6450-01-P
DEPARTMENT OF ENERGY

Western Area Power Administration

Transmission and Ancillary Services Rates, Pick-Sloan Missouri Basin, Eastern Division

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of Proposed Rate Adjustments.

SUMMARY: The Western Area Power Administration (Western) is proposing transmission service and ancillary service rate adjustments for Pick-Sloan Missouri Basin Program, Eastern Division (P-SMBP-ED). The proposed formula rates will provide sufficient revenue to repay all annual costs and assigned investment within the allowable time periods. The proposed formula rates are scheduled to go into effect May 1, 1998. This Federal Register notice continues the procedure for public participation in the transmission and ancillary service rate adjustments, which began with Western's Advance Announcement dated March 28, 1997.

DATES: The consultation and comment period for the proposed transmission service and ancillary service rates will end [insert 90 days after date of publication of this FEDERAL REGISTER notice]. Written comments should be received by Western by the end of the comment period to be assured consideration. Western will present a detailed explanation of the proposed rate at the public information forums which will be held at the following dates and times:

1. October 16, 1997 -- 9 a.m. MDT, Billings, Montana.

2. October 17, 1997 -- 9 a.m. CDT, Sioux Falls, South Dakota.

Western will receive written and oral comments at the public comment forums which will be held at the following times:

3. November 13, 1997 -- 9 a.m. MST, Billings, Montana.

4. November 14, 1997 -- 9 a.m. CST, Sioux Falls, South Dakota.

ADDRESSES:

Western's public information forums will be held at the following places:

1. Radisson Northern Hotel, Broadway & 1st Avenue North, Billings, Montana.

2. Howard Johnson, 3300 West Russell Street, Sioux Falls, South Dakota.

Western's public comment forums will be held at the following places:

3. Radisson Northern Hotel, Broadway & 1st Avenue North, Billings, Montana.

4. Howard Johnson, 3300 West Russell Street, Sioux Falls, South Dakota.

Written comments should be sent to: Gerald C. Wegner, Regional Manager, Upper Great Plains Region, Western Area Power Administration, P.O. Box 35800, Billings, MT

59107-5800.

FOR FURTHER INFORMATION CONTACT: Robert F. Riehl, Rates Manager, Upper Great Plains Region (UGPR), Western Area Power Administration, P.O. Box 35800, Billings, MT 59107-5800, (406) 247-7388. E-mail riehl@wapa.gov or visit UGPR's home page at http://www.wapa.gov/ugp/.

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I. Introduction/Background

Western initiated a public process to establish long-term open access transmission and ancillary service rates for the P-SMBP-ED with its advance announcement of March 28, 1997. Several options were identified and comments and ideas were solicited on these options. Forty-five letters were received as a result of the solicitation. The letters commented on fourteen issues. The most constant and consistent message received from the comments was that Western should choose a proposal that would have the least impact upon the P-SMBP-ED firm power rate. This Federal Register notice continues that process.

II. Western's proposal

1. Honor existing contract arrangements.

Western presently has the following transmission and related services contract agreements. Western intends to abide by the terms of these agreements and sustain the benefits incurred from these agreements.

Basin Electric Power Cooperative (Basin Electric) has a bilateral Contract, 90-BAO-415, with Western for Joint Transmission System services. The Contract became effective on the first day of the first full billing period following the date of its execution, January 5, 1995, and remains in effect through the hour ending 2400 of December 31, 2039. Basin Electric also has a Contract, 90-BAO-431, with Western for transmission service on the Montana Power Company (MPC) system. The Contract became effective on the date of its execution, November 6, 1990, and remains in effect through the hour 2400 on December 31, 2033.

Black Hills Corporation has a bilateral Contract, 88-BAO-320, with Western for transmission service. The Contract became effective October 1, 1988, and terminates at 12:01 a.m., October 1, 1998, as specified by the Contract.

Heartland Consumers Power District (Heartland) has a bilateral Contract, 89-BAO-344, with Western for Joint Transmission System services. The Contract became effective on the first billing day of the first full billing period following the date of its execution, December 28, 1995, and remains in effect through the hour ending 2400 on December 31, 2039.

Minnkota Power Cooperative, Inc. has a bilateral Contract, 88-BAO-313, with Western for transmission service. The Contract became effective the first day of the first billing period after the date of execution, October 6, 1989, and remains in effect through December 31, 2020, as specified in the Contract.

Missouri Basin Municipal Power Agency has a bilateral Contract, 8-07-60-P0002, with Western for use of the Joint Transmission System. The Contract became effective on the first day of the November 1977 billing period and remains in effect until midnight of December 31, 1997, as defined in the Contract.

Montana-Dakota Utilities Company has a bilateral Contract, 88-BAO-308, with Western for transmission service. The Contract became effective on its date of execution, July 1, 1988, and remains in effect until December 31, 2015.

MPC has a bilateral Contract, 4-07-60-P0228, with Western for transmission service. The Contract became effective October 15, 1984. Notice to terminate this Contract has been served and the Contract will terminate on or about June 30, 1998.

Northwestern Public Service Company has a bilateral Contract, 4-07-60-P0223, with Western for transmission service. The Contract became effective on April 1, 1984, and remains in effect until December 31, 2000.

Northern States Power Company has a Contract, 6-07-60-P0236, with Western for transmission service. The Contract became effective on the date of its execution, June 2, 1986. Notice to terminate this Contract has been served and the Contract will terminate on January 31, 2001.

<u>2. The Integrated System will be used for transmission service in all new electric service arrangements.</u>

Western, Basin Electric, and Heartland have combined their transmission facilities to form an Integrated System (IS) and herein developed transmission and ancillary service rates using a Federal Energy Regulatory Commission (FERC) approved rate design. Western has been designated as the operator of the IS by the other participants. The IS consists of the transmission facilities owned by Basin Electric, and Heartland east of the east-west electrical separation in the United States, the transmission facilities owned by Western in the P-SMBP-ED, and the Miles City DC Tie owned by Western and Basin Electric. These facilities interconnect with utilities in the states of Montana, North Dakota, South Dakota, Nebraska, Iowa, Colorado, Minnesota, and Missouri and in addition include facilities which interconnect with Canada.

Our approach for formation of the IS was to include facilities which followed the spirit and intent of the order and to make the system most useful to the transmission requesters. For these reasons we included several major facilities which were not a part of the Joint Transmission System. We included the second 345-kV transmission line between the Antelope Valley and Leland Olds generating stations; which follows the definitions used for acceptable transmission facilities in other filings. The 230-kV transmission line between Tioga, North Dakota, and Boundary Dam, which provides access to loads in Canada, has been included in the IS. The Miles City DC Tie, which provides for the transmission of electricity between the east-west electrical separation of the United States and increases access to transmission on the IS. The IS also differs from the Joint Transmission System in that it does not include the transmission facilities owned by the joint owners of the Laramie River Generating Station, which require the agreement of all participants prior to inclusion. Basin Electric, and Heartland do not constitute all the owners in the Laramie River Generating Station. If they reach agreement, Western, Basin Electric, and Heartland may consider inclusion of those facilities in the IS rate and tariff.

For each of their new electric service arrangements crossing the IS facilities, Western, Basin Electric, and Heartland will take service under the proposed IS rates. To avoid double charging for transmission services, credit will be given for transmission capacity reservations in existing Joint Transmission System service contracts for new transactions from existing resources. Western, as operator of the IS, will bill for service, collect payments, and distribute revenue to each participant.

III. Proposed Rates

The proposed rates conform to the spirit and intent of FERC Order Nos. 888 and 888-A. An Open Access Transmission Tariff (Tariff), specifying terms and conditions, is being developed under a separate process. Once implemented, Western, Basin Electric, Heartland, and others will take service under the proposed Tariff and rates for all new transmission and/or electric sales arrangements. Western is requesting public comment on a proposed rate formula that would be adjusted annually, on or about May

1 of each year, by inserting the previous year's data into the formula. The data herein is fiscal year 1996 data. These rates will support Western's Tariff and conform with the spirit and intent of FERC Order Nos. 888 and 888-A. Supporting information and impacts of these rates are detailed in a rate brochure available to all interested parties.

1. Proposed Revenue Requirement for IS Transmission Service

The proposed rate for IS transmission service (Network and Point to Point) is based on a revenue requirement that recovers: (i) the IS investment and interest cost for Western, Basin Electric, and Heartland facilities associated with providing IS transmission service; and (ii) the operation, maintenance, administrative and general cost for Western, Basin Electric and Heartland allocated to IS transmission service. This revenue requirement is offset by appropriate transmission revenues. Rates will be recalculated every year on or about May 1 based on the previous year's data. The previous year's data to be used in the recalculation will be made available for review 30 days before the new rates are implemented. Firm and Non-Firm Point to Point transmission service rates will be offered on an up-to basis to promote maximum usage and transmission revenues from the IS.

2. Proposed Rate for Network IS Transmission Service

The proposed rate for monthly Network IS transmission service is the product of the network customer's load ratio share times one-twelfth (1/12) of the annual network transmission revenue requirement. The network transmission revenue requirement is derived by annualizing the IS transmission investment, and adding transmission related annual costs, including operation, maintenance, interest, administrative and general costs. The annual costs are reduced by revenue credit for the Non-Firm transmission service. The load ratio share is based on the network customer's hourly load coincident with the IS monthly transmission system peak minus the coincident peak for all IS Firm Point-to-Point transmission service plus the point-to-point reservations. The Network rate includes the cost for scheduling, system control, and dispatch service needed to provide transmission service.

3. Proposed Rate for Firm Point-to-Point IS Transmission Service

The proposed Firm Point-to-Point IS rate is based on a revenue requirement derived by annualizing the IS transmission investment, and adding transmission related annual costs. These transmission related annual costs include operation, maintenance, interest, administrative and general costs. The annual costs are reduced by revenue credits for Non-Firm transmission. The resultant net annual cost to be recovered is divided by the capacity reservation needed for the annual average monthly IS transmission load. Using 1996 data, this methodology produced a charge of $3.07/kW-month for Firm Point-to-Point transmission service. This proposed rate may be adjusted each year on or about May 1, by a recalculation based on the previous years data using the formula: (Total Annual Revenue Requirement - Non Firm Revenue Credits) / Annual Average Transmission System Monthly Peak Load / 12 months. The point-to-point rate includes the cost for scheduling, system control, and dispatch service needed to provide transmission service.

4. Proposed Rate for Non-Firm Point-to-Point Service

The proposed rate for Non-Firm Point-to-Point IS transmission service is an energy rate up-to but never higher than the Firm Point-to-Point rate. This rate will remain in effect concurrently with the Firm Point-to-Point rate. The Non-Firm Point-to-Point rate includes the cost for scheduling, system control, and dispatch service needed to provide transmission service.

5. Proposed Rates for Ancillary Services

Western will provide ancillary services, subject to availability, as described below and as listed in Table 1. The rates are designed to recover only the costs incurred for providing the service(s).

6. Proposed Rate for Scheduling, System Control and Dispatch Service

Western's annualized costs for scheduling, system control and dispatch service is determined by multiplying the portion of the Watertown Operations Office net plant and communications facilities net plant associated with scheduling, system control and dispatch service by the transmission fixed charge rate. The annual cost for scheduling, system control and dispatch service is then divided by the number of daily schedules in FY 1996. Using 1996 data, this methodology for determining the scheduling, system control and dispatch service rate has produced a charge of $54.50/schedule/day. This rate and rate design is recovering only Western's revenue requirement.

7. Proposed Rate for Reactive Supply and Voltage Control Service

Western's annualized cost for reactive supply and voltage control is determined by multiplying the total P-SMBP-ED generation net plant by the generation fixed charge rate. The annualized cost is multiplied by the capability used for reactive support to determine Western's reactive service revenue requirement. Basin Electric's and Heartland's annual revenue requirements are based upon the annualized cost of equipment installed on their generators to provide this service. Western's, Basin

Electric's, and Heartland's revenue requirements are summed for the total revenue requirement. The reactive supply and voltage control service charge is then derived by dividing the revenue requirement by the total load in Western's control area. The annual cost is then divided by 12 months to obtain a monthly charge. Using 1996 data, this methodology for determining the rate for reactive supply and voltage control has produced a charge of $0.08/kW-month for transmission capacity reserved.

8. Proposed Rate for Regulation and Frequency Response Service

Regulation and frequency response service in the east side of the control area is provided primarily by Oahe generation and in the west side of the control area by Fort Peck, both of which are Corps of Engineers (Corps) facilities. The Corps generation fixed charge rate is applied to Oahe and Fort Peck net plant costs producing an annual generation revenue requirement for the Oahe and Fort Peck power plants. This revenue requirement is divided by the capacity at the plants to derive a dollar per kilowatt charge for Oahe's and Fort Peck's installed capacity. This dollar per kilowatt charge is then applied to capacity used at Oahe and Fort Peck for regulation and frequency response service in the control area. The capacity used for regulation and frequency response service has been determined to be 4 percent of the annual peak load. The 4 percent value was derived by averaging the incremental change in hourly load in the control area for the calendar year. The annual revenue requirement for regulation and frequency response service is determined by applying the dollar per kilowatt charge to the capacity used for regulation and frequency response. The regulation and frequency response service charge is then determined by dividing the revenue requirement by Western's load in the control area. The annual cost is then divided by 12 months to obtain a monthly charge.   Using 1996 data, this methodology for determining the rate for regulation and frequency response produced a charge of $0.09/kW-month of load for which Western is providing this service. This rate and rate design is recovering Western's revenue requirement only. Credit will be given to those transmission customers who provide Western with Automatic Generation Control (AGC) of generation facilities capable of providing this service.

9. Proposed Rate for Energy Imbalance Service

This service is not intended to provide backup for generation supply. Energy shall be returned with like energy (on peak with on peak, etc.) and accounts zeroed out monthly. Western reserves the right to apply a penalty to energy imbalances outside a 3 percent bandwidth (+/- 1.5 percent deviation). The penalty for under deliveries outside the 3 percent bandwidth is 100 mills/kWh. Over deliveries outside the 3 percent bandwidth will be forfeited to the control area.

10. Proposed Rate for Reserves

Western's annualized cost for reserves is determined by multiplying the P-SMBP-ED generation net plant costs by the generation fixed charge rate. The cost/kW-year is determined by dividing the plant costs by the plant capacity. The capacity used for reserves is determined by multiplying the peak IS load in the control area by the MAPP operating reserve requirement. The cost/kW-year is multiplied by the capacity used for reserves to determine the annual cost of reserves. The annual cost of reserves is divided by Western's peak load in the control area to calculate the annual charge. The annual cost is then divided by 12 months to obtain a monthly charge. Using 1996 data, this methodology for determining the reserve rate has produced a charge of $0.12/kW-month of customer load. This rate and rate design is recovering only Western's revenue requirement. If energy is taken under this service the energy charge will be the MAPP Rate for Emergency Energy, which is currently 30 mills/kWh.

Table 1- Proposed Service Rate Formulas for New Transactions

Service	**Rate Formula**	**1996 Data**	**Rate based on 1996 Data**
Network Transmission	Customer's Load Ratio Share * 1/12 * (Annual Transmission Revenue Requirement - Non-Firm Revenue Credits)	Customer's Load Ratio Share * 1/12 * ($116.4M - $12.6M)	for comparison estimate at $3.07/kW-Mo
Firm Point-to-Point Transmission	(Total Annual Revenue Requirement - Non-Firm Revenue Credits) / Annual Average Transmission System Monthly Peak Load / 12 months	($116.4M -$12.6M) / 2,819 MW / 12 months	$3.07/kW-Mo
Non-Firm Point-to-Point Transmission	Firm Point-to-Point rate / 730 hours per month	$3.07/kW-Mo / 730 hours/month	4.20 Mills/kWh
Scheduling, System Control, and Dispatch	transmission fixed charge rate* ((.4137 * Watertown net plant) + (.384 * communications net plant))/number of daily schedules per year	20.59% * $6.86M / 25,915 daily schedules per year	$54.50/ schedule/day

Reactive Supply and Voltage Control	((generation fixed charge rate * generation net plant cost * capability used for reactive support) + Basin Electric and Heartland revenue requirement) / load in control area / 12 months	((12.3%* $613.2M * 2.02%) + $1M) / 2,532 MW-yr / 12 months	$0.08/kW-Mo
Regulation and Frequency Response	COE fixed charge rate * COE generation net plant cost / plant capacity * capacity used for regulation / Western's load in control area / 12 months	10.4% * $251.6M / 937 MW * 64.6 MW / 1,615 MW / 12 months	$0.09/kW-Mo
Energy Imbalance	Penalty	100 mills/kWh charge for under deliveries outside 3% bandwidth(+/- 1.5%). Over deliveries outside 3% bandwidth forfeited to the control area.	
Reserves	generation fixed charge rate * generation net plant cost / plant capacity * capacity used for reserves / Western's load in control area / 12 months	12.3% * $613.2M / 2,517 MW * 80.75 MW / 1,615 MW / 12 months	$0.12/kW-Mo

IV. Cost Shifting

There is no immediate impact to the P-SMBP-ED firm power rate. In the first few years as new electric service arrangements move to the IS, costs will shift between the IS participants. Western will incur approximately $1 million/year of additional transmission cost, Heartland will incur approximately $200,000/year of additional transmission cost and Basin Electric's costs will be reduced approximately $2.4 million/year, based upon average Pick-Sloan generation. Western's increased transmission costs will have minimal impact to the P-SMBP-ED firm power rate. Although it is difficult to project cost shifting among the IS participants beyond the first few years following the implementation of this proposal, additional usage, and increased revenues should occur as existing transmission contracts terminate and are reformulated. This should mitigate the impact to the participants. Transition payments among the IS participants may be considered to mitigate impacts or cost shifts if in this public process the impacts are determined to be too severe.

V. Other Options

All other options mentioned in the Advance Announcement are evaluated in the customer rate brochure. The additional comment item of generation based rates is also examined in the customer rate brochure.

VI. Authorities

Transmission and ancillary services rates for the P-SMBP-ED are being established pursuant to the Department of Energy Organization Act (42 U.S.C. 7101 *et. seq.*) and the Reclamation Act of 1902 (43 U.S.C. 371 *et. seq.*), 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 section 5 of the Flood Control Act of 1944 (16 U.S.C. 825s) and other acts specifically applicable to the projects involved.

By Amendment No. 3 to Delegation Order No. 0204-108, published November 10, 1993 (58 FR 59716), the Secretary of DOE delegated (1) the authority to develop long-term power and transmission rates on a nonexclusive basis to the Administrator of Western; (2) the authority to confirm, approve, and place such rates into effect on an interim basis to the Deputy Secretary; and (3) the authority to confirm, approve, and place into effect on a final basis, to remand, or to disapprove such rates to the FERC. Existing DOE procedures for public participation in power rate adjustments are found at 10 CFR Part 903.

Regulatory Flexibility Analysis: Pursuant to the Regulatory Flexibility Act of 1980 (5 U.S.C. 601, *et. seq.*), each agency, when required to publish a proposed rule, is further required to prepare and make available for public comment an initial regulatory flexibility analysis to describe the impact of the proposed rule on small entities. In this instance the initiation of the IS transmission rate and ancillary service rate adjustments are related to non-regulatory services provided by Western at particular rates. Under 5 U.S. C. 601(2), rules of particular applicability relating to rates or services are not considered rules within the meaning of the act. Since the IS transmission rates and ancillary services are of limited applicability, no flexibility analysis is required.

Environmental Compliance: Western will conduct an environmental evaluation of the proposed rates and develop the appropriate level of environmental documentation pursuant to the National Environmental Policy Act (NEPA) of 1969 (42 U.S.C. 4321 *et. seq.*); the Council on Environmental Quality Regulations for implementing NEPA (40 CFR Parts 1500 through 1508); and the DOE NEPA Implementing Procedures and Guidelines (10 CFR Part 1021).

Review Under the Paperwork Reduction Act: In accordance with the Paperwork Reduction Act of 1980, (44 U.S.C. 3501 *et. seq.*), Western has received approval from the Office of Management and Budget for the collection of customer information in this rule, under control number 1910-0100.

Determination Under Executive Order 12866: DOE has determined that this is not a significant regulatory action because it does not meet the criteria of Executive Order 12866, 58 FR 51735. 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.

Availability of Information: All brochures, studies, comments, letters, memoranda, or other documents made or kept by Western for developing the proposed rates, will be made available for inspection and copying at the Upper Great Plains Regional Office, located at 2900 4th Avenue North, Billings, MT 59107-5800, during normal business hours.

Dated: September 5, 1997

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Michael S. Hacskaylo
Acting Administrator