Standard Paragraphs

E. Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 18 CFR 385.214). All such motions or protests should be filed on or before the comment date. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of these filings are on file with the Commission and are available for public inspection.

David P. Boergers,

Secretary.

[FR Doc. 98–21571 Filed 8–11–98; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Notice of Intent to File Application for New License

August 7, 1998.

a. Type of filing: Notice of Intent to File Application for New License.

b. Project No.: P–1273.

c. Date filed: May 26, 1998.

d. Submitted By: Parowan City Corporation, current licensee.

e. Name of Project: Center Creek.

f. Location: On Center Creek in Iron County, Utah.

g. Filed Pursuant to: Section 15 of the Federal Power Act, 18 CFR 16.6 of the Commission's regulations.

h. Expiration date of original license: December 20, 1004.

i. The project consists of: (1) a 20-foot-high, 54-foot-long concrete gravity dam; (2) a 25-foot-high, 980-foot-long earthfill embankment impounding; (3) a storage pond with storage capacity of 21 acre-feet; (4) a 26-inch-diameter pipe from the concrete dam to the pond; (5) a 19,300-foot-long steel penstock; (6) a powerhouse with an installed capacity of 600 kilowatts; (7) a 20,992-foot-long, 12.47-kilovolt transmission line; and (8) other appurtenances.

j. Pursuant to 18 CFR 16.7, information on the project is available at: The City of Parowan, 5 South Main, Parowan, UT 84761, Phone: (435) 477–3331.

k. FERC contact: Hector M. Pérez (202) 219–2843.

l. Pursuant to 18 CFR 16.9(b)(1) each application for a new license and any competing license applications must be filed with the Commission at least 24 months prior to the expiration of the existing license. All applications for license for this project must be filed by December 31, 2002.

David P. Boergers,

Secretary.

[FR Doc. 98–21622 Filed 8–11–98; 8:45 am]

BILLING CODE 6717–01–M

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Notice of Intent to File Application for New License

August 7, 1998.

a. Type of filing: Notice of Intent to File Application for New License.

b. Project No.: P–2782.

c. Date filed: May 26, 1998.

d. Submitted By: Parowan City Corporation, current license.

e. Name of Project: Red Creek.

f. Location: On Red Creek and South Fork in Iron County, Utah.

g. Filed Pursuant to: Section 15 of the Federal Power Act, 18 CFR 16.6 of the Commission's requirements.

h. Expiration date of original license: April 30, 2003.

i. The project consists of: (1) the 8-foot-high, 29-foot-long South Fork Diversion Dam and reservoir; (2) the 8-foot-high, 48-foot-long Red Creek Diversion Dam and reservoir; (3) the 10-inch-diameter, 4,263-foot-long South Fork steel pipeline; the 18-inch-diameter, 16,098-foot-long steel Red Creek pipeline; (4) a pumphouse with two electric pumps delivering water from the South Fork pipeline into the Red Creek pipeline; (5) a powerhouse with an installed capacity of 500 kilowatts; and (6) other appurtenances.

j. Pursuant to 18 CRF 16.7, information on the project is available at: The City of Parowan, 5 South Main, Parowan, UT 84761, Phone: (435) 477–3331.

k. FERC contact: Hector M. Pérez (202) 219–2843.

l. Pursuant to 18 CFR 16.9(b)(1) each application for a new license and any competing license applications must be filed with the Commission at least 24 months prior to the expiration of the existing license. All applications for license for this project must be filed by April 30, 2001.

David P. Boergers,

Secretary.

[FR Doc. 98–21623 Filed 8–11–98; 8:45 am]

BILLING CODE 6717–01–M

DEPARTMENT OF ENERGY

Western Area Power Administration

Pick-Sloan Missouri Basin Program, Eastern Division—Rate Order No. WAPA–79

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of rate order.

SUMMARY: Notice is given of the confirmation and approval by the Deputy Secretary of the Department of Energy (DOE) of Rate Order No. WAPA–79 and Rate Schedules UGP–AS1, UGP–AS2, UGP–AS3, UGP–AS4, UGP–AS5, UGP–AS6, UGP–FPT1, UGP–NFPT1, and UGP–NT1 placing formula rates into effect on an interim basis for firm and non-firm transmission on the Integrated System (IS) and ancillary services in Western Area Power Administration's (Western) Watertown control area.

The charges for the transmission and ancillary services will be implemented on August 1, 1998. Subsequent annual recalculation will be based on updated financial data and loads. Network Transmission Service charges will be based on the Transmission Customer's load-ratio share of the annual revenue requirement for transmission. Point-to-Point Transmission Service will be based on reserved capacity on the Transmission System. The charges for ancillary services will be based on the cost of resources used to provide these services.

FOR FURTHER INFORMATION CONTACT: Mr. Robert F. Riehl, Rates Manager, Upper Great Plains Customer Service Region, Western Area Power Administration, P.O. Box 35800, Billings, MT 59107–5800, (406) 247–7388, or e-mail (riehl@wapa.gov).

SUPPLEMENTARY INFORMATION: By Amendment No. 3 to Delegation Order No. 0204–108, published November 10, 1993 (58 FR 59716), the Secretary of Energy (Secretary) delegated (1) the authority to develop long-term power and transmission rates on a non-exclusive 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 Federal Energy Regulatory Commission (FERC).

Rate Order No. WAPA–79, confirming, approving, and placing the IS Network, Firm Point-to-Point, and Non-Firm Point-to-Point Transmission, and the new ancillary services formula rates into effect on an interim basis, is issued. These transmission and ancillary service formula rates are established pursuant to section 302 of DOE Organization Act, 42 U.S.C. 7152(a), through which the power marketing functions of the Secretary of the Interior and the Bureau of Reclamation were transferred to, and vested in, the Secretary. Rate Order No. WAPA–79 was prepared pursuant to Delegation Order No. 0204–108 (Delegation Order), existing DOE procedures for public participation in power rate adjustments in 10 CFR part 903, and procedures for approving Power Marketing Administration rates by the FERC in 18 CFR part 300. In addition to seeking final confirmation under the Delegation Order, Western requests the FERC review the proposed transmission rates for the Upper Great Plains Region (UGPR) for consistency with the standards of section 212 (a) of the Federal Power Act 16 U.S.C. 824k (a). In doing so, Western asks the FERC to determine that its rates are comparable to what it charges other customers and conform to the standards under the Delegation Order in a manner similar to the FERC's finding in *United States Department of Energy-Bonneville Power Administration,* 80 FERC ¶ 61,118 (1997).

Western has separately filed for approval of generally applicable terms and conditions under its Open Access Transmission Tariff (Tariff) in Docket No. NJ98–1–000. These rate schedules will be utilized under the Tariff for service in the UGPR of Western, and they are potentially subject to FERC review under the standards of 16 U.S.C. 824k (a). Because Western's transmission rates were established in accordance with 10 CFR part 903, 18 CFR part 300 and the Delegation Order, if the rates submitted by Western are found to violate the statutory standards, they must be remanded to the Administrator for further proceedings.

The new Rate Schedules UGP–AS1, UGP–AS2, UGP–AS3, UGP–AS4, UGP–AS5, UGP–AS6, UGP–FPT1, UGP–NFPT1, and UGP–NT1 will be promptly submitted to the FERC for confirmation and approval on a final basis.

Dated: July 31, 1998.

Elizabeth A. Moler,

Deputy Secretary.

Order Confirming, Approving, and Placing the Pick-Sloan Missouri Basin Program, Eastern Division Transmission and Ancillary Service Formula Rates Into Effect on an Interim Basis

August 1, 1998.

These transmission and ancillary service formula rates are established pursuant to the Department of Energy Organization Act (42 U.S.C. 7101 *et seq.*), through which the power marketing functions of the Secretary of the Interior and the Bureau of Reclamation (Reclamation) under 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 other acts specifically applicable to the project involved, were transferred to and vested in the Secretary of Energy (Secretary).

By Amendment No. 3 to Delegation Order No. 0204–108 (Delegation Order), published November 10, 1993 (58 FR 59716), the Secretary delegated: (1) the authority to develop long-term power and transmission rates on a non-exclusive basis to the Administrator of the Western Area Power Administration (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 Federal Energy Regulatory Commission (FERC).

Existing Department of Energy (DOE) procedures for public participation in power rate adjustments are found in 10 CFR part 903. Procedures for approving Power Marketing Administration rates by the FERC are found in 18 CFR part 300. In addition to seeking final confirmation under the Delegation Order, Western requests the FERC review the proposed transmission rates for the Upper Great Plains Region (UGPR) for consistency with the standards of section 212 (a) of the Federal Power Act (FPA), 16 U.S.C. 824k (a). In doing so, Western asks the FERC to determine that its rates are comparable to what it charges other customers and conform to the standards under the Delegation Order in a manner similar to the FERC's finding in *United States Department of Energy-Bonneville Power Administration,* 80 FERC ¶ 61,118 (1997).

Western has separately filed for approval of generally applicable terms and conditions under its Open Access Transmission Tariff (Tariff) in Docket No. NJ98–1–000. These rate schedules will be utilized under the Tariff for service in the UGPR of Western, and they are potentially subject to FERC review under the standards of 16 U.S.C. 824k(a). Because Western's transmission rates were established in accordance with 10 CFR part 903, 18 CFR part 300 and the Delegation Order, if the rates submitted by Western are found to violate the statutory standards, they must be remanded to the Administrator for further proceedings.

Acronyms/Terms and Definitions

As used in this rate order, the following acronyms/terms and definitions apply:

Acronym/Term	Definition
$/kW-month	Monthly charge for capacity (i.e., $ per kilowatt (kW) per month).
12-cp	12-month coincident peak average.
Ancillary Services	Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission System in accordance with good utility practice.
A&GE	Administrative and general expense.
Basin Electric	Basin Electric Power Cooperative.
Control Area	An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the Interconnection.
Corps of Engineers	U.S. Army Corps of Engineers.
DOE	U.S. Department of Energy.
DOE Order RA 6120.2	An order addressing power marketing administration financial reporting, used in determining revenue requirements for rate development.

Acronym/Term	Definition
Emergency Energy	Electric energy purchased by an electric utility whenever an event on the system causes insufficient operating capability to cover its own demand requirement.
Energy Imbalance Service	A service which provides energy correction for any hourly mismatch between a Transmission Customer's energy supply and the demand served.
Federal Customers	Western and Bureau of Reclamation customers taking delivery of long-term firm service under Firm Electric Service Contracts, and Project Use Power Customers.
FERC	Federal Energy Regulatory Commission.
FERC Order No. 888	FERC Order Nos. 888, 888–A, 888–B, and 888–C unless otherwise noted.
Firm Electric Service Contract	Contracts for the sale of long-term firm energy and capacity to Federal Customers, with contract rates of delivery based on an allocation of power from the Federal generation resource.
Firm Point-to-Point Transmission Service	Transmission service that is reserved and/or scheduled between Points of Receipt and Delivery.
Heartland	Heartland Consumers Power District.
IS	Integrated System.
ISO	Independent System Operator.
JTS	Joint Transmission System.
kW	Kilowatt; 1,000 watts.
kWh	Kilowatt-hour; the common unit of electric energy, equal to one kW taken for a period of 1 hour.
kW-month	Unit of electric capacity, equal to the maximum of kW taken during 1 month.
Load	A customer or an end-use device that receives power from the Transmission System.
LRS	Laramie River Station is a coal-fired generation plant near Laramie, Wyoming. LRS is a part of the Missouri Basin Power Project (MBPP).
Load-ratio share	Ratio of the Network Transmission Customer's coincident hourly load (including its designated network load not physically interconnected with the Transmission Provider) to the Transmission Provider's monthly Transmission System peak, calculated on a rolling 12-month basis.
Long-Term Firm Point-to-Point Transmission Service.	Firm Point-to-Point Transmission Service reservation with at least 12 consecutive equal monthly amounts.
MAPP	Mid-Continent Area Power Pool.
mill	Unit of monetary value equal to .001 of a U.S. dollar; i.e., 1/10th of a cent.
mills/kWh	Mills per kilowatt-hour.
MBMPA	Missouri Basin Municipal Power Agency.
MBSG	Missouri Basin Systems Group.
MVAR	Megavar, equal to 1,000,000 VARs
MW	Megawatt; equal to 1,000 kW or 1,000,000 watts.
NEPA	National Environmental Policy Act of 1969.
NERC	North American Electric Reliability Council.
Network Customer	An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service of the Tariff.
Non-Firm Point-to-Point	Point-to-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to interruption for economic reasons.
O&M	Operation and maintenance expense.
P–SMBP	Pick-Sloan Missouri Basin Program.
P–SMBP–ED	Pick-Sloan Missouri Basin Program-Eastern Division.
Point-to-Point Transmission Service	The reservation and transmission of capacity and energy on either a firm or a non-firm basis from designated Point(s) of Receipt to designated Point(s) of Delivery.
Provisional Rate Schedule	A Rate Schedule which has been confirmed, approved, and placed in effect on an interim basis by the Deputy Secretary of DOE.
Reclamation	Bureau of Reclamation, U.S. Department of the Interior.
Reactive Supply and Voltage Control From Generating Sources Service.	A service which provides reactive supply through changes to generator reactive output to maintain transmission line voltage and facilitate electricity transfers.
Regulation and Frequency Response Service	A service which provides for following the moment-to-moment variations in the demand or supply in a Control Area and maintaining scheduled interconnection frequency.
Reserve Services	Spinning Reserve Service and Supplemental Reserve Service.
Schedule	An agreed-upon transaction size (megawatts), beginning and ending ramp times and rate, and type of service required for delivery and receipt of power between the contracting parties and the Control Area(s) involved in the transaction.
Scheduling, System Control, and Dispatch Service.	A service which provides for (a) scheduling, (b) confirming and implementing an interchange schedule with other control areas, including intermediary control areas providing transmission service, and (c) ensuring operational security during the interchange transaction.
Service Agreement	The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and Western for service under the Tariff.
Short-Term Firm Point-to-Point Transmission Service.	Firm Point-to-Point Transmission Service with service of less duration than 1 year.
Spinning Reserve Service	Generation capacity needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation.

Acronym/Term	Definition
Supplemental Reserve Service	Generation capacity needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick start generation or by interruptible load. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation.
Supporting Documentation	Work papers which support the rate.
System	An interconnected combination of generation, transmission and/or distribution components comprising an electric utility, independent power producers(s) (IPP), or group of utilities and IPP(s).
Tariff	Western Area Power Administration Open Access Transmission Service Tariff, Docket No. NJ98–1–000.
Transmission Customer	Any eligible customer (or its designated agent) that receives transmission service under the Tariff.
Transmission Provider	Any utility that owns, operates, or controls facilities used for the transmission of electric energy in interstate commerce. UGPR, as operator of the IS, is the Transmission Provider for the purposes of this Federal Register notice.
Transmission System	The facilities owned, controlled, or operated by the Transmission Provider that are used to provide transmission service.
Transmission System Total Load	12-cp system peak for Network Transmission Service plus reserved capacity for all Firm Point-to-Point Transmission Service.
UGPR	This is the Upper Great Plains Customer Service Region of the Western Area Power Administration. Some places herein, UGPR maybe referenced generically as Western.
VAR	A unit of reactive power.
WAUGP	The NERC acronym for the Western Area Upper Great Plains control area. This control area is also known as the Watertown Control Area.
Watertown Operations Office	Western Area Power Administration, Upper Great Plains Customer Service Region, Operations Office, 1330 41st Street SE, Watertown, South Dakota 57201.
Western	This is the Western Area Power Administration, U.S. Department of Energy. Some places herein, Western is represented by the Upper Great Plains Customer Service Region (UGPR).

Effective Date

The Provisional Formula Rates will become effective on the first day of the first full billing period beginning on or after August 1, 1998, and will be in effect pending the FERC's approval of them or substitute formula rates on a final basis through July 31, 2003, or until superseded. These formula rates will be applied under Western Area Power Administration Open Access Transmission Service Tariff (Tariff), Docket No. NJ98–1–000, and conform with the spirit and intent of the FERC Order No. 888. These rates are implemented pursuant to Schedules 1 through 8 and Attachment H of the Tariff.

Public Notice and Comment

The Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions, 10 CFR part 903, have been followed by Western in the development of these formula rates and schedules. The Provisional Rates are for new services. Therefore, they represent a major rate adjustment as defined at 10 CFR 903.2(e) and 903.2(f)(1). The distinction between a minor and a major rate adjustment is used only to determine the public procedures for the rate adjustment.

The following summarizes the steps Western took to ensure involvement of interested parties in the rate process:

1. On March 28, 1997, UGPR distributed an Advance Announcement of Transmission Rate Adjustment to all UGPR customers and interested parties. UGPR gathered comments and suggestions on the advance announcement through May 2, 1997.

2. UGPR published a **Federal Register** notice on September 15, 1997 (62 FR 48272), officially announcing the proposed open access transmission and ancillary service rates adjustment, initiating the public consultation and comment period, announcing the public information and public comment forums, and outlining procedures for public participation.

3. On September 23, 1997, UGPR mailed a copy of the ''Upper Great Plains Region Proposed Open Access Transmission and Ancillary Service Rates'' brochure to all UGPR Transmission Customers and other interested parties. Comments received on the advance announcement were addressed in this brochure.

4. UGPR held public information forums on October 16, 1997, in Billings, Montana, and October 17, 1997, in Sioux Falls, South Dakota. Western representatives explained the need for the rate adjustment in greater detail and answered questions.

5. UGPR held comment forums on November 13, 1997, in Billings, Montana, and November 14, 1997, in Sioux Falls, South Dakota, to provide the public an opportunity to comment for the record. Representatives from seven organizations made comments at these forums.

6. Fifty comment letters were submitted during the 90-day consultation and comment period. The consultation and comment period ended on December 15, 1997. All comments have been considered in the preparation of this Rate Order.

Comments

Representatives of the following organizations made oral comments:

Basin Electric Power Cooperative, Bismarck, North Dakota
City of Sioux Center, Iowa
Minnesota Corn Processors, Marshall, Minnesota
Missouri Basin Municipal Power Agency, Sioux Falls, South Dakota
City of Marshall, Minnesota
Northwestern Public Service Company, Huron, South Dakota
Heartland Consumers Power District, Madison, South Dakota

The following individuals and organizations submitted written comments:

Jon Christensen, Member of Congress, 2nd District Nebraska
Missouri Basin Municipal Power Agency, Sioux Falls, South Dakota
Doug Bereuter, Member of Congress, 1st District, Nebraska
Bill Barrett, Member of Congress, 3rd District, Nebraska
Basin Electric Power Cooperative, Bismarck, North Dakota
State of South Dakota, Pierre, South Dakota
Minnesota Valley Cooperative, Montevideo, Minnesota
Verendrye Electric Cooperative, Inc., Velva, North Dakota
Douglas Electric Cooperative, Inc., Armour, South Dakota
Charles Mix Electric Association, Inc., Lake Andes, South Dakota
Lake Region Electric, Webster, South Dakota
Union County Electric Cooperative, Inc., Elk Point, South Dakota
Bon Homme Yankton Electric Association, Inc., Tabor, South Dakota
East River Electric Power Cooperative, Madison, South Dakota
Whetstone Valley Electric Cooperative, Inc., Milbank, South Dakota
Renville Sibley Cooperative Power Association, Danube, Minnesota
Codington-Clark Electric Cooperative, Inc., Watertown, South Dakota
Traverse Electric Cooperative, Inc., Wheaton, Minnesota
Intercounty Electric Association, Inc., Mitchell, South Dakota
H–D Electric Cooperative, Inc., Clear Lake, South Dakota
Dakota Energy Cooperative, Inc., Huron, South Dakota
FEM Electric Association, Inc., Ipswich, South Dakota
Tri County Electric Association, Inc., Plankinton, South Dakota
Sioux Valley Southwestern Electric, Colman, South Dakota
McCook Electric Cooperative, Salem, South Dakota
Kingsbury Electric Cooperative, Inc., De Smet, South Dakota
Fort Peck Tribes, Poplar, Montana
Lyon-Lincoln Electric Cooperative, Inc., Tyler, Minnesota.
Central Power Electric Cooperative, Minot, North Dakota
City of Elk Point, South Dakota
Cooperative Power, Eden Prairie, Minnesota
Oahe Electric Cooperative, Inc., Blunt, South Dakota
Powder River Energy Corporation, Sundance, Wyoming
Nishnabotna Valley Rural Electric Cooperative, Harlan, Iowa
Northwest Iowa Power Cooperative, Le Mars, Iowa
Turner-Hutchinson Electric Cooperative, Inc., Marion, South Dakota
Oliver-Mercer Electric Cooperative, Inc., Hazen, North Dakota
Northern Electric Cooperative, Inc., Bath, South Dakota
Minnkota Power Cooperative, Inc., Grand Forks, North Dakota
Lincoln Electric System, Lincoln, Nebraska
Lincoln-Union Electric Company, Alcester, South Dakota
Western Iowa Power Cooperative, Denison, Iowa
Central Montana Electric Power Cooperative, Billings, Montana
Northern States Power Company, Minneapolis, Minnesota
Northwestern Public Service Company, by Law Offices of Wright & Talisman, P.C., Washington, DC
Nebraska Public Power District, York, Nebraska
Heartland Consumers Power District, comments submitted by Sutherland, Asbill & Brennan, LLP, Washington, DC
Mid-West Electric Consumers Association, Denver, Colorado

Pick-Sloan Missouri Basin Program-Eastern Division Project Description

The initial stages of the Missouri River Basin Project were authorized by section 9 of the Flood Control Act of 1944 (58 Stat. 887, 891, Pub. L. No. 78–534). It was later renamed the Pick-Sloan Missouri Basin Program (P–SMBP). The P–SMBP is a comprehensive program, with the following authorized functions: flood control, navigation improvement, irrigation, municipal and industrial water development, and hydroelectric production for the entire Missouri River Basin. Multipurpose projects have been developed on the Missouri River and its tributaries in Colorado, Montana, Nebraska, North Dakota, South Dakota, and Wyoming.

UGPR markets significant quantities of Federally generated hydroelectric power from the Pick-Sloan Missouri Basin Program-Eastern Division (P–SMBP–ED). Western owns and operates an extensive system of high-voltage transmission facilities which UGPR uses to market approximately 2,400 MW of capacity from Federal projects within the Missouri River Basin. This capacity is generated by eight powerplants located in Montana, North Dakota, and South Dakota. UGPR utilizes the transmission facilities of Western and others to market this power and energy to customers located within the P–SMBP–ED. This marketing area includes Montana, east of the Continental Divide, all of North Dakota and South Dakota, eastern Nebraska, western Iowa, and western Minnesota.

History of Transmission System

Prior to 1959, Reclamation provided the total power supply needs to preference customers in the P–SMBP–ED marketing area. Reclamation constructed a Federal transmission system to supply power to those preference customers. In 1959, Reclamation notified the preference customers that it could no longer meet the total projected power needs past the year 1964 and urged these entities to make their own arrangements for supplemental power supply. Reclamation and certain supplemental power suppliers agreed to construct future transmission facilities within the region using a single system, joint planning concept.

In 1963, the Joint Transmission System (JTS) was created when Reclamation and Basin Electric Power Cooperative (Basin Electric) entered into the Missouri Basin Systems Group (MBSG) Pooling Agreement (Agreement). In 1977, Western was established and assumed the responsibility for the Reclamation-owned Federal transmission system and existing contracts. Heartland Consumers Power District (Heartland) and Missouri Basin Municipal Power Agency (MBMPA) were organized in the mid-1970's and subsequently signed the MBSG Agreement. Basin Electric, Heartland, and MBMPA all supply supplemental power to certain preference customers and are commonly referred to as supplemental power suppliers. The MBSG Agreement provided for joint planning and operation of some, but not all, of the transmission facilities for the JTS participants. Since then, the JTS participants have augmented the existing Federal transmission system, using a single system, joint planning concept, rather than build separate transmission systems themselves. Specific JTS rights and obligations are detailed in bilateral agreements between Western and the participants.

The MBSG Agreement also provides a mechanism for sharing the cost of the transmission facilities that considers the participants' ownership of the transmission facilities that comprise the JTS. The JTS cost-sharing method is based upon the concept that the original facilities were capable of delivering the Federal generation to load plus approximately 200 MW, per studies performed in the 1963 timeframe. Basin

Electric's Leland Olds No. 1 generator was the first generation added and was 210 MW.

The next generation addition did not occur until after 1969. Studies for each increment of generation thereafter demonstrated a need for transmission additions. Western had sufficient capacity in its original system to serve its own load, and since neither its generation nor its load was increasing, did not need the additional facilities to deliver to its loads. Therefore, it was agreed Western would not share in the cost of additional facilities provided by others. However, Western would share in the revenues generated by the system to the extent Western provided facilities and incurred investment costs after 1969. The post-1969 additions are the basis for the cost-sharing ratios.

The JTS cost-sharing method is as follows. Costs for the JTS are summed for Western, Basin Electric, Heartland, and MBMPA to arrive at a total transmission system cost. The total transmission system cost for the year is divided by the generation input for the year (4,127,000 kW for 1997) to determine the JTS cost per kW-year of generation input. The JTS participants, except Western, then pay into the JTS according to their generation input. These JTS revenues are then distributed back to the participants, including Western, based upon the ratio of costs associated with contributed facilities constructed since 1969.

Integrated System Description

Utilizing the single system, joint planning concept created by MBSG, the UGPR, Basin Electric, and Heartland combined their transmission facilities to form the Integrated System (IS) and herein develop transmission and ancillary service rates for transmission over the IS. This action is necessary because UGPR, Basin Electric and Heartland, whose facilities are fully integrated, did not have rates suitable for long-term open access Transmission Service. The transmission facilities included in the IS are transmission lines, substations, communication equipment, and facilities related to operation, maintenance, and support of the Transmission System. UGPR has been designated as the operator of the other participants' transmission facilities and as such will contract for service, determine and post on the Open Access Same-Time Information System available transmission capacity, bill for service, collect payments, distribute revenue to each participant, etc. 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, Minnesota, and Missouri and in addition include facilities which interconnect with Canada.

The approach for formation of the IS was to include facilities which followed the spirit and intent of the FERC Order No. 888 and to make the system most useful to all transmission requesters. The "seven factor test" defined in the FERC Order No. 888 was used to determine the distribution facilities that were excluded from the IS Transmission System. Several major facilities which were not a part of the JTS have been included in the IS. The second 345-kV transmission line between the Antelope Valley and Leland Olds generating stations, which meets the standards for acceptable transmission facilities set in the FERC rulings on filings by other transmission entities, has been included. The 230-kV transmission line between Tioga, North Dakota, and Boundary Dam, which provides access to generation and loads in Canada, has been included in the IS. The IS also includes the Miles City DC Tie, which opens the markets between the East-West electrical separation of the United States and increases access to other utilities. The IS differs from the JTS in that it does not include the Laramie River Station (LRS) transmission facilities. These facilities were not considered for inclusion in the IS since agreement of all the Missouri Basin Power Project (MBPP) participants would be required.

IS Transmission Service

UGPR will offer Network Integration (Network), Firm Point-to-Point and Non-Firm Point-to-Point (Point-to-Point) Transmission Service on the IS. The service offered is the transmission of energy and capacity from Points of Receipt to Points of Delivery on the IS. The IS Transmission Rates include the cost of Scheduling, System Control, and Dispatch Service, therefore an additional charge for this ancillary service is not required for transmission users.

Western, Basin Electric, and Heartland will take IS Transmission Service. Transmission Service to UGPR's Federal customers will continue to be bundled in their Firm Electric Service rate under existing contracts which expire in 2020.

UGPR prepared a cost of service study to develop the formula rates for the IS. UGPR is seeking approval of formula rates for calculation of Point-to-Point IS Transmission Rates, the Network IS Transmission Service revenue requirement, and ancillary service rates. UGPR is requesting the FERC to confirm that these rates are not unjust, unreasonable, unduly discriminatory, or preferential. The rates will be recalculated every year, effective May 1, based on the approved formula rates and updated financial and load data. UGPR will provide customers notice of changes in rates no later than April 1 of each year.

Ancillary Services

UGPR will offer to all customers the six ancillary services defined by the FERC. The six ancillary services are: (1) Scheduling, System Control, and Dispatch Service; (2) Reactive Supply and Voltage Control from Generation Sources Service; (3) Regulation and Frequency Response Service; (4) Energy Imbalance Service; (5) Spinning Reserves Service; and (6) Supplemental Reserves Service. The open access ancillary service formula rates are designed to recover only the costs incurred for providing the service(s). The charges for ancillary services are based on the cost of resources used to provide these services.

Existing and Provisional Rates

The following is a comparison of existing rates, and the Provisional Rates using 1997 data. These rates will be updated annually based on the approved formula rates. This is the first transmission rate filing made by the P-SMBP-ED. Prior to this, transmission services were provided through bilateral contract arrangements, therefore there is not an existing rate schedule for comparison.

COMPARISON OF EXISTING AND PROVISIONAL FORMULA RATES

Class of service	Existing rate schedule and rate	Rate schedule August 1, 1998
Network Transmission	N/A	UGP–NT1, Load-ratio share of 1/12 of the Annual Revenue Requirement for IS Transmission Service of $95,725,420.
Firm Point-to-Point Transmission	N/A	UGP–FPT1, Maximum of $2.87/kW-month.
Non-Firm Point-to-Point Transmission	N/A	UGP–NFPT1, Maximum of 3.93 mills/kWh.
Scheduling, System Control, and Dispatch	N/A	UGP–AS1, $46.06 per schedule per day for non-transmission customers.
Reactive Supply and Voltage Control from Generation Sources.	N/A	UGP–AS2 $0.07/kW-month.
Regulation and Frequency Response	N/A	UGP–AS3, $0.05/kW-month.
Energy Imbalance	N/A	UGP–AS4, For negative excursions outside of 3 percent bandwidth UGPR reserves the right to charge 100 mills/kWh. Positive excursions outside the bandwidth will be lost to the system.
Spinning/Supplemental Reserves	N/A	UGP–AS5 and 6, $0.12/kW-month of customer load.

Certification of Rates

Western's Administrator has certified the transmission and ancillary service rates placed into effect on an interim basis herein are the lowest possible consistent with sound business principles. The formula rates have been developed in accordance with agency administrative policies and applicable laws.

IS Transmission Service Discussion

The formula rates for Network and Point-to-Point Transmission Service will be implemented August 1, 1998. The rates will be recalculated annually based on updated financial and load data. Network service charges will be based on the Transmission Customer's load-ratio share of the annual revenue requirement for transmission. Firm Point-to-Point service will be based on reserved capacity on the Transmission System.

IS Transmission System Total Load: The IS Transmission System Total Load is the 12-cp system peak for Network Transmission Service plus the reserved capacity for all Long-Term Firm Point-to-Point Transmission Service.

The IS Transmission System Total Load is calculated as follows based upon 1997 data:

Network Transmission Load	2,447,000
Long-Term Firm Point-to-Point Reserved Capacity	331,000
IS Transmission System Total Load	2,778,000

Annual Costs: Western has calculated the annual cost of providing the various transmission and ancillary services using a FERC recognized methodology for annual cost calculation with fixed charge rates for various cost components. The cost components applicable to Western include operation and maintenance (O&M), administrative and general expense (A&GE), depreciation, and the cost of capital. These components are displayed as fixed charge rates or percentages of net investment. These fixed charge rates are then summed to arrive at a total fixed charge rate associated with the particular service for which a rate is being calculated. The fixed charge rate calculation for the various transmission and ancillary services can be summarized with the following formula:

+ O&M ÷ Net investment
+ A&GE ÷ Net investment
+ Depreciation expense ÷ Net investment
+ Annual interest expense ÷ Unpaid investment balance
= Total fixed charge rate.

To arrive at the annual cost of providing transmission service or one of the ancillary services, the total fixed charged rate is applied to the net investment allocated to the service as follows:

Total fixed charge rate × Net investment = Annual cost of providing service.

The source for UGPR's annual O&M, A&GE, depreciation expense, interest expense, and investment is the *Results of Operations for the Upper Great Plains Customer Service Region—Pick-Sloan Missouri Basin*. The source for unpaid investment balances is the amount reported in the *Historical Financial Document in Support of the Power Repayment Study for the Pick-Sloan Missouri Basin Program*. The source for Heartland's data is *Heartland Consumers Power District Annual Report*. The sources for Basin Electric's data are Basin Electric's *Consolidated Financial Statement, Rural Utility Service Form 12*, and other accounting records.

Annual Revenue Requirement for IS Transmission Service: The rates for IS Transmission Service (Network and Point-to-Point) are based on a revenue requirement that recovers the annual costs of Western, Basin Electric, and Heartland associated with providing IS Transmission Service plus any facility credits paid to Transmission Customers. The revenue requirement for IS Transmission Service includes the cost for Scheduling, System Control, and Dispatch Service needed to provide transmission service, therefore an additional charge for this ancillary service is not required for transmission users. The annual transmission costs are offset by appropriate transmission revenue credits to avoid over recovery of costs. The Annual Revenue Requirement for IS Transmission Service can be summarized with the following formula:

Annual IS transmission costs of UGPR, Basin Electric, and Heartland
+ Transmission Customer facility credits
− Transmission revenue credits
= Annual Revenue Requirement for IS Transmission Service.

Using 1997 data, the Annual Revenue Requirement for IS Transmission Service is:

$116,340,141
+ $194,444
− $20,809,165
= $95,725,420

Transmission Customer facility credits are credits paid to Transmission Customers for facilities that are integrated with the IS and increase both the capability and the reliability of the IS. The credits will be addressed in individual agreements, and appropriate adjustments will be made in subsequent rate calculations. The IS participants will evaluate requests for facility credits consistent with the FERC's guidance in the FERC Order No. 888, other relevant FERC policy, and the terms of the Tariff.

Transmission revenue credits include revenue from sales of Non-Firm, discounted Firm, and Short-Term Firm Point-to-Point Transmission Service; revenue from existing transmission agreements; revenue from Scheduling, System Control, and Dispatch Services; and any facility charges for transmission facility investments included in the revenue requirement. The following revenue credits have been applied in the IS Transmission Rate. The estimated Non-Firm Point-to-Point Transmission Service credit of $11,531,175 is based on 1997 non-firm energy sales on the IS Transmission System and actual sales of Non-Firm Point-to-Point Transmission Service on the IS Transmission System during 1997. Revenue from existing transmission agreements was $9,277,990 in 1997.

Network IS Transmission Service: The monthly charge for Network IS Transmission Service is the product of the Network Customer's load-ratio share times one-twelfth (1/12) of the Annual Revenue Requirement for IS Transmission Service of $95,725,420. The load-ratio share is the ratio of the Network Customer's coincident hourly load to the monthly IS Transmission System peak minus the coincident peak for all IS Firm Point-to-Point Transmission Service plus the IS Firm Point-to-Point reservations, calculated on a rolling 12-cp basis.

Firm Point-to-Point IS Transmission Service: The rate for Firm Point-to-Point IS Transmission Service is the Annual Revenue Requirement for IS Transmission Service divided by the IS Transmission System Total Load. The formula for the monthly rate is as follows: Annual Revenue Requirement for IS Transmission Service ÷ IS Transmission System Total Load ÷ 12 months, or, using 1997 data, $95,725,420 ÷ 2,778,000 kW ÷ 12 months. The formula produces a rate of $2.87/kW-month for Firm Point-to-Point Transmission Service. Firm Point-to-Point Transmission Service will be offered on an ''up to'' basis at daily, weekly, monthly, and yearly rates.

Non-Firm Point-to-Point IS Transmission Service: Non-Firm Point-to-Point IS Transmission Service will be offered at a rate up to, but never higher than, the Firm Point-to-Point rate. The formula for the rate is as follows: Monthly Firm Point-to-Point Rate ÷ 730 hours/month, or using 1997 data, $2.87/kW-month ÷ 730 hours/month. The formula produces a rate of 3.93 mills/kWh. Non-Firm Point-to-Point IS Transmission Service will be offered at hourly, daily, weekly, and monthly rates.

Transmission Service Comments

The following comments were received during the public comment period. UGPR paraphrased and combined comments when it did not affect the meaning. UGPR's response follows each comment. Changes were made in the formula rates and calculations as a result of the comments noted.

Comment: UGPR should use the IS to provide open access transmission and ancillary services. The following comments were made in support of this comment. IS is consistent with the FERC Order No. 888. The system is integrated since the facilities are jointly planned, constructed, and operated as one system. The system cannot be divided into separate systems defined by ownership and still serve its function as a reliable, efficient Transmission Provider. One IS rate eliminates pancaking of transmission tariffs and maximizes facility usage. IS will maintain the postage stamp rate concept of paying once to travel anywhere on the system. The IS will minimize revenue shifts.

Response: Western concurs with these comments.

Comment: Western should remove any end-use-load-serving substations and transmission facilities. UGPR should use the ''seven factor test'' to determine the facilities to exclude from the IS.

Response: UGPR has re-evaluated the facilities to be included in the IS using the ''seven factor test'' and made appropriate adjustments to the cost. Based upon the re-evaluation, UGPR removed appropriate end-use-load-serving substation and transmission line costs from the Annual Revenue Requirement for IS Transmission Service.

Comment: UGPR should explain guidelines used to determine the allocation of transmission facility and substation revenue requirements to generation versus transmission.

Response: UGPR evaluated the substations and transmission lines based on their usage (generation versus transmission). The substation and transmission line costs were then included in their respective categories. Watertown Operations Office costs were split based on the classification of Full Time Equivalent employees in generation or transmission. Communication facilities were split based on communication circuit usage.

Comment: UGPR should exclude the cost of non-Federal facilities and develop a ''Western only'' rate. UGPR should remove Western's and Basin Electric's generator step-up transformers, West-side facilities, the Miles City DC Tie, and Basin Electric's generator outlet lines. UGPR should include Heartland's LRS transmission facilities. UGPR should consider separate rates for the East and West regions of its system.

Response: UGPR, Basin Electric, and Heartland facilities are integrated. The rate includes each entity's facilities that are integrated. Therefore, it is inappropriate to develop a ''Western only'' rate.

The FERC has allowed generator step-up transformers to be included in transmission rates. Western's costs include step-up transformers in the Corps switchyards which perform a transmission function. Basin Electric's costs also include step-up transformers.

Western, Basin Electric, and Heartland have separated their costs between transmission and generation and have included only transmission related costs in the Transmission Service revenue requirement. Basin Electric's high-voltage lines referred to as ''generator outlet lines'' meet the ''seven factor test'' and are, therefore, included in the Transmission Service revenue requirement.

The IS participants did not consider the LRS facilities for inclusion in the IS since agreement of all the MBPP participants would be required.

UGPR operates under a unique situation in that it utilizes generation and transmission facilities located on both sides of the East-West electrical separation in Montana to meet its responsibilities in the Mid-Continent Area Power Pool (MAPP). UGPR has always operated all of its facilities on a single system basis. UGPR has marketed the generation plants on both sides of the electrical separation across the entire P–SMBP–ED and integrated deliveries from its resources for service to all UGPR power customers. The FERC has held that when an entity is able to adjust, second-by-second, the power flows over its entire system, including direct current ties, to integrate resources, the entity is utilizing its system as a single integrated transmission system and has allowed total system costs to be rolled into the IS Transmission Rate. The Miles City DC Tie provides some instantaneous support to the East-side transmission system and therefore contributes to the security aspect of reliability as defined by the North American Electric Reliability Council (NERC). The Miles City DC Tie provides reliability benefits to MAPP by instantaneously responding to disturbances on the East-side transmission systems through MW reductions and MVAR support. Therefore, the Miles City DC Tie and the transmission facilities in the East and West regions of the UGPR system are included in the IS rates.

Comment: If UGPR changes its rates to the IS rates which recover the cost of Basin Electric and Heartland facilities, it will cause Western's firm power rate to increase.

Response: Western has existing bilateral contracts with Basin Electric and Heartland. Western will continue the benefits and obligations contained in those contracts through their terms. The continuation of those benefits will minimize any firm power rate impacts which may result from the use of the IS by Western for the delivery of firm power.

Comment: Several comments made in the public process have compared the existing JTS rate used in the bilateral agreements between Western, Basin Electric, and Heartland to the proposed rate and have stated that the JTS rate is either below cost or the IS rates are inflated. Their comparisons and arguments are based on a JTS rate of $26.27/kW-year and an IS rate of $36.84/kW-year.

Response: The JTS rate is a cost-based rate for the combined facilities of Western, Basin Electric, Heartland, and MBMPA. The rate itself is applied to each participants' connected generation and other resource inputs. A generation or input based rate, like JTS, includes planning reserves (15 percent), losses (approximately 4 percent), surplus generation and the load in the billing units for recovery of the cost.

The IS rate is a cost-based rate for the combined facilities of Western, Basin Electric, and Heartland. In addition, MBMPA has asked and will receive credit for certain facilities at Irv Simmons Substation. The rate is applied to the loads on the Transmission System. A load-based rate, like the IS rate, includes only the load in the billing units for the recovery of cost.

Input-based billing units and load-based billing units are not directly comparable. Although input-based rates (JTS) and load-based rates (IS) recover equivalent costs, they have different billing units. Therefore, the representation of the rate in $/kW-year is not identical and cannot be compared one-for-one. If each rate is applied to the correct billing units they both recover the total and appropriate costs.

Comment: UGPR firm power customers should not be required to recover Basin Electric's and Heartland's stranded costs.

Response: The rate design for the IS does not recover the stranded costs of any parties (Western, Basin Electric, or Heartland). If costs are determined to be stranded they will be addressed in a separate contract between the entity holding the stranded costs and the Transmission Customer, as described in the Tariff filed by Western in Docket No. NJ98–1–000.

Comment: Who will review the costs for Basin Electric and Heartland to determine whether they are appropriate, and what recourse do the customers have to question the costs?

Response: Basin Electric and Heartland have submitted their data as a part of this public process. In addition, their data is and will continue to be submitted to MAPP, just as any other transmission-owning MAPP member.

On or about April 1 of each year the updated transmission cost data for Western, Basin Electric, and Heartland will be available for review. At this time a notice will be sent to Transmission Customers of changes to the rates that will be effective May 1.

The Transmission Customers' recourse is similar to any other entity in a public process or in the course of MAPP review.

Comment: Western should ask the FERC to review the Open Access Transmission and Ancillary Service Rates for consistency with the standards of Section 212 of the FPA.

Response: In addition to seeking final confirmation under the Delegation Order, Western is requesting the FERC review the proposed transmission rates for the UGPR for consistency with the standards of section 212 (a) of the FPA, 16 U.S.C. 824k (a). In doing so, Western is asking the FERC to determine that its rates are comparable to what it charges other customers and conform to the standards under the Delegation Order in a manner similar to the FERC's finding in *United States Department of Energy-Bonneville Power Administration,* 80 FERC ¶ 61,118 (1997).

Western has separately filed for approval of generally applicable terms and conditions under its Tariff in Docket No. NJ98–1–000. These rate schedules will be utilized under the Tariff for service in the UGPR of Western, and they are potentially subject to FERC review under the standards of 16 U.S.C. 824k (a).

Comment: Basin Electric's cost of capital calculation should be adjusted as follows: (1) the interest expense shown on page 89, line 9, column (b) in the brochure should be used in the calculation; (2) a 7 percent return on equity should be used; (3) Basin Electric's total cost of capital should be divided by its total capitalization rather than net plant investment to arrive at Basin Electric's weighted cost of capital.

Response: Basin Electric used the interest expense shown on Rural Utility Service Form 12a, line 22, column b. This amount is the actual interest expense for the year. The interest expense shown on page 89 of the brochure is based on an accrual schedule rather than actual interest expense.

Basin Electric has no basis for using a 7 percent return on equity. In the revenue requirement calculation in this **Federal Register** notice, Basin Electric utilizes the 10 percent margin for interest it charges its members which equates to a return on equity of approximately 9 percent. Since Basin Electric now uses its margin for interest to calculate its cost of capital, issue (3) above is no longer relevant.

Comment: Heartland should reduce their return on equity from 13 percent to 7 percent because 13 percent far exceeds the return on equity the FERC is allowing investor-owned utilities.

Response: Heartland has no basis for using a 7 percent return on equity. In this **Federal Register** notice Heartland calculated its cost of capital using its bond covenant requirement, similar to Basin Electric's margin for interest method. Heartland is required by Section 8.2 of its Bond Resolution to maintain rates at such levels that when revenues from rates are combined with other funds that the total amount will be sufficient to meet 1.15 times the debt service coverage requirement. Heartland develops rates for its customers on this basis, and it therefore uses the same approach here.

Comment: Basin Electric should allocate A&GE and general plant costs between IS transmission facilities and other transmission facilities and only include the portion allocated to IS transmission facilities in the IS Transmission System revenue requirement.

Response: UGPR agrees with this comment, and Basin Electric's costs have been adjusted accordingly.

Comment: The IS rate causes some MBMPA members to pay twice for the same transmission service.

Response: The MBMPA members will not pay twice for usage of the IS for the same service. Members of MBMPA will pay for transmission and ancillary services on the MBMPA resource separately from the service they receive from Western in its bundled firm power service.

Comment: Western is not charging itself for the Basin Electric and Heartland costs. Therefore, the rates it charges itself are not comparable.

Response: Western will be taking all service under the IS rates and therefore is charging itself for the Basin Electric and Heartland costs. Cost sharing benefits and obligations associated with service under existing bilateral contracts will continue until contract expiration.

Comment: The IS should provide for discounted rates.

Response: Western's Tariff and IS rates allow for ''up to'' rates for the Firm and Non-Firm Point-to-Point Transmission Service rates. IS rates, including discounts to those rates, will be posted on the MAPP Open Access Same-Time Information System (OASIS) and will be available under the terms and conditions as posted.

Comment: Basin Electric Class A member loads and Western's preference customer loads should be treated as native load in the determination of the IS rates.

Response: Basin Electric Class A member loads and Western's preference customer loads are treated as native load and are included in the IS Network load.

Comment: Western should remove the portion of its power supply and marketing expenses associated with power marketing from its O&M expenses.

Response: Western removed purchase power costs from O&M expenses. In addition, Western's remaining O&M expenses (including power marketing) were split between generation and transmission based on the ratio of generation investment to total investment and transmission investment to total investment respectively. Only the portion of O&M expenses assigned to transmission was included in the transmission rate.

Comment: Western should use actual non-firm sales to calculate the revenue credit for Western's use of the Transmission System to make non-firm sales.

Response: Western agrees with this comment and has used actual 1997 non-firm sales in the calculation of the IS Transmission Rate.

Comment: The load associated with existing transmission contracts should be included in the load denominator rather than as a revenue credit.

Response: Western did not include the transactions covered under existing transmission contracts in the IS load because these transactions are at discounted rates and including them in the load would cause under recovery of the IS revenue requirement. As these transmission contracts expire and the loads associated with them are converted to Western's Tariff and IS Transmission Rates, they will be included in the IS load.

Comment: Western adjusted Basin Electric's Network load for Western peaking power service received, Dakota Gasification Company (DGC) load, and Neal IV generation but has not explained or justified these adjustments. Western should explain or correct this calculation.

Response: Firm peaking power service sold to Basin Electric was adjusted out of Basin Electric's Network load and included in Western's Network load because Western is responsible for transmission of peaking power service. DGC load was adjusted out of Basin Electric's Network load in the September 15, 1997, proposed IS Transmission Rates. DGC load is included in Basin Electric's Network load in the IS Transmission Rates in this **Federal Register** notice. Basin Electric's load served by Neal IV generation is adjusted out of Basin Electric's Network load because it does not utilize the IS Transmission System.

Comment: MAPP Service Schedule F payments to the IS participants should be shown separately as revenue credits to Western, Basin Electric, and Heartland revenue requirements since these revenues are received separately.

Response: In the proposed IS rates, estimates of MAPP Service Schedule F payments were shown separately for each IS participant as the ''Calculated Value of Non-Firm Point-to-Point Transmission Services.'' As the operator of the IS system, Western anticipates receiving all MAPP Service Schedule F payments made to the IS participants and then distributing these revenues back to the participants according to the IS agreement.

Comment: Several comments were received that Western does not have the authority to develop an IS Transmission Rate with Basin Electric and Heartland based upon its ratemaking requirements.

Response: Western's authority to develop an IS Transmission Rate is derived from the DOE 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. Western's Administrator has been given wide discretion in fulfilling those power marketing functions. Western's use of the IS rate is also consistent with the DOE policy regarding Power Marketing Administration's compliance with the spirit and intent of the FERC Order No. 888 and the FERC's preference for regional transmission groups.

Western's role as the operator of the IS is analogous to the responsibility it had with the JTS. Western was responsible for collection of funds from non-Federal participants and then distributed those funds based upon contractual obligations. Western has also approved the rate developed pursuant to the contracts between the JTS members on a 2-year basis prior to implementation. Western is the operator of the JTS and is responsible for establishing whether new uses of the JTS could be entertained and meet established reliability criteria.

Western was established pursuant to sections 302(a)(1) (E) and (F) and 302(a)(3) of the DOE Organization Act. Section 302(a)(11)(E) transferred to Western the power marketing functions of Reclamation, including the construction, operation, and maintenance of transmission lines, and attendant facilities. Western is complying with the expressed ratemaking authority contained in section 9(c) of the Reclamation Act of 1939 as well as section 5 of the Flood Control Act of 1944. Section 9(c) states that:

> Any sale of electric power or lease of power privileges, made by the Secretary in connection with the operation of any project or division of a project, shall be for such periods, not to exceed forty years and at such rates as in his judgment will produce power revenues at least sufficient to cover an appropriate share of the annual operation and maintenance cost, * * *

The IS rate does ensure that Western will recover an appropriate share of the investment in the Federal transmission facilities in the associated projects.

Development of the IS Transmission Rate is also consistent with section 5 of the Flood Control Act of 1944. Section 5 provides:

> Electric power and energy generated at reservoir projects under the control of the War Department and in the opinion of the Secretary of War not required in the operation of such projects shall be delivered to the Secretary of the Interior, who shall transmit and dispose of such power and energy in such manner as to encourage the most widespread use thereof at the lowest possible rates to consumers consistent with sound business principles, the rate schedules to become effective upon confirmation and approval by the Federal Power Commission. Rate schedules shall be drawn having regard to the recovery (upon the basis of the application of such rate schedules to the capacity of the electric facilities of the projects) of the cost of producing and transmitting such electric energy, including the amortization of the capital investment allocated to power over a reasonable period of years. Preference in the sale of such power and energy shall be given to public bodies and cooperatives. The Secretary of Interior is authorized, from funds to be appropriated by the Congress to construct or acquire, by purchase or other agreement, only such

transmission lines and related facilities as may be necessary in order to make the power and energy generated at said projects available in wholesale quantities for sale on fair and reasonable terms and conditions to facilities owned by the Federal government, public bodies, cooperatives, and privately owned companies. All moneys received from such sales shall be deposited in the Treasury of the United States as miscellaneous receipts.

Development of the IS Transmission Rate by Western is consistent with the obligation to transmit and dispose of power and energy while encouraging widespread use of the Federal facilities consistent with sound business practices. The integration of the Federal facilities with the non-Federal facilities enables the marketing of Western's resource as well as encouraging the widespread use of the Federal transmission facilities in the Missouri River Basin. As stated above, this philosophy is repaying the Federal investment through the rate schedules as they are recovering the appropriate costs of producing and transmitting that resource. This practice is also a sound business principle given the current FERC philosophy which encourages widespread use of transmission resources.

Section 5 of the Flood Control Act of 1944 also permits Western to construct or acquire transmission lines that are necessary to deliver the Federal resource. In order to deliver that resource, including sales of surplus generation sold on a non-firm basis, and meet Western's contractual obligations, it is necessary to use the IS for reliability reasons. This has been confirmed in the Initial Decision in *Missouri Basin Municipal Power Agency*, 82 FERC ¶ 63,015 (1998).

Comment: Several comments received stated that Western is violating the Anti-Deficiency Act and various fiscal obligations by participating in the IS.

Response: The Anti-Deficiency Act, 31 U.S.C. 1341(a)(1), states that an officer of the Federal Government may not involve the Government in a contract or obligation requiring the payment of money prior to an appropriation unless authorized by law. Western has the responsibility to meet all of its contractual obligations that have been incurred pursuant to Reclamation Law. Western is annually appropriated money to perform its mission, including meeting the obligations it has incurred pursuant to its contracting authority. Western does utilize the IS to meet these contractual obligations, and hence money has been appropriated to carry out the functions as described under the DOE Organization Act. In addition, Western's contracts contain General Power Contract Provisions which specifically state that any activity provided for under those contracts are ''contingent on appropriations.''

Comment: Other comments received stated that Federal law prohibits ''payments to third parties.''

Response: To the contrary, 16 U.S.C. 833(i) and 825(s) do not state that third party payments are unlawful. They do not address third party payments at all. They do contain language indicating Congress' intention that all money which the United States receives from sales of power generated at Fort Peck Project and the Projects under control of the War Department (now the Corps operated facilities) are to be deposited in Treasury. Western is not violating this statute as a result of operating the IS. Western will deposit money it receives for debts due the United States for sales of its resource into the Treasury in the same manner it has in the past. However, money received on behalf of Basin Electric and Heartland will not be received as a result of debts owed to the United States, but will be received for debts owed Basin Electric and Heartland. Therefore, money received on their behalf is not required to be deposited into the Treasury.

Western has in the past deposited and will continue to deposit all money to which the United States is entitled into the Treasury in accordance with the above statutes. Western has administered the JTS for over 30 years. This administration included the receipt of revenue from outside sources and then redistributing that revenue to other members of the JTS, Basin Electric, Heartland, and MBMPA. Western has also approved the JTS rate prior to implementation.

Western is obligated under existing contracts to administer the transmission facilities of Basin Electric and Heartland. These obligations have arisen based upon the initial signing of the MBSG Agreement which was signed by Reclamation in 1962 and the initial bilateral agreements between Basin Electric and Reclamation which created the JTS. The role Western is playing in the IS is analogous to the role it played in administering the JTS, and Western is contractually obligated to perform those functions.

Comment: UGPR should continue its rights and obligations detailed in the bilateral contracts. In addition it should allow all existing loads to stay on the JTS and receive those benefits.

Response: UGPR agrees and Western, Basin Electric, and Heartland will continue the obligations and benefits among themselves as detailed in the bilateral agreements.

Comment: UGPR should continue to participate in the planning of an Independent System Operator (ISO).

Response: UGPR agrees and has several representatives on the MAPP committees involved with the planning and development of the MAPP ISO. As the proposal is being developed, Western will provide input and data to study the impact on the region and Western. Western will continue its involvement.

Ancillary Services Discussion

Six ancillary services will be offered to IS Transmission Customers; two of which are required to be purchased by IS Transmission Customers. These two are (1) Scheduling, System Control, and Dispatch Service and (2) Reactive Supply and Voltage Control Service from Generation Sources Service. The remaining four ancillary services—Regulation and Frequency Response Service, Energy Imbalance Service, Spinning Reserve Service, and Supplemental Reserve Service will also be offered.

Sales of Regulation and Frequency Response Service, Energy Imbalance Service, Spinning Reserve Service, and Supplemental Reserve Service may be limited since Western has allocated its power resources to preference entities under long-term commitments. If Western is unable to provide these services from its own resources, an offer will be made to purchase the services and pass through these costs to the customer, including an administrative charge.

Scheduling, System Control, and Dispatch Service: Western's annual revenue requirement 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 formula rate for Scheduling, System Control, and Dispatch Service is the revenue requirement for this service divided by the annual number of daily schedules, or, using 1997 data, $1,684,495 ÷ 36,571 daily schedules. Using 1997 data, this methodology for determining the rate for Scheduling, System Control, and Dispatch Service has produced a rate of $46.06/schedule/day. This rate and rate design is only recovering Western's revenue requirement.

Reactive Supply and Voltage Control from Generation Sources Service: Western's annual cost of providing

Reactive Supply and Voltage Control from Generation Sources Service is determined by multiplying the total P–SMBP–ED generation net plant by the generation fixed charge rate. The annual cost is multiplied by the capability used for reactive support to determine Western's reactive service revenue requirement. Basin Electric's annual revenue requirement is based upon the annual cost of equipment installed on its generators to provide this service. Western's and Basin Electric's annual revenue requirements are summed for the total revenue requirement for this service. The Reactive Supply and Voltage Control Service from Generation Sources Service rate is then derived by dividing the annual revenue requirement by the IS Transmission System Total Load. The annual rate is then divided by 12 months to obtain a monthly rate. Using 1997 data, this methodology for determining the rate for Reactive Supply and Voltage Control Service from Generation Sources Service has produced a rate of $0.07/kW-month for transmission service provided.

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 Engineer facilities. To calculate the annual cost of providing Regulation and Frequency Response Service, the Corps of Engineer's generation fixed charge rate is applied to Oahe generation and Fort Peck generation net plant investment. This cost is divided by the capacity at the plants to derive a dollar per kilowatt amount for Oahe and Fort Peck Powerplants' installed capacity. This dollar per kilowatt amount is then applied to the capacity of Oahe generation and Fort Peck generation reserved for regulation and frequency response in the control area. The capacity reserved for Regulation and Frequency Response Service has been determined to be 2 percent of the annual peak load. The 2 percent value was derived by averaging the incremental change in hourly load in the control area for the calendar year and dividing this amount in half. The annual revenue requirement for Regulation and Frequency Response Service is determined by applying the dollar per kilowatt amount to the capacity used for Regulation and Frequency Response Service. An annual rate for Regulation and Frequency Response Service is then determined by dividing the revenue requirement by the total load in the control area. The annual rate is then divided by 12 months to obtain a monthly rate. Using 1997 data, this methodology for determining the rate for Regulation and Frequency Response Service produced a rate of $0.05/kW-month of load for which Western is providing this service. This rate and rate design is recovering only Western's revenue requirement. Credit will be given to those Transmission Customers who provide Western with Automatic Generation Control (AGC) of generation facilities capable of providing this service.

Energy Imbalance Service: This service is not intended to provide backup for generation supply. Energy shall be returned in like timeframes (on-peak, off-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.

Reserve Services: Western's annual cost of generation for Reserve Services is determined by multiplying the generation fixed charge rate by the P–SMBP–ED generation net plant investment. The cost/kW-year is determined by dividing the annual cost of generation by the plant capacity. The capacity used for Reserve Services is determined by multiplying Western's peak IS load by the MAPP operating reserve requirement of 5 percent. The cost/kW-year is multiplied by the capacity used for Reserve Services to determine the annual revenue requirement for Reserve Services. The annual revenue requirement for Reserve Services is divided by Western's peak transmission load to calculate the annual rate. The annual rate is then divided by 12 months to obtain a monthly rate. Using 1997 data, this methodology for determining the rate for reserve services has produced a rate of $0.12/kW-month of customer load. This rate and rate design is recovering only Western's revenue requirement associated with Reserve Services. If energy is taken under this service, the energy charge will be the MAPP Rate for Emergency Energy, which is presently the greater of 30 mills/kWh or the prevailing market energy rate in the region.

Ancillary Services Comments

UGPR received written comments concerning the ancillary service rates during the public comment and consultation period. These comments have been paraphrased where appropriate, without compromising the meaning of the comment. Certain comments were duplicative in nature, and were combined. UGPR's response follows each comment.

Comment: The rate for Reactive Supply and Voltage Control from Generation Sources Service is overstated because it includes an excessive amount of generation cost. The revenue requirement should be determined by estimating the cost of the exciter/generator and then allocating that cost between real and reactive power generation. In addition, the load used to derive the rate is understated.

Response: Western estimated the amount of plant costs used to provide Reactive Supply and Voltage Control from Generation Sources Service by multiplying generation investment by the ratio of condensing operation of the generators to total generator operation. When Western's hydro units are condensing, they are removing VARs generated by line charging on the long transmission lines in the IS. Western believes this method is appropriate for allocating costs to Reactive Supply and Voltage Control Service from Generation Sources Service.

The load used in the denominator of the Reactive Supply and Voltage Control Service from Generation Sources Service rate has been changed from the combined East and West control area coincident peaks to the IS Transmission System Total Load to reflect that each unit of transmission service will be charged for this service. Entities that have existing contracts at this time were not included in the denominator because Western cannot charge these entities for this service and including them would cause under recovery of costs. In the future when these contracts expire and these entities take service under the Tariff, their loads will be included in the denominator.

Comment: The Regulation and Frequency Response Service Rate is overstated. The revenue requirement is overstated because Western's estimate of the percentage of generation required to provide regulation service (4 percent) is too high. In addition, the denominator of 1,615 MW is too low. Finally, Western should give credit to Transmission Customers which purchase regulation service from third parties.

Response: The 4 percent value was derived by averaging the incremental change in hourly load in the control area for the year. In accordance with recent FERC rulings related to this service, Western has divided the 4 percent value in half. The denominator is Western's 12-cp load in its East and West control areas, excluding those entities such as Northwestern Public Service Company, Montana-Dakota Utilities Company, and Montana Power Company that serve load in Western's control areas but have existing transmission agreements and/or provide their own regulation and frequency control service. Including these entities' loads in the denominator at this time would cause under recovery of costs associated with this service. If these entities take this service from Western in the future their loads will be included in the denominator.

Whether Western should provide credit to those preference customers who purchase Regulation and Frequency Response Service from third parties is outside the scope of this process.

Comment: Western's combined percentages for Reserve Services (5 percent) and Regulation and Frequency Response Service (4 percent) are too high. Customers should only have to purchase a total of 5 percent capacity for both Reserve Services and Regulation and Frequency Response Service.

Response: The MAPP operating reserve requirement is 5 percent. Regulation and Frequency Response Service is not included in this percentage and must therefore be provided for in addition to operating reserves. In this **Federal Register** notice Western has decreased the amount of capacity reserved for Regulation and Frequency Response Service from 4 percent to 2 percent.

Comment: Western should adjust the rates for Reactive Supply and Voltage Control from Generation Sources Service and Regulation and Frequency Response Service to recover the costs of the facilities of Basin Electric and Heartland that contribute to the services provided by Western and then provide for appropriate credits.

Response: The cost of Basin Electric's facilities that contribute to Reactive Supply and Voltage Control from Generation Sources Service have been included in that rate, and Basin Electric will receive the appropriate credit for these facilities. If Basin Electric, Heartland, or any other entity provides Western with control of that entity's generation facilities and those generation facilities are capable of providing adequate Reactive Supply and Voltage Control from Generation Sources Service and/or Regulation and Frequency Response Service, that entity will be given an appropriate credit.

Regulatory Flexibility Analysis

Pursuant to the Regulatory Flexibility Act of 1980 (5 U.S.C. 601–612) (Act), each agency, when required by 5 U.S.C. 553 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 adjustment is related to non-regulatory services provided by Western at a particular rate. 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 service rates are of limited applicability, no flexibility analysis is required.

Environmental Evaluation

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

Executive Order 12866

DOE has determined 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 the Office of Management and Budget is required.

Submission to Federal Energy Regulatory Commission

The formula rates herein confirmed, approved, and placed into effect on an interim basis, together with supporting documents, will be submitted to the FERC for confirmation and approval on a final basis.

Order

In view of the foregoing, and pursuant to the authority delegated to me by the Secretary of Energy, I confirm, approve, and place into effect on an interim basis, effective August 1, 1998, formula rates for transmission and ancillary services under Rate Schedules UGP–AS1, UGP–AS2, UGP–AS3, UGP–AS4, UGP–AS5, UGP–AS6, UGP–FPT1, UGP–NFPT1, and UGP–NT1. The rate schedules shall remain in effect on an interim basis, pending the FERC confirmation and approval of them or substitute formula rates on a final basis through July 31, 2003.

Dated: July 31, 1998.

Elizabeth A. Moler,

Deputy Secretary.

Rate Schedule UGP–AS1

Schedule 1 to Tariff

August 1, 1998

United States Department of Energy, Western Area Power Administration, Upper Great Plains Region, Integrated System

Scheduling, System Control, and Dispatch Service

Effective

The first day of the first full billing period beginning on or after August 1, 1998, through July 31, 2003.

Applicable

This service is required to schedule the movement of power through, out of, within, or into the Western Area Upper Great Plains control area (WAUGP). The charges for Scheduling, System Control, and Dispatch Service are to be based on the rate referred to below. The formula rate used to calculate the charges for service under this schedule was promulgated and may be modified pursuant to applicable Federal laws, regulations, and policies.

The rate will be applied to all schedules for WAUGP non-Transmission Customers. The WAUGP will accept any reasonable number of schedule changes over the course of the day without any additional charge.

The charges for Scheduling, System Control, and Dispatch Service may be modified upon written notice to the customer. Any change to the charges for the Scheduling, System Control, and Dispatch Service shall be as set forth in a revision to this rate schedule promulgated pursuant to applicable Federal laws, regulations, and policies and made part of the applicable Service Agreement.

The Upper Great Plains Region (UGPR) shall charge the non-Transmission Customer in accordance with the rate then in effect.

Formula Rate

$$\text{Rate per Schedule per Day} = \frac{\text{Annual Revenue Requirement for Scheduling, System Control, and Dispatch Service}}{\text{Number of Daily Schedules per Year}}$$

Rate

The rate to be in effect August 1, 1998, through April 30, 1999, is $46.06 per schedule per day. This rate is based on the above formula and on 1997 data. A recalculated rate will go into effect every May 1 based on the above formula and data. UGPR will notify the customer annually of the recalculated rate on or before April 1.

Rate Schedule UGP–AS2

Schedule 2 to Tariff

August 1, 1998

United States Department of Energy, Western Area Power Administration, Upper Great Plains Region, Integrated System

Reactive Supply and Voltage Control From Generation Sources Service

Effective

The first day of the first full billing period beginning on or after August 1, 1998, through July 31, 2003.

Applicable

In order to maintain transmission voltages on all transmission facilities within acceptable limits, generation facilities under the control of the Western Area Upper Great Plains control area (WAUGP) are operated to produce or absorb reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service (VAR Support) must be provided for each transaction on the transmission facilities. The amount of VAR Support that must be supplied with respect to the Transmission Customer's transaction will be determined based on the VAR Support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by WAUGP.

The Transmission Customer must purchase this service from the Transmission Provider. The charges for such service will be based upon the rate referred to below.

The formula rate used to calculate the charges for service under this schedule was promulgated and may be modified pursuant to applicable Federal laws, regulations, and policies.

The charges for VAR Support may be modified upon written notice to the Transmission Customer. Any change to the charges for VAR Support shall be as set forth in a revision to this rate schedule promulgated pursuant to applicable Federal laws, regulations, and policies and made part of the applicable Service Agreement. The Upper Great Plains Region (UGPR) shall charge the Transmission Customer in accordance with the rate then in effect.

Those Transmission Customers with generators in the control area providing WAUGP with adequate VAR Support will not be charged for this service. Any waiver of this charge or any crediting arrangements for VAR Support must be documented in the Transmission Customer's Service Agreement.

Formula Rate

$$\text{WAUGP VAR Support Rate} = \frac{\text{Annual Revenue Requirement for VAR Support}}{\text{Load Requiring VAR Support}}$$

Rate

The rate to be in effect August 1, 1998, through April 30, 1999, is:

Monthly: $0.07/kW-month
Weekly: $0.016/kW-week
Daily: $0.002/kW-day
Hourly: 0.096 mills/kWh

This rate is based on the above formula and on 1997 financial and load data. A recalculated rate will go into effect every May 1 based on the above formula and updated financial and load data. UGPR will notify the Transmission Customer annually of the recalculated rate on or before April 1.

Rate Schedule UGP–AS3
Schedule 3 to Tariff
August 1, 1998

United States Department of Energy, Western Area Power Administration, Upper Great Plains Region, Integrated System

Regulation and Frequency Response Service

Effective

The first day of the first full billing period beginning on or after August 1, 1998, through July 31, 2003.

Applicable

Regulation and Frequency Response Service (Regulation) is necessary to provide for the continuous balancing of resources, generation, and interchange, with load and for maintaining scheduled interconnection frequency at 60 cycles per second (60 Hz). Regulation is accomplished by committing on-line generation whose output is raised or lowered, predominantly through the use of automatic generating control equipment, as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Western Area Upper Great Plains control area (WAUGP) operator. The Transmission Customer must either purchase this service from WAUGP or make alternative comparable arrangements to satisfy its Regulation obligation. The charges for Regulation are referred to below. The amount of Regulation will be set forth in the Service Agreement.

The formula rate used to calculate the charges for service under this schedule was promulgated and may be modified pursuant to applicable Federal laws, regulations, and policies.

Charges for Regulation may be modified upon written notice to the Transmission Customer. Any change to the Regulation charges shall be as set forth in a revision to this rate schedule promulgated pursuant to applicable Federal laws, regulations, and policies and made part of the applicable Service Agreement. The Upper Great Plains Region (UGPR) shall charge the Transmission Customer in accordance with the rate then in effect.

Transmission Customers will not be charged for this service if they receive Regulation from another source, or self-supply it for their own load. Any waiver of this charge or any crediting arrangement for Regulation must be documented in the Transmission Customer's Service Agreement.

Formula Rate

$$\text{WAUGP Regulation Rate} = \frac{\text{Annual Revenue Requirement for Regulation}}{\text{Load in the Control Area Requiring Regulation}}$$

Rate

The rate to be in effect August 1, 1998, through April 30, 1999, is:

Monthly: $0.05/kW-month
Weekly: $0.012/kW-week
Daily: $0.002/kW-day

This rate is based on the above formula and on 1997 financial and load data. A recalculated rate will go into effect every May 1 based on the above formula and updated financial and load data. UGPR will notify the Transmission Customer annually of the recalculated rate on or before April 1.

If resources are not available from a WAUGP resource, UGPR will offer to purchase the Regulation and pass through the costs to the Transmission Customer, plus an amount for administration.

Rate Schedule UGP-AS4
Schedule 4 to Tariff
August 1, 1998

United States Department of Energy Western Area Power Administration, Upper Great Plains Region, Integrated System

Energy Imbalance Service

Effective

The first day of the first full billing period beginning on or after August 1, 1998, through July 31, 2003.

Applicable

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within the Western Area Upper Great Plains control area (WAUGP) over a single hour. The Transmission Customer must either obtain this service from WAUGP or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation.

The WAUGP shall establish a deviation band of +/−1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s). Deviation accounting will be completed monthly on an hour-to-hour basis.

The formula rate used to calculate the charges for service under this schedule was promulgated and may be modified pursuant to applicable Federal laws, regulations, and policies.

The Energy Imbalance Service compensation may be modified upon written notice to the Transmission Customer. Any change to the Transmission Customer compensation for Energy Imbalance Service shall be as set forth in a revision to this schedule promulgated pursuant to applicable Federal laws, regulations, and policies and made part of the applicable Service Agreement. The Upper Great Plains Region (UGPR) shall charge the Transmission Customer in accordance with the rate then in effect.

Formula Rate

UGPR reserves the right to implement the following upon providing notice to the Transmission Customer.

For negative excursions (under deliveries) outside the bandwidth, WAUGP will assess a penalty charge of 100 mills/kWh.

For positive excursions (over deliveries) outside the bandwidth, over deliveries of energy will be forfeited to the control area.

Rate

The bandwidth in effect August 1, 1998, through July 31, 2003, is 3 percent (+/−1.5 percent hourly deviation).

Rate Schedule UGP-AS5
Schedule 5 to Tariff
August 1, 1998

United States Department of Energy Western Area, Power Administration, Upper Great Plains Region, Integrated System

Operating Reserve—Spinning Reserve Service

Effective

The first day of the first full billing period beginning on or after August 1, 1998, through July 31, 2003.

Applicable

Spinning Reserve Service (Reserves) is needed to serve load immediately in the event of a system contingency. Reserves may be provided by generating units that are on-line and loaded at less than maximum output. The Transmission Customer must either purchase this service from Western Area Upper Great Plains control area (WAUGP) or make alternative comparable arrangements to satisfy its Reserves obligation. The charges for Reserves are referred to below. The amount of Reserves will be set forth in the Service Agreement.

The formula rate used to calculate the charges for service under this schedule was promulgated and may be modified pursuant to applicable Federal laws, regulations, and policies.

The charges for Reserves may be modified upon written notice to the Transmission Customer. Any change to the charges for Reserves shall be as set forth in a revision to this rate schedule promulgated pursuant to applicable Federal laws, regulations, and policies and made part of the applicable Service Agreement. The Upper Great Plains Region (UGPR) shall charge the Transmission Customer in accordance with the rate then in effect.

Formula Rate

$$\text{WAUGP Reserves Rate} = \frac{\text{Annual Revenue Requirement for Reserves}}{\text{Load Requiring Reserves}}$$

Rate

The rate to be in effect August 1, 1998, through April 30, 1999, is:

Monthly: $0.12/kW-month
Weekly: $0.028/kW-week
Daily: $0.004/kW-day

This rate is based on the above formula and on 1997 financial and load data. A recalculated rate will go into effect every May 1 based on the above formula and updated financial and load data. UGPR will notify the Transmission Customer annually of the recalculated rate on or before April 1.

If resources are not available from a WAUGP resource, UGPR will offer to purchase the Reserves and pass through the costs to the Transmission Customer, plus an amount for administration.

In the event that Reserves are called upon for Emergency Use, UGPR will assess a charge for energy used at the Mid-Continent Area Power Pool Rate for Emergency Energy, presently the greater of 30 mills/kWh or the prevailing market energy rate in the region. The Transmission Customer would be responsible for providing the transmission to get the Reserves to its destination.

Rate Schedule UGP–AS6
Schedule 6 to Tariff
August 1, 1998

United States Department of Energy, Western Area Power Administration Upper Great Plains Region, Integrated System

Operating Reserve—Supplemental Reserve Service

Effective

The first day of the first full billing period beginning on or after August 1, 1998, through July 31, 2003.

Applicable

Supplemental Reserve Service (Reserves) is needed to serve load in the event of a system contingency, however, it is not available immediately to serve load but rather within a short period of time. Reserves may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load. The Transmission Customer must either purchase this service from Western Area Upper Great Plains control area (WAUGP) or make alternative comparable arrangements to satisfy its Reserves obligation. The charges for Reserves are referred to below. The amount of Reserves will be set forth in the Service Agreement.

The formula rate used to calculate the charges for service under this schedule was promulgated and may be modified pursuant to applicable Federal laws, regulations, and policies.

The charges for Reserves may be modified upon written notice to the Transmission Customer. Any change to the charges for Reserves shall be as set forth in a revision to this rate schedule promulgated pursuant to applicable Federal laws, regulations, and policies and made part of the applicable Service Agreement. The Upper Great Plains Region (UGPR) shall charge the Transmission Customer in accordance with the rate then in effect.

Formula Rate

$$\text{WAUGP Reserves Rate} = \frac{\text{Annual Revenue Requirement for Reserves}}{\text{Load Requiring Reserves}}$$

Rate

The rate to be in effect August 1, 1998, through April 30, 1999, is:

Monthly: $0.12/kW-month
Weekly: $0.0028/kW-week
Daily: $0.004/kW-day

This rate is based on the above formula and on 1997 financial and load data. A recalculated rate will go into effect every May 1 based on the above formula and updated financial and load data. UGPR will notify the Transmission Customer annually of the recalculated rate on or before April 1.

If resources are not available from a WAUGP resource, UGPR will offer to purchase the Reserves and pass through the costs to the Transmission Customer, plus an amount for administration.

In the event Reserves are called upon for Emergency Energy, the UGPR will assess a charge for energy used at the Mid-Continent Area Power Pool Rate for Emergency Energy, presently the greater of 30 mills/kWh or the prevailing market energy rate in the region. The Transmission Customer would be responsible for providing the transmission to get the Reserves to its destination.

Rate Schedule UGP–FPT1
Schedule 7 to Tariff
August 1, 1998

United States Department Of Energy, Western Area Power Administration, Upper Great Plains Region, Integrated System

Long-Term Firm and Short-Term Firm Point-to-Point Transmission Service

Effective

The first day of the first full billing period beginning on or after August 1, 1998, through July 31, 2003.

Applicable

The Transmission Customer shall compensate the Upper Great Plains Region (UGPR) each month for Reserved Capacity pursuant to the applicable Firm Point-to-Point Transmission Service Agreement and rates referred to below. The formula rates used to calculate the charges for service under this schedule were promulgated and may be modified pursuant to applicable Federal laws, regulations, and policies.

UGPR may modify the rate for Firm Point-to-Point Transmission Service upon written notice to the Transmission Customer. Any change to the rate for Firm Point-to-Point Transmission Service shall be as set forth in a revision to this rate schedule promulgated pursuant to applicable Federal laws, regulations, and policies and made part of the applicable Service Agreement. UGPR shall charge the Transmission Customer in accordance with the rate then in effect.

Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by UGPR must be announced to all eligible Transmission Customers solely by posting on the Open Access Same-Time Information System (OASIS), (2) any Transmission Customer initiated requests for discounts, including requests for use by one's wholesale merchant or an affiliate's use, must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, UGPR must offer the same discounted transmission service rate for the same time period to all eligible Transmission Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

Formula Rate

$$\text{Firm Point-to-Point Transmission Rate} = \frac{\text{Annual IS Transmission Service Revenue Requirement}}{\text{IS Transmission System Total Load}}$$

Rate

The rate to be in effect August 1, 1998, through April 30, 1999, is as follows.

Maximum of:

Yearly: $34.44/kW of reserved capacity per year

Monthly: $ 2.87/kW of reserved capacity per month

Weekly: $ 0.66/kW of reserved capacity per week

Daily: $ 0.094/kW of reserved capacity per day

This rate is based on the above formula and 1997 data. A recalculated rate will go into effect every May 1 based on the above formula and updated financial and load data. UGPR will notify the Transmission Customer annually of the recalculated rate on or before April 1.

Rate Sched. UGP–NFPT1

Schedule 8 to Tariff

August 1, 1998

United States Department of Energy, Western Power Area Administration, Upper Great Plains Region Integrated System

Non-Firm Point-to-Point Transmission Service

Effective

The first day of the first full billing period beginning on or after August 1, 1998, through July 31, 2003.

Applicable

The Transmission Customer shall compensate Upper Great Plains Region (UGPR) for Non-Firm Point-to-Point Transmission Service pursuant to the applicable Non-Firm Point-to-Point Transmission Service Agreement and rate referred to below. The formula rates used to calculate the charges for service under this schedule were promulgated and may be modified pursuant to applicable Federal laws, regulations, and policies.

UGPR may modify the rate for Non-Firm Point-to-Point Transmission Service upon written notice to the Transmission Customer. Any change to the rate for Non-Firm Point-to-Point Transmission Service shall be as set forth in a revision to this rate schedule promulgated pursuant to applicable Federal laws, regulations, and policies and made part of the applicable Service Agreement. UGPR shall charge the Transmission Customer in accordance with the rate then in effect.

Discounts

Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by UGPR must be announced to all eligible Transmission Customers solely by posting on the Open Access Same-Time Information System (OASIS), (2) any Transmission Customer initiated requests for discounts, including requests for use by one's wholesale merchant or an affiliate's use, must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, UGPR must offer the same discounted transmission service rate for the same time period to all eligible Transmission Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

Formula Rate

$$\begin{array}{c}\text{Maximum}\\\text{Point-to-Point}\\\text{Transmission Rate}\end{array} = \begin{array}{c}\text{Firm Point-to-Point}\\\text{Transmission Rate}\end{array}$$

Rate

The rate to be in effect August 1, 1998, through April 30, 1999, is:

Maximum of:

Monthly: $2.87/kW of reserved capacity per month

Weekly: $0.66/kW of reserved capacity per week

Daily: $0.094/kW of reserved capacity per day

Hourly: 3.93 mills/kWh

This rate is based on the above formula and 1997 data. A recalculated rate will go into effect every May 1 based on the above formula and updated financial and load data. UGPR will notify the Transmission Customer annually of the recalculated rate on or before April 1.

Rate Schedule UGP–NT1

Attachment H to Tariff

August 1, 1998

United States Department of Energy, Western Area Power Administration Upper Great Plains Region, Integrated System

Annual Transmission Revenue Requirement for Network Integration Transmission Service

Effective

The first day of the first full billing period beginning on or after August 1, 1998, through July 31, 2003.

Applicable

The Transmission Customer shall compensate the Upper Great Plains Region (UGPR) each month for Network Transmission Service pursuant to the applicable Network Integration Service Agreement and annual revenue requirement referred to below. The formula for the annual revenue requirement used to calculate the charges for this service under this schedule was promulgated and may be modified pursuant to applicable Federal laws, regulations, and policies.

UGPR may modify the charges for Network Integration Transmission Service upon written notice to the Transmission Customer. Any change to the charges to the Transmission Customer for Network Integration Transmission Service shall be as set forth in a revision to this rate schedule promulgated pursuant to applicable Federal laws, regulations, and policies and made part of the applicable Service Agreement. UGPR shall charge the Transmission Customer in accordance with the revenue requirement then in effect.

Formula Rate

$$\text{Monthly Charge} = \frac{\begin{array}{c}\text{(Transmission Customer's Load-Ratio Share} \times \text{Annual Revenue}\\\text{Requirement for IS Transmission Service)}\end{array}}{\text{12 months}}$$

Annual Revenue Requirement

The annual revenue requirement in effect August 1, 1998, through April 30, 1999, is $95,725,420. This annual revenue requirement is based on 1997 data. A recalculated annual revenue requirement will go into effect every May 1 based on updated financial data. UGPR will notify the Transmission Customer annually of the recalculated annual revenue requirement on or before April 1.

[FR Doc. 98–21600 Filed 8–11–98; 8:45 am]

BILLING CODE 6450–01–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–6143–1]

Science Advisory Board; Closed Meeting Notice

An *ad hoc* Subcommittee of the Science Advisory Board will meet at the U.S. Environmental Protection Agency (EPA), Washington, D.C., on August 27–28, 1998. Pursuant to Section 10(d) of the Federal Advisory Committee Act (FACA) and 5 U.S.C. 552(b)(c)(2) and 552(b)(c)(6), EPA has determined that the meeting will be closed to the public. The purpose of the meeting is to recommend to the Assistant Administrator of the Office of Research and Development (ORD) the recipients of the Agency's 1997 Scientific and Technological Achievement Cash Awards. These awards are established to honor and recognize EPA employees who have made outstanding contributions in the advancement of science and technology through their research and development activities, as exhibited in publication of their results in peer reviewed journals. In making these recommendations, including the actual cash amount of each award, the Agency requires full and frank advice from the Science Advisory Board. This advice will involve professional judgments on the relative merits of various employees and their respective work. Such personnel issues, where disclosure would constitute an unwarranted invasion of personal privacy, are protected from disclosure by exemptions 2 and 6 of Section 552(b)(c) of the U.S.C. In accordance with the provisions of the Federal Advisory Committee Act, minutes of the meeting will be kept for Agency and Congressional review. For more information, contact Mr. Robert Flaak, Team Leader, Committee Operations Staff, Science Advisory Board (1400), U.S. Environmental Protection Agency, 401 M Street, SW., Washington, D.C. 20460, via telephone: (202) 260–5133 or via E-mail: flaak.robert@epa.gov

Dated: August 6, 1998.

Carol M. Browner,

Administrator.

[FR Doc. 98–21671 Filed 8–11–98; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–6143–9]

Science Advisory Board; Executive Committee; Notification of Public Advisory Committee Meeting

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: Pursuant to the Federal Advisory Committee Act, Pub. L. 92–463, notification is hereby given that the Science Advisory Board's (SAB) Executive Committee, will conduct a public teleconference meeting on Thursday, August 27, 1998, between the hours of 2 pm and 3 pm. All times noted are Eastern Time. The meeting is open to the public, however, due to limited space, seating will be on a first-come basis.

The meeting will be coordinated through a conference call connection in Conference Room 1 North, Waterside Mall (street level), U.S. Environmental Protection Agency, 401 M Street SW, Washington, DC 20460. The public is welcome to attend the meeting physically or through a telephonic link. Additional instructions about how to participate in the conference call can be obtained by calling Ms. Priscilla Tillery-Gadson at (202) 260–4126 by August 21, 1998.

In this meeting the Executive Committee plans to review drafts from several of its Committees. These anticipated drafts include:

(a) Environmental Health Committee's Review of 1,3 Butadiene Risk Assessment.

(b) Research Strategies Advisory Committee's Review of the ORD Budget Presentation Process.

FOR FURTHER INFORMATION CONTACT: Any member of the public wishing further information concerning the meeting or wishing to submit comments should contact Dr. Donald G. Barnes, Designated Federal Officer for the Executive Committee, Science Advisory Board (1400), U.S. Environmental Protection Agency, Washington DC 20460; telephone (202) 260–4126; FAX (202) 260–9232; and via E-Mail at: barnes.don@epa.gov. Copies of the relevant documents are available from the same source. Draft documents will also be available on the SAB Website (http://www.epa.gov/sab) at least one week prior to the meeting.

Dated: August 7, 1998.

Donald G. Barnes,

Staff Director, Science Advisory Board.

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ENVIRONMENTAL PROTECTION AGENCY

[OPP–34130; FRL–6024–3]

Increasing Transparency for the Tolerance Reassessment Process; Availability of Preliminary Risk Assessments for Nine Organophosphates

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: This Notice announces the availability of documents which were developed as part of EPA's process for making reregistration eligibility decisions for the organophosphate pesticides and for tolerance reassessments consistent with the Federal Food, Drug, and Cosmetic Act as amended by the Food Quality Protection Act of 1996 (FQPA). These documents are the preliminary risk assessments and related documents for azinphos-methyl, bensulide, ethion, fenamiphos, isofenphos, naled, phorate, profenofos, and terbufos. This Notice also starts a 60–day public comment period for the preliminary risk assessments. Comments are to be limited to issues directly associated with the nine organophosphates that have risk assessments placed in the docket and should be limited to issues raised in those documents. EPA will provide opportunity for comment on the hazard assessments and FQPA safety factor assessments for the other organophosphates at a later date. Opportunity for public comment will also be provided at a later date for a variety of science issues. Allowing access and comments on the preliminary risk assessments will strengthen stakeholder involvement and help ensure the Agency's decisions under FQPA are transparent, and based on the best available information. The tolerance reassessment process will ensure that the U.S. continues to have the safest and most abundant food supply. The Agency cautions that these risk assessments are preliminary assessments only and that further