Upper Great Plains Region

INTEGRATED SYSTEM
CUSTOMER RATE BROCHURE

PROPOSED
TRANSMISSION AND ANCILLARY SERVICE
RATES ADJUSTMENT

April 2005

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I. INTRODUCTION

This brochure provides information on Western Area Power Administration (Western) Upper Great Plains Region's (UGPR) proposed Integrated System (IS) Transmission and Ancillary Service Rates Adjustment (Proposed Rate). This action is necessary as existing rates expire on September 30, 2005. The Generator Step Up Transformers (GSUs) will be removed from the annual revenue requirement. The Federal Energy Regulatory Commission (FERC) decided after the approval of the original rate order that GSUs should not be included in transmission rates. The IS rate will be changed to comply with this decision. All the same services will be available and UGPR is proposing to use the same fixed charged methodology.

The rate adjustment procedures are outlined in Appendix B to this brochure. This action was first announced in a *Federal Register* notice (FRN) published on April 18, 2005. (See Appendix D for the FRN.) The proposed Transmission and Ancillary Services Rates are explained in greater detail in this rate brochure.

History of IS Transmission

Prior to 1959, the Bureau of Reclamation (Reclamation) provided the total power supply needs to preference customer in the Pick-Sloan Missouri Basin Program--Eastern Division (P-SMBP--ED) Marketing Area. A project description can be found in Appendix B. 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 supplement 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 contacts. Heartland Consumers Power District (Heartland) and Missouri Basin Municipal Power Agency (MBMPA) 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 Western, Basin Electric, Heartland, and MBMPA (Participants). Since then, the supplemental power suppliers 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 agreement between the Participants.

The MBSG Agreement also provided a mechanism for sharing the cost of the transmission facilities that considered 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. Basin Electric's Leland Olds No. 1 generator, which came on line in 1966 with 210 MW of capacity was the first generation added after the MBSG Agreement was signed. 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 its generation to load. Based on this principle, it was agreed Western would share in the revenues generated by the added capacity of the system to the extent Western provided facilities and incurred investment costs after 1969. The post-1969 additions were the basis for the cost-sharing ratios.

Costs for the JTS were summed for total transmission system cost. The total transmission system cost for the year was 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 Participants, except Western, then paid into the JTS according to their generation input. These JTS revenues were then distributed back to the participants (including Western) based upon the ratio of costs associated with contributed facilities constructed since 1969.

Later, through bilateral contracts, Western, Basin Electric, and Heartland combined their transmission facilities to form the IS and used a FERC recognized rate design. Western was designated as the operator of the IS by Basin Electric, and Heartland and, as such, contracts for service, bills for service, collects payments and distributes revenues to each participant of the IS.

II. Proposed Rates for IS Transmission and Ancillary Services

The IS offers Network Integration Transmission, Firm and Non-firm Point-to-Point Transmission, Scheduling, System Control and Dispatch Service, Reactive Supply and Voltage Control Service, Regulation and Frequency Response Service, and Reserve Services. The initial rate schedules for the IS were initially placed into effect by Rate Order No. WAPA-79 on August 1, 1998, and were effective through July 31, 2003. The FERC order to confirm these rate schedules was made on November 25, 1998. These rate schedules were then extended by Rate Order No. WAPA 100 through September 30, 2005.

The UGPR is initiating a public rate process which will include a minor revision to the Network Integration, Firm and Non-firm Transmission, and Ancillary Service Rates as described in Rate Schedules UGP-FPT1, UGP-NFPT1, UGP-NT1, UGP-AS1, UGP-AS2, UGP-AS3, UGP-AS4, UGP-AS5, and UGP-AS6. This revision is simply to remove the GSUs from transmission and put them in generation in the formula rate calculations. Table 1 compares the 2004 and proposed 2004 rate calculations for the IS Transmission and Ancillary Service Rates for 2004

The impact to the revenue requirement for transmission is less than 1 percent decrease and the impact to the firm power rate is approximately 0.05 mills/kWh increase based on the 2004 rate calculation. Therefore, this rate adjustment will be handled as a minor rate adjustment as defined in the Department of Energy's Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions. The proposed rate calculation is scheduled to go into effect October 1, 2005 and remain in effect until 2010 or superseded.

Table 1

Comparison of the 2004 and Proposed 2004 IS Transmission and Ancillary Service Rates

Service	**2004**	**2004 Proposed**	**Difference**
Transmission and Ancillary Services	**$137,088,496**/year	**$136,298,145**/year	**-$790,351**/year
Network Transmission	$128,017,923/year	$126,741,576/year	-$1,276,347/year
Firm Point-to-Point Transmission	$2.72/kWmonth	$2.69/kWmonth	-$0.03/kWmonth
Non-Firm Point-to-Point Transmission	3.73 mills/kWh	3.68 mills/kWh	-0.05 mills/kWh
Scheduling, System Control and Dispatch	$49.29/schedule/day	$49.77/schedule/day	$0.48/schedule/day
Reactive Supply and Voltage Control from Generation Sources	$0.06/kWmonth	$0.07/kWmonth	$0.01/kWmonth
Regulation and Frequency Response	$0.04/kWmonth	$0.04/kWmonth	
Spinning/Supplemental Reserves	$0.11/kWmonth	$0.12/kWmonth	$0.01/kWmonth

A. Proposed Transmission Service Rates

1. Revenue Requirement for IS Transmission Service

The proposed rates for the 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. The annual costs are offset by appropriate transmission revenues to avoid over recovery of costs. The proposed 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. Appendix A contains the cost support data for the 2004 IS Transmission Rates without the GSUs in the transmission cost.

2. Proposed Charge for Network IS Transmission Service.

The proposed charge for monthly Network IS Transmission Service is the product of the network customer's load ration share times one-twelfth (1/12) of the annual Network Transmission Revenue Requirement. The Network Transmission Revenue Requirement is the annual cost associated with providing transmission service less revenue credits for Non-Firm Transmission Service. The annual Network Transmission Revenue Requirement is $126,741,576 using the cost support data for the 2004 IS Transmission Rates without the GSUs in the transmission cost. (See Appendix A.) The load ratio share is the network customer's hourly load coincident with the IS monthly transmission system peak minus the coincident peak for all IS Firm Point-to-Point Transmission Service plus the Firm Point-to-Point reservations. Appendix A contains the IS load data.

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

The monthly rate for Firm Point-to-Point IS Transmission Service is 1/12 the annual cost associated with providing transmission service less revenue credits for Non-Firm Transmission Service divided by the capacity reservation needed to support the average monthly IS transmission system load. This proposed rate may be summarized with the following formula: (Total Annual Revenue Requirement – Non Firm Revenue Credits)/12 months/ Average Transmission System Monthly Peak Load or using the cost support data for the 2004 IS Transmission Rates without the GSUs in the transmission cost, ($126,741,576)/12 months/3,982,000 kW. This formula produced a rate of $2.69/kWmonth 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. See Appendix A for 2004 IS transmission rate design, 2004 IS transmission rate cost support data without GSUs in the transmission cost and 2004 IS load data.

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

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. This proposed rate may be summarized with the following formula: Monthly Firm Point-to-Point Rate/730 hours/month, or with the cost support data for the 2004 IS Transmission Rates without the GSUs in the transmission cost, 3.68 Mills/KWh.

B. Proposed Ancillary Service Rates

1. Proposed Rate for 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 the communications facilities net plant associated with Scheduling, System Control and Dispatch Service ($13,630,404) by the transmission fixed charge rate (24.989 percent). The annual revenue requirement for Scheduling, System Control and Dispatch Service is then divided by the number of daily schedules (68,435) in the calculation year. Using 2004 transmission rate data without GSUs in the transmission cost, this methodology for determining the Scheduling, System Control and Dispatch Service rate produced a rate of $49.77/schedule/day. This rate and rate design is recovering only Western's revenue requirement. See Appendix A for more information on Scheduling, System Control, and Dispatch Service rate design.

2. Proposed Rates for Reactive Supply and Voltage Control Services from Generation Sources Service

Western's annual cost for Reactive Supply and Voltage Control Services from Generation Sources Service is determined by multiplying the total P-SMBP--ED generation net plant ($500,989,691) by the generation fixed charge rate (14.232 percent). The annual cost is multiplied by the capability used for reactive support (2.02 percent) to determine Western's reactive service revenue requirement ($1,440,270/Year). Western's, Basin Electric's and Heartland's annual cost for Reactive Supply and Voltage Control from Generation Sources Service are summed to get the Total Reactive Supply and Voltage Control from Generation Sources Service Revenue Requirement for the IS. The Total Reactive Supply and Voltage Control Service from Generation Sources Service charge is then derived by dividing the annual revenue requirement by the total load in Western's control area (3,929,000/kW/Year). The annual cost is then divided by 12 months to obtain a monthly charge. Using the cost support data for the 2004 IS Transmission Rates without the GSUs in the transmission cost, this methodology for determining the rate for Reactive Supply and Voltage Control from Generation Service produced a rate of $0.07/kW-month for transmission capacity reserved. See Appendix A for more information on the Reactive Supply and Voltage Control from Generation Resources Service rate design.

3. Proposed Rate for Regulation and Frequency Response Service

Regulation and Frequency Response Service in the east side of the control area is provided primarily by Oahe generation and in the west side of the control area by Fort Peck, both of which are Corps of Engineers (Corps) facilities. The Corps generation fixed charge rate (12.206 percent) is applied to Oahe and Fort Peck net plant costs ($187,943,855) producing an annual Corps generation cost for the Oahe and Fort Peck Powerplants ($22,940,607/Year). This cost is divided by the capacity at the plants (937,000 kW) to derive a dollar per kilowatt charge for Oahe's and Fort Peck's installed capacity ($24.48/kW-Year). This dollar per kilowatt charge is then applied to the capacity of Oahe and Fort Peck generation reserved for regulation and frequency response in the control area (41,160 kW). The capacity reserved for Regulation and Frequency Response Service has been determined to be 4 percent of the annual peak load. The 4 percent value was derived by averaging the incremental change in hourly load in the control area for the calendar year. Western's annual revenue requirement for Regulation and Frequency Response Service ($983,239) is determined by applying the dollar per kilowatthour charge to the capacity used for Regulation and Frequency Response Service. The Total Regulation and Frequency Response Revenue Requirement is determined by adding Western's, Basin Electric's and Heartland's Regulation and Frequency Response Revenue Requirements. The Regulation and Frequency Response Service charge is then determined by dividing the total revenue requirement by the IS Network Load in the control area (1,075,623 kW/Year). The annual cost is then divided by 12 months to obtain a monthly charge. Using the cost support data for the 2004 IS Transmission Rates without the GSUs in the transmission cost, this methodology for determining the rate for Regulation and Frequency Response Service produced a rate of $0.04/kW-month of load for which Western is providing this service. Credit will be given to those transmission customers who provide Western with Automatic Generation Control (AGC) of generation facilities capable of providing this service. See Appendix A for more information on Regulation and Frequency Response Service rate design.

4. Proposed Rate for Energy Imbalance Service

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

5. Proposed Rate for Reserve Services

Western's annual cost of generation for Reserve Services is determined by multiplying the generation fixed charge rate (14.232 percent) by the P-SMBP--ED generation net plant costs ($500,989,691). The cost/kW-year ($1.40/kW-Year) is determined by dividing the annual cost of generation ($71,300,515) by the plant capacity (2,539,000 kW). The capacity used for Reserve Service (71,550 kW) is determined by multiplying the peak IS load in the control area by the Mid-Continent Area Power Pool (MAPP) operation reserve requirement. The cost/kW-year is multiplied by the capacity used for Reserve Service to obtain the annual revenue requirement ($2,009,278). The annual revenue requirement for Reserve Service is divided by Western's peak load in the control area (1,431,000 kW) to calculate the annual charge ($1.40/kW-Year). The annual cost is then divided by 12 months to obtain a monthly charge. Using the cost support data for the 2004 IS Transmission Rates without the GSUs in the transmission cost, this methodology for determining the reserve rate produced a rate of $0.12/kW-month of customer load for Spinning Reserves Service and $0.12/kW-month of customer load for Supplemental Reserve Service. This rate and rate design is recovering 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. See Appendix A for more information on Reserve Services rate design.

C. Revenue Sharing

Western will abide by its existing transmission agreements. As these arrangements expire or are terminated, Western will implement its open access tariff and rates in replacement agreements. As Western, Basin Electric, and Heartland enter in to new electric sales agreements, they will take transmission service under the open access tariff and rates. To avoid over recovery of transmission costs, the proposed the IS revenue requirement is credited with revenue received under existing transmission agreements and Western's, Basin Electric's, and Heartland's loads are included in the rate denominator. To avoid double payment to Western, Basin Electric and Heartland, IS usage will be credited back to the JTS cost-sharing calculation. The IS costs and revenues will be shared among Western, Basin Electric, and Heartland based on system usage and transmission costs.

D. Western's Firm Power Customer Impacts

According to the 2004 calculations there will be a total of $790,351 per year that the Firm Power Customers will have included in their rate. This has approximately 0.08 mills/kWh upward pressure on the firm power rate. This is less than a 0.5 percent increase to the firm power rate.

III. Rate Adjustment Procedure

Western's rate adjustment procedures are governed by the "Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions" (10 CFR Part 903). These procedures give interested parties an opportunity to participate in the development of power rates.

A. Notice of Proposed Rate and Consultation and Comment Period

Initially, a notice of the proposed rate and official time for public participation was published in the *Federal Register*. The title of this notice is Proposed Rates for Pick-Sloan Missouri Basin Program--Eastern Division, and establishes a consultation and comment period. This period began on the publication date of the FRN (April 18, 2005) and closes 30 days later (May 18, 2005). During this period, interested parties may consult with and obtain information from Western's representatives. They may also examine data used in the proposed rates and suggest changes. Specific details for providing comments are included in the FRN. As this rate action is considered a minor rate adjustment, no public information or comment forum is planned.

1. Written Comments

Interested parties may submit written comments and inquiries to Western during the consultation and comment period.

2. Revision of Proposed Rate

After the close of the consultation and comment period, Western will review and consider comments. If appropriate, the Proposed Rate will be revised. If the Administrator determines that further public comment should be invited or is necessary, interested parties will be given a period of at least 30 days to submit additional comments concerning the Proposed Rate.

B. Preliminary Decision on Interim Rate

Following the end of the consultation and comment period, the Administrator will develop provisional rates. The Deputy Secretary of Energy for the Department of Energy has the authority to confirm, approve, and place this rate into effect on an interim basis. The decision, together with an explanation of the principal factors leading to the decision, will be published in the *Federal Register*.

C. Final Approval of Interim Rate

The Deputy Secretary will submit information concerning the interim rate to the FERC and request final approval. The response of FERC will be to:

1. give final confirmation and approval to the interim rate,
2. disapprove the interim rate, or
3. remand the matter to Western for further study.

The interim rate does not become final until it is approved by FERC.

APPENDIX A

Rate Calculations

Integrated System Transmission and Ancillary Service Rates

INTEGRATED SYSTEM
ANNUAL REVENUE REQUIREMENT
FOR TRANSMISSION SERVICE Without GSUs
2003

Line No.		2003 W/O GSUs	Notes
1			
2		2003 W/O GSUs	
3	**Annual IS Transmission Costs**		**Notes**
4	Basin Electric	$ 41,154,286	Basin Electric Revenue Requirement Worksheet
5	Western	$92,249,674	Western Annual IS Transmission Costs Worksheet, L69
6	Heartland	$326,209	Heartland IS Tariff Worksheet
7		$133,730,169	L4 + L5 + L6
8			
9			
10	**Transmission Customer Facility Credits**		
11		$200,800	MRES Irv Simmons Revenue Requirement Worksheet
12		$2,281,647	NWPS Revenue Requirement Worksheet
13		$2,482,447	
14			
15			
16	**Transmission Revenue Credits**		
17			
18	**Short-Term Firm Point-to-Point Transmission Service Credit**		
19		($16,546)	
20			
21	**Non-Firm Point-to-Point Transmission Service Credit**		
22		($419,967)	
23			
24	**Revenue from Existing Transmission Agreements**		
25		($8,346,645)	
26			
27	**Scheduling, System Control and Dispatch Service Credit**		
28		($687,882)	
29			
30			
31	**Annual Revenue Requirement for IS Transmission Service**		
32			
33		$126,741,576	L7 + L13 + L19 + L22 + L25 + L28

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INTEGRATED SYSTEM
FIRM POINT-TO-POINT RATE DESIGN
2003

Line No.			Notes
1			
2	**2003 W/O GSUs**		
3	**Annual Revenue Requirement for IS Transmission Service**		**Notes**
4			
5	$126,741,576		IS Annual Revenue Requirement for
6			Transmission Service Worksheet, L33
7			
8	**IS Transmission System Total Load**		
9			
10		3,928,000	IS Transmission System Total Load Worksheet, C5L14
11			
12			
13	**Maximum Firm Point-to-Point Transmission Rate in $/KW-Month**		
14			
15	**$2.69**		L5 / L10 / 12 months

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INTEGRATED SYSTEM
NON-FIRM POINT-TO-POINT RATE DESIGN
2003

Line No.			
1			
2			
3	**Firm Point-to-Point Transmission Rate in $/KW-Month**		**Notes**
4			
5		$2.69	IS Firm Point-to-Point Rate Design Worksheet, L15
6			
7			
8			
9	**Maximum Non-Firm Point-to-Point Transmission Rate**		
10		**3.68**	(L5 * 1000) / 730 hours per month

RATE FOR SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE FOR 2003

A.	Fixed Charge Rate	24.989%	(1)
B.	Scheduling, System Control and Dispatch Net Plant Costs ($)	$13,630,404	(2)
C.	Annual Revenue Requirement for Scheduling, System Control and Dispatch Service	$3,406,102	(A x B)
D.	FY 2002 Number of Daily Schedules	68,435	
E.	Rate for Scheduling, System Control and Dispatch Service ($/schedule/day)	**$49.77**	(C / D)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual IS Transmission Costs", for 2003.

(2) Scheduling, System Control and Dispatch Plant Costs include the portion of Watertown Operations Office plant (39.6%) and communication facilities plant (69.8%) associated with Scheduling, System Control and Dispatch Service for transmission less total depreciation associated with this plant. (Reference FY 2002 Pick-Sloan and Fort Peck Results of Operations Schedule 1, the Transmission Plant-in-Service worksheet, and the Net Plant Investment worksheet.)

RATE FOR REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES FOR 2003 (INTEGRATED SYSTEM)

A.	WAPA Reactive Service Revenue Requirement	$1,440,270	(1)
B.	BEPC & HCPD Reactive Service Revenue Requirement	$1,625,298	(2)
C.	Total Reactive Revenue Requirement	$3,065,568	(A+B)
D.	2002 IS Transmission System Total Load (kW-Yr)	3,929,000	(3)
E.	Annual Reactive Charge ($/kW-Year)	$0.78	(C/D)
F.	Monthly Reactive Charge ($/kW-Month)	$0.07	(E/12)

(1) Reactive Service Revenue Requirement from "Reactive Supply and Voltage Control from Generation Sources For 2003, Western's Costs".

(2) Basin Electric cost support data.

(3) IS Firm Long Term Peak Transmission plus IS Short Term Firm Point-to-Point.

RATE FOR REGULATION AND FREQUENCY RESPONSE FOR 2003
(Integrated System)

A.	Western Regulation Revenue Requirement	$983,239	(1)
B.	BEPC & HCPD Regulation Revenue Requirement	$92,384	(2)
C.	Total Regulation Revenue Requirement	$1,075,623	(A + B)
D.	Load in Control Area(s) (kW-Year)	2,008,000	(3)
E.	Regulation Charge ($/kW-Year)	$0.54	(C / D)
F.	Regulation Charge ($/kW-Month)	$0.04	(E / 12 months)

(1) Regulation and Frequency Response Service from "Regulation and Frequency Response for 2003, Western's Costs".

(2) Basin Electric cost support data.

(3) Average of monthly peaks for 2003 Watertown Control Area.

Rate for Reserves for 2003

A.	Fixed Charge Rate	14.232%	(1)	
B.	Generation Net Plant Costs	$ 500,989,691	(2)	
C.	Annual Cost of Generation	$ 71,300,515	(A x B)	
D.	Plant Capacity (kW)	2,539,000		
E.	Cost/kW ($/kW)	$ 28.08	(C / D)	
F.	Monthly Charge ($/kW-mo)	$ 2.34	(E / 12 months)	
G.	Western's Load (kW-Yr)	1,431,000	(3)	
H.	Capacity used for Reserves (kW)	71,550	(Gx5%)	(4)
I.	Annual Reserves Revenue Requirement	$ 2,009,276	(E x H)	
J.	Annual Charge ($/kW-Year)	$ 1.40	(I /G)	
K.	Monthly Charge ($/kW-Month)	$ 0.12	(J/12)	

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program--Eastern Division Annual Generation Revenue Requirement", for 2003.

(2) Generation Net Plant Costs include the total Eastern Division Pick-Sloan Generation Plant-in-Service less total generation plant depreciation.

(3) Average of Western's monthly peaks for 2003.

(4) MAPP operating reserve requirement.

Integrated System Load Data

2003 IS Transmission System Total Load
(MW)

Line No.	(1) Date	(2) Hour Ending	(3) Network Load	(4) Long-Term Firm Point-to-Point Reservations	(5) Total
1	**01/23/03**	0900	3,407	789	4,196
2	**02/24/03**	0800	3,237	796	4,033
3	**03/05/03**	0800	3,126	794	3,920
4	**04/04/03**	0900	2,655	796	3,451
5	**05/29/03**	1700	2,546	760	3,306
6	**06/30/03**	1800	3,094	756	3,850
7	**07/25/03**	1700	3,761	750	4,511
8	**08/25/03**	1800	3,834	760	4,594
9	**09/05/03**	1800	3,152	680	3,832
10	**10/29/03**	1900	2,856	676	3,532
11	**11/24/03**	0800	3,189	681	3,870
12	**12/11/03**	1800	3,357	681	4,038
13					
14	**12 CP**		3,185	743	3,928

2003 IS Network Customer Control Area Load

Date	Hr End	East Control Area Load (1)	West Control Area Load (2)	Total Load
15-Jan-03	19:00	2157 MW	94 MW	2251 MW
9-Feb-03	9:00	2034 MW	87 MW	2121 MW
9-Mar-03	10:00	1961 MW	88 MW	2049 MW
16-Apr-03	11:00	1677 MW	41 MW	1718 MW
14-May-03	18:00	1479 MW	83 MW	1562 MW
29-Jun-03	17:00	1846 MW	102 MW	1948 MW
23-Jul-03	17:00	2063 MW	94 MW	2157 MW
7-Aug-03	17:00	2061 MW	106 MW	2167 MW
4-Sep-03	18:00	1860 MW	76 MW	1936 MW
26-Oct-03	10:00	1850 MW	56 MW	1906 MW
28-Nov-03	19:00	2086 MW	68 MW	2154 MW
28-Dec-03	19:00	2052 MW	74 MW	2126 MW
Total		23,126	969	24,095
			Average Control Area Load	2,008

(1) The East Control Area Load has the NWPS and MDU loads removed.

(2) The West Control Area Load does not have the Montana Power load removed.

Western's Transmission Cost Data

DETERMINATION OF PI(-SLOAN MISSOURI BASIN PROGRAM, EASTERN DIVISION
ANNUAL IS TRANSMISSION COSTS

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Source/Notes
1			
2	**A. Operation and Maintenance Expense for Transmission**		
3			
4	Transmission O&M Expense	$40,486,029	O&M Expenses Worksheet, C6L17
5	Transmission of Electricity by Others	$0	
6	Total O&M Expense for Transmission	$40,486,029	L4 + L5
7			
8	Net Transmission Plant Investment	$369,161,125	Net Plant Investment Worksheet, C6L11
9			
10	O&M as % of Net Transmission Plant Investment	10.967%	L6/L8
11			
12			
13	**B. A&G Expense for Transmission**		
14			
15	Transmission A&G Expense	$10,952,046	A&G Expenses Worksheet, C6L15
16			
17	Net Transmission Plant Investment	$369,161,125	L8
18			
19	A&G as % of Net Transmission Plant Investment	2.967%	L15/L17
20			
21			
22	**C. Depreciation Expense for Transmission**		
23			
24	Transmission Depreciation Expense	$19,854,170	Depreciation Expense Worksheet, C6L4
25			
26	Net Transmission Plant Investment	$369,161,125	L8
27			
28	Depreciation as a % of Net Transmission Plant Investment	5.378%	L24/L26

DETERMINATION OF PICK-SLOAN MISSOURI BASIN PROGRAM, EASTERN DIVISION
ANNUAL IS TRANSMISSION COSTS

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Source/Notes
29			
30			
31	**D. Taxes Other than Income Taxes for Transmission**		
32			
33	Not applicable.		
34			
35			
36	**E. Allocation of General Plant to Transmission**		
37			
38	No General Plant identified at this time, all plant is identified as either generation or transmission related.		
39			
40			
41	**F. Cost of Capital**		
42			
43	Weighted Transmission Composite Interest Rate	5.677%	Cost of Capital Worksheet, C6L9
44			
45			
46	**G. Transmission Fixed Charge Rate**		
47			
48	Operation and Maintenance Expense	10.967%	L10
49			
50	A&G Expense	2.967%	L19
51			
52	Depreciation Expense	5.378%	L28
53			
54	Taxes Other than Income Taxes	0.000%	
55			
56	Allocation of General Plant to Transmission	0.000%	

DETERMINATION OF PICK-SLOAN MISSOURI BASIN PROGRAM, EASTERN DIVISION
ANNUAL IS TRANSMISSION COSTS

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Source/Notes
57			
58	Cost of Capital	5.677%	L43
59			
60	Total	24.989%	
61			
62			
63	**H. Transmission Revenue Requirement**		
64			
65	Transmission Fixed Charge Rate	24.989%	L60
66			
67	Net Transmission Plant Investment	$369,161,125	L8
68			
69	Annual Western-UGPR Transmission Cost	$92,249,674	L65 * L67
70			

%ISTrate03 with out gsu05 print.xlw {Annual Costs WAPA}

Transmission Revenue from Existing Agreements
Pick Sloan Missouri Basin Program - Eastern Division
FY 2003

Line No.	Description	Amount
1		
2	Montana-Dakota Utilities Company	$431,455
3	MAPP	$4,889,767
4		
5	**Total**	$5,321,222

%ISTrate03 with out gsu05 print.xlw{Transmission Revenue}

O&M Expenses
Pick-Sloan Missouri Basin Program - Eastern Division
($)

Line No.	(1)	(2) WESTERN UGPR 1/	(3) WESTERN RMR 2/	(4) COE 3/	(5) BOR 3/	(6) Total
1						
2	**Total Electric Operating Expense**	163,907,265	69,659,693			233,566,958
3						
4	**Less:**					
5	**Other Power Supply Expenses**	109,418,105	40,303,590			149,721,695
6	**A&G Expenses**	11,135,749	6,054,929			17,190,678
7	**Sunflower Payment**		0			0
8	**Prior Year Adjustments**	1,360,299	1,863,564			3,223,863
9						
10	**Plus:**					
11	**Moveable Property Interest**	715,337	452,531			1,167,868
12	**Warehouse Stores Interest**	34,307	124,999			159,306
13						
14	**COE/BOR Total**			23,778,474	23,480,780	47,259,254
15	**PS Total O&M**	42,742,756	22,015,140	23,778,474	23,480,780	112,017,150
16						
17	**PS-ED Transmission O&M 4/**	40,263,676	222,353	0	0	40,486,029
18						
19	**PS-ED Generation O&M 5/**	2,479,080	0	23,778,474	23,480,780	49,738,334

1/ All Western UGPR O&M Expenses are from the FY 2002 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 11; except Moveable Property and Warehouse Stores Interest, which are from internal Western memos.

2/ All Western RMR O&M Expenses are from the FY 2002 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 11; except Moveable Property and Warehouse Stores Interest, which are from internal Western memos.

3/ Total BOR O&M Expenses are from the FY 2002 Historical Financial Data in Support of the Power Repayment Study for the Pick-Sloan Missouri Basin Program, Schedule 14. Total COE O&M Expenses are from the FY 2003 COE Statement of Revenues and Expenses.

4/ The portion of O&M expenses allocated to PS-ED transmission is based on the ratio of transmission plant-in-service to total plant-in-service, calculated on L6 of the Net Plant Investment Worksheet.

5/ The portion of O&M expenses allocated to PS-ED generation is based on the ratio of generation plant-in-service to total plant-in-service, calculated on L5 of the Net Plant Investment Worksheet.

A&G Expenses
Pick-Sloan Missouri Basin Program - Eastern Division
($)

Line No.	(1) Object Class	(2) WESTERN UGPR 1/	(3) WESTERN RMR 2/	(4) COE 3/	(5) BOR 3/	(6) Total
1						
2	1411	2,968,838	1,686,333	0	0	4,655,171
3	1412	1,904,056	1,372,746	0	0	3,276,802
4	1415	63,648	57,116	0	0	120,764
5	1416	59,376	17,477	0	0	76,853
6	1431	0	0	0	0	0
7	1432	0	0	0	0	0
8	1441	3,716,064	2,199,417	0	0	5,915,481
9	1442	2,849,473	721,840	0	0	3,571,313
10	2541	0	0	0	0	0
11	2596	0	0	0	0	0
11	25DA	0	0	0	0	0
12	25DH	0	0	0	0	0
13	**PS Total A&G**	11,561,455	6,054,929	0	0	17,616,384
14						
15	**PS-ED Transmission A&G 4/**	10,890,891	61,155	0	0	10,952,046
16						
17	**PS-ED Generation A&G 5/**	670,564	0	0	0	670,564

1/ Western UGPR A&G Expenses are from the FY 2002 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 11A.

2/ Western RMR A&G Expenses are from the FY 2002 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 11A.

3/ A&G Expenses for COE and BOR are unavailable. All COE and BOR A&G expenses are included in O&M Expenses.

4/ The portion of A&G expenses allocated to PS-ED transmission is based on the ratio of transmission plant-in-service to total plant-in-service, calculated on L6 of the Net Plant Investment Worksheet.

5/ The portion of A&G expenses allocated to PS-ED generation is based on the ratio of generation plant-in-service to total plant-in-service, calculated on L5 of the Net Plant Investment Worksheet.

DEPRECIATION EXPENSE
Pick-Sloan Missouri Basin Program - Eastern Division
($)

Line No.	(1)	(2) WESTERN UGPR	(3) WESTERN RMR	(4) COE	(5) BOR	(6) Total
1						
2	PS Depreciation Expense	20,950,262 1/	11,784,450 2/	8,989,072 3/	4,161,198 4/	45,884,982
3						
4	PS-ED Transmission Depreciation 5/	19,735,147	119,023	0	0	19,854,170
5						
6	PS-ED Generation Depreciation 6/	1,215,115	0	8,989,072	4,161,198	14,365,385

1/ FY 2002 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 4.

2/ FY 2002 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 4.

3/ FY 2003 Corps of Engineers Statement of Revenues and Expenses.

4/ From data provided by BOR.

5/ For UGPR, RMR and BOR the portion of depreciation expense allocated to PS-ED transmission is based on the ratio of transmission plant-in-service to total plant-in-service, calculated on L6 of the Net Plant Investment Worksheet. COE transmission depreciation is actual COE switchyard depreciation.

6/ For UGPR, RMR and BOR the portion of depreciation expense allocated to PS-ED generation is based on the ratio of generation plant-in-service to total plant-in-service, calculated on L5 of the Net Plant Investment Worksheet. COE generation depreciation is COE total depreciation less transmission depreciation.

COST OF CAPITAL
Pick-Sloan Missouri Basin Program - Eastern Division
($)

Line No.	(1)	(2) WESTERN UGPR		(3) WESTERN RMR		(4) COE		(5) BOR		(6) Total	
1											
2	**Long Term Debt:**										
3	FY 2002 Balances	378,047,962	1/	272,758,339	1/	400,897,913	1/	67,215,719	1/	1,118,919,933	
4											
5	**Interest Expenses:**										
6	FY 2003 Simple Interest	21,412,499	2/	20,204,397	3/	11,839,618	2/	5,566,516	4/		
7	Average Interest Rate	5.664%	L6/L3	7.407%	L6/L3	2.953%	L6/L3	8.282%	L6/L3		
8	Transmission Plant Factor	0.9927	5/	0.0073	6/	0.0000	7/	0.0000	8/		
9	Weighted Trans. Composite Rate									5.677%	9/
10	Generation Plant Factor	0.0338	10/	0.0000	11/	0.6634	12/	0.3028	13/		
11	Weighted Gen. Composite Rate									4.658%	14/

1/ Draft FY 2002 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedules 21X and 21RX.
2/ Draft FY 2002 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 33A.
3/ Draft FY 2002 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 33A.
4/ Draft FY 2002 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedules 21X and 21RX.
5/ C2L3, Net Plant Investment Worksheet/C6L3, Net Plant Investment Worksheet.
6/ C3L3, Net Plant Investment Worksheet/C6L3, Net Plant Investment Worksheet.
7/ C4L3, Net Plant Investment Worksheet/C6L3, Net Plant Investment Worksheet.
8/ C5L3, Net Plant Investment Worksheet/C6L3, Net Plant Investment Worksheet.
9/ (C2L7*C2L8)+(C3L7*C3L8)+(C4L7*C4L8)+(C5L7*C5L8).
10/ C2L4, Net Plant Investment Worksheet/C6L4, Net Plant Investment Worksheet.
11/ C3L4, Net Plant Investment Worksheet/C6L4, Net Plant Investment Worksheet.
12/ C4L4, Net Plant Investment Worksheet/C6L4, Net Plant Investment Worksheet.
13/ C5L4, Net Plant Investment Worksheet/C6L4, Net Plant Investment Worksheet.
14/ (C2L7*C2L10)+(C3L7*C3L10)+(C4L7*C4L10)+(C5L7*C5L10).

NET PLANT INVESTMENT
Pick-Sloan Missouri Basin Program - Eastern Division
($)

Line No.	(1)	(2) WESTERN UGPR		(3) WESTERN RMR		(4) COE		(5) BOR		(6) Total
1										
2	Total PS Plant-in-Service	760,798,395	1/	520,372,764	2/	867,115,735	3/	395,770,872	12/	2,544,057,766
3	PS-ED Transmission Plant-in-Service	716,637,924	4/	5,258,841	5/	0	6/	0		721,896,765
4	PS-ED Generation Plant-in-Service	44,160,471	7/	0		867,115,735	L2-L3	395,770,872	L2-L3	1,307,047,078
5	Generation Plant to Total Plant	0.0580	L4/L2	0.0000	L4/L2	1.0000	L4/L2	1.0000	L4/L2	
6	Transmission Plant to Total Plant	0.9420	L3/L2	0.0101	L3/L2	0.0000	L3/L2	0.0000	L3/L2	
7										
8	PS Accumulated Depreciation	372,625,200	8/	170,564,587	9/	432,999,007	10/	175,866,574	11/	1,152,055,368
9	PS-ED Trans. Accumulated Depreciation	351,012,938	L6*L8	1,722,702	L6*L8	0	13/	0	L6*L8	352,735,640
10	PS-ED Gen. Accumulated Depreciation	21,612,262	L5*L8	0	L5*L8	432,999,007	L8-L9	175,866,574	L5*L8	630,477,843
11	PS-ED Net Transmission Plant	365,624,986	L3-L9	3,536,139	L3-L9	0	L3-L9	0	L3-L9	369,161,125
12	PS-ED Net Generation Plant	22,548,209	L4-L10	0	L4-L10	434,116,728	L4-L10	219,904,298	L4-L10	676,569,235
		388,173,195								

1/ Transmission Plant-in-Service Worksheet, C2L436.
2/ FY 2002 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 1.
3/ FY 2003 Corps of Engineers Financial Statements, Electric and Power Multi-Purpose Plant in Service.
4/ Transmission Plant-in-Service Worksheet, C5L436.
5/ Transmission Plant-in-Service Worksheet, C5L443.
6/ Transmission Plant-in-Service Worksheet, C5L447.
7/ Transmission Plant-in-Service Worksheet, C4L436.
8/ FY 2002 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 4.
9/ FY 2002 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 4.
10/ FY 2003 Corps of Engineers Financial Statements, Statement of Assets and Liabilities.
11/ Draft FY 2002 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 15.
12/ Draft FY 2002 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 17.
13/ FY 2003 accumulated depreciation on the COE switchyards.

%ISTrate03 with out gsu05 print.xlw{investment}

TRANSMISSION PLANT-IN-SERVICE
Pick-Sloan Missouri Basin Program, Eastern Division

(1) DESCRIPTION	(2) FY2002 TOTALS ($)	(3) MISCELLANEOUS ADJUSTMENTS ($)	(4) GENERATION ADJUSTMENTS ($)	(5) TRANSMISSION TOTALS ($)	(6) SOURCE/NOTES
Transmission Lines					
BEULAH-GARRISON	352,214			352,214	Column 2 includes plant-in-service from FY 2002 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 1.
BISMARCK-GLENHAM	3,247,942			3,247,942	
BISMARCK-JAMESTOWN NO. 1	3,802,847			3,802,847	
BISMARCK-JAMESTOWN NO. 2	3,096,816			3,096,816	
BISMARCK-MEDORA	4,783,893			4,783,893	
BROOKINGS-SIOUX FALLS	684,315			684,315	
BROOKINGS-WATERTOWN NO. 1	645,505			645,505	
BROOKINGS-WATERTOWN NO. 2	3,318,558			3,318,558	
BROOKINGS-WHITE 115/230KV	2,699,475			2,699,475	
CARRINGTON-JAMESTOWN	377,544			377,544	
CHARLIE CREEK-BELFIELD	13,674,183			13,674,183	
CONRAD-SHELBY #2	5,804,318			5,804,318	
CRESTON-MARYVILLE	1,366,481			1,366,481	
DAWSON COUNTY - MILES CITY	2,622,978			2,622,978	
DAWSON-GLENDIVE	12,867			12,867	
DAWSON-MEDORA	2,862,712			2,862,712	
DAWSON-MEDORA	5,088			5,088	
DAWSON-O'FALLON CREEK	317,413			317,413	
DAWSON-WILLISTON	1,258,900			1,258,900	
DENISON-CRESTON	2,105,834			2,105,834	
DEVILS LAKE-CARRINGTON	5,904,906			5,904,906	
DEVILS LAKE-LAKOTA	1,872,142			1,872,142	
EDGELEY-FORMAN	377,081			377,081	
EDGELEY-GROTON	771,572			771,572	
FARGO-GRAND FORKS	1,765,244			1,765,244	
FARGO-MORRIS	5,138,962			5,138,962	
FORMAN-SUMMIT (BISMARCK)	922,098			922,098	
FORMAN-SUMMIT (HURON)	487,534			487,534	
FORT PECK-DAWSON #1	493,203			493,203	
FORT PECK-DAWSON #2	3,609,447			3,609,447	
FORT PECK-HAVRE	28,650,661			28,650,661	
FORT PECK-WHATELY	160,325			160,325	
FORT PECK-WILLISTON	1,426,555			1,426,555	
FORT PECK-WOLF POINT #2	7,663,747			7,663,747	
FORT RANDALL-FORT THOMPSON 1&2	6,717,269			6,717,269	
FORT RANDALL-GAVIN'S POINT	1,014,593			1,014,593	
FORT RANDALL-GREGORY	630,776			630,776	
FORT RANDALL-MT VERNON	1,002,309			1,002,309	
FORT RANDALL-O'NEILL	502,230			502,230	
FORT RANDALL-SIOUX CITY 1&2	8,532,125			8,532,125	
FORT THOMPSON-GRAND ISLAND	16,397,505			16,397,505	
FORT THOMPSON-HURON 230-KV 1&2	3,064,794			3,064,794	
FORT THOMPSON-SIOUX FALLS 1&2	9,542,122			9,542,122	
GARRISON-BISMARCK 230KV 1&2	5,175,481			5,175,481	
GARRISON-JAMESTOWN	4,089,817			4,089,817	
GARRISON-MALLARD	1,278,427			1,278,427	
GARRISON-WM. J. NEAL	545,452			545,452	
GAVINS POINT-BELDEN	455,727			455,727	
GAVINS POINT-SIOUX FALLS	1,289,877			1,289,877	
GRANITE FALLS- MORRIS	2,310,884			2,310,884	
GRANITE FALLS-MINNESOTA VALLEY	156,778			156,778	

TRANSMISSION PLANT-IN-SERVICE
Pick-Sloan Missouri Basin Program, Eastern Division

(1) DESCRIPTION	(2) FY2002 TOTALS ($)	(3) MISCELLANEOUS ADJUSTMENTS ($)	(4) GENERATION ADJUSTMENTS ($)	(5) TRANSMISSION TOTALS ($)	(6) SOURCE/NOTES
GREAT FALLS-CONRAD	12,811,702			12,811,702	
GREGORY-MISSION	899,833			899,833	
GROTON-HURON	1,212,199			1,212,199	
GROTON-SUMMIT	2,739,189			2,739,189	
HAVRE-RAINBOW	505,538			505,538	
HAVRE-SHELBY#2	1,621,462			1,621,462	
HESKETT-DEVAUL	434,209			434,209	
HETTINGER-NEW UNDERWOOD	10,966,327			10,966,327	
HURON-MT VERNON	617,623			617,623	
HURON-WATERTOWN 230KV 1&2	3,695,532			3,695,532	
JAMESTOWN-EDGELEY	324,360			324,360	
JAMESTOWN-FARGO NO. 1	3,211,097			3,211,097	
JAMESTOWN-FARGO NO. 2	2,811,544			2,811,544	
JAMESTOWN-GRAND FORKS	13,584,611			13,584,611	
JAMESTOWN-VALLEY CITY	304,934			304,934	
LEEDS-DEVILS LAKE	2,151,247			2,151,247	
LEEDS-ROLLA	322,883			322,883	
MALLARD-RUGBY	1,282,436			1,282,436	
MANDAN MICROWAVE SITE	70,317			70,317	
MARTIN-MISSION	750,437			750,437	
MARTIN-PHILIP	794,022			794,022	
MAURINE-RAPID CITY	1,284,931			1,284,931	
MILES CITY-BAKER	8,438,591			8,438,591	
MILES CITY-CUSTER	3,321,747			3,321,747	
NEW UNDERWOOD-PHILIP	802,149			802,149	
NEW UNDERWOOD-RAPID CITY NO. 1	388,492			388,492	
NEW UNDERWOOD-RAPID CITY NO. 2	309,991			309,991	
NEW UNDERWOOD-STEGALL (HURON)	2,672,947			2,672,947	
O'FALLON CREEK-MILES CITY	622,672			622,672	
OAHE-FORT THOMPSON 230KV 1&2	3,149,034			3,149,034	
OAHE-FORT THOMPSON 230KV 3&4	5,119,119			5,119,119	
OAHE-GLENHAM	2,773,817			2,773,817	
OAHE-MAURINE	1,791,779			1,791,779	
OAHE-NEW UNDERWOOD	4,501,574			4,501,574	
OAHE-PIERRE	388,816			388,816	
PIERRE-PHILIP	1,187,034			1,187,034	
RUGBY-LEEDS	226,217			226,217	
SHELBY-SHELBY#2	483,506			483,506	
SIOUX CITY-DENISON	1,661,311			1,661,311	
SIOUX CITY-SPENCER	1,938,353			1,938,353	
SIOUX CITY-SIOUX FALLS	3,301,496			3,301,496	
SUMMIT-WATERTOWN	6,743,203			6,743,203	
UTICA JCT-SIOUX FALLS	3,649,578			3,649,578	
VALLEY CITY-FORMAN	1,384,198			1,384,198	
WATERTOWN-GRANITE FALLS 1&2	3,918,674			3,918,674	
WATERTOWN-SIOUX CITY	26,679,769			26,679,769	
WATFORD CITY-BEULAH	1,401,905			1,401,905	
WILLISTON-WATFORD CITY	563,079			563,079	
WM. J. NEAL-RUGBY	506,273			506,273	
YELLOWTAIL-CUSTER	2,280,203			2,280,203	
Subtotal	327,591,486	0	0	327,591,486	
Substations				0	
ARMOUR SUBSTATION	912,490	(82,000)		830,490	
BELDEN SUBSTATION	129,744			129,744	
BELFIELD SUBSTATION	8,144,577			8,144,577	

TRANSMISSION PLANT-IN-SERVICE

Pick-Sloan Missouri Basin Program, Eastern Division

(1) DESCRIPTION	(2) FY2002 TOTALS ($)	(3) MISCELLANEOUS ADJUSTMENTS ($)	(4) GENERATION ADJUSTMENTS ($)	(5) TRANSMISSION TOTALS ($)	(6) SOURCE/NOTES
BERESFORD SUBSTATION	1,119,500	(190,315)		929,185	17% of the costs of this facility have been allocated to distribution.
BISBEE SUBSTATION	122,847	(61,424)		61,423	50% of the costs of this facility have been allocated to distribution.
BISMARK SUBSTATION	6,742,397			6,742,397	
BOLE SUB	3,181,126			3,181,126	
BONESTEEL SUBSTATION	2,050,826	(1,025,413)		1,025,413	50% of the costs of this facility have been allocated to distribution.
BROOKINGS SUBSTATION	2,923,952			2,923,952	
CARRINGTON SUBSTATION	1,025,157	(133,270)		891,887	13% of the costs of this facility have been allocated to distribution.
CIRCLE SUBSTATION	1,486,357			1,486,357	
CONRAD SUB	5,427,488			5,427,488	
CRESTON SUBSTATION	2,625,816	(55,000)		2,570,816	
CROSSOVER SUB	11,144,010			11,144,010	
CROSSOVER SUB	65,116			65,116	
CUSTER SUBSTATION	1,850,576			1,850,576	
CUSTER SUBSTATION	1,897,814			1,897,814	
CUSTER TRAIL SUBSTATION	113,566	(56,783)		56,783	50% of the costs of this facility have been allocated to distribution.
DAWSON COUNTY SUBSTATION	9,593,224	(767,458)		8,825,766	8% of the costs of this facility have been allocated to distribution.
DENISON SUBSTATION	7,678,296			7,678,296	
DEVAUL SUBSTATION	882,880	(529,728)		353,152	60% of the costs of this facility have been allocated to distribution.
DEVILS LAKE SUBSTATION	2,461,292	(270,742)		2,190,550	11% of the costs of this facility have been allocated to distribution.
EAGLE BUTTE SUBSTATION	1,117,251			1,117,251	
EDGELEY SUBSTATION	1,732,494	(242,549)		1,489,945	14% of the costs of this facility have been allocated to distribution.
ELLENDALE SUBSTATION	217,469	(124,000)		93,469	
FAITH SUBSTATION	1,217,665	(608,833)		608,832	50% of the costs of this facility have been allocated to distribution.
FARGO SUBSTATION	19,556,541	(47,000)		19,509,541	
FLANDREAU SUBSTATION	3,424,919	(582,236)		2,842,683	17% of the costs of this facility have been allocated to distribution.
FORMAN SUBSTATION	2,082,456	(270,719)		1,811,737	13% of the costs of this facility have been allocated to distribution.
FORT RANDALL SUB	263,439			263,439	
FORT THOMPSON #2	7,083,635			7,083,635	
FORT THOMPSON SUBSTATION	12,300,753	(354,000)		11,946,753	
GLENDIVE SUBSTATION	474,093			474,093	
GRAND FORKS SUBSTATION	9,144,153			9,144,153	
GRAND ISLAND SUBSTATION	7,568,188			7,568,188	
GRANITE FALLS SUBSTATION	9,117,795	(57,000)		9,060,795	
GREAT FALLS SUB	539,300			539,300	
GREAT FALLS SUB(BEFP)	74,003			74,003	
GREGORY SUBSTATION	1,476,377	(295,275)		1,181,102	20% of the costs of this facility have been allocated to distribution.
GROTON SUBSTATION	2,071,535			2,071,535	
HAVRE SUBSTATION	5,602,066	(952,351)		4,649,715	17% of the costs of this facility have been allocated to distribution.
HURON SUBSTATION	6,248,769			6,248,769	
JAMESTOWN SUBSTATION	11,036,368	(1,103,637)		9,932,731	10% of the costs of this facility have been allocated to distribution.
KILLDEER SUBSTATION	249,632			249,632	
LAKOTA SUBSTATION	1,552,595	(512,356)		1,040,239	33% of the costs of this facility have been allocated to distribution.
LEEDS SUBSTATION	999,413	(139,918)		859,495	14% of the costs of this facility have been allocated to distribution.
MARTIN SUBSTATION	691,496			691,496	
MARYVILLE SUBSTATION	1,525			1,525	
MAURINE SUBSTATION	5,606,861			5,606,861	
MIDLAND SUBSTATION	589,069			589,069	
MILES CITY SUB #2	206,200			206,200	
MILES CITY SUB #2	720,171			720,171	
MILES CITY SUB #3	2,415,285			2,415,285	
MILES CITY SUB #3 (BEFP)	1,151			1,151	
MILES CITY SUBSTATION	5,876,079			5,876,079	
MISSION SUBSTATION	2,481,597			2,481,597	
MORRIS SUBSTATION	4,519,237			4,519,237	
MT VERNON SUBSTATION	1,032,065			1,032,065	

TRANSMISSION PLANT-IN-SERVICE
Pick-Sloan Missouri Basin Program, Eastern Division

(1) DESCRIPTION	(2) FY2002 TOTALS ($)	(3) MISCELLANEOUS ADJUSTMENTS ($)	(4) GENERATION ADJUSTMENTS ($)	(5) TRANSMISSION TOTALS ($)	(6) SOURCE/NOTES
NEW UNDERWOOD SUBSTATION	5,237,475	(576,122)		4,661,353	11% of the costs of this facility have been allocated to distribution.
NEWELL SUBSTATION	992,151			992,151	
O'FALLON CREEK SUBSTATION	2,242,288	(1,154,144)		1,088,144	50% of the costs of this facility have been allocated to distribution.
PHILIP SUBSTATION	885,930			885,930	
PIERRE SUBSTATION	3,443,389	(1,721,695)		1,721,694	50% of the costs of this facility have been allocated to distribution.
RAINBOW SUBSTATION	701,370			701,370	
RAPID CITY SUBSTATION	3,490,189			3,490,189	
RICHLAND SUBSTATION	1,298,823	(1,039,058)		259,765	80% of the costs of this facility have been allocated to distribution.
ROLLA SUBSTATION	835,738	(208,935)		626,803	25% of the costs of this facility have been allocated to distribution.
RUDYARD SUBSTATION	2,469,782	(419,863)		2,049,919	17% of the costs of this facility have been allocated to distribution.
RUGBY SUBSTATION	6,176,606	(864,725)		5,311,881	14% of the costs of this facility have been allocated to distribution.
SAVAGE SUB	74,403			74,403	
SHELBY SUBSTATION	892,114			892,114	
SHELBY SUBSTATION #2	4,249,390			4,249,390	
SHELBY SUBSTATION #2	56,216			56,216	
SIOUX CITY #2	9,734,228			9,734,228	
SIOUX CITY SUBSTATION	14,844,390	(57,000)		14,787,390	
SIOUX FALLS SUBSTATION	5,570,723			5,570,723	
SPENCER	2,786,956			2,786,956	
SUMMIT SUBSTATION	2,576,653			2,576,653	
TYNDALL SUBSTATION	874,536			874,536	
VALLEY CITY SUBSTATION	2,200,697			2,200,697	
WALL SUBSTATION	748,393	(374,197)		374,196	50% of the costs of this facility have been allocated to distribution.
WASHBURN SUBSTATION	1,307,641			1,307,641	
WATERTOWN #2	2,954,635			2,954,635	
WATERTOWN STATIC VAR SYSTEM	11,707,621			11,707,621	
WATERTOWN SUBSTATION	9,975,193			9,975,193	
WATFORD CITY SUB	844,913	(30,000)		814,913	
WHATELY SUBSTATION	102,737	(51,369)		51,368	50% of the costs of this facility have been allocated to distribution.
WHATELY (NORTHERN) SUBSTATION	40,860			40,860	
WHITE 345/115 SUB	8,782,665			8,782,665	
WICKSVILLE SUBSTATION	655,076	(327,538)		327,538	50% of the costs of this facility have been allocated to distribution.
WILLISTON SUBSTATION	5,407,005	(37,000)		5,370,005	
WINNER SUBSTATION	3,180,986	(1,590,493)		1,590,493	50% of the costs of this facility have been allocated to distribution.
WOLF POINT SUBSTATION	7,296,850	(2,189,055)		5,107,795	30% of the costs of this facility have been allocated to distribution.
WOONSOCKET SUBSTATION	1,119,174			1,119,174	
YANKTON SUBSTATION	302,095			302,095	
Subtotal	326,930,587	(19,103,201)	0	307,827,386	
Line Taps & Related Equipment					
ANITA	6,259			6,259	
ASSINNIBOINE	35,005			35,005	
BAKER	112,990			112,990	
BIG BEND	81,801			81,801	
CANYON FERRY	72,351			72,351	
CHARLIE CREEK	1,119,513			1,119,513	
CHINOOK	3,943			3,943	
COTTON	1,399			1,399	
DICKINSON	63,736			63,736	
E. J. MANNING	5,358			5,358	
EAGLE	36,977			36,977	
FORSYTH	290,768			290,768	
HARLEM	220,802			220,802	
HETTINGER	4,451			4,451	
HIGHWOOD	22,896			22,896	
LAKE PLATTE	2,628			2,628	

TRANSMISSION PLANT-IN-SERVICE

Pick-Sloan Missouri Basin Program, Eastern Division

(1) DESCRIPTION	(2) FY2002 TOTALS ($)	(3) MISCELLANEOUS ADJUSTMENTS ($)	(4) GENERATION ADJUSTMENTS ($)	(5) TRANSMISSION TOTALS ($)	(6) SOURCE/NOTES
MALLARD	12,833			12,833	
MALTA	28,181			28,181	
NASHUA SUB	77,792			77,792	
O'NEILL SUB (NPP)	115,790			115,790	
POPLAR (MDU)	3,758			3,758	
PRIMGHAR	575			575	
SPALDING	22,234			22,234	
STANLEY	49,735			49,735	
STEGALL 230KV (BCPS)	3,599			3,599	
TERRY TAP	411,945	(205,973)		205,972	50% of the costs of this facility have been allocated to distribution.
TERRY TAP	4,330	(2,165)		2,165	50% of the costs of this facility have been allocated to distribution.
TIBER TAP	166,306			166,306	
V. T. HANLON	8,749			8,749	
WITTEN	25,430			25,430	
WM. J. NEAL	9,919			9,919	
YANKTON JCT.	30,753			30,753	
ZENITH	2,047			2,047	
Subtotal	3,054,853	(208,138)	0	2,846,715	
O&M Service & Maintenance Centers					
ARMOUR O&M SER. CEN.	890,105			890,105	
BISMARCK O&M SER. CEN.	1,646,880			1,646,880	
DAWSON SER. CEN.	22,545			22,545	
DEVILS LAKE O&M SER. CEN.	173,368			173,368	
FARGO LINE MAINT. FACILITY	583,926			583,926	
FARGO O&M SER. CEN.	584,576			584,576	
FORT PECK SER. CEN.	983,024			983,024	
FORT THOMPSON O&M S. C.	35,939			35,939	
HURON O&M SER. CEN.	2,395,958			2,395,958	
JAMESTOWN O&M SER. CEN.	994,335			994,335	
MILES CITY MTCE FACILITY	1,003,437			1,003,437	
MILES CITY MTCE FACILITY (BEFP)	21,817			21,817	
NEW UNDERWOOD SER. CEN.	96,884			96,884	
PHILIP O&M SER. CENT.	1,594,559			1,594,559	
PIERRE O&M SER. CEN.	887,378			887,378	
RAPID CITY GARAGE & STOR.	2,055,932			2,055,932	
SIOUX CITY O&M SER. CEN.	3,017,424			3,017,424	
SIOUX FALLS O&M SER. CEN.	77,456			77,456	
WATERTOWN MAINT. CEN.	1,197,839			1,197,839	
Subtotal	18,263,382	0	0	18,263,382	
Operation Centers					
WATERTOWN OPERATIONS CENT	1,752,542		(578,339)	1,174,203	Column 4 shows 33.0% of the Watertown Operations Center that was prorated to generation based on FTE associated with generation.
WATERTOWN OPER CTR (BFPS)	10,654,705		(3,516,053)	7,138,652	
Subtotal	12,407,247	0	(4,094,392)	8,312,855	
Mobile Equipment					
MOB 115KV SWITCH TRAILER	12,328			12,328	
MOB 115KV SWITCH TRAILER	57,413			57,413	
MOB SH.REACTOR	179,328			179,328	
MOB TRANSF 111KV 15MVA	213,000			213,000	
MOB TRANSF 115KV 10MVA	76,258			76,258	
MOB TRANSF 115KV 10MVA	142,235			142,235	
MOB TRANSF 115KV 25MVA	556,464			556,464	
MOB TRANSF 115KV 40MVA	499,220			499,220	
MOB TRANSF 230KV 1-33MVA	170,278			170,278	

TRANSMISSION PLANT-IN-SERVICE
Pick-Sloan Missouri Basin Program, Eastern Division

(1) DESCRIPTION	(2) FY2002 TOTALS ($)	(3) MISCELLANEOUS ADJUSTMENTS ($)	(4) GENERATION ADJUSTMENTS ($)	(5) TRANSMISSION TOTALS ($)	(6) SOURCE/NOTES
MOBILE BY PASS KIT (BISMARCK)	35,071			35,071	
MOBILE BY PASS KIT (FT.PECK)	7,038			7,038	
MOBILE BY PASS KIT (HURON)	163,695			163,695	
MOBILE SUB 110KV	127,144			127,144	
MOBILE SUB 115KV 20MVA	404,166			404,166	
MOBILE SUB 41.8 KV	192,498			192,498	
MOBILE SUB 69KV	71,118			71,118	
MOBILE TRANSFORMER-BILLINGS	248,943			248,943	
Subtotal	3,156,197	0	0	3,156,197	
Transmission-Related Generation Facilities					
BIG BEND-FORT THOMPSON (LOW VOLTAGE)	81,944		(81,944)	0	
CANYON FERRY-EAST HELENA "A"	141,044		(141,044)	0	
CANYON FERRY-EAST HELENA "B"	141,044		(141,044)	0	
FORT PECK POWERPLANT (COE)	5,256,790		(5,256,790)	0	
FORT THOMPSON-BIG BEND NO. 1	922,164		(922,164)	0	
FORT THOMPSON-BIG BEND NO. 2	690,735		(690,735)	0	
Subtotal	7,233,721	0	(7,233,721)	0	
Communication Facilities					Column 4 shows 30.2% of the Communication Facilities that were prorated to generation based on the number of communication channels dedicated to generation.
BANTRY	83,185		(25,122)	58,063	
BARRETT	241,189		(72,839)	168,350	
BATTLE MT. MICROWAVE	311,490		(94,070)	217,420	
BENEDICT	46,929		(14,173)	32,756	
BELLE PRAIRIE	593,434		(179,217)	414,217	
BEULAH	21,156		(6,389)	14,767	
BIG BEND REPEATER	183,098		(55,296)	127,802	
BIJOU REPEATER	246,519		(74,449)	172,070	
BISMARCK REPEATER	405,552		(122,477)	283,075	
BISON REPEATER	206,679		(62,417)	144,262	
BRINSMADE	205,419		(62,037)	143,382	
BRISTOL	14,685		(4,435)	10,250	
BRUNSVILLE REPEATER	201,619		(60,889)	140,730	
BUFFALO	255,051		(77,025)	178,026	
CAHOON	230,392		(69,578)	160,814	
CARRINGTON REPEATER	658,360		(198,825)	459,535	
CHARTER OAK REPEATER	20,306		(6,132)	14,174	
CHINOOK (BEFP)	284,048		(85,782)	198,266	
CHINOOK REPEATER	15,293		(4,618)	10,675	
CLARK MW REPEATER	296,066		(89,412)	206,654	
CLEVELAND REPEATER, N.D.	259,203		(78,279)	180,924	
COLEMAN REPEATER	288,294		(87,065)	201,229	
COLOME REPEATER	467,799		(141,275)	326,524	
CONRAD BUTTE REPEATER	271,041		(81,854)	189,187	
CRESTON REPEATER	16,324		(4,930)	11,394	
CROW LAKE REPEATER	294,289		(88,875)	205,414	
CROWN BUTTE	197,121		(59,531)	137,590	
CULBERTSON RADIO RELAY SITE	22,729		(6,864)	15,865	
CUSTER LOOKOUT	190,349		(57,485)	132,864	
DALTON (WES)	198,021		(59,802)	138,219	
DEVILS LAKE REPEATER	343,908		(103,860)	240,048	
DODSON REPEATER	276,812		(83,597)	193,215	
DOGDEN BUTTE	303,363		(91,616)	211,747	
DRISCOLL	196,788		(59,430)	137,358	
DUPREE REPEATER	1,821		(550)	1,271	

TRANSMISSION PLANT-IN-SERVICE

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(1) DESCRIPTION	(2) FY2002 TOTALS ($)	(3) MISCELLANEOUS ADJUSTMENTS ($)	(4) GENERATION ADJUSTMENTS ($)	(5) TRANSMISSION TOTALS ($)	(6) SOURCE/NOTES
DUTTON REPEATER	260,358		(78,628)	181,730	
EAST RAINY BUTTE	267,318		(80,730)	186,588	
ECKELSON	288,401		(87,097)	201,304	
ELKTON	314,834		(95,080)	219,754	
ELLENDALE REPEATER	309,889		(93,586)	216,303	
ERHARD	275,760		(83,280)	192,480	
EXIRA REPEATER	50,556		(15,268)	35,288	
F. L. BLAIR	39,437		(11,910)	27,527	
FAIRPOINT REPEATER	339,030		(102,387)	236,643	
FALLON REPEATER	271,939		(82,126)	189,813	
FLOWING WELLS	68,763		(20,766)	47,997	
FLOWING WELLS (BEFP)	1,162		(351)	811	
FORBES COMMUNICATION SITE	45,316		(13,685)	31,631	
FORT PECK RELAY (WES)	250,960		(75,790)	175,170	
FORT THOMPSON REPEATER	587,113		(177,308)	409,805	
FOX CREEK	564,210		(170,391)	393,819	
FRYBURG SUB & MICROWAVE	206,966		(62,504)	144,462	
GARRISON	129,540		(39,121)	90,419	
GARY REPEATER	225,859		(68,209)	157,650	
GAVIN'S POINT	186,134		(56,212)	129,922	
GAVINS POINT REPEATER	258,768		(78,148)	180,620	
GETTYSBURG REPEATER	288,912		(87,251)	201,661	
HAILSTONE BUTTE	174,289		(52,635)	121,654	
HALLOWAY REPEATER	263,547		(79,591)	183,956	
HATHAWAY	191,777		(57,917)	133,860	
HELENA RELAY (LAND ONLY)	422		(127)	295	
HERMOSA MICROWAVE	285,515		(86,226)	199,289	
HIGHLAND REPEATER	177,964		(53,745)	124,219	
HIGHMORE REPEATER	248,868		(75,158)	173,710	
HINSDALE	201,837		(60,955)	140,882	
HINSDALE REPEATER	13,747		(4,152)	9,595	
HOPEWELL REPEATER	365,686		(110,437)	255,249	
HUNTER MICROWAVE	333,962		(100,857)	233,105	
HURON DISTRICT OFFICE	810,284		(244,706)	565,578	
HYSHAM	259,920		(78,496)	181,424	
JAMESTOWN REPEATER	90,628		(27,370)	63,258	
JONES CREEK	37,140		(11,216)	25,924	
KELLY CREEK	315,487		(95,277)	220,210	
KILLDEER REPEATER	380,544		(114,924)	265,620	
KNEE HILL MW	279,815		(84,504)	195,311	
KONES CORNER REPEATER	470,207		(142,003)	328,204	
LAC QUI PARLE	310,285		(93,706)	216,579	
LAKE ANDEES REPEATER	310,602		(93,802)	216,800	
LEFOR	184,555		(55,736)	128,819	
LINDSAY RIDGE	221,145		(66,786)	154,359	
LODGEPOLE REPEATER	186,559		(56,341)	130,218	
MAKOSHIKA	1,401		(423)	978	
MALTA REPEATER	277,037		(83,665)	193,372	
MANDAN MICROWAVE SITE	70,317		(21,236)	49,081	
MARTIN REPEATER	326,356		(98,560)	227,796	
MAYVILLE	368,716		(111,352)	257,364	
MIDLAND REPEATER	398,001		(120,196)	277,805	
MILES CITY SUB (BEFP)	305,418		(92,236)	213,182	
MOE REPEATER	317,411		(95,858)	221,553	
MOORHEAD	251,422		(75,929)	175,493	

TRANSMISSION PLANT-IN-SERVICE

Pick-Sloan Missouri Basin Program, Eastern Division

(1) DESCRIPTION	(2) FY2002 TOTALS ($)	(3) MISCELLANEOUS ADJUSTMENTS ($)	(4) GENERATION ADJUSTMENTS ($)	(5) TRANSMISSION TOTALS ($)	(6) SOURCE/NOTES
MISSION REPEATER	24,821		(7,496)	17,325	
MORRIS REPEATER & MICROWAVE	293,289		(88,573)	204,716	
NEW CASTLE REPEATER	96,078		(29,016)	67,062	
O'KREEK REPEATER	551,796		(166,642)	385,154	
OAHE	227,222		(68,621)	158,601	
ORCHARD REPEATER	57,030		(17,223)	39,807	
OTO MICROWAVE	16,445		(4,966)	11,479	
PAGE N.D.	1,646		(497)	1,149	
PAHOJA SUB	62,995		(19,024)	43,971	
PEAK	252,757		(76,333)	176,424	
PHILIP JCT. REPEATER	297,029		(89,703)	207,326	
PICKSTOWN REPEATER	10,134		(3,060)	7,074	
PINE RIDGE	273,894		(82,716)	191,178	
PINE RIDGE (BEFP)	15,766		(4,761)	11,005	
PRIMGHAR REPEATER	7,810		(2,359)	5,451	
PUKWANNA REPEATER	255,427		(77,139)	178,288	
RAPID CITY REPEATER	341,292		(103,070)	238,222	
RICHARDSON COULEE	207,295		(62,603)	144,692	
RICHARDSON COULEE REPEATER	15,454		(4,667)	10,787	
RICHLAND REPEATER	532,827		(160,914)	371,913	
ROCKY RIDGE REPEATER	226,934		(68,534)	158,400	
ROLLAG	172,922		(52,222)	120,700	
RUGBY REPEATER	274,508		(82,901)	191,607	
RUTLAND	29,927		(9,038)	20,889	
SACO	1,237		(374)	863	
SENTINAL BUTTE	190,406		(57,503)	132,903	
SHEEP COULEE REPEATER	376,949		(113,839)	263,110	
SIOUX CITY REPEATER	321,681		(97,148)	224,533	
SIOUX FALLS REPEATER	279,666		(84,459)	195,207	
SIOUX PASS	42,198		(12,744)	29,454	
SNAKE BUTTE REPEATER	521,911		(157,617)	364,294	
SPALDING REPEATER	27,833		(8,406)	19,427	
SPIRIT MOUND	202,526		(61,163)	141,363	
STRASBERG	17,870		(5,397)	12,473	
TAPPEN REPEATER	268,439		(81,069)	187,370	
TORONTO REPEATER	285,888		(86,338)	199,550	
TRIPP REPEATER	209,822		(63,366)	146,456	
TURKEY RIDGE REPEATER	229,919		(69,436)	160,483	
TYLER REPEATER	297,746		(89,919)	207,827	
VIDA	337,513		(101,929)	235,584	
WALL REPEATER	434,552		(131,235)	303,317	
WATERTOWN REPEATER	369,401		(111,559)	257,842	
WAYSIDE	118,156		(35,683)	82,473	
WESSINGTON SPGS. REPEATER	340,101		(102,711)	237,390	
WESTFIELD	28,500		(8,607)	19,893	
WHITE SWAN	118,070		(35,657)	82,413	
WOLBACH REPEATER	48,672		(14,699)	33,973	
YELLOWTAIL PP (BEPS)	88,909		(26,851)	62,058	
YELLOWTAIL SWITCHYARD (BEPS)	271,476		(81,986)	189,490	
ZERO	50,948		(15,386)	35,562	
Subtotal	31,236,108	0	(9,433,304)	21,802,804	
Miles City Converter Station				0	
MILES CITY CONVERTER STATION	26,424,633			26,424,633	
MILES CITY CONVERTER STATION	412,466			412,466	
Subtotal	26,837,099	0	0	26,837,099	

TRANSMISSION PLANT-IN-SERVICE

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(1) DESCRIPTION	(2) FY2002 TOTALS ($)	(3) MISCELLANEOUS ADJUSTMENTS ($)	(4) GENERATION ADJUSTMENTS ($)	(5) TRANSMISSION TOTALS ($)	(6) SOURCE/NOTES
Distribution Facilities					
BUFORD TRENTON PUMP SUB	14,638	(14,638)		0	These facilities have been determined to be used solely for distribution and are therefore not recovered in the transmission rate.
BUFORD TRENTON TAP - BUFORD TRENTON P.P	657,834	(657,834)		0	
FALLON PUMPING PLANT SUBS	223,594	(223,594)		0	
FALLON RELIFT PUMPING PLANT	171,257	(171,257)		0	
FALLON-GLENDIVE PUMP #1	27,758	(27,758)		0	
FORT PECK-WOLF POINT	234,540	(234,540)		0	
FRAZER PUMP SUB	253,597	(253,597)		0	
GARRISON-SNAKE CREEK	569,241	(569,241)		0	
GLENDIVE P.P. #1 SUB.	570,157	(570,157)		0	
INTAKE SUBSTATION	108,040	(108,040)		0	
INTAKE-INTAKE PUMP	6,494	(6,494)		0	
KINSEY PUMP	49,256	(49,256)		0	
SAVAGE PUMPING PLANT SUBS	102,283	(102,283)		0	
SHIRLEY PUMP SUBSTATION	166,017	(166,017)		0	
SNAKE CREEK PUMP SUBSTATION	662,435	(662,435)		0	
SOUTH DAKOTA SCHOOL OF MINES	19,075	(19,075)		0	
TERRY PUMPING PLANT SWITCH	39,366	(39,366)		0	
TIBER DAM SUBSTATION	173,626	(173,626)		0	
VALLEY PUMP SUBSTATION (WIOTA)	38,507	(38,507)		0	
Subtotal Distribution Facilities	4,087,715	(4,087,715)	0	0	
Subtotal Upper Great Plains Region Facilities	760,798,395	(23,399,054)	(20,761,417)	716,637,924	
Rocky Mountain Region Facilities					Column 2 includes plant-in-service from FY 2002 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 1. These are RMR facilities utilized by both RMR and UGPR. The amount in Column 5 will be recovered by UGPR.
NEW UNDERWOOD-STEGALL	287,835			287,835	
STEGALL SUBSTATION	7,943,736	(7,641,127)		302,609	
STEGALL-WAYSIDE	2,978,205			2,978,205	
YELLOWTAIL SWITCHYARD	6,760,767	(5,070,575)		1,690,192	
	17,970,543	(12,711,702)	0	5,258,841	
				0	
Corps of Engineers Facilities				0	
CORPS SWITCHYARD FACILITIES	29,782,666		(29,782,666)	0	
	29,782,666	0	(29,782,666)	0	
TOTAL FACILITIES	808,551,604	(36,110,756)	(50,544,083)	721,896,765	

Western's Ancillary Service Cost Data

REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES FOR 2003 (WESTERN'S COSTS)

A. Fixed Charge Rate	14.232%	(1)
B. Generation Net Plant Costs ($)	$500,989,691	(2)
C. Annual Cost of Generation ($)	$71,300,515	(A x B)
D. Capability Used for Reactive Support (%)	2.02%	(3)
E. Reactive Service Revenue Requirement	$1,440,270	(C x D)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program--Eastern Division Annual Generation Revenue Requirement", for 2003.

(2) Generation Net Plant Costs include the total Eastern Division Pick-Sloan Generation Plant-in-Service less Depreciation Reserve.

(3) Five year average peak monthly percentage of condensing generation. Reference PO&M 59 Reports for 1992-1996.

RATE FOR REGULATION AND FREQUENCY RESPONSE FOR 2003
(Western's Costs)

A.	Fixed Charge Rate	12.206%	(1)
B.	Corps Generation Net Plant Costs ($)	187,943,855	(2)
C.	Annual Corps Generation Cost ($)	22,940,607	(A x B)
D.	Plant Capacity (kW)	937,000	
E.	Cost/kW ($/kW)	24.48	(C / D)
F.	Capacity Used for Regulation (kW)	40,160	(H x 2%)
G.	Regulation Revenue Requirement ($)	$983,239	(E x F)
H.	Load in Control Area(s) (kW-Year)	2,008,000	(3)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program--Eastern Division Annual Corps Revenue Requirement", for 2003.

(2) Corps Generation Net Plant is Electric Plant in Service for Oahe and Fort Peck less less Depreciation Reserve as of 9/30/03.

(3) Average of monthly peaks for 2003 Watertown Control Area.

DETERMINATION OF PICK-SLOAN MISSOURI BASIN PROGRAM, EASTERN DIVISION
ANNUAL GENERATION REVENUE REQUIREMENT

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Notes
1			
2	**A. Operation and Maintenance Expense for Generation**		
3			
4	Generation O&M Expense	$49,738,334	O&M Expenses Worksheet, C6L19
5			
6	Net Generation Plant Investment	$676,569,235	Net Plant Investment Worksheet, C6L12
7			
8	O&M as % of Net Generation Plant Investment	7.352%	L4/L6
9			
10			
11	**B. A&G Expense for Generation**		
12			
13	Generation A&G Expense	$670,564	A&G Expenses Worksheet, C6L17
14			
15	Net Generation Plant Investment	$676,569,235	L6
16			
17	A&G as % of Net Generation Plant Investment	0.099%	L13/L15
18			
19			

43

DETERMINATION OF PICK-SLOAN MISSOURI BASIN PROGRAM, EASTERN DIVISION
ANNUAL GENERATION REVENUE REQUIREMENT

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Notes
20	**C. Depreciation Expense for Generation**		
21			
22	Generation Depreciation Expense	$14,365,385	Depreciation Expense Worksheet, C6L6
23			
24	Net Generation Plant Investment	$676,569,235	L6
25			
26	Depreciation as a % of Net Generation Plant Investment	2.123%	L22/L24
27			
28			
29	**D. Taxes Other than Income Taxes for Generation**		
30			
31	Not applicable.		
32			
33			
34	**E. Allocation of General Plant to Generaqtion**		
35			
36	No General Plant identified at this time, all either generation or transmission related.		
37			
38			
39	**F. Cost of Capital**		
40			
41	Generation Composite Interest Rate	4.658%	Cost of Capital Worksheet, C6L11
42			

DETERMINATION OF PICK-SLOAN MISSOURI BASIN PROGRAM, EASTERN DIVISION
ANNUAL GENERATION REVENUE REQUIREMENT

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Notes
43			
44	**G. Generation Fixed Charge Rate**		
45			
46	Operation and Maintenance Expense	7.352%	L8
47			
48	A&G Expense	0.099%	L17
49			
50	Depreciation Expense	2.123%	L26
51			
52	Taxes Other than Income Taxes	0.000%	
53			
54	Allocation of General Plant to Generation	0.000%	
55			
56	Weighted Cost of Capital	4.658%	L41
57			
58	Total	14.232%	
59			
60			
61	**H. Generation Revenue Requirement**		
62			
63	Generation Fixed Charge Rate	14.232%	L59
64			
65	Net Generation Plant Investment	$676,569,235	L6
66			
67	Western Annual Generation Revenue Requirement	$96,288,878	L63 * L65
68			

DETERMINATION OF PICK-SLOAN MISSOURI BASIN PROGRAM, EASTERN DIVISION
ANNUAL CORPS GENERATION REVENUE REQUIREMENT

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Notes
1			
2	**A. Operation and Maintenance Expense for Corps Generation**		
3			
4	Corps Generation O&M Expense	$23,778,474	O&M Expenses Worksheet, C4L19
5			
6	Net Corps Generation Plant Investment	$434,116,728	Net Plant Investment Worksheet, C4L12
7			
8	O&M as % of Net Generation Plant Investment	5.477%	L4/L6
9			
10			
11	**B. A&G Expense for Corps Generation**		
12			
13	Corps Generation A&G Expense	$0	A&G Expenses Worksheet, C4L17
14			
15	Net Corps Generation Plant Investment	$434,116,728	L6
16			
17	A&G as % of Net Generation Plant Investment	0.000%	L13/L15
18			

DETERMINATION OF PICK-SLOAN MISSOURI BASIN PROGRAM, EASTERN DIVISION
ANNUAL CORPS GENERATION REVENUE REQUIREMENT

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Notes
19			
20	**C. Depreciation Expense for Corps Generation**		
21			
22	Corps Generation Depreciation Expense	$8,989,072	Depreciation Expense, C4L6
23			
24	Net Corps Generation Plant Investment	$434,116,728	L6
25			
26	Depreciation as a % of Net Generation Plant Investment	2.071%	L22/L24
27			
28			
29	**D. Taxes Other than Income Taxes for Corps Generation**		
30			
31	Not applicable.		
32			
33			
34	**E. Allocation of General Plant to Corps Generation**		
35			
36	No General Plant identified at this time, all either generation or transmission related.		
37			
38			
39	**F. Cost of Capital**		
40			
41	Generation Composite Interest Rate	4.658%	Cost of Capital Worksheet, C6L11
42			

DETERMINATION OF PICK-SLOAN MISSOURI BASIN PROGRAM, EASTERN DIVISION
ANNUAL CORPS GENERATION REVENUE REQUIREMENT

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Notes
43			
44	**G. Corps Generation Fixed Charge Rate**		
45			
46	Operation and Maintenance Expense	5.477%	L8
47			
48	A&G Expense	0.000%	L17
49			
50	Depreciation Expense	2.071%	L26
51			
52	Taxes Other than Income Taxes	0.000%	
53			
54	Allocation of General Plant to Generation	0.000%	
55			
56	Weighted Cost of Capital	4.658%	L41
57			
58	Total	12.206%	
59			
60			
61	**H. Corps Generation Revenue Requirement**		
62			
63	Corps Generation Fixed Charge Rate	12.206%	L69
64			
65	Net Corps Generation Plant Investment	$434,116,728	L6
66			
67	Western Annual Corps Generation Revenue Requirement	$52,988,703	L63 * L65
68			

Basin Electric's Transmission Cost Data

Revenue Requirement Worksheet
Utilizing RUS Form 12 Data
BASIN ELECTRIC POWER COOPERATIVE
No Generator Step- Up Transformers

For the 12 months ended 12/31/03

Line No.		Total	Allocator		Total Transmission	IS Transmission	Other Transmission
1	**GROSS REVENUE REQUIREMENT (page 3, line 28)**				$65,528,629	$40,832,642	$23,923,755
						$41,604,874.05	$772,232.26
	REVENUE CREDITS						
2	Third Party Receipts	($3,004,687)	TP	1.00000		($3,004,687)	
3							
4	Third Party Payments	$321,644	TP	1.00000		$321,644	
5							
6	NET REVENUE REQUIREMENT (line 1+ 2+ 4)					$38,149,599	

Revenue Requirement Worksheet
Utilitizing RUS form 12 Data
BASIN ELECTRIC POWER COOPERATIVE
No Generator Step- Up Transformers

For the 12 months ended 12/31/03

-1		-2 RUS Form 12	-3	-4	Allocator A	(5) Total Trans	(4a) Allocator B		(6) IS Transmission	(7) Other Transmission
	GROSS PLANT IN SERVICE									
1	Production	12h.1.A.6.e	**1,676,397,724**	NA		-	NA		-	-
2	Transmission *	12h.1.A.11.e	**468,736,368**	DA		468,736,368	DA		304,042,312	164,694,056
3	Distribution	12h.1.A.16.e	-	NA		-	NA		-	-
4	General	12h.1.A.17.e	**102,167,696**			-			-	-
4a	Direct Assign - Transmission		30,039,426	DA		30,039,426	DA		25,683,641	4,355,784
4b	Direct Assign - Production		19,473,299	NA		-	NA		-	-
4c	Other		52,654,971	WS	10.894%	5,736,492	WS	(page 4)	3,782,378	1,954,114
5	Intangible	12h.1.A.1.e	**61,130,445**	DA		61,128,175	DA		28,471,286	32,656,889
6	TOTAL GROSS PLANT (sum lines 1,2,4,5)		**$ 2,308,432,233**			**$ 565,640,460**			**$ 361,979,617**	**$ 203,660,844**
				GP	24.503%		GP		15.681%	8.822%
							TPGP		63.995%	36.005%
	ACCUMULATED DEPRECIATION									
7	Production	12h.1.B.1&4.f	**806,513,950**	NA		-	NA		-	-
8	Transmission	12h.1.B.5.f	**199,089,052**	DA		199,089,052	DA		142,588,774	56,500,278
9	Distribution	12h.1.B.6.f	-	NA		-	NA		-	-
10	General	12h.1.B.7.f	**70,305,449**			-			-	-
10a	Direct Assign - Transmission		20,278,816	DA		20,278,816	DA		17,237,310	3,041,506
10b	Direct Assign - Production		14,509,446	NA		-	NA		-	-
10c	Other		35,517,187	WS	10.894%	3,869,417	WS	(page 4)	2,551,315	1,318,102
11	Intangible	12h.1.B.12.f	**33,737,959**	DA		33,735,689	DA		15,370,999	18,364,690
12	TOTAL ACCUM. DEPR (sum lines 7,8,10,11)		**$ 1,109,646,410**			**$ 256,972,975**			**$ 177,748,398**	**$ 79,224,576**
	NET PLANT IN SERVICE									
13	Production	(line 1- line 7)	**869,883,774**	AUTO		-			-	-
14	Transmission	(line 2- line 8)	**269,647,316**	AUTO		269,647,316			161,453,538	108,193,778
15	Distribution	(line 3 - line 9)	-	AUTO		-			-	-
16	General	(line 4 - line 10)	**31,862,247**	AUTO					-	-
16a	Direct Assign		9,760,610	AUTO		9,760,610			8,446,331	1,314,278
16b	Production		4,963,853	AUTO		-			-	-
16c	Other		17,137,785	AUTO		1,867,075			1,231,063	636,012
17	Intangible	(line 5 - line 11)	**27,392,486**	AUTO		27,392,486			13,100,287	14,292,200
18	TOTAL NET PLANT (sum lines 13, 14, 16, 17)		**$ 1,198,785,823**			**$ 308,667,487**			**$ 184,231,219**	**$ 124,436,267**
				NP	25.748%		NP		15.368%	10.380%

* Adjustment of $1,199,738 made to transmission fixed assets is due to a correction for over accural of property tax
Differs from the RUS 12h by $1,199,738

Revenue Requirement Worksheet
Utilizing RUS Form 12 Data
BASIN ELECTRIC POWER COOPERATIVE
No Generator Step- Up Transformers

For the 12 months ended 12/31/03

Line No.	-1	-2 RUS Form 12 Reference	-3 Company Total	-4	Allocator A	(5) Total Transmission	(4a) Allocator B		(6) IS Transmission	(7) Other Transmission
	O&M									
1	Transmission less Account 565	12a.A.8.b+ A.16.b-12l.A.9.a	**12,340,959**	TE						
2	Direct Assignment	Accounting Records	3,660,250	DA		3,660,250	DA		3,476,010	184,240
3	Other	Accounting Records	8,680,709	TPWS		8,680,709	TPWS	(page 4)	5,151,220	3,529,490
4	A&G	12a.A.13.b	**33,568,050**							
5	Less FERC Annual Fees	Accounting Records	28,193	NA		-	NA		-	-
6	Production	Accounting Records	30,017,001	NA		-	NA		-	-
7	Transmission	Accounting Records	3,522,857	DA/TPWS		3,522,857	DA /TPWS	(page 4)	2,398,132	1,124,725
8	Distribution		-	NA		-			-	-
9	TOTAL O&M (sum lines 1 and 4)		**$ 45,909,009**			**$ 15,863,816**			**$ 11,025,361**	**$ 4,838,454**
	DEBT SERVICE									
10	Interest Expense	12a.A.22.b	**51,422,503**	NP	25.748%	13,240,443	NP	(page 2)	7,902,688	5,337,754
11	Principal Payments	12h.H.9.c	**100,242,198**	NP	25.748%	25,810,705	NP	(page 2)	15,405,373	10,405,332
12	Amort of Debt Discount (428)	12a.A.25.b	**4,304,131**							
13	Transmission	Accounting Records	858,639	DA		858,639	DA		591,534	267,105
14	Headquarters	Accounting Records	36,846	WS	10.894%	4,014	WS	(page 4)	2,647	1,367
15	Production	Accounting Records	2,498,828	NA		-	NA		-	-
16	Other Deductions	12a.A.25.b	909,818	NA			NA		-	-
17	TOTAL DEBT SERVICE (sum lines 10, 11, 12,16)		**$ 155,968,832**			**$ 39,913,800**			**$ 23,902,241**	**$ 16,011,559**
	TAXES OTHER THAN INCOME TAXES									
	LABOR RELATED		-							
18	Payroll		-	NA		-	NA		-	-
19	Highway and vehicle		-	NA		-	NA		-	-
20	PLANT RELATED									
21	Property total	12a.A.21.b (less income tax)	**9,910,571**						-	-
22	Property Headquarters	Accounting Records	1,746,408	GP	24.503%	427,926	GP	(page 2)	273,850	154,076
23	Transmission	12i. A.28	165,237	DA		165,237	DA		165,237	-
24	Production	12d & 12f	7,998,926	NA		-	NA			
25	TOTAL OTHER TAXES		**$ 9,910,571**			**$ 593,164**			**$ 439,087**	**$ 154,076**
26	**TOTAL OPERATING EXPENSES (Sum 9+17+25)**		**$ 211,788,412**			**$ 56,370,780**			**$ 35,366,689**	**$ 21,004,090**
27	**Margin**		**$ 35,566,753**	NP	25.748%	**9,157,849**	NP	(page 2)	**5,465,952**	**3,691,897**
28	**REV. REQUIREMENT (sum lines 26+27)**		247,355,165			65,528,629			40,832,642	24,695,987

Revenue Requirement Worksheet
Utilizing RUS Form 12 Data
BASIN ELECTRIC POWER COOPERATIVE
No Generator Step- Up Transformers

For the 12 months ended 12/31/03

A & G Allocation

WAGES AND SALARY ALLOCATOR (W/S)

	-1	-2	-3	-4		-5	-6	-7
ine #	(From Accounting Report - Cognos)		TOTAL	Allocator		Percent	IS Transmission	Other Transmission
1	Production		28,807,017					
2	Transmission-East		189,215				$2,322,305	$1,199,787
3	Transmission-West		345,030					
4	Transmission-Allocated		2,987,848					
5	Distribution		-					
6	Other		-					
7	Total Wages and Salaries (exclude adm)		$32,329,109	WS	Trans % of total wages	10.894%	7.183%	3.711%
							(col 6/col 3 L7)	(col 7/col 3 L7)
				TPWS	Trans % of total trans		65.935%	34.065%
							(% of total transmission)	(% of total transmission)

53

IS Transmission Wage and Salary Dollar Split

8	Net IS transmission Plant (p.2.c.6.L.14, 16a, 17)	183,000,156		
9	Net West & Other transmission Plant (p.2.c.7.L.14, 16a,17)	123,800,255		
10	Total (sum lines 8 -9)	$306,800,411		
11	Percent of IS to Total Transmission		ISTP	59.648%
12	Percent of West & Other to total Transmission		Other	40.352%
13	IS Trans Wage & Salary Dollar (L 4 times L8/L10-West)	$2,133,090		100.000%
14	West Transmission Wage & Salary	$0		
15	Other Transmission Wage & Salary (L 4 times L9-West/L10-West)	$854,757		
16	Total Transmission Wage and Salary Allocated (L.4)	$2,987,848		

Basin Electric Power Cooperative
IS Transmission Facilities
December 31, 2003

CPLX	LINES	BOOK COST	12/31/03 ACCUM DEPR	12/31/03 NET BOOK VALUE
009	230KV Line LO to Logan	751,708	425,071	326,637
012	230KV Lo#1 Dbl Circ Line to Washburn	1,485,282	1,450,404	34,878
021/022	345KV Line - Stanton to Fort Thompson	18,432,026	13,459,864	4,972,162
023/024	345KV Line - Stanton to Watertown	21,617,525	15,501,118	6,116,406
025	230KV Line - LO#1 to Logan (Minot, ND)	4,430,205	2,690,048	1,740,156
026	230KV Line - LO Switchyard to BEPC Sub	289,132	207,218	81,913
031	115KV Line - Logan to Kenmare	3,115,809	1,816,032	1,299,777
032	115KV Line - Logan to Mallard Substation	632,973	357,333	275,640
034	230KV - Philip Sub to Philip Tap Substation	853,709	646,668	207,041
127	345KV - AVS to LO North Line	9,598,714	3,655,411	5,943,303
128	345KV - AVS to LO South Line	11,215,381	4,208,612	7,006,769
129/130	500KV Line - AVS Switchyard to Broadland Sub	111,024,630	42,523,711	68,500,919
134	345KV - AVS to LO DBL Circuit Line	878,339	489,256	389,083
141	230KV Line -Broadland Sub to USBR Huron Sub	1,068,625	429,912	638,712
150	230KV - Dam Estavan to Logan Substation	15,071,877	8,323,362	6,748,516
152	345KV Line - AVS to Charlie Creek Substation	9,291,907	4,461,773	4,830,134
*185	230KV Line - Miles City-Bowman-New Underwood	9,481,900	5,844,503	3,637,397
311	115KV Tie Line - BEPC to USBR Groton Sub	136,010	70,857	65,153
361	69KV Line Cornbelt	26,856	1,306	25,551
411	230 KV Line RC to New Underwood	6,406,862	36,706	6,370,156
	TOTAL LINES	**$ 225,809,469**	**$ 106,599,164**	**$ 119,210,305**

*USBR owned/BEPC financed - amortization in lieu of depreciation

Basin Electric Power Cooperative
IS Transmission Facilities
December 31, 2003

CPLX	SUBSTATIONS	BOOK COST	12/31/03 ACCUM DEPR	12/31/03 NET BOOK VALUE
010	230KV LO #1 Step-up Sub-Main Transformer	347,562	346,433	1,129
013	230KV LO Washburn Substation	71,594	70,298	1,296
016	230/115/69KV LO Substation	1,193,246	983,415	209,831
019	345KV LO #2 Step-up Sub-Main Transformer	1,886,449	1,404,928	481,521
036	345KV FT Thompson Substation	2,374,699	1,524,502	850,197
039	230/115KV Storla, SD Substation	1,939,189	1,470,682	468,507
040	230/115KV Philip, SD Substation	829,493	555,363	274,130
042	230KV Philip,SD Tap Substation	214,957	164,769	50,189
046	Martin, SD USBR Sub Capacitor Installed	200,287	108,241	92,046
047	Armour, SD USBR Sub Capacitor Installed	137,379	103,886	33,492
058	115KV Williston, ND Substation	643,259	370,990	272,268
060	230/115KV Dickinson, ND Substation	1,204,038	914,243	289,796
061	115KV Spirit Mound Switchyard	1,406,589	979,459	427,131
063	Static VAR Suppt-Victory Hill Sub-Sctbluff	1,647,967	1,108,953	539,014
126	500KV Broadland SD, Substation	12,470,254	4,985,854	7,484,400
142	230KV USBR Huron Substation Addition	1,669,836	676,777	993,058
145	Manning,ND Sub Capacitor Installed	186,623	125,688	60,935
153	345/115KV Charlie Creek Substation	5,342,658	2,898,978	2,443,680
191	AVS #1 - Main Step-up Transformer	3,022,923	1,217,618	1,805,305
193	AVS Spare - Main Step-up Transformer	2,748,457	1,108,699	1,639,758
194	Bowman Sub -230 KV breakers	1,326,693	40,934	1,285,759
195	Hettinger Capacitors	711,787	1,633	710,154
196	Baker Capacitors	711,787	1,633	710,154
310	345/115KV Groton Substation Addition	5,019,759	2,479,370	2,540,389
362	69KV Substation - Cornbelt	150,000	7,292	142,708
711	230KV LO #1 Switchyard and AVS Addition	5,087,710	3,683,039	1,404,672
720	345/230KV LO#2 Switchyard and AVS Addition	16,129,966	8,540,762	7,589,204
734	Tioga Substation	387,866	128,103	259,764
735	345/230KV Watertown Substation	2,871,896	2,190,080	681,816
737	230/115KV Logan Substation & Sask Addition	4,115,005	2,495,700	1,619,305
767	345KV AVS Switchyard & Charlie Creek Add't	18,877,662	7,825,774	11,051,888
	TOTAL SUBSTATIONS	**$ 94,927,587**	**$ 48,514,093**	**$ 46,413,494**

Generator Step-Up Transformers in IS

Basin Electric Power Cooperative
IS Transmission Facilities
December 31, 2003

CPLX	SUBSTATIONS	BOOK COST	12/31/03 ACCUM DEPR	12/31/03 NET BOOK VALUE
010	230KV LO #1 Step-up Sub-Main Transformer	347,562	346,433	1,129
019	345KV LO #2 Step-up Sub-Main Transformer	1,886,449	1,404,928	481,521
191	AVS #1 - Main Step-up Transformer	3,022,923	1,217,618	1,805,305
193	AVS Spare - Main Step-up Transformer	2,748,457	1,108,699	1,639,758
118	LRS	3,800,336	1,804,619	1,995,718
	Total	**11,805,726**	**5,882,296**	**5,923,430**

Basin Electric Power Cooperative
IS Transmission Facilities
December 31, 2003

	MICROWAVE	BOOK COST	12/31/03 ACCUM DEPR	12/31/03 NET BOOK VALUE
043	Microwave Communication - ND	7,581,383	4,534,273	3,047,110
044	Microwave Communication - SD	5,473,017	3,388,946	2,084,071
136	Microwave Communication - SD - AVS	1,074,891	709,892	364,999
137	Microwave Communication - ND - AVS	1,263,513	842,643	420,870
139	Microwave Communication - ND - Sask	1,279,463	807,404	472,059
155	Microwave Communication-ND-Charlie Crk	1,000,407	642,440	357,967
308	Microwave Communication - SD - Groton	161,504	94,648	66,856
	SUBTOTAL MICROWAVE	**17,834,179**	**11,020,246**	**6,813,933**
	Less Non-Transmission Microwave - (33.927%)	(6,050,602)	(3,738,839)	(2,311,763)
	TOTAL MICROWAVE	**$ 11,783,577**	**$ 7,281,407**	**$ 4,502,170**
	TSM			
070	Mandan Transmission Maintenance Bldg	6,014,293	4,011,923	2,002,371
071	Gettysburg Transmission Maintenance Bldg	1,147,620	1,005,850	141,770
072	Groton Transmission Maintenance Bldg	2,024,470	502,853	1,521,617
109	Logan Transmission Maintenance Bldg	1,152,246	828,693	323,553
119	Broadland Transmission Maintenance Bldg	1,030,499	912,292	118,207
120	AVS Transmission Maintenance Bldg	3,323,482	2,724,292	599,189
	TOTAL TSM	**$ 14,692,610**	**$ 9,985,903**	**$ 4,706,707**
	OTHER			
325	MC DC Tie	18,989,386	9,526,497	9,462,889
	TOTAL OTHER	**$ 18,989,386**	**$ 9,526,497**	**$ 9,462,889**
	General Ledger Accum Depr Adjust		(2,632,303)	
	GRAND TOTAL	**$ 366,202,629**	**$ 179,274,761**	**$ 186,927,868**

Basin Electric Power Cooperative
IS Revenue Requirement Worksheet
Third Party Payments and Receipts
December 31, 2003

Worksheet 3

Third Party Payments

ICCUA	224,112
LaCreek	97,532
Total Payments	**$ 321,644**

Third Party Receipts

ICCUA	338,508
MDU/AVS	159,360
MAPP	2,506,819
Total Receipts	**$ 3,004,687**

Basin Electric's Ancillary Service Cost Data

Generation Revenue Requirement
Utilizing RUS Form 12 Data
BASIN ELECTRIC POWER COOPERATIVE

For the 12 months ended 12/31/03

	East	West	Other
GROSS REVENUE REQUIREMENT (page 3, line 27)	$ 242,092,659	$ 76,651,196	$ 8,909,799
Percent of revenue requirement to net plant	41.6354%	29.3608%	18.7209%

Production	LOS	AVS	SM	LRS	Other
$ 327,653,654	$ 74,912,976	$ 164,981,819	$ 2,197,864	$ 76,651,196	$ 8,909,799

Line No.	(1)	(2) RUS Form 12 Reference	(3) Company Total	(4) Allocator		(5) Production	(6) LOS	(7) AVS	(8) SM	(9) LRS	(10) Other
	GROSS PLANT IN SERVICE										
1	Production	12h.1.A.6.e	1,676,397,724	DA		1,676,397,724	227,440,705	827,919,898	24,930,271	547,061,063	49,045,786
2	Transmission *	12h.1.A.11.e	468,736,368	NA		-	-	-	-	-	-
3	Distribution	12h.1.A.16.e	-	NA		-	-	-	-	-	-
4	General	12h.1.A.17.e	102,167,696	WS		-	-	-	-	-	-
4a	Direct Assign - Transmission		30,039,426	NA		-	-	-	-	-	-
4b	Direct Assign - Production		19,473,299	DA		19,473,299	5,081,306	6,278,821	209,393	5,869,879	2,033,900
4c	Other		52,654,971	WS	89.106%	46,918,480	13,650,550	19,035,539	275,678	13,778,828	177,885
5	Intangible	12h.1.A.1.e	61,130,445	NA		-	-	-	-	-	-
6	TOTAL GROSS PLANT (sum lines 1-5)		$ 2,308,432,233			$1,742,789,503	246,172,560	$853,234,258	$25,415,343	566,709,771	$51,257,571
				GP	75.497%		10.664%	36.962%	1.101%	24.550%	2.220%
	ACCUMULATED DEPRECIATION										
7	Production	12h.1.B.1&4.f	806,513,950	DA		806,513,950	145,633,145	348,669,120	17,483,979	291,368,873	3,358,833
8	Transmission	12h.1.B.5.f	199,089,052	NA		-	-	-	-	-	-
9	Distribution	12h.1.B.6.f	-	NA		-	-	-	-	-	-
10	General	12h.1.B.7.f	70,305,449	WS							
10a	Direct Assign - Transmission		20,278,816	NA		-	-	-	-	-	-
10b	Direct Assign - Production		14,509,446	DA		14,509,446	3,866,783	5,286,410	189,848	4,980,380	186,025
10c	Other		35,517,187	WS	89.106%	31,647,770	9,207,661	12,839,980	185,952	9,294,188	119,988
11	Intangible	12h.1.B.12.f	33,737,959	DA		-	-	-	-	-	-
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		$ 1,109,646,410			852,671,166	158,707,589	366,795,511	17,859,779	305,643,441	3,664,846
	NET PLANT IN SERVICE										
13	Production	(line 1- line 7)	869,883,774	AUTO		869,883,774	81,807,560	479,250,778	7,446,292	255,692,191	45,686,953
14	Transmission	(line 2- line 8)	269,647,316	AUTO		-	-	-	-	-	
15	Distribution	(line 3 - line 9)	-	AUTO		-	-	-	-	-	
16	General	(line 4 - line 10)	31,862,247	AUTO		-	-		-		
16a	Direct Assign		9,760,610	AUTO		-	-		-		
16b	Production		4,963,853	AUTO		4,963,853	1,214,523	992,411	19,546	889,499	1,847,875
16c	Other		17,137,785	AUTO		15,270,710	4,442,889	6,195,559	89,726	4,484,640	57,897
17	Intangible	(line 5 - line 11)	27,392,486	AUTO		-	-	-	-	-	-
18	TOTAL NET PLANT (sum lines 13, 14, 16, 17)		$ 1,198,785,823			890,118,337	87,464,972	486,438,747	7,555,563	261,066,329	47,592,725
				NP	74.252%		7.296%	40.578%	0.630%	21.778%	3.970%

* Adjustment of $1,199,738 made to transmission fixed assets is due to a correction for over accural of property tax
Differs from the RUS 12h by $1,199,738

Generation Revenue Requirement
Utilizing RUS Form 12 Data
BASIN ELECTRIC POWER COOPERATIVE

For the 12 months ended 12/31/03

No.	(1)	(2) Reference	(3) Company Total	(4) Allocator		(5) Production	(6) LOS	(7) AVS	(8) SM	(9) LRS	(10) Other
	O&M										
1	Production	12a.A.5.b+ A.15.b	**146,765,131**	DA		146,765,131	48,786,203	70,037,434	797,916	25,960,881	1,182,697
2	A&G	12a.A.13.b	**33,568,050**								
3	Less FERC Annual Fees	Accounting Records	28,193			-	-	-	-	-	-
4	Production		30,017,001	WS	89.106%	30,017,001	8,733,202	12,178,353	176,370	8,815,271	113,805
5	Transmission		3,522,857	NA		-	-	-	-	-	-
8	Distribution		-			-	-	-	-	-	-
9	TOTAL O&M (sum lines 1 and 4)		**$ 180,333,181**			**176,782,132**	**57,519,405**	**82,215,787**	**974,286**	**34,776,152**	**1,296,502**
	DEBT SERVICE					70,451,800					
10	Interest Expense	12a.A.22.b	**51,422,503**	NP	74.252%	38,182,061	3,751,853	20,866,028	324,100	11,198,568	2,041,513
11	Principal Payments	Accounting Records	**100,242,198**	NP	74.252%	74,431,493	7,313,801	40,675,898	631,794	21,830,307	3,979,693
12	Amort of Debt Discount (428)	12a.A.25.b	**4,304,131**	NP		-	-	-	-	-	-
13	Transmission	Accounting Records	858,639	NA			-	-	-	-	-
14	Headquarters	Accounting Records	36,846	WS	89.106%	32,832	9,552	13,320	193	9,642	124
15	Production	Accounting Records	2,498,828	DA		2,498,828	259,789	1,411,564	24,097	662,219	141,159
16	Other Deductions	12a.A.25.b	909,818	DA/WS		-	-	-	-	-	-
17	TOTAL DEBT SERVICE (Sum lines 10,11,12)		**$ 155,968,832**			**$115,145,213**	**$11,334,995**	**$62,966,809**	**$980,184**	**$33,700,736**	**$6,162,489**
	TAXES OTHER THAN INCOME TAXES										
	LABOR RELATED										
	Payroll		-	WS							
18	Highway and vehicle		-	WS							
19	PLANT RELATED										
20	Property and Other Total	12a.A.21.b (less income tax)	**9,910,571**	GP							
21	Property Headquarters	Accounting Records	1,746,408	GP	75.497%	1,318,480	186,238	645,501	19,228	428,735	38,778
22	Transmission	12i. A.28	165,237	NA		-	-	-	-	-	-
23	Production	12d & 12f	7,998,926	DA		7,998,926	3,277,342	4,721,583	-	2	-
24	TOTAL OTHER TAXES		**$ 9,910,571**			**$9,317,406**	**$3,463,580**	**$5,367,083**	**$19,228**	**$428,737**	**$38,778**
25	**TOTAL OPERATING EXPENSES (Sum 9+17+24)**		**$346,212,584**			**$301,244,751**	**$72,317,980**	**150,549,678**	**$1,973,698**	**$68,905,624**	**$7,497,771**
26	**Margin**		**$ 35,566,753**	NP	74.252%	**$26,408,903**	**$2,594,996**	**$14,432,141**	**$224,166**	**$7,745,572**	**$1,412,028**
27	**REV. REQUIREMENT (sum lines 25 + 26)**		**$381,779,337**		85.823%	**$327,653,654**	**$74,912,976**	**164,981,819**	**$2,197,864**	**$76,651,196**	**$8,909,799**

Line #	WAGES AND SALARY ALLOCATOR (W/S)									
(1)	(2) (From Accounting Report - Cognos)	(3) TOTAL	(4) Allocator		(5) Production	(6) LOS	(7) AVS	(8) SM	(9) LRS	(10) Other
1	Production - LOS	$8,381,167	WS	89.106%	$28,807,017	25.925%	36.151%	0.524%	26.168%	0.338%
2	Production - AVS	$11,687,444								
3	Production - SM	$169,261	PRWS			29.094%	40.572%	0.588%	29.368%	0.379%
4	Production - LRS	$8,459,927								
5	Production - Other	$109,218								
6	Transmission	$3,522,092								
7	Other	$0								
	Total Wages and Salaries (exclude adm)	**$32,329,110**								

Basin Electric Power Cooperative
IS Ancillary Services
Reactive Supply and Voltage Control - 2003

SUMMARY

Plant	Reactive Power Costs	Revenue Require Percentage	Ancillary Services Revenue Require	Fuel Cost	Total Costs
LOS #1	76,912	41.6354%	32,022	26,542	58,565
LOS #2	508,961	41.6354%	211,908	38,834	250,742
AVS #1	2,276,207	41.6354%	947,707	42,733	990,440
AVS #2	308,181	41.6354%	128,312	44,222	172,534
Spirit Mound (Units 1 & 2)	152,618	41.6354%	63,543	287	63,830
LRS - BEPC*	1,707,974	29.3608%	501,475	53,774	36,645
LRS - HCPD	146,780	33.4396%	49,083	3,460	52,542
Reactive Supply and Voltage Control Requirement					**$ 1,625,298**

*Costs prorated on east side capacity entitlement to total LRS plant capacity.

Basin Electric Power Cooperative
IS Ancillary Services
Reactive Allocation Factor - 2003

Allocation Factor for Reactive Power Support Portion of Generator Capacity

Unit	A Reactive Rating (MVAR)	B Generator Rating (MVA) *	C Alloc Factor A^2/(D^2+A^2)
LOS #1	148.00	240.00	0.275508
LOS #2	223.00	487.00	0.173333
Total LOS	371.00	727.00	0.206615
AVS #1	231.00	490.00	0.181833
AVS #2	231.00	491.00	0.181228
Total AVS	462.00	981.00	0.181530
Spirit Mound #1	33.00	52.00	0.287108
Spirit Mound #2	33.00	44.00	0.360000
Total SM	66.00	96.00	0.320955
LRS Unit #1	300.00	593.00	0.203782
	1,199.00	**2,397.00**	**0.200134**

*URGE ratings from 2003 case

Basin Electric Power Cooperative
IS Ancillary Services
Reactive Supply And Voltage Control Allocation Factor - 2002

Allocation Factor for Reactive Power Support Portion of Exciter Capacity

Unit	A Rated Exciter Current A	B Maxium Current @Full Load (A)	C Minimum Current @ Full Load (A)	F Rated Voltage	Rated MW (a*f)/10^6
LOS #1	2,849	2,849	990	375	1.0684
LOS #2	5,425	5,425	1,885	430	2.3328
AVS #1	5,625	5,625	1,945	400	2.2500
AVS #2	5,625	5,625	1,945	400	2.2500
Spirit Mound #1					
Spirit Mound #2 (Avg)					2.0541
LRS Unit #1	4,692	4,692	3,000	505	2.3695
Total					**12.3247**

Basin Electric Power Cooperative
IS Ancillary Services
Generator Summary 2003

Generator Summary
Summer Peak Load
2003

Bus	Name	BSVLT	COD	MCNS	MW	MVAR	QMAX	QMIN
67103	ANTEL31	G24.0	2	1	480.0	74.2	200.0	-175.0
67107	ANTEL32	G24.0	2	1	480.0	74.2	200.0	-175.0
67110	LELAN41	G22.0	2	1	105.0	-23.6	120.0	-90.0
67111	LELAN32	G20.0	-2	1	373.0	-56.0	225.0	-56.0
67116	SPIRIT71	G13.8	-2	0	0.0	0.0	0.0	0.0
67117	SPIRIT72	G13.8	-2	0	0.0	0.0	0.0	0.0
67118	LARAM31	G24	2	1	593.5	103.9	310	-250
	TOTAL				**2031.5**	**331.9**	**1055.0**	**746.0**

Generator Summary
Winter Peak Load
2003

Bus	Name	BSVLT	COD	MCNS	MW	MVAR	QMAX	QMIN
67103	ANTEL31	G24.0	2	1	480.0	59.4	200.0	-175.0
67107	ANTEL32	G24.0	2	1	480.0	59.4	200.0	-175.0
67110	LELAN41	G22.0	2	1	0.0	-36.7	120.0	-90.0
67111	LELAN32	G20.0	-2	1	350.0	-56.0	225.0	-56.0
67116	SPIRIT71	G13.8	-2	0	0.0	0.0	0.0	0.0
67117	SPIRIT72	G13.8	-2	0	0.0	0.0	0.0	0.0
67118	LARAM31	G24	2	1	593.5	98.5	310	-250
	TOTAL				**1903.5**	**310.0**	**1055.0**	**746.0**

Basin Electric Power Cooperative
IS Ancillary Services
Reactive Power Costs - 2003

Real Power Allocation Ratio - Other Plant

$$\frac{\text{Exciter MW Requirements (worksheet 2)}}{\text{Generator MW Capacity (worksheet 1)}} \times \frac{\text{Generator MVAR @ Peak (worksheet 3)}}{\text{Generator MVAR Capability (worksheet 1)}} =$$

$$\frac{12.3247 \text{ MW}}{2{,}397.00 \text{ MW}} \times \frac{331.9 \text{ MVAR}}{1{,}199 \text{ MVAR}} =$$

0.1423%

Reactive Power Costs
Real Power Allocation Ratio - Fuel

$$\frac{\text{Exciter MW Requirements (worksheet 2)}}{\text{MWH generated}} \times \frac{\text{Generator MVAR @ Avg (worksheet 3)}}{\text{Generator MVAR Capability (worksheet 1)}} =$$

$$\frac{12.3247 \text{ MW}}{18{,}036{,}832 \text{ MWH}} \times \frac{320.95 \text{ MVAR}}{1{,}199 \text{ MVAR}} =$$

0.1602%

Basin Electric Power Cooperative
IS Ancillary Services
Reactive Power/Voltage Control

Ancillary
Worksheet 5

Generating Plant Costs
As of December 31, 2003
(Net Plant)

Line #	Description	LOS # 1	LOS #2	AVS #1	AVS #2	SM	LRS	Other	HCPD
1	Generating Plant (ACCT 310-348)	25,954,184	55,853,376	364,846,247	114,404,531	7,446,292	255,692,190	45,686,954	25,564,806
2	Substation Plant (Acct 353)	3,244,558	3,244,558	17,935,080	17,935,080	425,921	13,705,787	49,367,890	398,179
3	**Total Plant**	**$ 29,198,742**	**$ 59,097,933**	**$ 382,781,327**	**$ 132,339,611**	**$ 7,872,213**	**$ 269,397,977**	**$ 95,054,844**	**$ 25,962,985**
	Generators								
4	Total Plant	75,554	1,249,690	5,073,785	(leased)	436,530	3,038,610		326,066
5	Allocated to Reactive Power (WS1)	27.6575%	18.9758%	18.9971%	18.9971%	19.2906%	18.9218%		18.9218%
6	Reactive Power Plant (L4*L5)	**$ 20,896**	**$ 237,139**	**$ 963,873**	**$ -**	**$ 84,209**	**$ 574,961**		**$ 61,698**
	Exciters								
7	Total Plant	21,386	100,301	550,035	(leased)	82,388	603,732		61,029
8	Allocated to Reactive Power (WS2)	65.2510%	65.2535%	65.4222%	65.4222%	65.3372%	63.9386%		63.9386%
9	Reactive Power Plant (L7*L8)	**$ 13,955**	**$ 65,450**	**$ 359,845**	**$ -**	**$ 53,830**	**$ 386,018**		**$ 39,021**
	Voltage Regulators								
10	Total Plant	572	117,250	27,502	(leased)	4,119	91,158		9,782
11	Allocated to Reactive Power (100%)	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%		100.0000%
12	Reactive Power Plant (L10*L11)	**$ 572**	**$ 117,250**	**$ 27,502**	**$ -**	**$ 4,119**	**$ 91,158**		**$ 9,782**
	Step-Up Transformers								
13	Total Plant	1,129	481,521	2,625,184	819,879	-	1,995,718		76,797
14	Allocated to Reactive Power	6.2500%	1.6162%	14.9306%	14.7569%	33.3333%	14.0580%		14.0580%
15	Reactive Power Plant (L13*L14)	**71**	**7,782**	**391,955**	**120,989**	**-**	**280,557**		**10,796**
	Other Plant								
16	Total Plant (L3-L4-L7-L10-L13)	29,100,101	57,149,170	374,504,822	131,519,732	7,349,175	263,668,758		25,489,311
17	Allocated to Reactive Power (Wkst 4)	0.1423%	0.1423%	0.1423%	0.1423%	0.1423%	0.1423%		0.1423%
18	Reactive Power Plant (L12*L13)	**$ 41,418**	**$ 81,340**	**$ 533,033**	**$ 187,192**	**$ 10,460**	**$ 375,280**		**$ 36,279**
	Total Reactive Power Plant								
19	(L5+L8+L11+L14)	**$ 76,912**	**$ 508,961**	**$ 2,276,207**	**$ 308,181**	**$ 152,618**	**$ 1,707,974**		**$ 146,780**
	Fuel Expense								
20	Total	16,565,433	24,236,576	26,670,239	27,599,220	179,196	33,561,043		2,159,156
21	Allocated to Reactive Power (wkst 4)	0.1602%	0.1602%	0.1602%	0.1602%	0.1602%	0.1602%		0.1602%
22	Reactive Power Expense (L16*L17)	**$ 26,542**	**$ 38,834**	**$ 42,733**	**$ 44,222**	**$ 287**	**$ 53,774**		**$ 3,460**

Basin Electric Power Cooperative
IS Ancillary Services
Regulation and Frequency Response - 2003

Summary

A	Total LOS and AVS Net Plant Investment	$ 603,417,613	(ancillary worksheet 5)
B	Facilities with AGC (LOS 1 & AVS)	$ 544,319,679	(Ancillary worksheet 5 less LOS 2)
C	B/A	90.2061%	
D	AGC Facilities	$ 66,104	
E	AGC Facilities Percentage (D/B)	0.0121%	
F	Generation Revenue Requirement	$ 216,399,812	(Generation revenue require * line C percent)
G	Plant Allocated to AGC	$ 26,280	(E x F)
H	**Regulation Revenue Requirement**	**$ 92,384**	(D + G)

Heartland's Transmission Cost Data

HEARTLAND CONSUMERS POWER DISTRICT
INTEGRATED SYSTEM TARIFF - EAST SIDE
December 31, 2003

24-Feb-04

Line	Description		Cost of Service Amount	
1.	Transmission Plant Investment **		$1,659,146.53	Page 5, Line L62,L64,L65
2.	Less Accumulated Depreciation & IDC **		($523,761.81)	Page 5, Lines M62,64,65,N62,64,65
3.	General Plant - Trans Share		$104,754.45	Page 5, Line L76
4.	Less Accum Depre & IDC-GP-Trans		($62,796.04)	Page 5, Lines M76,N76
5.	Materials & Supplies - Trans		$0.00	Page 3
6.	Cash Working Capital		$2,834.99	1/12 of Line 16 + 17 (this page)
7.	**Transmission Investment Rate Base**		**$1,180,178.12**	
8.				
9.	Rate of Return *	7.06%	$83,320.58	Line 7 x Line 9 rate (this page)
10.	Transmission Depr Expense **		$32,594.12	Page 5, Line P62,P64,P65
11.	GP Depr Expense - Trans Share		$3,568.45	Page 5, Line P76
12.	GP Maintenance		$3,185.15	Page 2, Line C46
13.	Income Tax		$197.27	Page 2, Line C52
14.	Taxes Other than Income		$18,059.91	Page 2, Lines C56,C58,C60,C61
15.	A & G Expenses		$151,264.13	Page 2, Line C67
16.	Transmission O & M		$34,019.85	Page 2, Line C73,C74
17.	Less:Trans of Elect by Others		$0.00	Page 3
18.	**Subtotal Transmission Revenue Requirement**		**$326,209.46**	
19.				
20.	Annual Trans Third Party Payment		$0.00	
21.	Annual Trans Third Party Revenue		$20,736.34	Revenues from MAPP Schedule F
22.				
23.	**Total Transmission Revenue Requirement**		**$305,473.12**	

* Weighted Cost of Capital
** Doesn't Include HCPD's TP-II Investment

HEARTLAND CONSUMERS POWER DISTRICT
INTEGRATED SYSTEM TARIFF - WEST SIDE
December 31, 2003

24-Feb-04

Line	Description		Cost of Service Amount	
1.	Transmission Plant Investment		$0.00	Page 7, Line T58,T60,T61
2.	Less Accumulated Depreciation & IDC		$0.00	Page 7, Lines U58,60,61,V58,60,61
3.	General Plant - Trans Share		$0.00	Page 7, Line T72
4.	Less Accum Depre & IDC-GP-Trans		$0.00	Page 7, Lines U72,V72
5.	Materials & Supplies - Trans		$0.00	Page 3
6.	Cash Working Capital		$0.00	1/12 of Line 16 + 17 (this page)
7.	**Transmission Investment Rate Base**		**$0.00**	
8.				
9.	Rate of Return *	7.06%	$0.00	Line 7 x Line 9 rate (this page)
10.	Transmission Depr Expense		$0.00	Page 7, Line X58,X60,X61
11.	GP Depr Expense - Trans Share		$0.00	Page 7, Line X72
12.	GP Maintenance		$0.00	Page 2, Line F46
13.	Income Tax		$0.00	Page 2, Line F52
14.	Taxes Other than Income		$0.00	Page 2, Lines F56,F58,F60,F61
15.	A & G Expenses		$0.00	Page 2, Line F67
16.	Transmission O & M		$0.00	Page 2, Line F73,F74
17.	Less:Trans of Elect by Others		$0.00	Page 3
18.	**Subtotal Transmission Revenue Requirement**		**$0.00**	
19.				
20.	Annual Trans Third Party Payment		$0.00	
21.	Annual Trans Third Party Revenue		$0.00	
22.				
23.	**Total Transmission Revenue Requirement**		**$0.00**	

* Weighted Cost of Capital

HCPD TRANSMISSION & GENERAL PLANT (EAST SIDE & WEST SIDE)

December 31, 2003

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24-Feb-04

	HCPD Invest	East Side	Depr	IDC	West Side	Depr	IDC
LRS	$49,168,404.13	$3,354,274.00	28.37%	28.26%	$3,954,269.57	100.00%	100.00%
TP-I	$871,635.18	$871,635.18	7.37%	7.34%		0.00%	0.00%
TP-II	$6,752,305.09	$6,752,305.09	57.11%	56.88%		0.00%	0.00%
TP-II Marshall	$402,535.87	$402,535.87	3.40%	3.39%		0.00%	0.00%
TP-III Groton	$384,975.48	$384,975.48	3.26%	3.24%		0.00%	0.00%
	------------------------	------------------------			------------------------		
	$57,579,855.75	$11,765,725.62			$3,954,269.57		
		9.86%			***7.62%***		
General Plant Improvement	$592,725.31	$58,463.99	0.49%	0.49%	$0.00	0.00%	0.00%
Furniture & Equipment	$128,606.49	$12,685.22		0.11%	$0.00		0.00%
Furniture & Equipment-EPD	$246,442.94	$24,308.12		0.20%	$0.00		0.00%
Transportation Equipment	$39,280.26	$3,874.44		0.03%	$0.00		0.00%
Headquarter's Improvement	$54,976.84	$5,422.69		0.05%	$0.00		0.00%
	------------------------	------------------------			------------------------		
	$58,641,887.59	$11,870,480.08	100.00%	100.00%	$3,954,269.57	100.00%	100.00%

	Depreciation	East Side	West Side
Accum Depr-Plant	$23,871,008.59	$2,354,538.10	$1,819,101.22
Accum Depr-Gen'l Plant	$382,907.83	$37,768.45	$0.00
Accum Depr-Trans Equip	$11,925.85	$1,176.32	$0.00
	------------------------	------------------------	------------------------
	$24,265,842.27	$2,393,482.87	$1,819,101.22

	Int During Const	East Side	West Side
1977 IDC	$29,680,964.00		
1979 IDC	$28,763,565.00		
Times 24%	$14,026,687.00	$1,383,534.71	$1,068,910.15

	Annual Depr	East Side	West Side
Depr Exp-Plant	$2,355,000.00	$232,287.51	$179,463.86
Depr Exp-Gen'l Plant	$15,485.28	$1,527.40	$0.00
Depr Exp-Trans Equip	$9,048.53	$892.51	$0.00
	------------------------	------------------------	------------------------
	$2,379,533.81	$234,707.43	$179,463.86

A	A	B	C	D	E	F
42	**HCPD TRANSMISSION & GENERAL PLANT (EAST SIDE & WEST SIDE)**					
43	**December 31, 2003**					
44	**Page 2 of 7**					
45		**GP Maint**	**East Side**			**West Side**
46	HCPD	$32,292.05	$3,185.15			$0.00
47	LRS	$0.00	$0.00			$0.00
48		-------------------------	-----------------------------			-------------------------
49		$32,292.05	$3,185.15			$0.00
50						
51		**Income Tax**	**East Side**			**West Side**
52		$2,000.00	$197.27			$0.00
53						
54		**Tax Other Than**	**East Side**			**West Side**
55		**Income**				
56	HCPD Payroll	$41,973.89	$4,140.13			$0.00
57	LRS Payroll	$0.00	$0.00			$0.00
58	Headquarter's	$13,787.91	$1,359.98			$0.00
59	LRS (HCPD)	$186,768.14	$18,422.04			$14,232.75
60	TP-I	$8,342.28	$8,342.28			$0.00
61	TP-III	$4,217.52	$4,217.52			$0.00
62	TP-II	$80,371.65	$0.00			$0.00
63		-------------------------	-----------------------------			-------------------------
64		$335,461.39	$36,481.96			$14,232.75
65						
66		**A&G Expenses**	**East Side**			**West Side**
67	HCPD	$1,533,560.77	$151,264.13			$0.00
68	LRS-Trans	$133,421.32	$100,065.99			$33,355.33
69		-------------------------	-----------------------------			-------------------------
70		$1,666,982.09	$251,330.12			$33,355.33
71						
72		**Transm O&M**	**East Side**			**West Side**
73	TP-I	$29,539.30	$29,539.30			$0.00
74	TP-III Groton	$4,480.55	$4,480.55			$0.00
75	LRS-Trans	$115,934.06	$86,950.55			$28,983.52
76		-------------------------	-----------------------------			-------------------------
77		$149,953.91	$120,970.40			$28,983.52
78	*** Not Included in Transm O&M and Trsm by Others:*					
79	*Network Transm Service Charge*	*$1,372,259.61*				
80	*Ancillary Services*	*$33,604.12*				
81						
82						

HCPD TRANSMISSION & GENERAL PLANT (EAST SIDE & WEST SIDE)

December 31, 2003

A	B	C	D	E	F
	Trsm by Others	**East Side**			**West Side**
LRS-Trans	($49,654.08)	($37,240.56)			($12,413.52)
	-------------------------	-----------------------------			------------------------
	($49,654.08)	($37,240.56)			($12,413.52)

A	B	C	D	E	F
	Material & Supplies	**East Side**			**West Side**
REA Acct 163 Balance Sheet Items	$0.00	$0.00			$0.00

A	B	C	D	E	F
Rate of Return					
2003 Liability	$53,938,293.73	90.35%	6.42%		5.80%
2003 Equity	$5,763,467.49	9.65%	13.00%		1.25%
	----------------------				------------------------
	$59,701,761.22				**7.06%**

Equity @ 13% based on risk from:
- Contractual commitment
- Magnitude of surplus power
- Competition
- Basin at 12%
- Phone Conversations with Auditors

HCPD TRANSMISSION & GENERAL PLANT (EAST SIDE) 24-Feb-04

December 31, 2003

CPX	Description	Investment	Accum Depr	Accum IDC	Net Book	Annual Depr
	LINES					
049	345 kV Line from LRS to NB Border (50%)	$170,416.26				
050	345 kV Line NB Border to Stegall Sub (50%)	$14,968.31				
051	345 Line From LRS to NB Border	$137,815.17				
052	345 kV Line From NB Border to Sidney Sub	$213,292.60				
053	345 kV Line from Stegall Sub to Sidney Sub	$286,411.91				
074	345 kV Line From LRS to CO Border (.10457)	$112,442.49				
077	LRS PlantSite Lines (.42786)	$31,082.68				
091	Nebraska Tax	$11,492.90				
101	230 kV Line From Sidney Sub to WAPA Sub	$28,871.31				
103	230 kV Line Stegall Sub to Stegall/WAPA	$18,007.22				
	Subtotal Lines	***$1,024,800.85***				
	SUBSTATIONS					
048	345 kV LRS Substation (.42786)	$148,437.79				
078	345/230 kV Stegall Substation	$177,680.30				
079	345/230 kV Sidney Substation	$241,094.55				
084	230 kV Stegall-WAPA Sub Addition	$35,271.55				
054	230/345 kV Trsn Facilities-NPPD (Intang Plant)	$1,633,730.01				
100	230/115 kV Sidney Substation Addition	$17,550.88				
116	LRS #1 Main Transformer (.87766)	$95,876.46				
	Subtotal Substations	***$2,201,203.75***				
	MICROWAVE COMMUNICATIONS					
131	Microwave-Wyoming (50%)	$39,510.82				
133	Microwave-Nebraska	$43,210.74				
135	Microwave-North Dakota	$340.92				
138	Microwave-South Dakota	$3,124.90				
		$86,187.38				
	Less Microwave Non-Transmission (70%)	$60,331.17				
	Subtotal Microwave Communications	***$25,856.21***				

HCPD TRANSMISSION & GENERAL PLANT (EAST SIDE)
December 31, 2003

J	K	L	M	N	O	P
CPX	**Description**	**Investment**	**Accum Depr**	**Accum IDC**	**Net Book**	**Annual Depr**
	MAINTENANCE BUILDINGS					
107	Maintenance Building-Stegall	$71,874.49				
108	Maintenance Building-LRS (50%)	$30,538.70				

	Subtotal Maintenance Buildings	***$102,413.19***				
	Total LRS Transmission-East Side	***$3,226,004.60***	$642,390.81	$375,999.06	$2,207,614.73	$63,375.22
	Total LRS General Plant-East Side	***$128,269.40***	$25,542.15	$14,950.13	$87,777.13	$2,519.87
		----------------------------	----------------------	----------------------	----------------------	----------------------
	Total LRS-East Side	***$3,354,274.00***	***$667,932.96***	***$390,949.19***	***$2,295,391.86***	***$65,895.08***
	HEARTLAND TRANSMISSION					
	TP-I Irv Simmons	$871,635.18	$173,567.77	$101,591.30	$596,476.11	$17,123.37
	TP-II	$6,752,305.09	$1,344,579.22	$786,998.37	$4,620,727.50	$132,649.78
	TP-II Marshall	$402,535.87	$80,156.53	$46,916.58	$275,462.76	$7,907.86
	TP-III Groton Sub	$384,975.48	$76,659.75	$44,869.87	$263,445.86	$7,562.89
		----------------------------	----------------------	----------------------	----------------------	----------------------
	Total HCPD Transmission-East Side	***$8,411,451.62***	***$1,674,963.27***	***$980,376.13***	***$5,756,112.22***	***$165,243.90***
	HEARTLAND GENERAL PLANT					
	General Plant Improvement	$58,463.99	$11,641.87	$6,814.13		$1,148.53
	Furniture & Equipment	$12,685.22	$37,768.45	$1,478.49		$1,527.40
	Furniture & Equipment-EPD	$24,308.12		$2,833.17		
	Transportation Equipment	$3,874.44	$1,176.32	$451.58		$892.51
	Headquarter's Improvement	$5,422.69		$632.03		
		----------------------------	----------------------	----------------------	----------------------	----------------------
	Total HCPD General Plant-East Side	***$104,754.45***	***$50,586.64***	***$12,209.40***	***$41,958.41***	***$3,568.45***
	TOTAL EAST SIDE TRANSMISSION & GENERAL PLANT	***$11,870,480.08***	***$2,393,482.87***	***$1,383,534.71***	***$8,093,462.49***	***$234,707.43***
		===============	============	=============	=============	===========

A	R	S	T	U	V	W	X
1		**HCPD TRANSMISSION & GENERAL PLANT (WEST SIDE)**		24-Feb-04			
2		**December 31, 2003**					
3		**Page 6 of 7**					
4							
5	**CPX**	**Description**	**Investment**	**Accum**	**Accum**	**Net**	**Annual**
6				**Depr**	**IDC**	**Book**	**Depr**
7		**LINES**					
8	049	345 kV Line from LRS -Stegall (50%)	$170,416.26				
9	050	345 kV Line from LRS-Stegall Sub (50%)	$14,968.31				
10	073	230 kV Line From LRS to D Johnston	$163,808.79				
11	074	345 kV Line From LRS-Story (.104569)	$962,841.92				
12	075	345 kV Line from CO Border to Story Sub	$969,899.69				
13	077	LRS PlantSite Lines (.57214)	$41,564.16				
14	102	230 kV Stegall Tie Line	$20,461.61				
15	104	345 kV Line- to CO Border	$552,803.72				
16	105	345 kV Line -CO Border to Ault	$176,226.00				
17	106	230 kV Sidney Tie Line	$15,568.45				
18			------------------------				
19		***Subtotal Lines***	***$3,088,558.91***				
20							
21		**SUBSTATIONS**					
22	045	230 kV LRS Switch Station (4 Terminals)	$132,912.22				
23	048	345 kV LRS Substation (5 of 8 Trmls)(.57214)	$198,492.97				
24	076	230 kV D Johnston Substation	$22,510.81				
25	085	345 kV Ault Substation	$140,895.26				
26	086	230 kV Story Substation	$24,621.21				
27	116	LRS #1 Main Transformer (.12234)	$13,364.54				
28	117	LRS #2 Main Transformer	$54,608.46				
29	118	LRS #3 Main Transformer	$61,728.02				
30	190	345 kV Story Substation	$167,567.99				
31			------------------------				
32		***Subtotal Substations***	***$816,701.48***				
33							
34		**MICROWAVE COMMUNICATIONS**					
35	131	Microwave-Wyoming (50%)	$39,510.83				
36	132	Microwave-Colorado	$22,057.48				
37			------------------------				
38			$61,568.31				
39		Less Microwave Non-Transmission (70%)	$43,097.82				
40			--------------------				
41		***Subtotal Microwave Communications***	***$18,470.49***				

A	R	S	T	U	V	W	X
42		**HCPD TRANSMISSION & GENERAL PLANT (WEST SIDE)**					
43		**December 31, 2003**					
44		**Page 7 of 7**					
45	**CPX**	**Description**	**Investment**	**Accum**	**Accum**	**Net**	**Annual**
46				**Depr**	**IDC**	**Book**	**Depr**
47		**MAINTENANCE BUILDINGS**					
48	108	Maintenance Building-LRS (50%)	$30,538.69				
49			------------------------				
50		***Subtotal Maintenance Buildings***	***$30,538.69***				
51							
52		***Total LRS Transmission-West Side***	***$3,905,260.39***	$1,796,555.30	$1,055,662.09	$1,053,043.00	$177,239.59
53		***Total LRS General Plant-West Side***	***$49,009.18***	$22,545.92	$13,248.06	$13,215.20	$2,224.27
54			------------------------	------------------------	------------------------	------------------------	------------------------
55		***Total LRS-West Side***	***$3,954,269.57***	***$1,819,101.22***	***$1,068,910.15***	***$1,066,258.20***	***$179,463.86***
56							
57		**HEARTLAND TRANSMISSION**					
58		TP-I Irv Simmons	$0.00	$0.00	$0.00	$0.00	$0.00
59		TP-II	$0.00	$0.00	$0.00	$0.00	$0.00
60		TP-II Marshall	$0.00	$0.00	$0.00	$0.00	$0.00
61		TP-III Groton Sub	$0.00	$0.00	$0.00	$0.00	$0.00
62			------------------------	------------------------	------------------------	------------------------	------------------------
63		***Total HCPD Transmission-West Side***	***$0.00***	***$0.00***	***$0.00***	***$0.00***	***$0.00***
64							
65		**HEARTLAND GENERAL PLANT**					
66		General Plant Improvement	$0.00	$0.00	$0.00		$0.00
67		Furniture & Equipment	$0.00	$0.00	$0.00		$0.00
68		Furniture & Equipment-EPD	$0.00		$0.00		
69		Transportation Equipment	$0.00	$0.00	$0.00		$0.00
70		Headquarter's Improvement	$0.00		$0.00		
71			------------------------	------------------------	------------------------	------------------------	------------------------
72		***Total HCPD General Plant-West Side***	***$0.00***	***$0.00***	***$0.00***	***$0.00***	***$0.00***
73							
74		***TOTAL WEST SIDE TRANSMISSION***					
75		***& GENERAL PLANT***	***$3,954,269.57***	***$1,819,101.22***	***$1,068,910.15***	***$1,066,258.20***	***$179,463.86***
76			============	============	============	============	==========

Transmission Customer Facility Credits

Western Minnesota Municipal Power Agency
Summary of Irv Simmons Transmission Revenue Requirement

12/31/2003						12/31/2003
				Power Acc. Depr		$ 110,631,716
	Rate	Revenue	Power Supply Plant			$ 237,533,664
Description	Amount	Base	Requirement	Accumulated Depr %		46.6%
Transmission Plant		$ 1,957,786				
Accumulated Depreciation		$ 911,842		Remaining Depr %	53.42%	
Net Transmission Plant		$ 1,045,944			53.42%	
Working Capital		$ 7,090				
Rate Base	$ 1,053,034					
Cost of Capital		5.61%	$ 59,047			
Transmission Depr Expense		$ 1,957,786	4.42%	$86,460		
A&G Expenses		$ 2,568				
Taxes		$ 11,439				
Insurance		$ 24,291				
Transmission O&M		$ 18,424				
Less MAPP Transmission Revenue			$	(1,429)		
Irv Simmons Revenue Requirement			$	200,800		

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/02

Jtilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT. joint Plant Transmission Faciliti

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT	(page 3, line 29)				$ 2,564,522
	REVENUE CREDITS	(Note T)				
2	Account No. 454	(page 4, line 34)	0	TP	0.77513	0
3	Account No. 456	(page 4, line 37)	364,940	TP	0.77513	282,875
4	Revenues from Grandfathered Interzonal Transactions		0	TP	0.77513	0
5	Revenues from service provided by the ISO at a discount		0	TP	0.77513	0
6	TOTAL REVENUE CREDITS (sum lines 2-5)					282,875
7	NET REVENUE REQUIREMENT (line 1 minus line 6)					$ 2,281,647
						$0.2600
	DIVISOR					
8	Average of 12 coincident system peaks for requirements (RQ) service			(Note A)		215,417
9	Plus 12 CP of firm bundled sales over one year not in line 8			(Note B)		13,200
10	Plus 12 CP of Network Load not in line 8			(Note C)		0
11	Less 12 CP of firm P-T-P over one year (enter negative)			(Note D)		0
12	Plus Contract Demand of firm P-T-P over one year					0
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)					0
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)					0
15	Divisor (sum lines 8-14)					228,617
16	Annual Cost ($/kW/Yr)	(line 7 / line 15)	9.980			
17	Network & P-to-P Rate ($/kW/Mo	(line 16 / 12)	0.832			

Line No.			Peak Rate		Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	0.192		$0.192
19	Point-To-Point Rate ($/kW/Day)	(line 18 / 5; line 18 / 7)	0.038	Capped at weekly rate	$0.027
20	Point-To-Point Rate ($/MWh)	(line 19 / 16; line 19 / 24 times 1,000)	2.399	Capped at weekly and daily rates	$1.142
21	FERC Annual Charge($/MWh)	(Note E)	$0.000	Short Term	$0.000 Short Term
22			$0.000	Long Term	$0.000 Long Term

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/02

Jtilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT. joint Plant Transmission Faciliti

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
1	Production	206.42.g	140,223,226	NA		
2	Transmission	206.53.g	29,827,890	TP	0.77513	23,120,419
3	Distribution	206.69.g	161,885,283	NA		
4	General & Intangible	206.5.g & 83.g	8,138,386	W/S	0.06543	532,515
5	Common	356.1	35,607,387	CE	0.04011	1,428,356
6	TOTAL GROSS PLANT (sum lines 1-5)		375,682,172	GP=	6.676%	25,081,289
	ACCUMULATED DEPRECIATION					
7	Production	219.18-22.c	93,252,152	NA		
8	Transmission	219.23.c	19,216,405	VEst.	74.641%	14,343,311
9	Distribution	219.24.c	51,792,611	NA		
10	General & Intangible	219.25.c	2,385,907	W/S	0.06543	156,116
11	Common	356.1	7,921,319	CE	0.04011	317,756
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		174,568,394			14,817,183
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	46,971,074			
14	Transmission	(line 2- line 8)	10,611,485			8,777,107
15	Distribution	(line 3 - line 9)	110,092,672			
16	General & Intangible	(line 4 - line 10)	5,752,479			376,399
17	Common	(line 5 - line 11)	27,686,068			1,110,600
18	TOTAL NET PLANT (sum lines 13-17)		201,113,778	NP=	5.104%	10,264,106
	ADJUSTMENTS TO RATE BASE (Note F)					
19	Account No. 281 (enter negative	273.8.k	0	NA	zero	0
20	Account No. 282 (enter negative	275.2.k	-51,552,746	VEst.	0.06446	-2,586,989
21	Account No. 283 (enter negative	277.9.k	0	NP	0.05104	0
22	Account No. 190	234.8.c	0	NP	0.05104	0
23	Account No. 255 (enter negative	267.8.h	-5,631,935	VEst.	0.06446	-193,216
24	TOTAL ADJUSTMENTS (sum lines 19- 23)		-57,184,681			-2,780,205
25	LAND HELD FOR FUTURE USE	214.x.d (Note G)	0	VEst.	0.74641	0
	WORKING CAPITAL (Note H)					
26	CWC	calculated	1,128,524			93,881
27	Materials & Supplies (Note G)	227.6.c & .15.c	1,619		1.00000	1,619
28	Prepayments (Account 165)	111.46.d	2,908,102	GP	0.06676	194,151
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		4,038,246			289,651
30	RATE BASE (sum lines 18, 24, 25, & 29)		147,967,343			7,773,553

Accumulated Depreciation of Joint Pl
Transmission Facilities
-4,873,093

Amount related to Exclusions

	Accumulated Deferred Income Taxes
736,101	Accumulated Deferred Income Taxes
	Accumulated Deferred Income Taxes
	Accumulated Deferred Income Taxes
169,818	Accumulated Deferred Investment Ta

Excluded transmission maintained and supplied by others

Formula Rate - Non-Levelized | Rate Formula Template | For the 12 months ended 12/31/02

Utilizing FERC Form 1 Data

Jtilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT. joint Plant Transmission Faciliti

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)		
	O&M							
1	Transmission	321.100.b	3,842,752	TE	0.77513	3,723,773		Reduce non-565 by TE Ratio
2	Less Account 565	321.88.b	3,313,656		1.00000	3,313,656		
3	A&G	323.168.b	8,737,814	W/S	0.04011	350,509		
4	Less FERC Annual Fees		0	W/S	0.04011	0		
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note		238,715	W/S	0.04011	9,576		
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.77513	0		
6	Common	356.1	0	CE	0.04011	0		
7	Transmission Lease Payments		0		1.00000	0		
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)		9,028,195			751,050		
	DEPRECIATION EXPENSE						Excluded	
9	Transmission	336.7.b	900,067	VRB0(	0.74641	699,500	200,567	
10	General	336.9.b	104,453	W/S	0.04011	4,190		
11	Common	336.10.b	873,825	CE	0.04011	35,053		
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		1,878,345			738,743		
	TAXES OTHER THAN INCOME TAXES (Note J)							
	LABOR RELATED							
13	Payroll	262.i	12,736	W/S	0.04011	511		
14	Highway and vehicle	262.i	0	W/S	0.04011	0		
15	PLANT RELATED							
16	Property	262.i	6,666,480	GP	0.06676	445,067		
17	Gross Receipts	262.i	0	NA	zero	0		
18	Other	262.i	38,485	GP	0.06676	2,569		
19	Payments in lieu of taxes		0	GP	0.06676	0		
20	TOTAL OTHER TAXES (sum lines 13 - 19)		6,717,701			448,148		
	INCOME TAXES	(Note K)						
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		35.00%					
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		12.07%					
	where WCLTD=(page 4, line 27) and R= (page 4, line30) and FIT, SIT & p are as given in footnote K.							
23	1 / (1 - T) = (from line 21)		1.5385					
24	Amortized Investment Tax Credit (266.8f) (enter negative)		-513,600					
25	Income Tax Calculation = line 22 * line 28		1,324,360	NA		69,576		
26	ITC adjustment (line 23 * line 24)		-790,154	NP	0.05104	-19,212	From detail on VRBase00t w/ exclusions	
27	Total Income Taxes	(line 25 plus line 26)	534,207			50,364		
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		10,968,127	NA		576,217		
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		29,126,575			2,564,522		

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/02

Jtilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT. joint Plant Transmission Faciliti

SUPPORTING CALCULATIONS AND NOTES

Line No.	TRANSMISSION PLANT INCLUDED IN ISO RATES			
1	Total transmission plant (page 2, line 2, column 3)		29,827,890	Transmission Plant Grandfathered wi Joint Plants from VRB00t
2	Less transmission plant excluded from ISO rates (Note M)		6,707,471	6,707,471
3	Less transmission plant included in OATT Ancillary Services (Note N)		0	
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)		23,120,419	
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)	TP=	0.77513	
	TRANSMISSION EXPENSES			
6	Total transmission expenses (page 3, line 1, column 3)		3,842,752	
7	Less transmission expenses included in OATT Ancillary Services (Note L)		0	
8	Included transmission expenses (line 6 less line 7)		3,842,752	
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)		1.00000	
10	Percentage of transmission plant included in ISO Rates (line 5)	TP	0.77513	
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)	TE=	0.77513	

WAGES & SALARY ALLOCATOR (W&S)

Line		Form 1 Reference	$	TP	Allocation				
12	Production	354.18.b	382,336	0.00	0				
13	Transmission	354.19.b	216,556	0.78	167,859				
14	Distribution	354.20.b	2,202,437	0.00	0		W&S Allocator		
15	Other	354.21,22,23.b	508,279	0.00	0		($ / Allocation)		
16	Total (sum lines 12-15)		3,309,608		167,859	=	0.05072	= WS	Wages & salaries by others for excluded facilities MEC, OTP, MDU
							0.06543	= Wsact	

COMMON PLANT ALLOCATOR (CE) (Note O)

Line			$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	340,074,785					
18	Gas	200.3.d	89,901,937	0.79091	*	0.05072	=	0.04011
19	Water	200.3.e	0					
20	Total (sum lines 17 - 19)		429,976,722					

RETURN (R)

Line		$
21	Long Term Interest (117, sum of 56c through 60c)	$103,711,649
22	Preferred Dividends (118.29c) (positive number)	$ -

	Development of Common Stock:				
23	Proprietary Capital (112.14d)				-455,982,860
24	Less Preferred Stock (line 28)				0
25	Less Account 216.1 (112.12d) (enter negative)				728,521,607
26	Common Stock (sum lines 23-25)				272,538,747

		$	%	Cost (Note P)	Weighted	
27	Long Term Debt (112, sum of 16d through 19d)	1,531,040,784	85%	0.0677	0.0575	=WCLTD
28	Preferred Stock (112.3d)	0	0%	0.0000	0.0000	
29	Common Stock (line 26)	272,538,747	15%	0.1100	0.0166	
30	Total (sum lines 27-29)	1,803,579,531			0.0741	=R

REVENUE CREDITS

				Load
	ACCOUNT 447 (SALES FOR RESALE)	(310-311)	(Note Q)	
31	a. Bundled Non-RQ Sales for Resale (311.x.h)			197,175
32	b. Bundled Sales for Resale included in Divisor on page 1			197,175
33	Total of (a)-(b)			0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			$0
	ACCOUNT 456 (OTHER ELECTRIC REVENUES)	(330.x.n)		
35	a. Transmission charges for all transmission transactions			$462,006
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1			$97,066
37	Total of (a)-(b)			$364,940

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/02

Jtilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT. joint Plant Transmission Faciliti

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter

A Peak as would be reported on page 401, column d of Form 1 at the time of the ISO coincident monthly peaks.

B Labeled LF, LU, IF, IU on pages 310-311 of Form 1at the time of the ISO coincident monthly peaks.

C Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.

D Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.

E The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.

F The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.

G Identified in Form 1 as being only transmission related.

H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 100-111 line 46 in the Form 1.

I Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.

J Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.

K The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

Inputs Required:			
	FIT =	35.00%	
	SIT=	0.00%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.

M Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts

P Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.

Q Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the divisor.

R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.

T The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

APPENDIX B

PROPOSED SCHEDULE

- Informal Customer Meetings took place March 22, 2005
- Public Process
  - FRN for Proposed Rate Adjustment published April 18, 2005.
  - 30 day comment period began April 18, 2005, and ends May 18, 2005
  - Publication of Interim Rate August 2005
  - Implement Interim Rate October 1, 2005

APPENDIX C
PROJECT DESCRIPTION

The Pick-Sloan Missouri Basin Program (P-SMBP) was authorized by Congress in Section 9 of the Flood Control Act of December 22, 1944, commonly referred to as the Flood Control Act of 1944. The multipurpose program provides flood control, irrigation, navigation, recreation, preservation and enhancement of fish and wildlife and power generation. Multipurpose projects have been developed on the Missouri River and its tributaries in Colorado, Montana, Nebraska, North Dakota, South Dakota and Wyoming.

In addition to the multipurpose water projects authorized by Section 9 of the Flood Control Act of 1944, certain other existing projects have been integrated with the P-SMBP for power marketing, operation and repayment purposes. The Colorado-Big Thompson, Kendrick, and Shoshone Projects were combined with the P-SMBP in 1954, followed by the North Platte Project in 1959. These projects are referred to as the "Integrated Projects" of P-SMBP.

The Flood Control act of 1944 also authorized the inclusion of the Fort Peck Project with the P-SMBP for operation and repayment purposes. The Riverton Project was integrated with the P-SMBP in 1954, and in 1970 was reauthorized as a unit of P-SMBP.

The P-SMBP is administered by two regions. The Upper Great Plains Region with a regional office in Billings, Montana, markets the Eastern Division of P-SMBP and the Rocky Mountain Region with a regional office in Loveland, Colorado, markets the Western Division of P-SMBP. The Upper Great Plains Region markets power in western Iowa, Montana east of the Continental Divide, North Dakota, South Dakota, and the eastern two-thirds of Nebraska. The Rocky Mountain Region markets P-SMBP power in northeastern Colorado, east of the Continental Divide in Wyoming, west of the 101st meridian in Nebraska and northern Kansas. The P-SMBP power is marketed to approximately 300 firm power customers by the Upper Great Plains Region and approximately 40 firm power customers by the Rocky Mountain Region.

APPENDIX D

PROPOSED RATE ADJUSTMENT FEDERAL REGISTER NOTICE

Comment Date: 5 p.m. eastern time on April 25, 2005.

12. Puget Sound Energy, Inc.

[Docket No. ER05–778–000]

Take notice that on April 4, 2005, Puget Sound Energy, Inc. (PSE) tendered for filing a Non-Standard Provisions Agreement under the Western System Power Pool Agreement between PSE and Calpine Energy Management, L.P. (CEM). PSE requests an effective date of June 6, 2005.

PSE states that the filing was served on CEM.

Comment Date: 5 p.m. eastern time on April 25, 2005.

13. UAE Mecklenburg Cogeneration LP

[Docket No. ER05–779–000]

Take notice that on April 4, 2005, Virginia Electric and Power Company tender for filing a Notice of Cancellation of the market-based rate tariff of UAE Mecklenburg Cogeneration LP. Virginia Electric and Power Company requests an effective date of August 19, 2004.

Comment Date: 5 p.m. eastern time on April 25, 2005.

14. James H. Hance, Jr.

[Docket No. ID–4237–000]

Take notice that on April 4, 2005, James H. Hance, Jr., filed an application for authorization under section 305(b) of the Federal Power Act to hold interlocking positions in Duke Energy Corporation and Sprint Corporation.

Comment Date: 5 p.m. eastern time on April 25, 2005.

Standard Paragraph

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). 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 notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed on or before the comment date. Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant and all parties to this proceeding.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the ''eFiling'' link at *http://www.ferc.gov.* Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

This filing is accessible on-line at *http://www.ferc.gov,* using the ''eLibrary'' link and is available for review in the Commission's Public Reference Room in Washington, DC. There is an ''eSubscription'' link on the Web site that enables subscribers to receive e-mail notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please e-mail *FERCOnlineSupport@ferc.gov,* or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Linda Mitry,

Deputy Secretary.

[FR Doc. E5–1806 Filed 4–15–05; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Western Area Power Administration

Pick-Sloan Missouri Basin Program—Eastern Division—Notice of Proposed Transmission and Ancillary Services Rates—Rate Order No. WAPA–122

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of Proposed Transmission and Ancillary Services Rates.

SUMMARY: The Western Area Power Administration (Western) is proposing a minor transmission and ancillary services rate adjustment for the Pick-Sloan Missouri Basin Program—Eastern Division (P–SMBP—ED). The P–SMBP—ED transmission and ancillary service rate schedules will expire on September 30, 2005. The proposed rates will provide sufficient revenue to pay all annual costs, including interest expense, and repayment of required investment within the allowable periods. Western will prepare a brochure providing detailed information on the rates to all interested parties. Western intends to conduct the public participation according to the minor rate adjustment process as defined in the Department of Energy's (DOE) Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions. Western expects the proposed rates to go into effect October 1, 2005, and remain in effect through September 30, 2010. Publication of this **Federal Register** notice begins the formal process for the proposed rates.

DATES: The consultation and comment period begins today and will end May 18, 2005. Western will accept written comments anytime during the consultation and comment period.

ADDRESSES: Send written comments to Robert J. Harris, Regional Manager, Upper Great Plains Region, Western Area Power Administration, 2900 4th Avenue North, Billings, MT 59101–1266, or e-mail at *UGP_ISRate@wapa.gov.* Western will post information about the rate process on its Web site at *http://www.wapa.gov/ugp/rates/2005ISRateAdj/default.htm.* Western will post official comments received via letter and e-mail to its Web site after the close of the comment period. Western must receive written comments by the end of the consultation and comment period to ensure they are considered in Western's decision process.

FOR FURTHER INFORMATION CONTACT: Mr. Jon R. Horst, Rates Manager, Upper Great Plains Region, Western Area Power Administration, 2900 4th Avenue North, Billings, MT 59101–1266, telephone (406) 247–7444, e-mail *horst@wapa.gov.*

SUPPLEMENTARY INFORMATION: The Deputy Secretary of Energy approved Rate Schedules UGP–FPT1, UGP–NFPT1, UGP–NT1, UGP–AS1, UGP–AS2, UGP–AS3, UGP–AS4, UGP–AS5, and UGP–AS6 for P–SMBP—ED firm and non-firm transmission rates and ancillary services rates on August 1, 1998, Rate Order No. WAPA–79. The Federal Energy Regulatory Commission (Commission) confirmed and approved the rate schedules on November 25, 1998, under FERC Docket No. EF98–5031–000. These rate schedules were then extended through September 30, 2005, by Rate Order No. WAPA–100, which was confirmed and approved by the Commission on December 16, 2003, under FERC Docket No. EF03–5032–000. The rate schedules for Rate Order No. WAPA–79 and Rate Order No. WAPA–100 contain formulary rates that are recalculated yearly using the fixed charge rate methodology. The proposed formulary rates will continue to use the fixed charge rate methodology and will continue to be recalculated from yearly updated financial and load data. However, the Generator Step Up Transformers are proposed for removal from the transmission revenue requirement. After the approval of the original transmission and ancillary service rates for P–SMBP—ED the Commission decided that Generator Step Up Transformers should not be included in transmission rates for jurisdictional utilities. Consistent with Western's goal to observe Commission precedent to the extent consistent with its mission and permitted by law and regulation, the transmission and ancillary services rates are being modified. The removal of the Generator Step Up Transformers will produce less than a 1-percent change in the annual revenues for the P–SMBP—ED under Rate Order No. WAPA–100 based on the 2004–2005 rate calculation. Therefore, Western intends to conduct the public participation according to a minor rate adjustment process as defined in the DOE Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions. Western intends for the proposed rate to go into effect October 1, 2005, and remain in effect through September 30, 2010.

Under Rate Schedule UGP–FPT1, the 2004–2005 existing rate for Long-Term Firm and Short-Term Firm Point-to-Point Transmission Service is $2.72 per kilowattmonth (kWmonth). The proposed rate for Long-Term Firm and Short-Term Firm Point-to-Point Transmission Service is $2.69/KWmonth. Under Rate Schedule UGP–NFPT1, the existing rate calculation for Non-Firm Point-to-Point Transmission Service is 3.73 mills per kilowatthour (kWh). The proposed rate for Non-Firm Point-to-Point Transmission Service is 3.68 mills per kWh. Under Rate Schedule UGP–NT1 the existing annual revenue requirement for Network Integration Transmission Service is $128,017,923. The proposed annual revenue requirement for Network Integration Transmission service is $126,741,576.

Under Rate Schedule UGP–AS1, the existing rate for Scheduling System Control and Dispatch (Scheduling and Dispatch) Service is $49.29/schedule/day. The proposed rate for Scheduling and Dispatch Service is $49.77/schedule/day. Under Rate Schedule UGP–AS2, the existing rate for Reactive Supply and Voltage Control from Generation Sources (Reactive) Service is $0.06/kWmonth. The propose rate for Reactive Service is $0.07/kWmonth. Under Rate Schedule UGP–AS3, the existing rate calculated for Regulation and Frequency Response (Regulation) Service is $0.04/kWmonth. The proposed rate for Regulation Service is $0.05/kWmonth. Under Rate Schedule UGP–AS4, there is no change in the rate for Energy Imbalance Service between the existing and the proposed rates. Under Rate Schedules UGP–AS5 and UGP–AS6, the existing rate calculated for Reserves is $0.11/kWmonth. The proposed rate for Reserves is $0.12/kWmonth.

The impact to total transmission rates, including firm/non-firm/network and ancillary services is less than a 1-percent change in annual revenues. The proposed rates will result in a decrease of 0.5765 percent in annual revenues. The revenue requirements for the individual services and comparison values are outlined in the following table.

Service	Existing revenue requirement	Proposed revenue requirement	Percentage change
Transmission	$128,017,923	$126,741,576	−0.9970
Scheduling and Dispatch	3,373,281	3,406,102	0.9729
Reactive	2,736,253	3,065,568	12.0352
Reserves	1,895,268	2,009,276	6.0154
Regulation	1,065,771	1,075,623	0.9243

Legal Authority

Because the proposed removal of Generator Step Up Transformers results in less than a 1-percent change in annual transmission revenues for the P–SMBP—ED under Rate Order WAPA–100, the proposed rates constitute a minor rate adjustment as defined by 10 CFR part 903. Consistent with these regulations, Western has elected not to hold either a public information forum or a public comment forum. After review and consideration of public comments related to the proposed rate extension, Western will submit proposed rates to the Deputy Secretary of Energy for approval on an interim basis.

Western is establishing Integrated System Transmission and Ancillary Service Rates for P–SMBP—ED under the Department of Energy Organization Act (42 U.S.C. 7152); the Reclamation Act of 1902 (ch. 1093, 32 Stat. 388), as amended and supplemented by subsequent enactments, particularly section 9(c) of the Reclamation Project Act of 1939 (43 U.S.C. 485h(c)) and section 5 of the Flood Control Act of 1944 (16 U.S.C. 825s); and other acts specifically applicable to the projects involved.

By Delegation Order No. 00–037.00, effective December 6, 2001, the Secretary of Energy delegated: (1) The authority to develop power and transmission rates to Western's Administrator; (2) the authority to confirm, approve, and place such rates into effect on an interim basis to the Deputy Secretary of Energy; and (3) the authority to confirm, approve, and place into effect on a final basis, to remand, or to disapprove such rates to the Commission. Existing DOE procedures for public participation in power rate adjustments (10 CFR part 903) were published on September 18, 1985 (50 FR 37835).

Availability of Information

All brochures, studies, comments, letters, memorandums, or other documents that Western initiates or uses to develop the proposed rates are available for inspection and copying at the Upper Great Plains Regional Office, located at 2900 4th Avenue North, Billings, Montana. Many of these documents and supporting information are also available on its Web site under the "2005 IS Rate Adjustment" section located at *http://www.wapa.gov/ugp/rates/2005ISRateAdj/default.htm*.

Regulatory Procedure Requirements

Regulatory Flexibility Analysis

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

Environmental Compliance

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

Determination Under Executive Order 12866

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

Small Business Regulatory Enforcement Fairness Act

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

Dated: April 1, 2005.

Michael S. Hacskaylo,

Administrator.

[FR Doc. 05–7694 Filed 4–15–05; 8:45 am]

BILLING CODE 6450–01–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–7900–9]

Mid/Atlantic Visibility Union (MANE–VU) Annual Meeting

AGENCY: Environmental Protection Agency.

ACTION: Notice of meeting.

SUMMARY: The United States Environmental Protection Agency is announcing the 2005 Annual Board Meeting of the Mid-Atlantic Northeast/Visibility Union (MANE–VU). This meeting will deal with appropriate matters relating to Regional Haze and visibility improvement in Federal Class I areas within MANE–VU.

DATES: The meeting will be held on May 5, 2005 starting at 9 a.m. (e.s.t.).

ADDRESSES: The Lucerne Inn, Route 1A, Lucerne-in-Mane, Dedham, Maine 04429; (207) 843–5123.

FOR FURTHER INFORMATION CONTACT: Marcia L. Spink, Associate Director, Air Protection Division, U.S. Environmental Protection Agency, Region III, 1650 Arch Street, Philadelphia, PA 19103; (215) 814–2100. For Documents and Press Inquiries Contact: Ozone Transport Commission (OTC), 444 North Capitol Street NW., Suite 638, Washington, DC 20001; (202) 508–3840; e-mail: *ozone@otcair,org*; Web site *http://www.otcair,org*.

SUPPLEMENTARY INFORMATION: The Mid-Atlantic/Northeast Visibility Union MANE–VU's was formed in 2001, in response to EPA's issuance of the Regional Haze rule. MANE–VU's members include Connecticut, Delaware, the District of Columbia, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, the Penobscot Indian National, the St. Regis Mohawk Tribe along with EPA and Federal Land Managers. This meeting will be open to the public.

Type of Meeting: Open.

Agenda: Copies of the final agenda are available from the OTC office (202) 508–3840, by e-mail: *ozone@otcair.org* or via the OTC Web site at *http://www.otcair.org*.

Dated: April 13, 2005.

Donald S. Welsh,

Regional Administrator, Region III.

[FR Doc. 05–7719 Filed 4–15–05; 8:45 am]

BILLING CODE 6560–50–M

ENVIRONMENTAL PROTECTION AGENCY

[OPP–2004–0024; FRL–7703–6]

Utah State Plan for Certification of Applicators of Restricted Use Pesticides; Notice of Approval

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: In the **Federal Register** of January 10, 2005, EPA issued a notice of intent to approve an amended Utah Plan for the certification of applicators of restricted use pesticides. In the notice EPA solicited comments from the public on the proposed action to approve the amended Utah Plan. The amended Certification Plan Utah submitted to EPA contained several changes to its current Certification Plan. The proposed amendments add new subcategories as well as a Memorandum of Understanding regarding future implementation of an EPA federal pesticide certification program for the Navajo Indian Country. No comments were received and EPA hereby approves the amended Utah Plan.

ADDRESSES: The amended Utah Certification Plan can be reviewed at the locations listed under Unit I.B. of the **SUPPLEMENTARY INFORMATION**.

FOR FURTHER INFORMATION CONTACT: Barbara Barron, Pesticide Program, 8P–P3T, Environmental Protection Agency, Region VIII, 999 18th St., Suite 300, Denver, CO 80202–2466; telephone number: (303) 312–6617; e-mail address: *barron.barbara@epa.gov*.

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this Action Apply to Me?

This action is directed to the public in general. This action may, however, be of interest to those involved in agriculture and anyone involved with the distribution and application of pesticides for agricultural purposes. Others involved with pesticides in a non-agricultural setting may also be affected. In addition, it may be of interest to others, such as, those persons who are or may be required to conduct testing of chemical substances under the Federal Food, Drug, and Cosmetic Act (FFDCA), or the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA). Since other entities may also be interested, the Agency has not attempted to describe all the specific entities that may be affected by this action. If you have any questions regarding the applicability of this action to a particular entity, consult the person listed under **FOR FURTHER INFORMATION CONTACT**.

B. How Can I Get Copies of this Document and Other Related Information?

1. *Docket*. EPA has established an official public docket for this action under docket identification (ID) number OPP–2004–0024. The official public docket consists of the documents specifically referenced in this action, any public comments received, and other information related to this action. Although a part of the official docket, the public docket does not include Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. The official public docket is the collection of materials that is available for public viewing at the Public Information and Records Integrity Branch (PIRIB), Rm. 119, Crystal Mall #2, 1801 S. Bell St., Arlington, VA. This docket facility is open from 8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays. The docket telephone number is (703) 305–5805.

2. *Electronic access*. You may access this **Federal Register** document electronically through the EPA Internet under the ''**Federal Register**'' listings at *http://www.epa.gov/fedrgstr/*.

An electronic version of the public docket is available through EPA's electronic public docket and comment system, EPA Dockets. You may use EPA Dockets at *http://www.epa.gov/edocket/* to submit or view public comments, to access the index listing of the contents of the official public docket, and to access those documents in the public docket that are available electronically.