: Pass through of any transmission-related costs or credits incurred by Western due to electric industry restructuring or other changes in the industry. The costs or credits in component 2, as well as any changes to these costs or credits, will be passed through to each appropriate transmission customer.

The estimated rates resulting from the proposed formula rate for firm COTP transmission service for April 2001 to March 2002 are: Summer—$0.94 per kWmonth, winter—$1.12 per kWmonth, and spring—$1.00 per kWmonth. These rates resulting from the proposed formula rate result in a 30-percent decrease during the summer, a 16-percent decrease during the winter, and a 25-percent decrease during the spring compared to the existing rate of $1.34 per kWmonth.

The proposed formula rate for nonfirm COTP transmission is based on the same two components used in the proposed formula rate for firm COTP transmission. The estimated rates resulting from the proposed formula rate for nonfirm transmission service for April 2001 to March 2002 are: Summer—1.29 mills/kWh, winter—1.54 mills/kWh, and spring—1.37 mills/kWh. These rates for nonfirm COTP transmission service result in an 11-percent decrease during the summer, a 6-percent increase during the winter, and a 5-percent decrease during the spring compared to the existing rate of 1.45 mills/kWh. If the rates from the proposed formula rate are higher than other transmission rates in California, firm or nonfirm transmission service for 1 year or less may be sold at lower rates.

Rates resulting from the proposed formula rate for COTP transmission service are based on a revenue requirement that recovers: (i) Western's share of costs for facilities that support the transfer capability of the COTP; (ii) Western's share of the nonfacilities costs allocated to transmission; and (iii) any transmission-related costs or credits incurred by Western due to electric industry restructuring or other changes in the industry. The rates resulting from the proposed formula rate include Western's cost for scheduling, system control and dispatch service, and reactive supply and voltage control service associated with transmission service. The proposed formula rate would apply to existing COTP transmission service and future point-to-point transmission service.

Proposed Rates for Ancillary Services

Western will provide ancillary services, subject to availability, at the proposed rates in Table 3. Western designed these proposed rates to recover only the costs it incurs for providing the service(s). If these cost-based rates are higher than other ancillary service rates in California, sales of ancillary services of 1 year or less may be sold at lower rates.

TABLE 3.—PROPOSED RATES FOR ANCILLARY SERVICES

Ancillary service type	Rate
Transmission Scheduling, System Control and Dispatch Service—required to schedule movement of power through, out of, within, or into a control area.	Appropriate transmission rates include Western's cost.
Reactive Supply and Voltage Control Service—reactive power support provided from generation facilities necessary to maintain transmission voltages within acceptable limits of the system.	Appropriate transmission rates include Western's cost.
Regulation and Frequency Response Service—provides generation to match resources and loads on a real-time continuous basis.	Monthly: $2.496 per kWmonth. Weekly: $0.574 per kWweek. Daily: $0.082 per kWday.
Energy Imbalance Service—provied when a difference occurs between the scheduled and actual delivery of energy to a load or from a generation resource within a control area over a single month.	*Within Limits of deviation Band:* Accumulated deviations are to be corrected or eliminated within 30 days. Any net deviations that are accumulated at the end of the month (positive or negative) are to be exchanged with like hours of energy or charged at the composite rate for CVP firm power then in effect.
Hourly Deviation (MW)—net scheduled amount of energy for the hour minus the hourly net metered (actual delivered) amount.	*Outside Limits of Deviation Band:* (i) *Positive Deviations*—the greater of no charge, or any additional cost incurred. (ii) *Negative Deviations*—during on-peak hours, the greater of 3 times the proposed rates for CVP firm power or any additional cost incurred. During off-peak hours, the greater of the proposed rates for CVP firm power or any additional cost incurred.
Spinning Reserve Service—provides capacity available the first 10 minutes to take load and is synchronized with the power system.	Monthly: $2.946 per kWmonth. Weekly: $0.672 per kWweek. Daily: $0.096 per kWday. Hourly: $0.0040 per kWh.
Supplemental Reserve Service—provides capacity not synchronized, but can be available to service loads within 10 minutes.	Monthly: $2.491 per kWmonth. Weekly: $0.574 per kWweek. Daily: $0.082 per kWday. Hourly: $0.0034 per kWh.

Since the proposed rates constitute a major rate adjustment as defined by the procedures for public participation in general rate adjustments, as cited below, Western will hold both a public information forum and a public comment forum. After reviewing public comments, Western will recommend provisional rates for approval on an interim basis by the DOE Deputy Secretary.

These proposed rates for the CVP and COTP are established pursuant to the DOE Organization Act, 42 U.S.C. 7101–7352; the Reclamation Act of 1902, ch. 1093, 32 Stat. 388, as amended and supplemented by subsequent enactments, 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 projects involved.

By Amendment No. 3 to Delegation Order No. 0204–108, published November 10, 1993 (58 FR 59716), the Secretary of Energy delegated: (1) The authority to develop long-term power and transmission rates on a nonexclusive basis to Western's Administrator; and (2) the authority to confirm, approve, and place into effect on a final basis, to remand, or to disapprove such rates to FERC. In Delegation Order No. 0204–172, effective November 24, 1999, the Secretary of Energy delegated the authority to confirm, approve, and place such rates into effect on an interim basis to the Deputy Secretary. Existing DOE procedures for public participation in power rate adjustments (10 CFR part 903) became effective on September 18, 1985 (50 FR 37835).

Availability of Information

All brochures, studies, comments, letters, memoranda, or other documents made or kept by Western for developing the proposed rates are available for inspection and copying at the Sierra Nevada Regional Office, 114 Parkshore Drive, Folsom, California.

Regulatory Procedural Requirements

Regulatory Flexibility Analysis

The Regulatory Flexibility Act of 1980 (5 U.S.C. 601, *et seq.*) requires Federal agencies to perform a regulatory flexibility analysis if a final rule is likely to have a significant economic impact on a substantial number of small entities and there is a legal requirement to issue a general notice of a proposed rulemaking. Western has determined that this action does not require a Regulatory Flexibility analysis since it is a rulemaking involving rates or services for public property.

Environmental Compliance

In compliance with the National Environmental Policy Act (NEPA) of

1969, 42 U.S.C. 4321, *et seq.*; Council on Environmental Quality Regulations (40 CFR parts 1500–1508); and DOE NEPA Regulations (10 CFR part 1021), Western has determined that this action is categorically excluded from the preparation of 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 Office of Management and Budget is required.

Small Business Regulatory Enforcement Fairness Act

Western has determined that this rule is exempt from congressional notification requirements under 5 U.S.C. 801 because the action is a rulemaking of particular applicability relating to rates or services and involves matters of procedure.

Dated: October 16, 2000.

Michael S. Hacskaylo,

Administrator.

[FR Doc. 00–28626 Filed 11–07–00; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Western Area Power Administration

Proposed Salt Lake City Area Integrated Projects Firm Power Rate Formula Adder

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of proposed rates.

SUMMARY: The Western Area Power Administration's (Western) Colorado River Storage Project (CRSP) Management Center (MC) is proposing a rate formula adder to the existing rate for firm long-term sales of Salt Lake City Area Integrated Projects (SLCA/IP) power. The SLCA/IP consists of the CRSP, Collbran, and Rio Grande Projects which were integrated for marketing and ratemaking purposes on October 1, 1987. The CRSP described here includes two CRSP participating projects which have power facilities, Dolores and Seedskadee Projects.

In the long term, the existing SLCA/IP composite rate of 17.57 mills/kilowatthour (kWh) is sufficient to pay for all costs including operation, maintenance, replacement, and interest expenses and to repay investment and irrigation assistance obligations within the required period. CRSP MC staff will continue to monitor the long-term firm power rate for the SLCA/IP to determine if a long-term rate adjustment will need to be placed into effect.

The proposed rate formula adder is needed to provide additional revenue in the CRSP Basin Fund, a revolving fund in the United States Treasury, to pay for near-term purchase power costs and to increase the working capital in the CRSP Basin Fund. The proposed rate formula adder scheduled to go into effect on February 1, 2001, will remain in effect until September 30, 2003, or until superseded by another rate adjustment, whichever occurs first. This **Federal Register** notice initiates the formal process for the proposed rate formula adder.

DATES: The consultation and comment period will begin when this **Federal Register** notice is published and will end December 8, 2000. Public information forum and public comment forum meeting dates are scheduled for these locations:

1. Public information forum—November 20, 2000, 10:30 a.m., Salt Lake City, Utah; Public comment forum—November 20, 2000, 2 p.m., Salt Lake City, Utah.
2. Public information forum—November 21, 2001, 10:30 a.m., Phoenix, Arizona; Public comment forum—November 21, 2001, 2 p.m., Phoenix, Arizona.

ADDRESSES: The address for the Salt Lake meetings is at the Sheraton Hotel (formerly the Hilton), 150 West 500 South, Salt Lake City, Utah. The address for the meetings in Phoenix is Western Area Power Administration, Desert Southwest Region, 615 South 43rd Avenue, Phoenix, Arizona. Written comments may be sent to: Mr. Dave Sabo, CRSP Manager, CRSP Management Center, Western Area Power Administration, P.O. Box 11606, Salt Lake City, UT 84147–0606, e-mail sabo@wapa.gov. Western should receive written comments by the end of the consultation and comment period to be assured they are considered. Oral comments will be received at the public comment meetings.

FOR FURTHER INFORMATION CONTACT: Ms. Carol Loftin, Rates Manager, CRSP Management Center, Western Area Power Administration, P.O. Box 11606, Salt Lake City, UT 84147–0606, telephone (801) 524–6380, e-mail loftinc@wapa.gov, or visit CRSP MC's home page at: www.wapa.gov/crsp/crsp.htm.

SUPPLEMENTARY INFORMATION: The existing long-term rate for SLCA/IP firm power is designed to recover an annual revenue requirement based on repaying power investment; paying interest, purchased power, operation, maintenance, and replacement expenses; and repaying irrigation assistance costs, as required by law.

The Deputy Secretary of the Department of Energy (DOE) approved the existing Rate Schedule SLIP–F6 for SLCA/IP firm power on March 23, 1998 (Rate Order No. WAPA–78). The Federal Energy Regulatory Commission (FERC) confirmed and approved the rate schedule on July 17, 1998, in FERC Docket No. EF98–5171–000. The existing Firm Power Rate Schedule expires on March 31, 2003. Under Rate Schedule SLIP–F6, the energy rate is 8.10 mills/kWh, and the capacity rate is $3.44 per kilowattmonth (kWmonth). The composite rate (revenue requirements per kWh usage) is 17.57 mills/kWh.

The proposed rate formula adder is needed to provide additional revenue to fund near-term purchased power costs and to increase the working capital balance in the CRSP Basin Fund. Higher-than-normal purchased power expenses have resulted from lower-than-expected hydrology conditions, higher-than-normal purchase power prices, and the summer test release for endangered fish from Glen Canyon Dam (GCD).

The rate formula adder will be applied during the next 3 fiscal years (FY) from February 1, 2001, through September 30, 2003. The following proposed formulas will be used to determine the rate formula adder:

(1) BB + ER—PP—O&M = EB

BB = CRSP Basin Fund balance at the beginning of the FY

ER = expected revenues for the current FY

PP = estimated purchase power costs which could include non-reimbursable purchase power costs

O&M = operation and maintenance expenses which includes non-reimbursable expenses, replacements, and transmission expenses

EB = CRSP Basin Fund balance at the end of the FY

(2) RB—EB = RN

RB = minimum required balance in the CRSP Basin Fund at the end of the FY (FY 2001 = $35 million, FY 2002 = $50 million, FY 2003 = $60 million)

RN = additional revenue needed

The RN is divided by the projected energy sales as shown in the existing ratesetting study to determine the additional composite rate needed.