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