Integrated System Transmission and Ancillary Services Rate Calculation

Western Area Power Administration
Basin Electric Power Cooperative
Heartland Consumers Power District

Effective May 1, 2008

Integrated System
Transmission and Ancillary Services
Rate Calculation

Effective May 1, 2008

IS Transmission and Ancillary Service Rates ..... 1 - 7

IS Load Data ..... 8 - 9

Western's Transmission Cost Data ..... 10 - 27

Western's Ancillary Service Cost Data ..... 28 - 35

Basin Electric's Transmission Cost Data ..... 36 - 46

Basin Electric's Ancillary Service Cost Data ..... 47 - 58

Missouri River Energy Service's Ancillary Service Cost Data..... 59 - 67

Heartland's Transmission Cost Data ..... 68 - 74

NWPS Transmission Revenue Requirement Adjustment Worksheet 75

Transmission Customer Facility Credits ..... 76 - 84

Integrated System Transmission and Ancillary Service Rates

INTEGRATED SYSTEM
ANNUAL REVENUE REQUIREMENT
FOR TRANSMISSION SERVICE
2007

Line No.			
1			
2			
3	**Annual IS Transmission Costs**		**Notes**
4	Basin Electric	$40,910,880	Basin Electric Revenue Requirement Worksheet
5	Western	$103,137,204	Western Annual IS Transmission Costs Worksheet, L69
6	Heartland	$1,022,307	Heartland IS Tariff Worksheet
7		$145,070,391	L4 + L5 + L6
8			
9			
10	**Transmission Customer Facility Credits**		
11		$387,424	MRES Irv Simmons Revenue Requirement Worksheet
12		$5,732,510	MRES MBPP from Revenue Requirement Worksheet
13		$2,633,127	NWPS Revenue Requirement Worksheet
14		$8,753,061	
15			
16	**Transmission Revenue Requirement Adjustment**		
17			
18		$1,010,685	NWPS Revenue Requirement Adjustment Worksheet
19			
20			
21	**Transmission Revenue Credits**		
22			
23	**Short-Term Firm Point-to-Point Transmission Service Credit**		
24		($68,750)	
25			
26	**Non-Firm Point-to-Point Transmission Service Credit**		
27		($80,455)	
28			
29	**Revenue from Existing Transmission Agreements**		
30		($4,867,484)	
31			
32	**Scheduling, System Control and Dispatch Service Credit**		
33		($502,967)	
34			
35			
36	**Annual Revenue Requirement for IS Transmission Service**		
37			
38		$149,314,481	L7 + L14 + L18 + L24 + L27 + L30 + L33

INTEGRATED SYSTEM
FIRM POINT-TO-POINT RATE DESIGN
2007

Line No.			
1			
2			
3	**Annual Revenue Requirement for IS Transmission Service**		**Notes**
4			
5		$149,314,481	IS Annual Revenue Requirement for
6			Transmission Service Worksheet, L33
7			
8	**IS Transmission System Total Load**		
9			
10		4,181,000 KW	IS Transmission System Total Load Worksheet, C5L14
11			
12			
13	**Maximum Firm Point-to-Point Transmission Rate in $/KW-Mo**		
14			
15		**$2.98 / KW-Mo**	L5 / L10 / 12 months

INTEGRATED SYSTEM
NON-FIRM POINT-TO-POINT RATE DESIGN
2007

Line No.			
1			
2			
3	**Firm Point-to-Point Transmission Rate in $/KW-Mo**		**Notes**
4			
5		$2.98 / KW-Mo	IS Firm Point-to-Point Rate Design Worksheet, L15
6			
7			
8			
9	**Maximum Non-Firm Point-to-Point Transmission Rate**		
10		**4.08 Mills/KWh**	(L5 * 1000) / 730 hours per month

RATE FOR SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE FOR 2007

A.	Fixed Charge Rate	22.684%	(1)
B.	Scheduling, System Control and Dispatch Net Plant Costs ($)	$15,848,930	(2)
C.	Annual Revenue Requirement for Scheduling, System Control and Dispatch Service	$3,595,171	(A x B)
D.	FY 2007 Number of Daily Schedules	64,218	
E.	Rate for Scheduling, System Control and Dispatch Service ($/schedule/day)	**$55.98**	(C / D)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual IS Transmission Costs", for 2006.

(2) Scheduling, System Control and Dispatch Plant Costs include the portion of Watertown Operations Office plant (38.21%) and communication facilities plant (67.73%) associated with Scheduling, System Control and Dispatch Service for transmission less total depreciation associated with this plant. (Reference FY 2006 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 2007 (INTEGRATED SYSTEM)

A.	WAPA Reactive Service Revenue Requirement	$1,629,702	(1)
B.	BEPC & HCPD Reactive Service Revenue Requirement	$1,714,735	(2)
C.	MRES Reactive Service Revenue Requirement	$339,897	(3)
D.	Total Reactive Revenue Requirement	$3,684,334	(A+B+C)
E.	2007 IS Transmission System Total Load (kW-Yr)	4,181,000	(4)
F.	Annual Reactive Charge ($/kW-Yr)	$0.88	(D/E)
G.	Monthly Reactive Charge ($/kW-Mo)	$0.07	(F/12)

(1) Reactive Service Revenue Requirement from "Reactive Supply and Voltage Control from Generation Sources For 2006, Western's Costs".

(2) Basin Electric cost support data.

(3) Missouri River Energy Services cost support data.

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

Rate for Reserves for 2007

A.	Fixed Charge Rate		13.900%	(1)
B.	Generation Net Plant Costs		$ 484,482,449	(2)
C.	Annual Cost of Generation		$ 67,343,060	(A x B)
D.	Plant Capacity (kW)		2,230,000	
E.	Cost/kW ($/kW)		$ 30.20	(C / D)
F.	Monthly Charge ($/kW-mo)		$ 2.52	(E / 12 months)
G.	Western's Load (kW-Yr)		1,553,500	(3)
H.	Capacity used for Reserves (kW)		77,675	(Gx5%) (4)
I.	Annual Reserves Revenue Requirement	$	2,345,785	(E x H)
J.	Annual Charge ($/kW-Yr)	$	1.51	(I /G)
K.	Monthly Charge ($/kW-mo)	$	0.13	(J/12)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Generation Revenue Requirement", for 2006.

(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 2007.

(4) MAPP operating reserve requirement.

RATE FOR REGULATION AND FREQUENCY RESPONSE FOR 2007
(Integrated System)

A.	Western Regulation Revenue Requirement	$962,915	(1)
B.	BEPC & HCPD Regulation Revenue Requirement	$97,188	(2)
C.	Total Regulation Revenue Requirement	$1,060,103	(A + B)
D.	Load in Control Area(s) (kW-Yr)	2,344,000	(3)
E.	Regulation Charge ($/kW-Yr)	$0.45	(C / D)
F.	Regulation Charge ($/kW-Mo)	$0.04	(E / 12 months)

(1) Regulation and Frequency Response Service from "Regulation and Frequency Response for 2007, Western's Costs".

(2) Basin Electric cost support data.

(3) Average of monthly peaks for 2007 Watertown Control Area.

Integrated System Load Data

2007 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	**01/30/07**	800	3,861	471	4,332
2	**02/15/07**	800	3,915	501	4,416
3	**03/02/07**	2000	3,448	496	3,944
4	**04/04/07**	800	3,321	501	3,822
5	**05/21/07**	1700	3,138	500	3,638
6	**06/25/07**	1700	3,906	493	4,399
7	**07/24/07**	1800	4,447	488	4,935
8	**08/13/07**	1600	3,921	498	4,419
9	**09/04/07**	1800	3,696	500	4,196
10	**10/31/07**	900	3,085	494	3,579
11	**11/28/07**	1900	3,749	501	4,250
12	**12/14/07**	800	3,745	501	4,246
13					
14	**12 CP**		3,686	495	4,181

2007 IS Network Customer Control Area Load

Date	Hr End	East Control Area Load (1)	West Control Area Load (2)	Total Load
January 30, 2007	8:00	2460 MW	92 MW	2552 MW
February 15, 2007	8:00	2536 MW	92 MW	2628 MW
March 2, 2007	20:00	2171 MW	92 MW	2263 MW
April 4, 2007	8:00	2088 MW	74 MW	2162 MW
May 21, 2007	17:00	1805 MW	74 MW	1879 MW
June 25, 2007	17:00	2315 MW	80 MW	2395 MW
July 24, 2007	18:00	2506 MW	119 MW	2625 MW
August 13, 2007	16:00	2057 MW	97 MW	2154 MW
September 4, 2007	18:00	2278 MW	93 MW	2371 MW
October 31, 2007	9:00	1970 MW	77 MW	2047 MW
November 28, 2007	19:00	2420 MW	77 MW	2497 MW
December 14, 2007	8:00	2468 MW	90 MW	2558 MW
Total		27,074	1057	28,131
			Average Control Area Load	2,344

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

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

Western's
Transmission Cost Data

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
1			
2	**A. Operation and Maintenance Expense for Transmission**		
3			
4	Transmission O&M Expense	$44,984,499	O&M Expenses Worksheet, C6L17
5	Transmission of Electricity by Others	$0	
6	Total O&M Expense for Transmission	$44,984,499	L4 + L5
7			
8	Net Transmission Plant Investment	$454,669,386	Net Plant Investment Worksheet, C6L11
9			
10	O&M as % of Net Transmission Plant Investment	9.894%	L6/L8
11			
12			
13	**B. A&G Expense for Transmission**		
14			
15	Transmission A&G Expense	$11,640,493	A&G Expenses Worksheet, C6L12
16			
17	Net Transmission Plant Investment	$454,669,386	L8
18			
19	A&G as % of Net Transmission Plant Investment	2.560%	L15/L17
20			
21			
22	**C. Depreciation Expense for Transmission**		
23			
24	Transmission Depreciation Expense	$20,596,945	Depreciation Expense Worksheet, C6L4
25			
26	Net Transmission Plant Investment	$454,669,386	L8
27			
28	Depreciation as a % of Net Transmission Plant Investment	4.530%	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	5.700%	Cost of Capital Worksheet, C6L9
44			
45			
46	**G. Transmission Fixed Charge Rate**		
47			
48	Operation and Maintenance Expense	9.894%	L10
49			
50	A&G Expense	2.560%	L19
51			
52	Depreciation Expense	4.530%	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	5.700%	L43
59			
60	Total	22.684%	
61			
62			
63	**H. Transmission Revenue Requirement**		
64			
65	Transmission Fixed Charge Rate	22.684%	L60
66			
67	Net Transmission Plant Investment	$454,669,386	L8
68			
69	Annual Western-UGPR Transmission Cost	$103,137,204	L65 * L67
70			

Transmission Revenue from Existing Agreements
Pick Sloan Missouri Basin Program - Eastern Division
FY 2007

Line No.	Description	Amount
1		
2	Montana-Dakota Utilities Company	$491,240
3	MAPP	$2,927,587
4		
5	**Total**	$3,418,827

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 4/	(6) Total
1						
2	**Total Electric Operating Expense**	294,539,056	89,806,284			384,345,340
3						
4	**Less:**					
5	**Other Power Supply Expenses**	235,818,188	54,071,259			289,889,447
6	**A&G Expenses**	12,206,886	6,612,687			18,819,573
7	**Sunflower Payment**		0			0
8	**Prior Year Adjustments**	14,185	0			14,185
9						
10	**Plus:**					
11	**Moveable Property Interest**	551,018	280,878			831,896
12	**Warehouse Stores Interest**	82,638	89,725			172,363
13						
14	**COE/BOR Total**			27,379,939	29,502,446	56,882,385
15	**PS Total O&M**	47,133,453	29,492,941	27,379,939	29,502,446	133,508,779
16						
17	**PS-ED Transmission O&M 5/**	44,701,367	283,132	0	0	44,984,499
18						
19	**PS-ED Generation O&M 6/**	966,236	0	27,379,939	29,502,446	57,848,621

1/ All Western UGPR O&M Expenses are from the FY 2006 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 Schedule 5.

2/ All Western RMR O&M Expenses are from the FY 2006 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 11; except Moveable Property and Warehouse Stores Interest, which are from Schedule 5.

3/ Total Corps O&M Expenses are from the FY 2007 Corps of Engineers Financial Statements

4/ Total BOR O&M Expenses are from the FY 2006 Historical Financial Data in Support of the Power Repayment Study for the Pick-Sloan Missouri Basin Program, Schedule 14.

5/ 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.

6/ 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.

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	21,581,106 1/	13,481,660 2/	3,035,528 3/	3,970,060 4/	42,068,354
3						
4	PS-ED Transmission Depreciation 5/	20,467,521	129,424	0	0	20,596,945
5						
6	PS-ED Generation Depreciation 6/	442,413	0	3,035,528	3,970,060	7,448,001

1/ FY 2006 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 4.

2/ FY 2006 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 4.

3/ FY 2007 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. All COE facilities moved to generation, therefore, there is no COE transmission 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.

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

Line No.	(1) Object Class 6/	(2) WESTERN UGPR 1/	(3) WESTERN RMR 2/	(4) COE 3/	(5) BOR 3/	(6) Total
1						
2	1411	2,359,816	1,432,052	0	0	3,791,868
3	1412	1,727,319	1,723,923	0	0	3,451,242
4	1415	86,437	65,569	0	0	152,006
5	1416	5,839	22,031	0	0	27,870
6	1431	278	0	0	0	278
7	1432	(319)	0	0	0	(319)
8	1441	4,611,627	2,661,315	0	0	7,272,942
9	1442	3,415,889	707,797	0	0	4,123,686
10	**PS Total A&G**	12,206,886	6,612,687	0	0	18,819,573
11						
12	**PS-ED Transmission A&G 4/**	11,577,011	63,482	0	0	11,640,493
13						
14	**PS-ED Generation A&G 5/**	250,241	0	0	0	250,241

1/ Western UGPR A&G Expenses are from the FY 2006 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 2006 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.

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	906,108,885	1/	567,607,967	2/	932,750,812	3/	409,004,391	12/	2,815,472,055
3	PS-ED Transmission Plant-in-Service	859,391,612	4/	5,422,856	5/	0	6/	0		864,814,468
4	PS-ED Generation Plant-in-Service	18,617,722	7/	0		932,750,812	L2-L3	409,004,391	L2-L3	1,360,372,925
5	Generation Plant to Total Plant	0.0205	L4/L2	0.0000	L4/L2	1.0000	L4/L2	1.0000	L4/L2	
6	Transmission Plant to Total Plant	0.9484	L3/L2	0.0096	L3/L2	0.0000	L3/L2	0.0000	L3/L2	
7										
8	PS Accumulated Depreciation	430,241,409	8/	219,180,189	9/	503,572,371	10/	200,516,643	11/	1,353,510,612
9	PS-ED Trans. Accumulated Depreciation	408,040,952	L6*L8	2,104,130	L6*L8	0	13/	0	L6*L8	410,145,082
10	PS-ED Gen. Accumulated Depreciation	8,819,949	L5*L8	0	L5*L8	503,572,371	L8-L9	200,516,643	L5*L8	712,908,963
11	PS-ED Net Transmission Plant	451,350,660	L3-L9	3,318,726	L3-L9	0	L3-L9	0	L3-L9	454,669,386
12	PS-ED Net Generation Plant	9,797,773	L4-L10	0	L4-L10	429,178,441	L4-L10	208,487,748	L4-L10	647,463,962

1/ Transmission Plant-in-Service Worksheet, C2L505.
2/ FY 2006 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 1.
3/ FY 2007 Corps of Engineers Financial Statements, Electric and Power Multi-Purpose Plant in Service.
4/ Transmission Plant-in-Service Worksheet, C5L505.
5/ Transmission Plant-in-Service Worksheet, C5L514.
6/ Transmission Plant-in-Service Worksheet, C5L518.
7/ Transmission Plant-in-Service Worksheet, C4L505.
8/ FY 2006 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 4.
9/ FY 2006 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 4.
10/ FY 2007 Corps of Engineers Financial Statements, Statement of Assets and Liabilities.
11/ FY 2006 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 15.
12/ FY 2006 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 17.
13/ FY 2007 accumulated depreciation on the COE switchyards.

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 2006 Balances	523,134,677	1/	305,438,876	1/	509,820,207	1/	84,289,623	1/	1,422,683,383	
4											
5	**Interest Expenses:**										
6	FY 2006 Simple Interest	29,771,932	2/	21,676,162	2/	17,367,128	2/	3,817,595	2/	72,632,817	
7	Average Interest Rate	5.691%	L6/L3	7.097%	L6/L3	3.407%	L6/L3	4.529%	L6/L3		
8	Transmission Plant Factor	0.9937	3/	0.0063	4/	0.0000	5/	0.0000	6/		
9	Weighted Trans. Composite Rate									5.700%	7/
10	Generation Plant Factor	0.0137	8/	0.0000	9/	0.6857	10/	0.3007	11/		
11	Weighted Gen. Composite Rate									3.776%	12/

1/ FY 2006 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedules 21X and 21RX.
2/ FY 2006 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 33A.
3/ C2L3, Net Plant Investment Worksheet/C6L3, Net Plant Investment Worksheet.
4/ C3L3, Net Plant Investment Worksheet/C6L3, Net Plant Investment Worksheet.
5/ C4L3, Net Plant Investment Worksheet/C6L3, Net Plant Investment Worksheet.
6/ C5L3, Net Plant Investment Worksheet/C6L3, Net Plant Investment Worksheet.
7/ (C2L7*C2L8)+(C3L7*C3L8)+(C4L7*C4L8)+(C5L7*C5L8).
8/ C2L4, Net Plant Investment Worksheet/C6L4, Net Plant Investment Worksheet.
9/ C3L4, Net Plant Investment Worksheet/C6L4, Net Plant Investment Worksheet.
10/ C4L4, Net Plant Investment Worksheet/C6L4, Net Plant Investment Worksheet.
11/ C5L4, Net Plant Investment Worksheet/C6L4, Net Plant Investment Worksheet.
12/ (C2L7*C2L10)+(C3L7*C3L10)+(C4L7*C4L10)+(C5L7*C5L10).

Line No.	(1) DESCRIPTION	(2) FY2006 TOTALS ($) a	(3) MISCELLANEOUS ADJUSTMENTS ($) b	(4) GENERATION ADJUSTMENTS ($) c	(5) TRANSMISSION TOTALS ($) d	(6) SOURCE/NOTES e
1	**Transmission Lines**					
2	AURORA- BROOKINGS 115-KV T/L	133,158			133,158	
3	AURORA-FLANDREAU 115-KV T/L	96,623			96,623	
4	BEULAH-GARRISON	352,214			352,214	
5	BISMARCK-GLENHAM	5,000,750			5,000,750	
6	BISMARCK-JAMESTOWN NO. 1	5,473,497			5,473,497	
7	BISMARCK-JAMESTOWN NO. 2	3,096,816			3,096,816	
8	BISMARCK-MEDORA	4,770,063			4,770,063	
9	BROOKINGS-SIOUX FALLS	1,174,861			1,174,861	
10	BROOKINGS-WATERTOWN NO. 2	645,505			645,505	
11	BROOKINGS-WATERTOWN NO. 3	3,318,558			3,318,558	
12	BROOKINGS-WHITE 115/230KV	2,952,237			2,952,237	
13	CARRINGTON-JAMESTOWN	377,544			377,544	
14	CHARLIE CREEK-BELFIELD	13,674,183			13,674,183	
15	CONRAD-SHELBY #3	5,804,318			5,804,318	
16	CRESTON-MARYVILLE	1,366,481			1,366,481	
17	DAWSON COUNTY - MILES CITY	2,622,978			2,622,978	
18	DAWSON-GLENDIVE	553,800			553,800	
19	DAWSON-MEDORA	2,862,712			2,862,712	
20	DAWSON-MEDORA	5,088			5,088	
21	DAWSON-O'FALLON CREEK	317,413			317,413	
22	DAWSON-WILLISTON	1,258,900			1,258,900	
23	DENISON-CRESTON	6,932,503			6,932,503	
24	DEVILS LAKE-CARRINGTON	7,237,288			7,237,288	
25	DEVILS LAKE-LAKOTA	1,872,142			1,872,142	
26	EDGELEY-FORMAN	377,081			377,081	
27	EDGELEY-GROTON	771,572			771,572	
28	ELK CREEK-NEWELL-MAURINE 115-kV T/L	60,704			60,704	
29	FARGO-GRAND FORKS	2,369,098			2,369,098	
30	FARGO-MORRIS	6,910,157			6,910,157	
31	FORMAN-SUMMIT (BISMARCK)	922,098			922,098	
32	FORMAN-SUMMIT (HURON)	487,534			487,534	
33	FORT PECK-DAWSON #1	493,203			493,203	
34	FORT PECK-DAWSON #2	7,919,832			7,919,832	
35	FORT PECK-HAVRE	28,806,330			28,806,330	
36	FORT PECK-WHATELY	160,325			160,325	
37	FORT PECK-WILLISTON	6,016,073			6,016,073	
38	FORT PECK-WOLF POINT #2	7,663,747			7,663,747	
39	FORT RANDALL-FORT THOMPSON 1&2	6,717,269			6,717,269	
40	FORT RANDALL-GAVIN'S POINT	1,014,593			1,014,593	
41	FORT RANDALL-GREGORY	799,107			799,107	
42	FORT RANDALL-MT VERNON	967,828			967,828	
43	FORT RANDALL-O'NEILL	502,230			502,230	
44	FORT RANDALL-SIOUX CITY 1&2	8,532,125			8,532,125	
45	FORT THOMPSON-GRAND ISLAND	16,397,505			16,397,505	
46	FORT THOMPSON-HURON 230-KV 1&2	3,990,211			3,990,211	
47	FORT THOMPSON-SIOUX FALLS 1&2	9,542,122			9,542,122	
48	GARRISON-BISMARCK 230KV 1&2	5,176,778			5,176,778	
49	GARRISON-JAMESTOWN	4,306,775			4,306,775	
50	GARRISON-MALLARD	1,266,645			1,266,645	
51	GARRISON-WM. J. NEAL	1,559,377			1,559,377	
52	GAVINS POINT-BELDEN	455,727			455,727	
53	GAVINS POINT-SIOUX FALLS	1,331,321			1,331,321	
54	GRANITE FALLS- MORRIS	3,279,089			3,279,089	
55	GRANITE FALLS-MINNESOTA VALLEY	156,778			156,778	
56	GREAT FALLS-CONRAD	12,811,702			12,811,702	
57	GREGORY-MISSION	2,148,291			2,148,291	
58	GROTON-HURON	1,212,199			1,212,199	
59	GROTON-SUMMIT	3,176,751			3,176,751	
60	HAVRE-RAINBOW	505,538			505,538	

Line No.	(1) DESCRIPTION a	(2) FY2006 TOTALS ($) b	(3) MISCELLANEOUS ADJUSTMENTS ($) c	(4) GENERATION ADJUSTMENTS ($) d	(5) TRANSMISSION TOTALS ($) e	(6) SOURCE/NOTES
61	HAVRE-SHELBY#2	5,561,905			5,561,905	
62	HESKETT-DEVAUL	434,209			434,209	
63	HETTINGER-NEW UNDERWOOD	10,966,327			10,966,327	
64	HURON-MT VERNON	617,623			617,623	
65	HURON-WATERTOWN 230KV 1&3	4,886,323			4,886,323	
66	JAMESTOWN-EDGELEY	324,360			324,360	
67	JAMESTOWN-FARGO NO. 1	3,963,119			3,963,119	
68	JAMESTOWN-FARGO NO. 2	3,155,850			3,155,850	
69	JAMESTOWN-GRAND FORKS	13,584,611			13,584,611	
70	JAMESTOWN-VALLEY CITY	1,055,414			1,055,414	
71	LEEDS-DEVILS LAKE	2,151,247			2,151,247	
72	LEEDS-ROLLA	322,883			322,883	
73	MALLARD-RUGBY	1,282,436			1,282,436	
74	MARTIN-MISSION	750,437			750,437	
75	MARTIN-PHILIP	794,022			794,022	
76	MAURINE-RAPID CITY	4,578,394			4,578,394	
77	MILES CITY-BAKER	8,470,654			8,470,654	
78	MILES CITY-CUSTER	3,575,128			3,575,128	
79	NEW UNDERWOOD-PHILIP	2,116,605			2,116,605	
80	NEW UNDERWOOD-RAPID CITY NO. 1	1,019,427			1,019,427	
81	NEW UNDERWOOD-RAPID CITY NO. 2	309,991			309,991	
82	NEW UNDERWOOD-STEGALL (HURON)	2,672,947			2,672,947	
83	OAHE-FORT THOMPSON 230KV 1&2	3,149,034			3,149,034	
84	OAHE-FORT THOMPSON 230KV 3&4	5,119,119			5,119,119	
85	OAHE-GLENHAM	5,768,280			5,768,280	
86	OAHE-MAURINE	1,791,779			1,791,779	
87	OAHE-NEW UNDERWOOD	6,447,607			6,447,607	
88	OAHE-PIERRE	388,816			388,816	
89	O'FALLON CREEK-MILES CITY	622,672			622,672	
90	PIERRE-PHILIP	1,187,034			1,187,034	
91	RAPID CITY-ELK CREEK 115-kV T/L	52,064			52,064	
92	RUGBY-LEEDS	226,217			226,217	
93	SHELBY-SHELBY#2	576,090			576,090	
94	SIOUX CITY-DENISON	1,661,311			1,661,311	
95	SIOUX CITY-SPENCER	1,938,353			1,938,353	
96	SIOUX FALLS- SIOUX CITY	3,217,192			3,217,192	
97	SIOUX FALLS-VIRGIL FODNESS 230KV T-LINE	277,897			277,897	
98	SUMMIT-WATERTOWN	6,743,203			6,743,203	
99	TIBER TAP-TIBER	1,084,858			1,084,858	
100	UTICA JCT-SIOUX FALLS	3,496,153			3,496,153	
101	VALLEY CITY-FORMAN	1,527,895			1,527,895	
102	VIRGIL FODNESS-UTICA JUNCTION-FT RANDALL/RASM	312,931			312,931	
103	WATERTOWN-GRANITE FALLS 1&2	5,269,587			5,269,587	
104	WATERTOWN-SIOUX CITY	26,679,769			26,679,769	
105	WATFORD CITY-BEULAH	1,401,905			1,401,905	
106	WILLISTON-WATFORD CITY	563,079			563,079	
107	WM. J. NEAL-RUGBY	4,604,611			4,604,611	
108	YELLOWTAIL-CUSTER	2,280,203			2,280,203	
109	**Subtotal**	379,688,920	0	0	379,688,920	
1	**Substations**					
2	ARMOUR SUBSTATION	2,024,198	(82,000)		1,942,198	
3	ASH SUBSTATION	63,325			63,325	
4	AURORA SUBSTATION	2,899,881			2,899,881	
5	BELDEN SUBSTATION	187,367			187,367	
6	BELFIELD SUBSTATION	8,092,824			8,092,824	
7	BERESFORD SUBSTATION	3,492,462	(593,719)		2,898,743	17% of the costs of this facility have been allocated to distribution.
8	BISBEE SUBSTATION	272,529	(136,265)		136,264	50% of the costs of this facility have been allocated to distribution.
9	BISMARK SUBSTATION	8,747,677			8,747,677	
10	BOLE SUB (BEFP)	20,062			20,062	
11	BOLE SUB (BEPS)	3,177,623			3,177,623	
12	BONESTEEL SUBSTATION	3,442,909	(1,721,454)		1,721,455	50% of the costs of this facility have been allocated to distribution.
13	BROOKINGS SUBSTATION	3,831,478			3,831,478	

Line No.	(1) DESCRIPTION	a	(2) FY2006 TOTALS ($)	b	(3) MISCELLANEOUS ADJUSTMENTS ($)	c	(4) GENERATION ADJUSTMENTS ($)	d	(5) TRANSMISSION TOTALS ($)	e	(6) SOURCE/NOTES
14	CARRINGTON SUBSTATION		3,543,522		(460,658)				3,082,864		13% of the costs of this facility have been allocated to distribution.
15	CIRCLE SUBSTATION		1,507,470						1,507,470		
16	CONRAD SUB		256,825						256,825		
17	CONRAD SUB (BEPS)		5,188,006						5,188,006		
18	CRESTON SUBSTATION		4,947,247		(55,000)				4,892,247		
19	CROSSOVER SUB		172,082						172,082		
20	CROSSOVER SUB		11,108,808						11,108,808		
21	CUSTER SUBSTATION (BEFP)		2,822,570						2,822,570		
22	CUSTER SUBSTATION		1,801,240						1,801,240		
23	CUSTER TRAIL SUBSTATION		103,149		(51,575)				51,574		50% of the costs of this facility have been allocated to distribution.
24	DAWSON COUNTY SUBSTATION		9,705,450		(776,436)				8,929,014		8% of the costs of this facility have been allocated to distribution.
25	DENISON SUBSTATION		16,024,051						16,024,051		
26	DEVAUL SUBSTATION		867,667		(520,600)				347,067		60% of the costs of this facility have been allocated to distribution.
27	DEVILS LAKE SUBSTATION		2,524,910		(277,740)				2,247,170		11% of the costs of this facility have been allocated to distribution.
28	EAGLE BUTTE SUBSTATION		1,182,314						1,182,314		
29	EDGELEY SUBSTATION		3,477,612		(486,866)				2,990,746		14% of the costs of this facility have been allocated to distribution.
30	ELK CREEK SUBSTATION		2,078,657						2,078,657		
31	ELLENDALE SUBSTATION		217,469		(124,000)				93,469		
32	EXIRA SWITCHING STATION		4,131,969						4,131,969		
33	FAITH SUBSTATION		1,223,906		(611,953)				611,953		50% of the costs of this facility have been allocated to distribution.
34	FARGO SUBSTATION		20,289,567		(47,000)				20,242,567		
35	FLANDREAU SUBSTATION		3,555,808		(604,487)				2,951,321		17% of the costs of this facility have been allocated to distribution.
36	FORMAN SUBSTATION		3,892,711		(506,052)				3,386,659		13% of the costs of this facility have been allocated to distribution.
37	FORT RANDALL		253,780						253,780		
38	FORT THOMPSON #2		7,406,002						7,406,002		
39	FORT THOMPSON SUBSTATION		14,120,405		(354,000)				13,766,405		
40	GLENDIVE SUBSTATION		1,737,088						1,737,088		
41	GRAND FORKS SUBSTATION		9,320,077						9,320,077		
42	GRAND ISLAND SUBSTATION		9,168,166						9,168,166		
43	GRANITE FALLS SUBSTATION		9,942,635		(57,000)				9,885,635		
44	GREAT FALLS SUB (BEFP)		87,834						87,834		
45	GREAT FALLS SUB		470,826						470,826		
46	GREGORY SUBSTATION		1,469,031		(293,806)				1,175,225		20% of the costs of this facility have been allocated to distribution.
47	GROTON SUBSTATION		3,223,858						3,223,858		
48	HAVRE SUBSTATION		6,018,078		(1,023,073)				4,995,005		17% of the costs of this facility have been allocated to distribution.
49	HURON SUBSTATION		11,054,374						11,054,374		
50	JAMESTOWN SUBSTATION		17,706,641		(1,770,664)				15,935,977		10% of the costs of this facility have been allocated to distribution.
51	KILLDEER SUBSTATION		517,489						517,489		
52	LAKOTA SUBSTATION		1,599,216		(527,741)				1,071,475		33% of the costs of this facility have been allocated to distribution.
53	LEEDS SUBSTATION		980,361		(137,250)				843,111		14% of the costs of this facility have been allocated to distribution.
54	MARTIN SUBSTATION		659,799						659,799		
55	MARYVILLE SUBSTATION		1,525						1,525		
56	MAURINE SUBSTATION		5,597,075						5,597,075		
57	MIDLAND SUBSTATION		676,396						676,396		
58	MILES CITY #2		4,846,195						4,846,195		
59	MILES CITY #2 (BEFP)		801,103						801,103		
60	MILES CITY SUB #3		2,000,253						2,000,253		
61	MILES CITY SUB #3 (BEFP)		226,697						226,697		
62	MILES CITY SUBSTATION (BEFP)		160,336						160,336		
63	MILES CITY SUBSTATION		714,993						714,993		
64	MISSION SUBSTATION		2,561,297						2,561,297		
65	MORRIS SUBSTATION		4,605,529						4,605,529		
66	MT VERNON SUBSTATION		1,901,459						1,901,459		
67	NEW UNDERWOOD SUBSTATION		7,280,008		(800,801)				6,479,207		11% of the costs of this facility have been allocated to distribution.
68	NEWELL SUBSTATION		970,535						970,535		
69	Non-Facility		250,036						250,036		
70	O'FALLON CREEK SUBSTATION		2,261,957		(1,130,979)				1,130,978		50% of the costs of this facility have been allocated to distribution.
71	PHILIP SUBSTATION		1,745,206						1,745,206		
72	PIERRE SUBSTATION.		4,482,776		(2,241,388)				2,241,388		50% of the costs of this facility have been allocated to distribution.
73	RAINBOW SUBSTATION		723,556						723,556		
74	RAPID CITY SUBSTATION		3,719,251						3,719,251		
75	RICHLAND SUBSTATION		1,458,734		(1,166,987)				291,747		80% of the costs of this facility have been allocated to distribution.
76	ROLLA SUBSTATION		979,520		(244,880)				734,640		25% of the costs of this facility have been allocated to distribution.

Line No.	(1) DESCRIPTION	a	(2) FY2006 TOTALS ($)	b	(3) MISCELLANEOUS ADJUSTMENTS ($)	c	(4) GENERATION ADJUSTMENTS ($)	d	(5) TRANSMISSION TOTALS ($)	e	(6) SOURCE/NOTES
77	RUDYARD SUBSTATION		2,561,386		(435,436)				2,125,950		17% of the costs of this facility have been allocated to distribution.
78	RUGBY SUBSTATION		6,186,072		(866,050)				5,320,022		14% of the costs of this facility have been allocated to distribution.
79	SAVAGE SUB		74,403						74,403		
80	SHELBY SUBSTATION		1,101,278						1,101,278		
81	SHELBY SUBSTATION #2 (BEFP)		226,456						226,456		
82	SHELBY SUBSTATION #2 (BEPS)		4,194,041						4,194,041		
83	SIOUX CITY #2		9,393,406						9,393,406		
84	SIOUX CITY SUBSTATION		15,222,171		(57,000)				15,165,171		
85	SIOUX FALLS SUBSTATION		6,410,385						6,410,385		
86	SPENCER		3,240,715						3,240,715		
87	SULLY BUTTES		74,428						74,428		
88	SUMMIT SUBSTATION		2,740,513						2,740,513		
89	TYNDALL SUBSTATION		880,286						880,286		
90	UTICA JCT.		139,641						139,641		
91	VALLEY CITY SUBSTATION		2,942,704						2,942,704		
92	VERONA		25,210						25,210		
93	VIRGIL FODNESS SUBSTATION		2,524,096						2,524,096		
94	WALL SUBSTATION		1,576,622		(788,311)				788,311		50% of the costs of this facility have been allocated to distribution.
95	WARD SUBSTATION		3,448,181						3,448,181		
96	WASHBURN SUBSTATION		1,386,664						1,386,664		
97	WATERTOWN #2		2,968,649						2,968,649		
98	WATERTOWN STATIC VAR SYSTEM		11,703,689						11,703,689		
99	WATERTOWN SUBSTATION		13,583,686						13,583,686		
100	WATFORD CITY SUB		1,030,526		(30,000)				1,000,526		
101	WHATELY (NORTHERN)		40,860						40,860		
102	WHATELY SUBSTATION		104,409		(52,204)				52,205		50% of the costs of this facility have been allocated to distribution.
103	WHITE 345/115 SUB		8,904,332						8,904,332		
104	WICKSVILLE SUBSTATION		660,601		(330,301)				330,300		50% of the costs of this facility have been allocated to distribution.
105	WILLISTON SUBSTATION		6,684,168						6,684,168		
106	WINNER SUBSTATION		3,222,335		(1,611,167)				1,611,168		50% of the costs of this facility have been allocated to distribution.
107	WOLF POINT SUBSTATION		7,241,104		(2,172,331)				5,068,773		30% of the costs of this facility have been allocated to distribution.
108	WOONSOCKET SUBSTATION		1,063,437						1,063,437		
109	YANKTON SUBSTATION		302,095						302,095		
110	**Subtotal**		402,433,990		(23,147,174)		0		379,286,816		
111											
112	**Line Taps & Related Equipment**										
113	ANITA		6,259						6,259		
114	ASSINNIBOINE		35,005						35,005		
115	BAKER (BEFP)		133,554						133,554		
116	BAKER		97,832						97,832		
117	CANYON FERRY (BEFP)		15,145						15,145		
118	CANYON FERRY		30,065						30,065		
119	CHARLIE CREEK		1,119,513						1,119,513		
120	CHINOOK		3,943						3,943		
121	COTTON		1,399						1,399		
122	DICKINSON		63,736						63,736		
123	E. J. MANNING		51,274						51,274		
124	EAGLE		156,285						156,285		
125	FORSYTH		32,070						32,070		
126	FORSYTH		273,368						273,368		
127	HARLEM		220,802						220,802		
128	HETTINGER		4,451						4,451		
129	HIGHWOOD		22,896						22,896		
130	LAKE PLATTE		2,628						2,628		
131	MALLARD		12,833						12,833		
132	MALTA		28,181						28,181		
133	NASHUA SUB		72,368						72,368		
134	O'NEILL SUB (NPP)		115,790						115,790		
135	POPLAR (MDU)		3,758						3,758		
136	PRIMGHAR		575						575		
137	SPALDING		22,234						22,234		
138	STANLEY		49,735						49,735		
139	STEGALL 230KV (BCPS)		3,599						3,599		

Line No.	(1) DESCRIPTION	a	(2) FY2006 TOTALS ($)	b	(3) MISCELLANEOUS ADJUSTMENTS ($)	c	(4) GENERATION ADJUSTMENTS ($)	d	(5) TRANSMISSION TOTALS ($)	e	(6) SOURCE/NOTES
140	TERRY TAP		64,792						64,792		
141	TERRY TAP		371,751		(185,876)				185,875		50% of the costs of this facility have been allocated to distribution.
142	TIBER TAP		166,306		(83,153)				83,153		50% of the costs of this facility have been allocated to distribution.
143	VETAL TAP		232,375						232,375		
144	V. T. HANLON		8,749						8,749		
145	WITTEN		25,430						25,430		
146	WM. J. NEAL		9,919						9,919		
147	YANKTON JCT.		30,753						30,753		
148	ZENITH		2,047						2,047		
149	**Subtotal**		3,491,421		(269,029)		0		3,222,392		
150											
151	**O&M Service & Maintenance Centers**										
152	ARMOUR O&M SER. CEN.		896,000						896,000		
153	BISMARCK O&M SER. CEN.		7,244,719						7,244,719		
154	DAWSON SER. CEN.		22,545						22,545		
155	DEVILS LAKE O&M SER. CEN.		3,966,711						3,966,711		
156	Fargo Line Maintenance Facility		849,677						849,677		
157	FARGO O&M SER. CEN.		794,988						794,988		
158	FORT PECK SER. CEN.		5,872,609						5,872,609		
159	FORT THOMPSON O&M S. C.		315,000						315,000		
160	HAVRE SERVICE CENTER		191,341						191,341		
161	HURON O&M SER. CEN.		2,447,467						2,447,467		
162	JAMESTOWN O&M SER. CEN.		4,551,937						4,551,937		
163	MILES CITY MTCE FAC.		21,817						21,817		
164	MILES CITY MTCE FAC.		1,003,437						1,003,437		
165	NEW UNDERWOOD SER. CEN.		96,884						96,884		
166	PHILIP O&M SER. CENT.		1,705,195						1,705,195		
167	PIERRE O&M SER. CEN.		1,047,818						1,047,818		
168	RAPID CITY GARAGE & STOR.		2,055,932						2,055,932		
169	SIOUX CITY O&M SER. CEN.		3,009,019						3,009,019		
170	SIOUX FALLS O&M SER. CEN.		77,456						77,456		
171	WATERTOWN MAINT. CEN.		1,208,780						1,208,780		
172	**Subtotal**		37,379,331		0		0		37,379,331		
173											
174	**Operation Centers**										
175	WATERTOWN OPERATIONS CENT		2,076,752				(664,561)		1,412,191		
176	WATERTOWN OPER CTR (BEPS)		11,303,989				(3,617,276)		7,686,713		Column 4 shows 32.0% of the Watertown Operations Center that was
177	**Subtotal**		13,380,741		0		(4,281,837)		9,098,904		prorated to generation based on FTE associated with generation.
178											
179	**Mobile Equipment**										
180	MOB 115KV SWITCH TRAILER		12,328						12,328		
181	MOB 115KV SWITCH TRAILER		57,413						57,413		
182	MOB TRANSF 111KV 15MVA		213,000						213,000		
183	MOB TRANSF 115KV 10MVA		76,258						76,258		
184	MOB TRANSF 115KV 10MVA		142,235						142,235		
185	MOB TRANSF 115KV 25MVA		556,464						556,464		
186	MOB TRANSF 115KV 40MVA		499,220						499,220		
187	MOB TRANSF 230KV 1-33MVA		170,278						170,278		
188	MOB TRANS		248,943						248,943		
189	MOBILE BY PASS KIT (BISMARCK)		35,071						35,071		
190	MOBILE BY PASS KIT (FT.PECK)		7,038						7,038		
191	MOBILE BY PASS KIT (HURON)		163,695						163,695		
192	MOBILE SUB 110KV		127,144						127,144		
193	MOBILE SUB 115KV 20MVA		404,166						404,166		
194	MOBILE SUB 41.8 KV		192,498						192,498		
195	MOBILE SUB 69KV		71,118						71,118		
196	MOB SH.REACTOR		179,328						179,328		
197	**Subtotal**		3,156,197		0		0		3,156,197		
198											
199	**Transmission-Related Generation Facilities**										
200	BIG BEND-FORT THOMPSON (LOW VOLTAGE)		81,944				(81,944)		0		
201	CANYON FERRY-EAST HELENA "A"		141,044				(141,044)		0		
202	CANYON FERRY-EAST HELENA "B"		141,044				(141,044)		0		

Line No.	(1) DESCRIPTION	(2) FY2006 TOTALS ($)	(3) MISCELLANEOUS ADJUSTMENTS ($)	(4) GENERATION ADJUSTMENTS ($)	(5) TRANSMISSION TOTALS ($)	(6) SOURCE/NOTES
203	FORT PECK POWERPLANT (COE)	417,067		(417,067)	0	
204	FORT THOMPSON-BIG BEND NO. 1	922,164		(922,164)	0	
205	FORT THOMPSON-BIG BEND NO. 2	690,735		(690,735)	0	
206	Subtotal	2,393,998	0	(2,393,998)	0	
207						
208	**Communication Facilities**					
209	ATLANTIC COMMUNICATION SITE	17,199		(5,550)	11,649	Column 4 shows 32.27% of the Communication Facilities that were prorated to generaion based on the number of communication channels dedicated to generation.
210	BAKER RELAY	27,791		(8,968)	18,823	
211	BANTRY	55,421		(17,884)	37,537	
212	BARRETT	244,695		(78,963)	165,732	
213	BATTLE MT. MICROWAVE	470,739		(151,908)	318,831	
214	BELLE PRAIRIE	16,111		(5,199)	10,912	
215	BELLE PRAIRIE	577,323		(186,302)	391,021	
216	BENEDICT	36,772		(11,866)	24,906	
217	BEULAH	21,156		(6,827)	14,329	
218	BIG BEND	113,362		(36,582)	76,780	
219	BIJOU REPEATER	603,315		(194,690)	408,625	
220	BISMARCK REPEATER	405,324		(130,798)	274,526	
221	BISON REPEATER	210,846		(68,040)	142,806	
222	BRINSMADE	237,551		(76,658)	160,893	
223	BRISTOL	11,441		(3,692)	7,749	
224	BRUNSVILLE REPEATER	201,619		(65,062)	136,557	
225	BUFFALO	255,051		(82,305)	172,746	
226	CAHOON	240,466		(77,598)	162,868	
227	CARRINGTON REPEATER	726,955		(234,588)	492,367	
228	CHARTER OAK REPEATER	12,546		(4,049)	12,546	
229	CHARTER OAK REPEATER	3,121		(1,007)	3,121	
230	CHINOOK (BEFP)	284,048		(91,662)	192,386	
231	CHINOOK REPEATER	15,293		(4,935)	10,358	
232	CLARK MW REPEATER	588,027		(189,756)	398,271	
233	CLEVELAND REPEATER, N.D.	263,617		(85,069)	178,548	
234	COLEMAN REPEATER	288,294		(93,032)	195,262	
235	COLOME REPEATER	469,005		(151,348)	317,657	
236	CONRAD BUTTE REPEATER	371,283		(119,813)	251,470	
237	CONRAD BUTTE REPEATER	84,384		(27,231)	57,153	
238	CRESTON REPEATER	11,107		(3,584)	7,523	
239	CROW LAKE REPEATER	311,803		(100,619)	211,184	
240	CROWN BUTTE	203,198		(65,572)	137,626	
241	CULBERTSON RADIO RELAY SITE	22,729		(7,335)	15,394	
242	CUSTER LOOKOUT	196,436		(63,390)	133,046	
243	DALTON (WES)	198,021		(63,901)	134,120	
244	DEVILS LAKE REPEATER	482,745		(155,782)	326,963	
245	DODSON REPEATER	276,812		(89,327)	187,485	
246	DOGDEN BUTTE	274,024		(88,427)	185,597	
247	DRISCOLL	196,774		(63,499)	133,275	
248	DUPREE REPEATER	1,821		(588)	1,233	
249	DUTTON REPEATER	288,741		(93,177)	195,564	
250	EAST RAINY BUTTE	287,339		(92,724)	194,615	
251	ECKELSON	288,401		(93,067)	195,334	
252	ELKTON	323,756		(104,476)	219,280	
253	ELLENDALE REPEATER	319,122		(102,981)	216,141	
254	ELLSWORTH AIR BASE	59,669		(19,255)	40,414	
255	ERHARD	302,696		(97,680)	205,016	
256	EXIRA REPEATER	50,556		(16,314)	34,242	
257	F. L. BLAIR	39,437		(12,726)	26,711	
258	FAIRPOINT REPEATER	339,030		(109,405)	229,625	
259	FALLON REPEATER	271,939		(87,755)	184,184	
260	FLOWING WELLS	68,763		(22,190)	46,573	
261	FORBES COMMUNICATION SITE	45,316		(14,623)	30,693	
262	FORT PECK RELAY (WES)	250,960		(80,985)	169,975	
263	FORT THOMPSON REPEATER	306,861		(99,024)	207,837	
264	FORT THOMPSON REPEATER (EAST RIVER)	301,614		(97,331)	204,283	
265	FOX CREEK MICROWAVE	579,063		(186,864)	392,199	

Line No.	(1) DESCRIPTION a	(2) FY2006 TOTALS ($) b	(3) MISCELLANEOUS ADJUSTMENTS ($) c	(4) GENERATION ADJUSTMENTS ($) d	(5) TRANSMISSION TOTALS ($) e	(6) SOURCE/NOTES
266	FRYBURG SUB & MICROWAVE	210,967		(68,079)	142,888	
267	GARRISON	193,069		(62,303)	130,766	
268	GARY REPEATER	228,494		(73,735)	154,759	
269	GAVIN'S POINT	169,009		(54,539)	114,470	
270	GAVINS POINT REPEATER	278,568		(89,894)	188,674	
271	GETTYSBURG REPEATER	296,476		(95,673)	200,803	
272	GRAND FORKS MINNKOTA (MPC)	23,847		(7,695)	16,152	
273	HAILSTONE BUTTE	188,523		(60,836)	127,687	
274	HALLOWAY REPEATER	266,614		(86,036)	180,578	
275	HATHAWAY	17,314		(5,587)	11,727	
276	HATHAWAY	191,777		(61,886)	129,891	
277	HELENA RELAY (LAND ONLY)	422		(136)	286	
278	HERMOSA MICROWAVE	302,701		(97,682)	205,019	
279	HIGHLAND REPEATER	177,964		(57,429)	120,535	
280	HIGHMORE REPEATER	251,511		(81,163)	170,348	
281	HINSDALE	201,837		(65,133)	136,704	
282	HINSDALE REPEATER	25,153		(8,117)	17,036	
283	HOPEWELL REPEATER	384,133		(123,960)	260,173	
284	HUNTER MICROWAVE	333,962		(107,770)	226,192	
285	HURON DISTRICT OFFICE	817,927		(263,945)	553,982	
286	HYSHAM	250,143		(80,721)	169,422	
287	JAMESTOWN REPEATER	46,981		(15,161)	31,820	
288	JONES CREEK	251,034		(81,009)	170,025	
289	KELLY CREEK	15,210		(4,908)	10,302	
290	KELLY CREEK	300,277		(96,899)	203,378	
291	KILLDEER REPEATER	369,183		(119,135)	250,048	
292	KNEE HILL MW	308,285		(99,484)	208,801	
293	KNEE HILL MW	119,303		(38,499)	80,804	
294	KONES CORNER REPEATER	470,207		(151,736)	318,471	
295	LAC QUI PARLE	747,619		(241,257)	506,362	
296	LAKE ANDES REPEATER	743,352		(239,880)	503,472	
297	LEFOR	188,835		(60,937)	127,898	
298	LINDSAY RIDGE	235,489		(75,992)	159,497	
299	LODGEPOLE REPEATER	186,559		(60,203)	126,356	
300	MAKOSHIKA	1,401		(452)	949	
301	MALTA REPEATER	289,599		(93,454)	196,145	
302	MANDAN MICROWAVE SITE	69,988		(22,585)	47,403	
303	MAPLE RIVER	172,792		(55,760)	117,032	
304	MARTIN REPEATER	288,354		(93,052)	195,302	
305	MAYVILLE	420,419		(135,669)	284,750	
306	MIDLAND REPEATER	660,339		(213,091)	447,248	
307	MILES CITY SUB (BEFP)	305,418		(98,558)	206,860	
308	MOE REPEATER	317,411		(102,428)	214,983	
309	MOORHEAD	251,422		(81,134)	170,288	
310	MORRIS REPEATER & MICROWAVE	24,821		(8,010)	16,811	
311	MORRIS REPEATER & MICROWAVE	299,933		(96,788)	203,145	
312	NEWCASTLE REPEATER	216,330		(69,810)	146,520	
313	OAHE	440,321		(142,092)	298,229	
314	O'KREEK REPEATER	508,754		(164,175)	344,579	
315	ORCHARD REPEATER	51,068		(16,480)	34,588	
316	OTO MICROWAVE	16,445		(5,307)	11,138	
317	OTTUMWA ROAD REPEATER SITE	7,685		(2,480)	5,205	
318	PAGE N.D.	1,646		(531)	1,115	
319	PAHOJA SUB	66,444		(21,441)	45,003	
320	PEAK	269,133		(86,849)	182,284	
321	PHILIP JCT. REPEATER	545,125		(175,912)	369,213	
322	PICKSTOWN REPEATER	10,134		(3,270)	6,864	
323	PINE RIDGE	15,766		(5,088)	10,678	
324	PINE RIDGE	273,894		(88,385)	185,509	
325	PRIMGHAR REPEATER	11,990		(3,869)	8,121	
326	PUKWANNA REPEATER	258,360		(83,373)	174,987	
327	RAPID CITY REPEATER	353,479		(114,068)	239,411	
328	RICHARDSON COULEE	207,295		(66,894)	140,401	

Line No.	(1) DESCRIPTION	(2) FY2006 TOTALS ($) b	(3) MISCELLANEOUS ADJUSTMENTS ($) c	(4) GENERATION ADJUSTMENTS ($) d	(5) TRANSMISSION TOTALS ($) e	(6) SOURCE/NOTES
329	RICHARDSON COULEE REPEATER	24,536		(7,918)	16,618	
330	RICHLAND MW REPEATER (BEPS)	532,827		(171,943)	360,884	
331	ROCKY RIDGE REPEATER	226,934		(73,232)	153,702	
332	ROLLAG	172,922		(55,802)	117,120	
333	RUGBY REPEATER	276,659		(89,278)	187,381	
334	RUTLAND	32,018		(10,332)	21,686	
335	SACO	1,237		(399)	838	
336	SENTINEL BUTTE	216,955		(70,011)	146,944	
337	SHEEP COULEE REPEATER	475,744		(153,523)	322,221	
338	SIOUX CITY REPEATER	576,462		(186,024)	390,438	
339	SIOUX FALLS REPEATER	367,833		(118,700)	249,133	
340	SIOUX PASS	42,198		(13,617)	28,581	
341	SNAKE BUTTE REPEATER	732,730		(236,452)	496,278	
342	SPALDING REPEATER	36,491		(11,776)	24,715	
343	SPIRIT MOUND	226,293		(73,025)	153,268	
344	STRASBERG	17,870		(5,767)	12,103	
345	SUMMIT REPEATER	50,053		(16,152)	33,901	
346	TAPPEN REPEATER	275,429		(88,881)	186,548	
347	TENNANT COMMUNICATIONS SITE	8,782		(2,834)	5,948	
348	TORONTO REPEATER	285,888		(92,256)	193,632	
349	TRIPP REPEATER	186,047		(60,037)	126,010	
350	TRIPP REPEATER	46,216		(14,914)	31,302	
351	TURKEY RIDGE REPEATER	569,163		(183,669)	385,494	
352	TYLER REPEATER	449,771		(145,141)	304,630	
353	VIDA	14,357		(4,633)	9,724	
354	VIDA	323,156		(104,282)	218,874	
355	WALL REPEATER	454,607		(146,702)	307,905	
356	WATERTOWN REPEATER	682,037		(220,093)	461,944	
357	WAYSIDE	118,156		(38,129)	80,027	
358	WESSINGTON SPGS. REPEATER	565,164		(182,378)	382,786	
359	WESTFIELD	19,003		(6,132)	12,871	
360	WHITE SWAN	116,529		(37,604)	78,925	
361	WHITLOCK (BCPS)	117,922		(38,052)	79,869	
362	WOLBACH REPEATER	52,848		(17,054)	35,794	
363	YELLOWTAIL PP (BEPS)	88,909		(28,691)	60,218	
364	YELLOWTAIL SWITCHYARD (BEPS)	271,476		(87,605)	183,871	
365	(DELETE) ZERO (PROPOSED)	50,948		(16,441)	34,507	
366	Subtotal	37,006,170	0	(11,941,887)	25,064,283	
367						
368	**Miles City Converter Station**					
369	MILES CITY CONVERTER STATION	21,531,734			21,531,734	
370	MILES CITY CONVERTER STATION	963,035			963,035	
371	Subtotal	22,494,769	0	0	22,494,769	
372						
373	**Distribution Facilities**					
374	BUFORD TRENTON TAP - BUFORD TRENTON P.P.	650,001	(650,001)		0	
375	BUFORD TRENTON PUMP SUB	184,827	(184,827)		0	These facilities have been determined to be used solely for distribution
376	FALLON PUMPING PLANT SUBS	223,594	(223,594)		0	and are therefore not recovered in the transmission rate.
377	FALLON RELIFT PUMPING PLA	171,257	(171,257)		0	
378	FALLON-GLENDIVE PUMP #4	25,506	(25,506)		0	
379	FORT PECK-WOLF POINT	234,540	(234,540)		0	
380	FRAZER PUMP SUB	253,597	(253,597)		0	
381	GARRISON-SNAKE CREEK	569,241	(569,241)		0	
382	GLENDIVE P.P. #1 SUB.	425,706	(425,706)		0	
383	INTAKE SUBSTATION	108,040	(108,040)		0	
384	INTAKE-INTAKE PUMP	6,494	(6,494)		0	
385	KINSEY PUMP	49,256	(49,256)		0	
386	SAVAGE PUMPING PLANT SUBS	102,283	(102,283)		0	
387	SHIRLEY PUMP SUBSTATION	166,017	(166,017)		0	
388	SNAKE CREEK PUMP SUBSTATI	662,435	(662,435)		0	
389	SOUTH DAKOTA SCHOOL OF MINES AND TECHNOLOGY	19,075	(19,075)		0	
390	TERRY PUMPING PLANT SWITC	474,404	(474,404)		0	
391	TIBER DAM SUBSTATION	318,568	(318,568)		0	

Line No.	(1) DESCRIPTION	a	(2) FY2006 TOTALS ($)	b	(3) MISCELLANEOUS ADJUSTMENTS ($)	c	(4) GENERATION ADJUSTMENTS ($)	d	(5) TRANSMISSION TOTALS ($)	e	(6) SOURCE/NOTES
392	WIOTA SUBSTATION		38,507		(38,507)				0		
393	**Subtotal Distribution Facilities**		4,683,348		(4,683,348)		0		0		
394											
395	**Subtotal Upper Great Plains Region Facilities**		906,108,885		(28,099,551)		(18,617,722)		859,391,612		
396											
397											
398											
399	**Rocky Mountain Region Facilities**										
400	NEW UNDERWOOD-STEGALL		287,835						287,835		Column 2 includes plant-in-service from FY 2006 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.
401	STEGALL SUBSTATION		8,927,702		(8,625,093)				302,609		
402	STEGALL-WAYSIDE		2,978,205						2,978,205		
403	YELLOWTAIL SWITCHYARD		7,416,827		(5,562,620)				1,854,207		
404			19,610,569		(14,187,713)		0		5,422,856		
405											
406	**Corps of Engineers Facilities**										
407	CORPS SWITCHYARD FACILITIES		29,782,666				(29,782,666)		0		
408			29,782,666		0		(29,782,666)		0		
409											
410	**TOTAL FACILITIES**		955,502,120		(42,287,264)		(48,400,388)		864,814,468		

Western's
Ancillary Services
Cost Data

REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES FOR 2007
(WESTERN'S COSTS)

A. Fixed Charge Rate	13.900%	(1)
B. Generation Net Plant Costs ($)	$484,482,449	(2)
C. Annual Cost of Generation ($)	$67,343,060	(A x B)
D. Capability Used for Reactive Support (%)	2.42%	(3)
E. Reactive Service Revenue Requirement	$1,629,702	(C x D)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Generation Revenue Requirement", for 2006.

(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 2003-2007.

RATE FOR REGULATION AND FREQUENCY RESPONSE FOR 2007
(Western's Costs)

A.	Fixed Charge Rate	10.863%	(1)
B.	Corps Generation Net Plant Costs ($)	177,171,365	(2)
C.	Annual Corps Generation Cost ($)	19,246,125	(A x B)
D.	Plant Capacity (kW)	937,000	
E.	Cost/kW ($/kW)	20.54	(C / D)
F.	Capacity Used for Regulation (kW)	46,880	(H x 2%)
G.	Regulation Revenue Requirement ($)	$962,915	(E x F)
H.	Load in Control Area(s) (kW-Yr)	2,344,000	(3)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Corps Revenue Requirement", for 2006.

(2) Corps Generation Net Plant is Electric Plant in Service for Oahe and Fort Peck less less Depreciation Reserve as of 9/30/07.

(3) Average of monthly peaks for 2007 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	$57,848,621	O&M Expenses Worksheet, C6L19
5			
6	Net Generation Plant Investment	$647,463,962	Net Plant Investment Worksheet, C6L12
7			
8	O&M as % of Net Generation Plant Investment	8.935%	L4/L6
9			
10			
11	**B. A&G Expense for Generation**		
12			
13	Generation A&G Expense	$250,241	A&G Expenses Worksheet, C6L17
14			
15	Net Generation Plant Investment	$647,463,962	L6
16			
17	A&G as % of Net Generation Plant Investment	0.039%	L13/L15
18			
19			

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	7,448,001	Depreciation Expense Worksheet, C6L6
23			
24	Net Generation Plant Investment	$647,463,962	L6
25			
26	Depreciation as a % of Net Generation Plant Investment	1.150%	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 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	3.776%	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	8.935%	L8
47			
48	A&G Expense	0.039%	L17
49			
50	Depreciation Expense	1.150%	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	3.776%	L41
57			
58	Total	13.900%	
59			
60			
61	**H. Generation Revenue Requirement**		
62			
63	Generation Fixed Charge Rate	13.900%	L59
64			
65	Net Generation Plant Investment	$647,463,962	L6
66			
67	Western Annual Generation Revenue Requirement	$89,997,491	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	$27,379,939	O&M Expenses Worksheet, C4L19
5			
6	Net Corps Generation Plant Investment	$429,178,441	Net Plant Investment Worksheet, C4L12
7			
8	O&M as % of Net Generation Plant Investment	6.380%	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	$429,178,441	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	$3,035,528	Depreciation Expense, C4L6
23			
24	Net Corps Generation Plant Investment	$429,178,441	L6
25			
26	Depreciation as a % of Net Generation Plant Investment	0.707%	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	3.776%	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	6.380%	L8
47			
48	A&G Expense	0.000%	L17
49			
50	Depreciation Expense	0.707%	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	3.776%	L41
57			
58	Total	10.863%	
59			
60			
61	**H. Corps Generation Revenue Requirement**		
62			
63	Corps Generation Fixed Charge Rate	10.863%	L69
64			
65	Net Corps Generation Plant Investment	$429,178,441	L6
66			
67	Western Annual Corps Generation Revenue Requirement	$46,621,654	L63 * L65
68			

Basin Electric's Transmission Cost Data

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

For the 12 months ended 12/31/07

Line No.			Total	Allocator		Total Transmission		IS Transmission	MBPP East Transmission	Other Transmission
1	GROSS REVENUE REQUIREMENT (page 3, line 28)					$ 68,498,405		$ 40,067,715	$ 7,902,188	$ 20,528,501
							(MBPP West)		$ (7,380,668)	$ 7,380,668
	REVENUE CREDITS									
2	Third Party Receipts		$ 2,750,556	TP	1.00000			$ 1,434,058	$ -	$ 1,316,498
3										
4	Third Party Payments		$ 321,644	TP	1.00000			$ 321,644	$ -	$ -
5		(line 2 - 4)	$ 2,428,912					$ 1,112,414	$ -	$ 1,316,498
6	NET REVENUE REQUIREMENT	(line 1+ 5)						$ 38,955,301	$ 521,521	$ 26,592,671
7	TOTAL IS REVENUE REQUIREMENT							$ 39,476,822		

Revenue Requirement Worksheet
Utilitizing RUS form 12 Data
BASIN ELECTRIC POWER COOPERATIVE

For the 12 months ended 12/31/07

Line No.	(1)	(2) RUS Form 12	(3)	(4) Allocator A		(5) Total Trans	(4a) Allocator B		(6) IS Transmission	(7) MBPP Transmission	(8) Other Transmission
	GROSS PLANT IN SERVICE										
1	Production	12h.A.6	1,839,659,587	NA		-	NA		-		-
2	Transmission	12h.A.11	503,657,186	DA		503,657,186	DA		308,732,232	90,527,447	104,397,507
3	Distribution	12h.A.16	-	NA		-	NA				
4	General	12h.A.17	116,407,311								
4a	Direct Assign - Transmission		35,340,593	DA		35,340,593	DA		27,858,269	3,919,314	3,563,010
4b	Direct Assign - Production		23,130,076	NA		-	NA				
4c	Other		57,936,642	WS	11.263%	6,525,159	WS	(page 4)	3,750,221	570,951	2,203,987
5	Intangible	12h.A.1	69,684,061	DA		65,450,935	DA		28,471,286	2,617,629	34,362,020
6	TOTAL GROSS PLANT (sum lines 1,2,4,5)	12h.A.18 (Note A)	$ 2,529,408,145			$ 610,973,873			$ 368,812,008	$ 97,635,341	$ 144,526,524
				GP	24.155%		GP				
							TPGP				
	ACCUMULATED DEPRECIATION										
7	Production	12h.B.1-4	976,692,543	NA			NA				
8	Transmission	12h.B.5	241,259,126	DA		241,259,126	DA		169,102,822	50,154,850	22,001,454
9	Distribution	12h.B.6	-	NA			NA				
10	General	12h.B.7	81,560,753								
10a	Direct Assign - Transmission		24,822,121	DA		24,822,121	DA		21,058,012	3,155,856	608,253
10b	Direct Assign - Production		18,382,311	NA			NA				
10c	Other		38,356,320	WS	11.263%	4,319,910	WS	(page 4)	2,482,793	377,992	1,459,125
11	Intangible	12h.B.12	40,859,984	DA		40,634,284	DA		18,558,305	1,690,716	20,385,263
12	TOTAL ACCUM. DEPR (sum lines 7,8,10,11)	12h.B.18	$ 1,340,372,406			$ 311,035,441			$ 211,201,931	$ 55,379,414	$ 44,454,096
	NET PLANT IN SERVICE										
13	Production	(line 1- line 7)	862,967,044	AUTO			AUTO				
14	Transmission	(line 2- line 8)	262,398,060	AUTO		262,398,060	AUTO		139,629,410	40,372,596	82,396,053
15	Distribution	(line 3 - line 9)	-	AUTO			AUTO				
16	General	(line 4 - line 10)	34,846,558	AUTO			AUTO				
16a	Direct Assign	(line 4a - line 10a)	10,518,471	AUTO		10,518,471	AUTO		6,800,258	763,457	2,954,757
16b	Production	(line 4b - line 10b)	4,747,765	AUTO			AUTO				
16c	Other	(line 4c - line 10c)	19,580,322	AUTO		2,205,249	AUTO		1,267,428	192,959	744,861
17	Intangible	(line 5 - line 11)	28,824,077	AUTO		24,816,651	AUTO		9,912,981	926,914	13,976,757
18	TOTAL NET PLANT (sum lines 13, 14, 16, 17)		$ 1,189,035,739			$ 299,938,431			$ 157,610,077	$ 42,255,926	$ 100,072,428
				NP	25.225%		NP		13.255%	3.554%	8.416%

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

For the 12 months ended 12/31/07

Line No.	(1)	(2) RUS Form 12 Reference	(3) Company Total	(4) Allocator A		(5) Total Transmission	(4a) Allocator B		(6) IS Transmission	(7) MBPP Transmission	(8) Other Transmission
	O&M										
1	Transmission less Account 565	12a.A.8.+ A.16.-12LA.8	18,588,076			-			-	-	-
2	Direct Assignment. (Note B)	Accounting Records	9,286,145	DA		9,286,145	DA		6,762,154	1,713,975	810,016
3	Other	Accounting Records	9,301,931	TPW	100.000%	9,301,931	TPW	(page 4)	5,858,764	-	3,443,168
4	A&G	12a.A.13	43,028,667			-					
5	Less Regulatory Fees	Accounting Records	533,335	NA		-	NA				
6	Production (Note C)	Accounting Records	2,083,523	NA		-	NA				
7	Transmission (Note D)	Accounting Records	1,306,008	DA/TPW		1,306,008	DA /TPW	(page 4)	701,666	81,644	522,698
8	Headquarters		39,105,801	WSW	10.379%	4,058,943	WSW	(page 4)	2,556,500	-	1,502,443
9	TOTAL O&M (sum lines 1 and 4)		$ 61,616,743			$ 23,953,027			$ 15,879,083	$ 1,795,619	$ 6,278,325
	DEBT SERVICE										
10	Interest Expense	12a.A.22-24.	70,529,802	NP	25.225%	17,791,390	NP	(page 2)	9,348,926	2,506,487	5,935,977
11	Principal Payments	12h.H	76,513,245	NP	25.225%	19,300,734	NP	(page 2)	10,142,049	2,719,126	6,439,559
12	Amort of Debt Discount (428)	12a.A.26	3,462,681								
13	Transmission	Accounting Records	905,897	DA	100.000%	905,897	DA		717,039	169,131	19,727
14	Headquarters	Accounting Records	52,148	WSW	10.379%	5,413	WSW	(page 4)	3,409	-	2,004
15	Production	Accounting Records	2,504,617	NA		-	NA		-		-
16	Other Deductions	12a.A.26	7,456,104	NA		-	NA		-		-
17	TOTAL DEBT SERVICE (sum lines 10, 11, 12,16)		$ 157,961,812			$ 38,003,433			$ 20,211,423	$ 5,394,743	$ 12,397,267
	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 (excludes income tax)	1,429,917								
22	Tax Reclassification	Accounting Records	(59,386)	NA	0.000%	-	NA				
23	Gross Receipts (Note E)	12a.A.21	1,489,303	DA		1,489,303	DA		1,322,174	-	167,129
24	Production			NA		-	NA		-		-
25	TOTAL OTHER TAXES		$ 1,429,917			$ 1,489,303			$ 1,322,174	$ -	$ 167,129
26	TOTAL OPERATING EXPENSES (Sum 9+17+25)		$ 221,008,472			$ 63,445,762			$ 37,412,679	$ 7,190,362	$ 18,842,722
27	Margin		$ 20,030,019	NP	25.225%	$ 5,052,642	NP	(page 2)	$ 2,655,036	$ 711,826	$ 1,685,780
28	REV. REQUIREMENT (sum lines 26+27)		$ 241,038,491			$ 68,498,405			$ 40,067,715	$ 7,902,188	$ 20,528,502

A & G Allocation

WAGES AND SALARY ALLOCATOR (W/S)

Line No.	(1) From Accounting Report	(2)	(3) TOTAL	(4) Allocator		(5) Percent	(6) IS Transmission	(7) MBPP Transmission	(8) Other Transmission
1	Production		34,861,239				2,542,960	387,152	$1,494,486
2	Transmission-East		188,883						
3	Transmission-West		387,152	WS	Trans % of total wages	11.263%	6.473%	0.985%	3.804%
4	Transmission-Allocated		3,848,563	WSW	Exclude West trans	10.379%	6.537%		3.842%
5	Distribution		-						
6	Other Transmission		-	TPWS	Trans % of total trans		57.473%	8.750%	33.777%
7	Total Wages and Salaries (sum lines 1-6) (exclude adm)		$39,285,837	TPW	(Trans % excluding West)		62.984%		37.016%

IS Transmission Wage and Salary Dollar Split

Line No.					
8	Net IS transmission Plant (p.2.c.6.L.14, 16a, 17)	156,342,649			
9	Net Other transmission Plant (p.2.c.8.L.14, 16a,17)	99,327,567			
10	Total (sum lines 8 -9)	$255,670,215			
11	Percent of IS to Total Transmission (Note F)		ISTP		61.168%
12	Percent of Other to total Transmission		Other		38.832%
13	IS Trans Wage & Salary Dollar (L 4 times L 11)	$2,354,077			100.000%
14	Other Transmission Wage & Salary (L 4 times L 12)	$1,494,486			
15	Total Transmission Wage and Salary Allocated (L.4)	$3,848,563			

Note

A Total does not include plant held for future use or CWIP
B Includes Lease payments of $2,819,842 for member facilities in the IS system and O&M that is charged to specific lines or substations.
C A&G costs directly allocated to MBPP - Costs split between MBPP Production and MBPP Transmission based on MBPP Wages
D Includes OASIS costs for West Side and Common Use System plus A&G costs allocated to MBPP Transmission
E SD Gross receipts taxes paid in lieu of property with a portion directly assigned to Common Use System (CUS).
Payroll taxes are included in the RUS 500 series of accounts along with the labor costs. ND Trans Line tax is included in O&M, line 2.
F MBPP net plant is excluded in the percentage calculations on line 11 and 12 as costs for transmission and A&G are directly allocated to MBPP

Basin Electric Power Cooperative
Lines
December 31, 2007

Worksheet 1
Page 1

CPX	Lines	Book Cost	Accum Depr	Net Book	Annual Depreciation
009	230KV LOS#1 to Logan (NSP)	751,708	507,828	243,880	20,689
012	230kv LO#1 DC Line to Washburn	1,485,282	1,450,404	34,878	-
021	345 kv line Stanton to SD Border	9,297,594	7,900,978	1,396,617	258,964
022	345 kv line - SD to Ft Thompson	9,134,431	7,558,156	1,576,275	240,854
023	345 kv line Stanton to SD Border	11,511,850	9,682,371	1,829,479	305,497
024	345 kv line SD to Watertown	10,164,504	8,289,869	1,874,635	312,739
025	230 kv line LOS#1 to Logan	4,430,205	3,131,860	1,298,345	110,453
026	230 kv line-230/115/69-sub (16)	289,132	239,523	49,609	8,076
031	115 kv line Logan to Kenmare	3,115,809	2,115,831	999,978	74,950
032	115 kv line Logan to Mallard	632,973	415,928	217,045	14,649
034	230 kv line Philip Tap-Philip Sub	853,709	739,556	114,153	23,222
127	345 kv N line #1 dbl circ	10,442,907	4,391,145	6,051,762	197,491
128	345 kv S line #2 dbl circ	11,215,381	5,018,718	6,196,663	202,527
129	500 kv AVS switchyd to SD bdr	57,926,565	26,497,315	31,429,250	1,066,860
130	500 kv SD bdr to Broadland sub	53,098,066	24,189,717	28,908,348	973,967
134	345 kv dbl circ line	942,053	593,176	348,877	28,287
141	230 kv line Broadland to Huron	1,068,625	512,497	556,128	20,646
150	230 kv line Estavan to Sask bdr	15,071,877	9,887,671	5,184,206	391,077
152	345 kv line AVS to Charlie Creek	9,291,907	5,439,125	3,852,781	244,338
185	230 kv line MC-Bowman-NU	9,481,900	6,928,944	2,552,956	271,110
311	115 kv tie line to Groton sub	136,010	86,344	49,667	3,872
361	69KV Line Cornbelt	41,112	4,551	36,561	1,200
411	230 KV Line RC to New Underwood	6,010,877	611,376	5,399,501	144,502
	Total IS Lines	**$ 226,394,477**	**$ 126,192,883**	**$ 100,201,594**	**$ 4,915,969**

Basin Electric Power Cooperative
Substations
December 31, 2007

Worksheet 1
Page 2

CPX	Substations	Book Cost	Accum Depr	Net Book	Annual Depreciation
013	230KV LO Washburn Substation	71,594	70,298	1,296	-
016	230/115/69KV LO Substation	1,234,995	1,113,463	121,532	26,262
036	345KV FT Thompson Substation	2,374,699	1,932,502	442,197	102,000
039	230/115KV Storla, SD Substation	2,207,566	1,701,430	506,136	91,443
040	230/115KV Philip, SD Substation	862,865	697,649	165,216	38,063
042	230KV Philip,SD Tap Substation	214,957	188,304	26,653	5,884
046	Martin, SD USBR Sub Capacitor Installed	200,287	141,600	58,687	8,340
047	Armour, SD USBR Sub Capacitor Installed	137,379	119,939	17,439	4,013
058	115KV Williston, ND Substation	643,259	444,859	198,400	18,467
060	230/115KV Dickinson, ND Substation	1,204,038	1,048,222	155,817	33,495
061	115KV Spirit Mound Switchyard	1,406,589	1,136,680	269,909	39,305
063	Static VAR Suppt-Victory Hill Sub-Sctbluff	1,647,967	1,317,605	330,361	52,163
126	500KV Broadland SD, Substation	12,470,254	5,959,883	6,510,370	243,503
142	230KV USBR Huron Substation Addition	1,669,836	806,660	863,176	32,471
145	Manning,ND Sub Capacitor Installed	186,623	146,432	40,191	5,186
153	345/115KV Charlie Creek Substation	5,342,496	3,484,877	1,857,620	146,513
194	Bowman Sub -230 KV breakers	1,393,433	195,874	1,197,559	38,735
195	Hettinger Capacitors	827,735	92,789	734,946	22,789
196	Baker Capacitors	827,735	92,789	734,946	22,789
310	345/115KV Groton Substation Addition	5,019,759	3,013,774	2,005,985	133,601
325	230 mw Miles City DC Tie	18,989,386	11,629,361	7,360,025	525,716
362	69KV Substation - Cornbelt	1,557,920	173,515	1,384,405	45,765
408	RC Tie East Interconnect	1,060,552	124,923	935,629	29,469
470	Groton Clutch	1,872,537	55,632	1,816,905	37,088
711	230KV LO #1 Switchyard and AVS Addition	5,087,828	4,099,598	988,231	133,410
720	345/230KV LO#2 Switchyard and AVS Add	16,127,179	10,075,318	6,051,861	388,144
734	Tioga substation - Capacitor bank	387,866	170,803	217,063	10,675
735	345/230KV Watertown Substation	2,871,896	2,508,025	363,871	79,486
737	230/115KV Logan Substation & Sask Addition	4,115,005	2,936,945	1,178,060	110,311
767	345KV AVS Switchyard & Charlie Creek Add't	18,800,068	9,308,261	9,491,807	387,171
	Total IS Substations	**$ 110,814,301**	**$ 64,788,010**	**$ 46,026,291**	**$ 2,812,257**

Basin Electric Power Cooperative
Maintenance Buildings & Microwave
December 31, 2007

Worksheet 1
Page 3

CPX	Maintenance Buildings	Book Cost	Accum Depr	Net Book	Annual Depreciation
070	Mandan Transmission Maint Bldg	6,336,634	4,550,750	1,785,884	215,103
071	Gettysburg Trans Maint Bldg	1,041,319	917,910	123,409	37,384
072	Groton Trans Maint Bldg	2,091,174	1,014,977	1,076,197	150,594
109	Logan Trans Maint Bldg	1,142,052	922,321	219,731	40,265
119	Broadland Trans Maint Bldg	1,096,289	994,774	101,514	31,899
120	AVS Plantsite Trans Maint Bldg	4,053,277	2,961,889	1,091,388	124,782
	Total Maintenance Buildings	$ 15,760,745	$ 11,362,620	$ 4,398,124	$ 600,027

CPX	Microwave	Book Cost	Accum Depr	Net Book	Annual Depreciation
043	Microwave - North Dakota	7,550,864	5,988,607	1,562,258	375,459
044	Microwave -South Dakota	3,961,253	3,108,307	852,945	216,740
136	Microwave - SD AVS	834,723	690,547	144,176	37,412
137	Microwave - AVS	1,270,496	1,071,288	199,208	54,577
139	Microwave - ND Sask	1,279,463	1,055,440	224,023	57,248
155	Microwave - ND CC	1,000,407	826,915	173,491	46,119
308	Microwave - SD Groton	143,259	112,915	30,344	7,723
	Subtotal Microwave	**$ 16,040,463**	**$ 12,854,019**	**$ 3,186,445**	**$ 795,278**
	Non IS transmission 24.614%	(3,948,200)	(3,163,888)	(784,311)	(195,750)
	Total Microwave	**$ 12,092,264**	**$ 9,690,130**	**$ 2,402,133**	**$ 599,528**
	Accum Depr Adjustment		(3,314,505)		
	Total IS Facilities	**$ 365,061,787**	**$ 208,719,139**	**$ 156,342,649**	**$ 8,927,781**

Basin Electric Power Cooperative
MBPP Transmission Facilities
December 31, 2007

CPLX	LINES	BOOK COST	12/31/07 ACCUM DEPR	12/31/07 NET BOOK VALUE	12/31/07 YTD DEPR
049	345kv line from LRS-Stegall	5,917,563	3,299,405	2,618,158	109,120
050	345kv line from LRS-Stegall Sub	519,922	281,693	238,229	9,385
051	345KV Line from LRS to NB Border	2,392,317	1,272,938	1,119,380	44,471
052	345KV Line - NB Border To Sidney Sub	3,702,714	1,939,478	1,763,236	67,929
053	345 KV LINE - Stegall Sub to Sidney Sub	4,971,800	2,635,722	2,336,078	92,897
073	230kv line from LRS to D Johnston	2,868,108	1,608,069	1,260,039	48,128
074	345kv line from LRS-Story	18,392,775	10,589,274	7,803,500	314,888
075	345kv line from CO Border to Story Sub	16,558,245	9,203,445	7,354,800	299,463
077	LRS Plantsite Lines	1,255,831	639,544	616,287	27,290
091	NEBRASKA TAX	161,866	84,028	77,838	3,447
096	MBPP-Tri-State	12,498	12,498	-	-
101	230KV Line - Sidney Sub To WAPA Sub	499,280	282,633	216,647	9,161
102	230kv Stegall Tie Line	353,438	190,408	163,030	6,541
103	230KV Tie Line Stegall Sub - Stegall/WAPA	311,212	170,964	140,248	5,668
104	345kv line - 048 to CO Border	8,978,538	4,456,085	4,522,453	157,441
105	345kv line-CO Border to Ault	3,597,852	1,795,411	1,802,441	64,290
106	230kv Sidney Tie Line	268,113	153,272	114,841	5,085
	SUBTOTAL LINES	**$ 70,762,073**	**$ 38,614,868**	**$ 32,147,205**	**$ 1,265,204**
	SUBSTATIONS				
045	230kv LRS Switch Station	2,289,416	1,216,093	1,073,323	45,129
048	345kv LRS Substation	5,891,131	3,404,952	2,486,178	108,876
076	230kv D Johnson Substation	379,358	215,490	163,868	7,086
078	345/230 KV Stegall Substation	3,014,708	1,689,802	1,324,906	58,003
079	345/230 KV Sidney Substation	4,083,137	2,314,231	1,768,905	77,541
084	230 KV Stegall-WAPA Sub Addition	599,773	329,345	270,428	11,949
086	230kv Story Substation	412,617	233,389	179,228	7,892
100	230/115 KV Sidney Substation Addition	284,620	147,406	137,214	6,021
190	345kv Story Substation	2,823,113	1,500,751	1,322,362	54,499
	SUBTOTAL SUBSTATIONS	**$ 19,777,872**	**$ 11,051,459**	**$ 8,726,413**	**$ 376,995**

Basin Electric Power Cooperative
West System Transmission Facilities
December 31, 2007

CPX	Description	Installed Costs	Accum Depr	12/31/07 NET BOOK VALUE	12/31/07 YTD DEPR
	MICROWAVE COMMUNICATONS				
131	Microwave Communication-WY	1,171,874	847,984	323,890	50,931
132	Microwave Communication-CO	320,451	270,465	49,986	7,703
133	Microwave - NB	664,161	560,127	104,033	18,135
135	Microwave - ND	6,016	6,016	0	-
138	Microwave - SD	46,623	35,913	10,710	2,794
		2,209,125	1,720,505	488,619	79,563
	Less Non-Trans MW (15.05376%)	(332,556)	(259,001)	(73,556)	(11,977)
	SUBTOTAL MICROWAVE	$ 1,876,568	$ 1,461,504	$ 415,064	$ 67,586
	MAINTENANCE BUILDING				
107	Trans Maintenance Building - Stegall	1,096,289	883,219	213,071	58,434
108	LRS Trans Maintenance Bldg	933,958	798,635	135,323	21,802
	SUBTOTAL MAINTENANCE	**$ 2,030,247**	**$ 1,681,854**	**$ 348,393**	**$ 80,237**
	OTHER				
085	345kv Ault Substation	2,548,498	1,647,978	900,520	63,536
088	230KV OCB-Tri-State	69,131	42,737	26,394	1,861
	SUBTOTAL OTHER	**$ 2,617,629**	**$ 1,690,716**	**$ 926,914**	**$ 65,397**
	General Ledger Accum Depr Adjust		**501,022**		
	GRAND TOTAL	**$ 97,064,389**	**$ 55,001,422**	**$ 42,062,967**	**$ 1,855,418**

Basin Electric Power Cooperative
Electric Plant In Service
December 31, 2007

Worksheet 2

	LOS Generation	AVS Generation	SMS Generation	LRS Generation	Other Generation	IS Transmission	West Transmission	BHP Common Use Transmission	Rapid City DC Tie	Excluded Transmission	Headquarters	Totals
Book Basis-Generation	291,769,947	850,265,622	24,930,271	553,474,334	119,219,413							1,839,659,587
Accum Depr	(174,808,031)	(439,092,142)	(21,231,368)	(343,837,870)	(14,021,324)	-	-	-	-	-		(992,990,735)
G/L Adjust -Accum Depr	4,156,666	5,342,695	8,828	6,784,565	5,438	-						16,298,191
Net Book	121,118,582	416,516,176	3,707,730	216,421,028	105,203,527	-						862,967,044
Book Basis-Transmission					1,790,035	308,732,232	90,527,447	35,209,874	37,037,634	30,359,963		503,657,185
Accum Depr					(116,632)	(172,417,327)	(49,653,919)	(4,806,281)	(4,267,620)	(13,622,240)		(244,884,019)
G/L Adjust -Accum Depr					683	3,314,505	(501,022)	28,167	25,010	757,549		3,624,893
Net Book					1,674,086	139,629,410	40,372,506	30,431,760	32,795,024	17,495,273		262,398,059
Book Basis General Plant	6,277,782	7,392,229	230,428	6,414,072	282,554	31,806,469	4,251,870	3,127,180	435,829	-	56,188,898	116,407,311
Accum Depr	(4,880,879)	(6,097,531)	(203,760)	(5,114,365)	(60,327)	(24,221,900)	(3,414,857)	(505,611)	(102,642)	-	(35,923,239)	(80,525,112)
G/L Adjust -Accum Depr						-					(1,035,642)	(1,035,642)
Net Book General Plant	1,396,903	1,294,698	26,668	1,299,707	222,227	7,584,569	837,013	2,621,569	333,188	-	19,230,017	34,846,557
Book Basis Intangibles	-	1,049,145	-	-	3,181,710	28,471,286	2,617,629	426,659	-	33,935,361	2,270	69,684,060
Accum Depr		(113,308)			(110,122)	(18,558,305)	(1,690,716)	(234,859)		(20,150,404)	(2,270)	(40,859,984)
Net Book Intangibles	-	935,837	-	-	3,071,588	9,912,981	926,914	191,800	-	13,784,957	-	28,824,077
Total	122,515,486	418,746,711	3,734,398	217,720,735	110,171,428	157,126,960	42,136,433	33,245,129	33,128,211	31,280,230	19,230,017	1,189,035,736
Gross Plant	298,047,728.94	858,706,995.83	25,160,699.05	559,888,406.06	124,473,711.90	369,009,986.96	97,396,945.66	38,763,713.23	37,473,462.86	64,295,324.31	56,191,168.3500	2,529,408,143
Accum Depr with Adjustments	(175,532,243)	(439,960,285)	(21,426,301)	(342,167,671)	(14,302,284)	(211,883,027)	(55,260,513)	(5,518,585)	(4,345,252)	(33,015,095)	(36,961,152)	(1,340,372,407)
Net Plant	122,515,485.58	418,746,711.21	3,734,398.01	217,720,735.00	110,171,427.67	157,126,960.16	42,136,432.67	33,245,128.50	33,128,211.18	31,280,229.54	19,230,016.67	1,189,035,736

Note: Transmission totals do not include the microwave adjustments. See facilities listings for adjustments

Basin Electric Power Cooperative
IS Revenue Requirement Worksheet
Third Party Payments and Receipts
December 31, 2007

Worksheet 3

Third Party Payments

ICCUA		224,112
LaCreek Electric		101,678
Total Payments	**$**	**321,644**

Third Party Receipts

ICCUA		338,508
MAPP		1,095,550
Total Receipts	**$**	**1,434,058**

Basin Electric's Ancillary Services Cost Data

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

For the 12 months ended 12/31/07

	East	West	Groton	Other
GROSS REVENUE REQUIREMENT (page 3, line 27)	$ 279,494,015	$ 72,867,786	$ 7,549,373	$10,453,214
Percent of revenue requirement to net plant	50.3189%	32.7505%	16.9585%	16.3054%

Production	LOS	AVS	SM	LRS	Groton	Other
$ 370,364,389	$ 103,795,696	$ 174,476,793	$ 1,221,526	$ 72,867,786	$ 7,549,373	$ 10,453,214

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

For the 12 months ended 12/31/07

Line No.	(1)	(2) RUS Form 12 Reference	(3) Company Total	(4) Allocator		(5) Production	(6) LOS	(7) AVS	(8) SM	(9) LRS	(10) Groton	(11) Other
	GROSS PLANT IN SERVICE											
1	Production	12h.A.6.	1,839,659,587	DA		1,839,659,587	291,769,947	850,265,622	24,930,271	553,474,334	46,490,961	72,728,452
2	Transmission	12h.A.11	503,657,186	NA								
3	Distribution	12h.A.16	-	NA		-						
4	General	12h.A.17	116,407,311	WS		-						
4a	Direct Assign - Transmission		35,340,593	NA		-						
4b	Direct Assign - Production		23,130,076	DA		20,597,064	6,277,782	7,392,229	230,428	6,414,072	106,001	176,553
4c	Other		57,936,642	WS	88.737%	51,411,483	15,127,002	21,105,853	179,709	14,570,533	242,244	186,141
5	Intangible	12h.A.1	69,684,061	NA		4,230,855	-	1,049,145	-	-	-	3,181,710
6	TOTAL GROSS PLANT (sum lines 1,2,4,5)	12h.A.18 (Note A)	$ 2,529,408,145			1,915,898,989	313,174,731	879,812,849	25,340,408	574,458,939	46,839,206	76,272,857
				GP	75.745%		12.381%	34.783%	1.002%	22.711%	1.852%	3.015%
	ACCUMULATED DEPRECIATION											
7	Production	12h.B.1-4	976,692,543	DA		976,692,543	170,651,365	433,749,446	21,222,541	337,053,306	2,122,626	11,893,259
8	Transmission	12h.B.5	241,259,126	NA			-	-	-	-		-
9	Distribution	12h.B.6	-	NA		-	-	-	-	-		-
10	General	12h.B.7	81,560,753	WS			-	-	-	-		-
10a	Direct Assign - Transmission		24,822,121	NA		-	-	-	-	-		-
10b	Direct Assign - Production		18,382,311	DA		18,382,311	6,481,630	6,354,402	203,760	5,265,729	39,524	37,266
10c	Other		38,356,320	WS	88.737%	34,036,410	10,014,666	13,972,899	118,975	9,646,262	160,375	123,233
11	Intangible	12h.B.12	40,859,984	DA		223,430	-	113,308	-	-	-	110,122
12	TOTAL ACCUM. DEPR (sum lines 7,8,10,11)	12h.B.18	$ 1,340,372,406			$1,029,334,694	187,147,661	454,190,055	21,545,276	351,965,297	2,322,525	12,163,881
	NET PLANT IN SERVICE											
13	Production	(line 1 - line 7)	862,967,044	AUTO		862,967,044	121,118,582	416,516,176	3,707,730	216,421,028	44,368,334	60,835,193
14	Transmission	(line 2 - line 8)	262,398,060	AUTO			-	-	-	-	-	-
15	Distribution	(line 3 - line 9)	-	AUTO		-	-	-	-	-		-
16	General	(line 4 - line 10)	34,846,558	AUTO		-	-	-	-	-		-
16a	Direct Assign	(line 4a - line 10a)	10,518,471	AUTO		-	-	-	-	-		-
16b	Production	(line 4b - line 10b)	4,747,765	AUTO		2,214,753	(203,848)	1,037,827	26,668	1,148,343	66,477	139,287
16c	Other	(line 4c - line 10c)	19,580,322	AUTO		17,375,073	5,112,336	7,132,954	60,735	4,924,271	81,869	62,908
17	Intangible	(line 5 - line 11)	28,824,077	AUTO		4,007,425	-	935,837	-	-	-	3,071,588
18	TOTAL NET PLANT (sum lines 13, 14, 16, 17)		$ 1,189,035,739			886,564,295	126,027,070	425,622,794	3,795,133	222,493,642	44,516,680	64,108,976
				NP	74.562%		10.599%	35.796%	0.319%	18.712%	3.744%	5.392%

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

For the 12 months ended 12/31/07

No.	(1)	(2) Reference	(3) Company Total	(4) Allocator		(5) Production	(6) LOS	(7) AVS	(8) SM	(9) LRS	(11) Groton	(10) Other
	O&M											
1	Production	12a.A.5+ A.15	207,937,888	DA		207,937,888	72,064,572	94,347,653	513,374	38,985,836	913,300	1,113,153
2	A&G	12a.A.13	43,028,667									
3	Less Regulatory Fees	Accounting Records	533,335	NA		-	-	-	-	-		-
4	Production (Note B)		2,083,523	DA	0.000%	-	-	-	-	2,083,523		-
5	Transmission (Note C)		1,306,008	NA		-	-	-	-	-		-
6	Headquarters		39,105,801	WSW	84.953%	33,221,677	13,640,918	19,032,404	162,054	-	218,446	167,855
7	TOTAL O&M (sum lines 1 and 2)		$ 250,966,555			243,243,088	85,705,490	113,380,057	675,429	41,069,360	1,131,746	1,281,008
	DEBT SERVICE											
8	Interest Expense	12a.A.22-24	70,529,802	NP	74.562%	52,588,162	7,475,523	25,246,585	225,115	13,197,612	2,640,587	3,802,740
9	Principal Payments	12h.H.9	76,513,245	NP	74.562%	57,049,514	8,109,714	27,388,396	244,213	14,317,240	2,864,603	4,125,348
10	Amort of Debt Discount (428)	12a.A.26	3,462,661	NP		-	-	-	-	-		-
11	Transmission	Accounting Records	903,541	NA		-	-	-	-	-		-
12	Headquarters	Accounting Records	52,148	WSW	84.953%	44,301	18,190	25,380	216	-	291	224
13	Production	Accounting Records	2,504,617	DA		2,504,617	363,777	1,266,505	12,622	535,535	162,236	163,942
14	Other Deductions	12a.A.26	7,456,104	NA		-	-	-	-	-	-	-
15	TOTAL DEBT SERVICE (Sum lines 8,9,10,14)		$ 157,961,812			112,186,594	15,967,205	53,926,865	482,166	28,050,387	5,667,718	8,092,253
	TAXES OTHER THAN INCOME TAXES											
	LABOR RELATED											
	Payroll		-	WS		-	-	-	-	-	-	-
16	Highway and vehicle		-	WS		-	-	-	-	-	-	-
17	PLANT RELATED											
18	Property and Other Total	12a.A.21 (excludes income tax)	1,429,917	GP		-	-	-	-	-	-	-
19	Property Headquarters	Accounting Records	(59,386)	NA	0.000%	-	-	-	-	-	-	-
20	Gross Receipts Tax	12a.A.21	1,489,303	NA		-	-	-	-	-	-	-
21	Production (Note D)			DA		-	-	-	-	-	-	-
22	TOTAL OTHER TAXES		$ 1,429,917			-	-	-	-	-	-	-
23	**TOTAL OPERATING EXPENSES (Sum 7+15+22)**		$ 410,358,284			355,429,683	101,672,695	167,306,922	1,157,595	69,119,747	6,799,463	9,373,260
24	**Margin**		$ 20,030,019	NP	74.562%	$14,934,706	$2,123,001	$7,169,871	$63,931	$3,748,039	$749,910	$1,079,954
25	**REV. REQUIREMENT (sum lines 23 + 24)**		$ 430,388,303			$370,364,389	$103,795,696	$174,476,793	$1,221,526	$72,867,786	$7,549,373	$10,453,214

Line # **WAGES AND SALARY ALLOCATOR (W/S)**

(1)	(2)	(3) TOTAL	(4) Allocator		(5) Production	(6) LOS	(7) AVS	(8) SM	(9) LRS	(11) Groton	(10) Other
1	Production - LOS	$10,257,359	WS	88.737%	$34,861,239	26.110%	36.429%	0.310%	25.149%	0.4181%	0.3213%
2	Production - AVS	$14,311,515	WSW (Excludes LRS)	84.953%	$29,405,810	34.882%	48.669%	0.414%		0.559%	0.429%
3	Production - SM	$121,858									
4	Production - LRS	$9,880,027	PRWS			29.423%	41.053%	0.350%	28.341%	0.471%	0.362%
5	Production - Groton	$164,262	PRWSW (Excludes LRS)		$24,981,212	41.060%	57.269%	0.488%		0.656%	0.505%
6	Production - Other	$126,219									
7	Transmission	$4,424,598									
8	Other	$0									
	Total Wages and Salaries (exclude adm)	**$39,285,837**									

Note

A Total does not include plant held for future use or CWIP
B A&G costs directed allocated to MBPP - Costs split between MBPP Production and MBPP Transmission based on MBPP Wages
C Includes OASIS costs for West Side and Common Use System plus A&G costs allocated to MBPP Transmission
D Production taxes are included in the RUS 500 series of accounts.

Basin Electric Power Cooperative
IS Ancillary Services
Regulation and Frequency Response - 2007

Summary

A	Total LOS and AVS Net Plant Investment	$	537,634,758	(ancillary worksheet 5)
B	Facilities with AGC (LOS 1 & AVS)	$	448,511,285	(Ancillary worksheet 5 less LOS 2)
C	B/A		83.4230%	
D	AGC Facilities	$	64,041	
E	AGC Facilities Percentage (D/B)		0.0143%	
F	Generation Revenue Requirement	$	232,143,383	(Generation revenue require * line C percent)
G	Plant Allocated to AGC	$	33,147	(E x F)
H	**Regulation Revenue Requirement**	**$**	**97,188**	(D + G)

Basin Electric Power Cooperative
IS Ancillary Services
Reactive Supply and Voltage Control - 2007

SUMMARY

Plant	Reactive Power Costs	Revenue Require Percentage	Ancillary Services Revenue Require	Fuel Cost	Total Costs
LOS #1	64,826	50.3189%	32,620	25,776	58,396
LOS #2	394,419	50.3189%	198,468	62,053	260,521
AVS #1	1,694,506	50.3189%	852,657	51,983	904,640
AVS #2	338,485	50.3189%	170,322	44,215	214,538
Spirit Mound (Units 1 & 2)	99,195	50.3189%	49,914	725	50,638
Groton	770,420	16.9585%	130,652	7,961	138,613
LRS - BEPC*	1,245,918	32.7505%	408,044	87,942	32,734
LRS - HCPD	116,020	41.6900%	48,369	6,286	54,655
Reactive Supply and Voltage Control Requirement					$ 1,714,735

*Costs prorated on east side capacity entitlement to total LRS plant capacity (0.065997).

Basin Electric Power Cooperative
IS Ancillary Services
Reactive Allocation Factor - 2007

Ancillary
Worksheet 1

Allocation Factor for Reactive Power Support Portion of Generator Capacity

Unit	A Reactive Rating (MVAR)	B * Generator Rating (MVA)	E Alloc Factor A^2/(B^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
Groton	35.00	127.30	0.070280
LRS Unit #1	300.00	593.00	0.203782
	1,234.00	**2,524.30**	

*URGE ratings from 2003 case

Basin Electric Power Cooperative
IS Ancillary Services
Reactive Supply And Voltage Control Allocation Factor - 2007

Ancillary
Worksheet 2

Allocation Factor for Reactive Power Support Portion of Exciter Capacity

	A	B	C	D	E	F	
Unit	Rated Exciter Current A	Maxium Current @Full Load (A)	Minimum Current @ Full Load (A)	AMPS Use Reactive Power Support (Max-Min)	(D/B) Use	Rated Voltage	Rated MW (a*f)/10^6
LOS #1	2,849	2,849	990	1,859	0.652510	375	1.0684
LOS #2	5,425	5,425	1,885	3,540	0.652535	430	2.3328
AVS #1	5,625	5,625	1,945	3,680	0.654222	400	2.2500
AVS #2	5,625	5,625	1,945	3,680	0.654222	400	2.2500
Spirit Mound #1					0.653372		2.0541
Spirit Mound #2 (Avg)					0.626640	290	0.2874
Groton	991	991	370	621	0.360614	505	2.3695
LRS Unit #1	4,692	4,692	3,000	1,692			12.6121
Total							

Generator Summary
Summer Peak Load
2007

Bus	Name	BSVLT	COD	MCNS	MW	MVAR	QMAX	QMIN
67103	ANTEL31	G24.0	2	1	480.0	93.9	200.0	-175.0
67107	ANTEL32	G24.0	2	1	480.0	93.9	200.0	-175.0
67110	LELAN41	G22.0	2	1	225.0	-22.0	120.0	-90.0
67111	LELAN32	G20.0	2	1	475.0	-18.8	225.0	-56.0
67116	SPIRIT71	G13.8	-2	0	0.0	0.0	30.0	-15.0
67117	SPIRIT72	G13.8	-2	0	0.0	0.0	30.0	-15.0
67274	GROTON1	G13.8	2	0	72.0	28.1	30.0	-15.0
67118	LARAM31	G24	2	1	593.5	48.8	285	-83.0
	TOTAL				**2325.5**	**305.5**	**1120.0**	**624.0**

Generator Summary
Winter Peak Load
2007

Bus	Name	BSVLT	COD	MCNS	MW	MVAR	QMAX	QMIN
67103	ANTEL31	G24.0	2	1	480.0	61.7	200.0	-175.0
67107	ANTEL32	G24.0	2	1	480.0	61.7	200.0	-175.0
67110	LELAN41	G22.0	2	1	187.0	-62.3	120.0	-90.0
67111	LELAN32	G20.0	-2	1	165.0	-56.0	225.0	-56.0
67116	SPIRIT71	G13.8	-2	0	0.0	0.0	30.0	-15.0
67117	SPIRIT72	G13.8	-2	0	0.0	0.0	30.0	-15.0
67274	GROTON1	G13.8	2	0	0.0	0.0	30.0	-15.0
67118	LARAM31	G24	2	1	593.5	58.2	285	-83.0
	TOTAL				**1905.5**	**299.9**	**1120.0**	**624.0**

Basin Electric Power Cooperative
IS Ancillary Services
Reactive Power Costs - 2007

Real Power Allocation Ratio - Other Plant

Exciter MW Requirements (worksheet 2) / Generator MW Capacity (worksheet 1)	X	Generator MVAR @ Peak (worksheet 3) / Generator MVAR Capability (worksheet 1)	=
12.6121 MW / 2,524.30 MW	X	305.5 MVAR / 1,234 MVAR	=

0.1237%

Reactive Power Costs
Real Power Allocation Ratio - Fuel

Exciter MW Requirements (worksheet 2) / MWH generated	X	Generator MVAR @ Avg (worksheet 3) / Generator MVAR Capability (worksheet 1)	=
12.6121 MW / 17,415,306 MWH	X	302.7 MVAR / 1,234 MVAR	=

0.1556%

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

Generating Plant Costs
As of December 31, 2007
(Net Plant)

Line #	Description	LOS # 1	LOS #2	AVS #1	AVS #2	SM	LRS	Groton	Other	HCPD
1	Generating Plant (ACCT 310-348)	31,995,109	89,123,473	312,697,579	103,818,597	3,707,730	216,421,028	44,368,334	60,835,193	26,518,431
2	**Total Plant**	**$ 31,995,109**	**$ 89,123,473**	**$ 312,697,579**	**$ 103,818,597**	**$ 3,707,730**	**$ 216,421,028**	**$ 44,368,334**	**$ 60,835,193**	**$ 26,518,431**
	Generators									
3	Total Plant	53,968	884,188	4,175,107	(leased)	208,784	2,425,984	2,460,378		254,128
4	Allocated to Reactive Power (Wkst 1)	27.5508%	17.3333%	18.1833%	18.1228%	32.0955%	20.3782%	7.0280%		20.3782%
5	Reactive Power Plant (L3*L4)	**$ 14,869**	**$ 153,259**	**$ 759,174**	**$ -**	**$ 67,010**	**$ 494,371**	**$ 172,915**		**$ 51,787**
	Exciters									
6	Total Plant	15,276	63,174	448,552	(leased)	39,404	478,922	434,184		47,564
7	Allocated to Reactive Power (Wkst 2)	65.2510%	65.2535%	65.4222%	65.4222%	65.3372%	36.0614%	62.6640%		36.0614%
8	Reactive Power Plant (L6*L7)	**$ 9,968**	**$ 41,223**	**$ 293,453**	**$ -**	**$ 25,746**	**$ 172,706**	**$ 272,077**		**$ 17,152**
	Voltage Regulators									
9	Total Plant	408	86,451	22,428	(leased)	1,970	72,780	100,000		7,624
10	Allocated to Reactive Power (100%)	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%		100.0000%
11	Reactive Power Plant (L9*L10)	**$ 408**	**$ 86,451**	**$ 22,428**	**$ -**	**$ 1,970**	**$ 72,780**	**$ 100,000**		**$ 7,624**
	Step-Up Transformers									
12	Total Plant	587	222,696	1,569,189	1,425,294	-	1,704,205	735,347		48,078
13	Allocated to Reactive Power (Wkst 6)	6.2500%	1.6162%	14.9306%	14.7569%	0.0000%	14.0580%	23.3133%		14.0580%
14	Reactive Power Plant (L12*L13)	**$ 37**	**$ 3,599**	**$ 234,289**	**$ 210,330**	**$ -**	**$ 239,577**	**$ 171,433**		**$ 6,759**
	Other Plant									
15	Total Plant (L2-L5-L8-L11-L14)	31,969,828	88,838,941	311,388,236	103,608,267	3,613,004	215,441,595	43,651,909		26,435,109
16	Allocated to Reactive Power (Wkst 4)	0.1237%	0.1237%	0.1237%	0.1237%	0.1237%	0.1237%	0.1237%		0.1237%
17	Reactive Power Plant (L15*L16)	**$ 39,544**	**$ 109,887**	**$ 385,163**	**$ 128,155**	**$ 4,469**	**$ 266,484**	**$ 53,994**		**$ 32,698**
	Total Reactive Power Plant									
18	(L5+L8+L11+L14+L17)	**$ 64,826**	**$ 394,419**	**$ 1,694,506**	**$ 338,485**	**$ 99,195**	**$ 1,245,918**	**$ 770,420**		**$ 116,020**
	Fuel Expense									
19	Total	16,563,792	39,875,592	33,404,422	28,412,935	465,600	56,511,974	5,115,916		4,039,661
20	Allocated to Reactive Power (wkst 4)	0.1556%	0.1556%	0.1556%	0.1556%	0.1556%	0.1556%	0.1556%		0.1556%
21	Reactive Power Expense (L19*L20)	**$ 25,776**	**$ 62,053**	**$ 51,983**	**$ 44,215**	**$ 725**	**$ 87,942**	7,961		**$ 6,286**

Basin Electric Power Cooperative
IS Ancillary Services
Transformer Allocation
Reactive Power Costs

Ancillary
Worksheet 6

A	B	C	D
Plant	Transformer MVA *	Generator	Allocation Ratio (B-C/B)
AVS #1	576	490	0.149306
AVS #2	576	491	0.147569
LO #1	256	240	0.062500
LO #2	495	487	0.016162
SM #1	72	52	0.277778
SM #2	72	44	0.388889
Groton	166	127.3	0.233133
LRS #3	690	593	0.140580

* Emergency Rating

Missouri River Energy Services
Ancillary Services
Cost Data

Generation Revenue Requirement For the 12 months ended 12/31/07
EIA 412
Missouri River Energy Services/ Western Minnesota

	Production	LRS	WPP	Exira	Other
GROSS REVENUE REQUIREMENT (page 3, line 27)	$ 48,925,897	$37,480,486	$2,100,409	$ 8,888,227	$ 456,775
Net Plant	$141,693,207	$57,421,304	$5,957,634	$ 75,226,152	$ 3,088,117
Percent of revenue requirement to net plant	34.53%	65.27%	35.26%	11.82%	14.79%

Generation Revenue Requirement For the 12 months ended 12/31/07
EIA 412
Missouri River Energy Services/ Western Minnesota

Line No.	(1)	(2) EIA 412 Reference	(3) Company Total	(4) Allocator		(5) Production	WMMPA LRS	WMMPA WPP	WMMPA Exira	WMMPA Wind
	GROSS PLANT IN SERVICE									
1	Production		272,168,356	DA	1.00000	272,168,356	171,973,267	17,842,746	78,803,536	3,548,807
2	Transmission		59,848,790	NA	0.00000	-				
3	Distribution		-	NA		-				
4	General		13,151,035	WS	0.73791	9,704,303	6,131,795	636,192	2,809,781	126,535
4a	Direct Assign - Transmission			NA		-				
4b	Direct Assign - Production			DA		-				
4c	Other			WS		-				
5	Intangible		9,775,844	NA	0.00000					
6	TOTAL GROSS PLANT (sum lines 1,2,4,5)		$ 354,944,025	GP	79.413%	281,872,659	178,105,062	18,478,938	81,613,317	3,675,342
				$ -						
	ACCUMULATED DEPRECIATION									
7	Production		135,353,358	DA	1.00000	135,353,358	116,528,861	12,090,221	6,167,267	567,008
8	Transmission		29,763,690	NA		-				
9	Distribution			NA		-				
10	General		6,540,205	WS	0.73791	4,826,093	4,154,896	431,083	219,897	20,217
10a	Direct Assign - Transmission			NA		-				
10b	Direct Assign - Production			DA		-				
10c	Other			WS		-				
11	Intangible		4,861,672	DA		-				
12	TOTAL ACCUM. DEPR (sum lines 7,8,10,11)		$ 176,518,925			140,179,451	120,683,758	12,521,304	6,387,164	587,225
	NET PLANT IN SERVICE									
13	Production	(line 1- line 7)	136,814,998	AUTO		136,814,998	55,444,406	5,752,525	72,636,269	2,981,799
14	Transmission	(line 2- line 8)	30,085,099	AUTO		-				
15	Distribution	(line 3 - line 9)	-	AUTO		-				
16	General	(line 4 - line 10)	6,610,831	AUTO		4,878,209	1,976,899	205,109	2,589,883	106,318
16a	Direct Assign	(line 4a - line 10a)	-	AUTO		-				
16b	Production	(line 4b - line 10b)	-	AUTO		-				
16c	Other	(line 4c - line 10c)	-	AUTO		-				
17	Intangible	(line 5 - line 11)	4,914,172	AUTO		-				
18	TOTAL NET PLANT (sum lines 13, 14, 16, 17)	12a.B.L5 less L2	$ 178,425,100	NP	79.413%	$ 141,693,207	57,421,304	5,957,634	75,226,152	3,088,117
				$ -						

09

Generation Revenue Requirement For the 12 months ended 12/31/07
EIA 412
Missouri River Energy Services/ Western Minnesota

No.	(1)	(2) Reference	(3) Company Total	(4) Allocator		(5) Production	WMMPA LRS	WPP	Exira	Other
	O&M									
1	Production		**15,976,831**	DA	1.00000	15,976,831	14,723,259	267,085	905,864	80,623
2	A&G		**8,143,587**	WS	81.662%	6,650,250	6,128,459	111,172	377,060	33,559
3	Less Regulatory Fees			NA		-				
4	Production			NA						
5	Transmission			NA		-				
6	Headquarters			NA						
7	TOTAL O&M (sum lines 1 and 2)		$ 24,120,418			22,627,081	20,851,718	378,257	1,282,924	114,182
	DEBT SERVICE									
8	Debt Service- Excluding Transmission Bond Resolution		**23,207,223**	GP 2	88.575%	20,555,844	12,988,489	1,347,595	5,951,732	268,028
9	Debt Service- Transmission Bond Resolution		**2,220,036**	NA	0.000%	-	-	-	-	-
10	Amort of Debt Discount (428)			Excluded		-	-	-	-	-
11	Transmission			NA		-	-	-	-	-
12	Headquarters			WS			-	-	-	-
13	Production			DA			-	-	-	-
14	Other Deductions			NA		-	-	-	-	-
15	TOTAL DEBT SERVICE (Sum lines 8,9,10,14)		$ 25,427,259		80.842%	20,555,844	12,988,489	1,347,595	5,951,732	268,028
				$ -						
	TAXES OTHER THAN INCOME TAXES									
	LABOR RELATED									
	Payroll		-	WS		-				
16	Highway and vehicle		-	WS		-				
17	PLANT RELATED									
18	Property and Other Total			GP		-				
19	General Plant		48,634	GP	81.662%	39,716	36,600	664	2,252	200
20	Gross Receipts Tax			NA		-				
21	Production (Note C)		655,102	DA	100.000%	655,102	413,935	42,947	189,678	8,542
22	TOTAL OTHER TAXES		$ 703,736	$ 211,441		$ 694,818	450,535	43,611	191,930	8,742
23	**TOTAL OPERATING EXPENSES (Sum 7+15+22)**		$ 50,251,413			43,877,743	34,290,741	1,769,463	7,426,586	390,952
24	Margin	$ -	$ 6,356,815	GP	79.413%	$5,048,154	3,189,745	330,946	1,461,641	65,823
25	**REV. REQUIREMENT (sum lines 23 + 24)**		$ 56,608,228		86.416%	$ 48,925,897	$ 37,480,486	$ 2,100,409	$ 8,888,227	$ 456,775

Generation Revenue Requirement For the 12 months ended 12/31/07
EIA 412
Missouri River Energy Services/ Western Minnesota

Line # WAGES AND SALARY ALLOCATOR (W/S)

(1)	(2)		(3) TOTAL	(4) Allocator	(5) Production	Production W/S Allocator
			$		Allocation	
1	Production		1,612,292	1.00	1,612,292	73.791%
2	Transmission		572,647	0.00	0	
3	Distribution		0	0.00	0	
4	Other		-		-	
5	Total (sum lines 18-21)	$ -	$ 2,184,939		$ 1,612,292	

Missouri River Energy Services/ Western Minnesota

IS Ancillary Services

Reactive Supply and Voltage Control - 2007

SUMMARY

Plant	Reactive Power Costs	Revenue Require Percentage	Ancillary Services Revenue Require	Fuel Cost	Total Costs
LRS - MRES/WMMPA	$ 330,893	65.2728%	$ 215,983	$ 34,111	$ 250,094
Exira	$ 447,806	11.8153%	$ 52,910	$ 8,767	$ 61,676
Watertown Power Plant	$ 79,117	35.2558%	$ 27,893	$ 233	$ 28,127
					$ 339,897

Missouri River Energy Services/ Western Minnesota

IS Ancillary Services

Reactive Allocation Factor - 2007

Ancillary

Worksheet 1

Allocation Factor for Reactive Power Support Portion of Generator Capacity

Unit	A Reactive Rating (MVAR)	B * Generator Rating (MVA)	E Alloc Factor A^2/(B^2+A^2)
LRS Unit #1**	300.00	593.00	0.203782
WPP	32.69	75.00	0.159650
Exira 1	26.00	71.18	0.117729
Exira 2	26.00	71.18	0.117729
Exira 3	26.00	71.18	0.117729
Total Exira	78.00	213.53	0.117729

** = Used Basin 2006%.

Missouri River Energy Services/ Western Minnesota

Ancillary

IS Ancillary Services

Worksheet 2

Reactive Supply And Voltage Control Allocation Factor - 2007

Allocation Factor for Reactive Power Support Portion of Exciter Capacity

	A	B	C	D	E	F	
Unit	Rated Exciter Current A	Maxium Current @Full Load (A)	Minimum Current @ Full Load (A)	AMPS Use Reactive Power Support (Max-Min)	(D/B) Use	Rated Voltage	Rated MW (a*f)/10^6
WPP **	640	640	552	88	0.137500	285	0.01824
Exira 1	2,977	2,977		2,977	0.249057	185	0.05507
Exira 2	2,977	2,977		2,977	0.249057	185	0.05507
Exira 3	2,977	2,977		2,977	0.249057	185	0.05507
Total Exira *	8,931	8,931		8,931	0.249057	555	0.49567
LRS Unit #1**	4,692	4,692	3,000	1,692	0.360614	505	2.3695
Total							3.0486
	* = Average of WPP & LRS.				0.2491		
	** = Used Basin 2006%.						

Missouri River Energy Services/ Western Minnesota Ancillary

IS Ancillary Services

Worksheet 5

Reactive Power/Voltage Control

Generating Plant Costs
As of December 31, 2007
(Net Plant)

Line #	Description	Basin for LRS- 2006 #s	MRES/WMMPA LRS *	WPP	Exira	Other	Total Gen.	Source
1	Net Generating Plant (ACCT 310-348)	$ 223,446,307	$ 55,444,406	$ 5,752,525	$ 72,636,269	$ 2,981,799	$ 136,814,998	
2	**Total Plant**	$ 223,446,307	$ 55,444,406	$ 5,752,525	$ 72,636,269	$ 2,981,799	$ 136,814,998	
	Generators		1.15%	5.84%	2.50%			
3	Total Plant	2,579,141	639,995	335,947	1,815,907			
4	Allocated to Reactive Power (Wkst 1)	20.3782%	20.3782%	15.9650%	11.7729%			
5	Reactive Power Plant (L3*L4)	$ 525,582	$ 130,419	$ 53,634	$ 213,784	$ -	$ 397,837	Worksheet 1
	Exciters		0.23%	1.10%	0.30%			
6	Total Plant	512,397	127,134	63,370	217,909			
7	Allocated to Reactive Power (Wkst 2)	36.0614%	36.0614%	13.7500%	24.9057%			
8	Reactive Power Plant (L6*L7)	$ 184,777	$ 45,846	$ 8,713	$ 54,272	$ -	$ 108,831	Worksheet 2
	Voltage Regulators		0.03%	0.06%	0.05%			
9	Total Plant	77,374	19,184	3,168	36,318			
10	Allocated to Reactive Power (100%)	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%		N/A
11	Reactive Power Plant (L9*L10)	$ 77,374	$ 19,184	$ 3,168	$ 36,318	$ -	$ 58,670	
	Step-Up Transformers		0.80%	0.30%	0.30%			
12	Total Plant	1,776,946	440,919	17,258	217,909			
13	Allocated to Reactive Power (Wkst 6)	14.0580%	14.0580%	35.0000%	21.6667%			Worksheet 6
14	Reactive Power Plant (L12*L13)	$ 249,803	$ 61,984	$ 6,040	$ 47,214	$ -	$ 115,238	
	Other Plant		99.54%	98.76%	99.52%			
15	Total Plant (L2-L5-L8-L11-L14)	222,408,772	55,186,972	5,680,969	72,284,682	2,981,799		
16	Allocated to Reactive Power*	0.1331%	0.1331%	0.1331%	0.1331%			N/A- Used Basin #
17	Reactive Power Plant (L15*L16)	$ 296,049	$ 73,459	$ 7,562	$ 96,218	$ -	$ 177,240	
18	**Total Reactive Power Plant** (L5+L8+L11+L14+L17)	$ 1,333,585	$ 330,893	$ 79,117	$ 447,806	$ -	$ 857,816	
	Fuel Expense							
19	Total	55,605,347	21,659,282	148,052	5,566,544	0		
20	Allocated to Reactive Power*	0.1575%	0.1575%	0.1575%	0.1575%	0.1575%		N/A- Used Basin #
21	Reactive Power Expense (L19*L20)	$ 87,571	$ 34,111	$ 233	$ 8,767	$ -	$ 43,110	

* = Used BEPC 2006 % to allocate MRES LRS $.

Missouri River Energy Services/ Western Minnesota

IS Ancillary Services

Transformer Allocation

Reactive Power Costs

Ancillary

Worksheet 6

A	B	C	D
Plant	Transformer MVA *	Generator	Allocation Ratio (B-C/B)
LRS **	690	593	0.140580
WPP	80	52	0.35000
Exira 1	60	47	0.2166667
Exira 2	60	47	0.2166667
Exira 3	60	47	0.2166667
Total Exira	180	141	0.2166667

** = Used Basin 2006%.

* Emergency Rating

Heartland's
Transmission Cost Data

HEARTLAND CONSUMERS POWER DISTRICT 30-Apr-08
INTEGRATED SYSTEM TRANSMISSION REVENUE REQUIREMENT
December 31, 2007

MBPP TRANSMISSION FACILITIES

Line	Description	Cost of Service Amount	
1.	Transmission Plant Investment	$7,290,954.06	Page 3, Line L50+Page 5 Line T48
2.	Less Accumulated Depreciation & IDC	($4,953,519.55)	Page 3, Lines M50,N50 + Page 5 Lines U48,V48
3.	General Plant - Trans Share	$175,963.11	Page 3, Line L52 + Page 5 Line T49
4.	Less Accum Depre & IDC-GP-Trans	($94,605.69)	Page 3, Lines M52,N52 + Page 5 Lines U49,V49
5.	Materials & Supplies - Trans	$0.00	Page 2, Lines C88,F88
6.	Cash Working Capital	$26,271.12	1/12 of Line 16 + 17 (this page)
7.	**Transmission Investment Rate Base**	**$2,445,063.05**	
8.			
9.	Rate of Return * 6.57%	$160,640.64	Line 7 x Line 9 rate (this page)
10.	Transmission Depr Expense	$303,319.65	Page 3, Line P50 + Page 5, Line X48
11.	GP Depr Expense - Trans Share	$5,795.01	Page 3, Line P52 + Page 5, Line X49
12.	GP Maintenance	$0.00	Page 1, Lines C42,F42
13.	Income Tax	$0.00	Page 1, Lines C47,F47
14.	Taxes Other than Income	$23,257.83	Page 1, Lines C52,C54,F52,F54
15.	A & G Expenses	$14,443.05	Page 2, Lines C66, F66
16.	Transmission O & M	$218,449.07	Page 2, Lines C73,F73
17.	Less:Trans of Elect by Others	$96,804.36	Page 2, Lines C82,F82
18.	**Subtotal Transmission Revenue Requirement**	**$822,709.62**	
19.			
20.	Annual Trans Third Party Payment	$0.00	
21.	Annual Trans Third Party Revenue	$0.00	
22.			
23.	**Total MBPP Transmission Revenue Requirement**	**$822,709.62**	

TRANSMISSION PROJECTS 1 AND 3 FACILITIES (PREVIOUSLY APPROVED IS FACILITIES)

Line	Description	Cost of Service Amount	
24.	Transmission Plant Investment **	$1,292,610.66	Page 4, Line L66,L69
25.	Less Accumulated Depreciation & IDC **	($506,322.24)	Page 4, Lines M66,69,N66,69
26.	General Plant - Trans Share	$111,025.93	Page 4, Line L80
27.	Less Accum Depre & IDC-GP-Trans	($75,299.91)	Page 4, Lines M80,N80
28.	Materials & Supplies - Trans	$0.00	Page 2
29.	Cash Working Capital	$2,815.06	1/12 of Line 39 + 40 (this page)
30.	**Transmission Investment Rate Base**	**$824,829.50**	
31.			
32.	Rate of Return * 6.57%	$54,191.30	Line 30 x Line 32 rate (this page)
33.	Transmission Depr Expense **	$31,033.66	Page 4, Line P66,P69
34.	GP Depr Expense - Trans Share	$4,822.01	Page 4, Line P80
35.	GP Maintenance	$2,989.98	Page 1, Line C41
36.	Income Tax	$0.00	Page 1, Line C47
37.	Taxes Other than Income	$6,471.72	Page 1, Lines C51,C53,C55,C56
38.	A & G Expenses	$66,307.70	Page 2, Line C65
39.	Transmission O & M	$33,780.69	Page 2, Line C71,C72,C74
40.	Less:Trans of Elect by Others	$0.00	Page 2, Line C83
41.	**Subtotal Transmission Revenue Requirement**	**$199,597.06**	
42.			
43.	Annual Trans Third Party Payment	$0.00	
44.	Annual Trans Third Party Revenue	$14,599.01	Revenues from MAPP Schedule F
45.			
46.	**Total Transmission Project 1 and 3 Revenue Requirement**	**$184,998.05**	

INTEGRATED SYSTEM TRANSMISSION REVENUE REQUIREMENT	**$1,007,707.68**	Line 23 + 46 (this page)

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

	A	B	C	D	E	F	G	H	I
1	HCPD TRANSMISSION & GENERAL PLANT (EAST SIDE & WEST SIDE)					k:\data\accounting\transm07			
2	December 31, 2007					30-Apr-08			
3	Page 1 of 6								
4		HCPD Invest	East Side	Depr	IDC	West Side	Depr	IDC	
5	LRS	$49,746,891.00	$3,504,561.44	30.19%	30.05%	$3,962,355.74	100.00%	100.00%	
6	TP-I	$907,635.18	$907,635.18	7.82%	7.78%		0.00%	0.00%	
7	TP-II	$6,752,305.09	$6,752,305.09	58.17%	57.91%		0.00%	0.00%	
8	TP-II Marshall	$0.00	$0.00	0.00%	0.00%		0.00%	0.00%	
9	TP-III Groton	$384,975.48	$384,975.48	3.32%	3.30%		0.00%	0.00%	
10		$57,791,806.75	$11,549,477.19			$3,962,355.74			
11			*9.40%*			*7.59%*			
12	General Plant Improvement	$617,234.18	$58,013.47	0.50%	0.50%	$0.00	0.00%	0.00%	
13	Furniture & Equipment	$128,606.49	$12,087.65		0.10%	$0.00		0.00%	
14	Furniture & Equipment-EPD	$325,113.36	$30,557.21		0.26%	$0.00		0.00%	
15	Transportation Equipment	$55,329.26	$5,200.36		0.04%	$0.00		0.00%	
16	Headquarter's Improvement	$54,976.84	$5,167.24		0.04%	$0.00		0.00%	
17									
18		$58,973,066.88	$11,660,503.12	100.00%	100.00%	$3,962,355.74	100.00%	100.00%	
19									
20									
21		Depreciation	East Side			West Side			
22	Accum Depr-Plant	$34,411,833.16	$3,234,347.52			$2,611,067.32			
23	Accum Depr-Gen'l Plant	$448,304.13	$42,135.84						
24	Accum Depr-Trans Equip	$47,305.43	$4,446.21						
25									
26		$34,907,442.72	$3,280,929.57			$2,611,067.32			
27									
28		Int During Const	East Side			West Side			
29	1977 IDC	$29,680,964.00							
30	1979 IDC	$28,763,565.00							
31	Times 24%	$14,026,687.00	$1,318,359.88			$1,064,303.20			
32									
33		Annual Depr	East Side			West Side			
34	Depr Exp-Plant	$2,965,000.00	$278,678.57			$224,975.36			
35	Depr Exp-Gen'l Plant	$29,424.34	$2,765.58						
36	Depr Exp-Trans Equip	$7,060.56	$663.62						
37									
38		$3,001,484.90	$282,107.76			$224,975.36			
39									
40		GP Maint	East Side			West Side			
41	HCPD	$118,061.25	$2,989.98						
42	MBPP		$0.00			$0.00			
43	LRS		$0.00			$0.00			
44		$118,061.25	$2,989.98						
45									
46		Income Tax	East Side			West Side			
47		$2,000.00	$0.00			$0.00			
48									
49		Tax Other Than	East Side			West Side			
50		Income							
51	HCPD Payroll	$63,001.02	$1,595.54						
52	LRS Payroll	$0.00	$0.00						
53	Headquarter's	$6,690.06	$169.43						
54	LRS (HCPD)	$154,950.82	$10,915.95			$12,341.88			
55	TP-I	$3,171.56	$3,171.56						
56	TP-III	$1,535.19	$1,535.19						
57	TP-II	$47,920.96	$0.00						
58									
59		$277,269.61	$17,387.67			$12,341.88			

	A	B	C	D	E	F	G	H	I
60	HCPD TRANSMISSION & GENERAL PLANT (EAST SIDE & WEST SIDE)								
61	December 31, 2007								
62	Page 2 of 6								
63									
64		A&G Expenses	East Side			West Side			
65	HCPD	$2,618,199.19	$66,307.70						
66	LRS	$153,666.84	$14,443.05						
67									
68		$2,771,866.03	$80,750.76						
69									
70		Transm O&M	East Side			West Side			
71	TP-I	$31,054.78	$31,054.78						
72	TP-III Groton	$2,725.91	$2,725.91						
73	LRS-Trans	$218,449.07	$109,224.54			$109,224.54			
74									
75									
76		$252,229.76	$143,005.23			$109,224.54			
77									
78									
79									
80									
81		Trsm by Others	East Side			West Side			
82	LRS-Trans	$96,804.36	$48,402.18			$48,402.18			
83									
84		$96,804.36	$48,402.18			$48,402.18			
85									
86									
87		Material & Supplies	East Side			West Side			
88	REA Acct 163 Balance Sheet Items	$0.00	$0.00			$0.00			
89									
90	**Rate of Return**								
91	2007 Liability	$51,062,996.67	90.80%	6.42%	5.83%				
92	2007 Net Assets	$5,172,505.58	9.20%	8.00%	0.74%				
93									
94		$56,235,502.25			**6.57%**				
95									
96									
97									
98									
99									
100									
101									

	J	K	L	M	N	O	P	Q
1		HCPD TRANSMISSION & GENERAL PLANT (EAST SIDE)		30-Apr-08				
2		December 31, 2007						
3		Page 3 of 6						
4								
5	CPX	Description	Investment	Accum Depr	Accum IDC	Net Book	Annual Depr	
6								
7		LINES						
8	049	345 kV Line from LRS to NB Border (50%)	$170,416.26					
9	050	345 kV Line NB Border to Stegall Sub (50%)	$14,968.31					
10	051	345 Line From LRS to NB Border	$137,815.17					
11	052	345 kV Line From NB Border to Sidney Sub	$213,292.60					
12	053	345 kV Line from Stegall Sub to Sidney Sub	$286,411.91					
13	074	345 kV Line From LRS to CO Border (.10457)	$112,442.49					
14	077	LRS PlantSite Lines (.42786)	$31,082.68					
15	091	Nebraska Tax	$11,492.90					
16	101	230 kV Line From Sidney Sub to WAPA Sub	$28,871.31					
17	103	230 kV Line Stegall Sub to Stegall/WAPA	$18,007.22					
18								
19		***Subtotal Lines***	***$1,024,800.85***					
20								
21		SUBSTATIONS						
22	048	345 kV LRS Substation (.42786)	$150,604.64					
23	078	345/230 kV Stegall Substation	$177,680.30					
24	079	345/230 kV Sidney Substation	$241,006.03					
25	084	230 kV Stegall-WAPA Sub Addition	$35,271.55					
26	054	230/345 kV Trsn Facilities-NPPD (Intang Plant)	$1,633,730.01					
27	100	230/115 kV Sidney Substation Addition	$17,550.88					
28	116	LRS #1 Main Transformer (.87766)	$95,876.46					
29								
30		***Subtotal Substations***	***$2,351,719.87***					
31								
32		MICROWAVE COMMUNICATIONS						
33	131	Microwave-Wyoming (50%)	$38,491.66					
34	133	Microwave-Nebraska	$41,313.81					
35	135	Microwave-North Dakota	$340.92					
36	138	Microwave-South Dakota	$3,124.90					
37								
38			$83,271.29					
39		Less Microwave Non-Transmission (70%)	$58,289.90					
40								
41		***Subtotal Microwave Communications***	***$24,981.39***					
42								
43		MAINTENANCE BUILDINGS						
44	107	Maintenance Building-Stegall	$72,608.77					
45	108	Maintenance Building-LRS (50%)	$30,450.56					
46								
47		***Subtotal Maintenance Buildings***	***$103,059.33***					
48								
49								
50		***Total LRS Transmission-East Side***	***$3,376,520.72***	$940,844.30	$381,756.21	$2,053,920.21	$81,065.24	
51								
52		***Total LRS General Plant-East Side***	***$128,040.72***	$35,677.67	$14,476.54	$77,886.51	$3,074.07	
53								
54		***Total LRS-East Side***	***$3,504,561.44***	***$976,521.97***	***$396,232.75***	***$2,131,806.72***	***$84,139.30***	
55								
56								
57								
58								
59								

HCPD TRANSMISSION & GENERAL PLANT (EAST SIDE)

December 31, 2007

Page 4 of 6

	Investment	Accum Depr	Accum IDC	Net Book	Annual Depr
HEARTLAND TRANSMISSION					
TP-I Irv Simmons	$907,635.18	$252,906.31	$102,619.05	$552,109.82	$21,790.97
TP-II	$6,752,305.09	$1,881,483.42	$763,429.16	$4,107,392.50	$162,112.79
TP-II Marshall	$0.00	$0.00	$0.00	$0.00	$0.00
TP-III Groton Sub	$384,975.48	$107,270.77	$43,526.10	$234,178.61	$9,242.69
Total HCPD Transmission-East Side	***$8,044,915.75***	***$2,241,660.50***	***$909,574.32***	***$4,893,680.93***	***$193,146.45***
HEARTLAND GENERAL PLANT					
General Plant Improvement	$58,013.47	$16,165.05	$6,559.12		$1,392.82
Furniture & Equipment	$12,087.65	$42,135.84	$1,366.65		$2,765.58
Furniture & Equipment-EPD	$30,557.21		$3,454.86		
Transportation Equipment	$5,200.36	$4,446.21	$587.96		$663.62
Headquarter's Improvement	$5,167.24		$584.22		
Total HCPD General Plant-East Side	***$111,025.93***	***$62,747.09***	***$12,552.82***	***$35,726.02***	***$4,822.01***
TOTAL EAST SIDE TRANSMISSION & GENERAL PLANT	***$11,660,503.12***	***$3,280,929.57***	***$1,318,359.88***	***$7,061,213.66***	***$282,107.76***

	R	S	T	U	V	W	X
1		HCPD TRANSMISSION & GENERAL PLANT (WEST SIDE)		30-Apr-08			
2		December 31, 2007					
3		Page 5 of 6					
4							
5	CPX	Description	Investment	Accum Depr	Accum IDC	Net Book	Annual Depr
6							
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	$520,419.42				
16	105	345 kV Line -CO Border to Ault	$208,610.29				
17	106	230 kV Sidney Tie Line	$15,568.45				
18							
19		***Subtotal Lines***	***$3,088,558.90***				
20							
21		SUBSTATIONS					
22	045	230 kV LRS Switch Station (4 Terminals)	$136,427.08				
23	048	345 kV LRS Substation (5 of 8 Trmls)(.57214)	$201,390.49				
24	076	230 kV D Johnston Substation	$22,510.81				
25	085	345 kV Ault Substation	$143,063.70				
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	$168,160.13				
31							
32		***Subtotal Substations***	***$825,874.44***				
33							
34		MICROWAVE COMMUNICATIONS					
35	131	Microwave-Wyoming (50%)	$38,491.66				
36	132	Microwave-Colorado	$19,747.79				
37							
38			$58,239.45				
39		Less Microwave Non-Transmission (70%)	$40,767.62				
40							
41		***Subtotal Microwave Communications***	***$17,471.84***				
42							
43		MAINTENANCE BUILDINGS					
44	108	Maintenance Building-LRS (50%)	$30,450.56				
45							
46		***Subtotal Maintenance Buildings***	***$30,450.56***				
47							
48		***Total LRS Transmission-West Side***	***$3,914,433.34***	$2,579,487.97	$1,051,431.07	$283,514.30	$222,254.41
49		***Total LRS General Plant-West Side***	***$47,922.40***	$31,579.35	$12,872.13	$3,470.92	$2,720.95
50							
51		***Total LRS-West Side***	***$3,962,355.74***	***$2,611,067.32***	***$1,064,303.20***	***$286,985.22***	***$224,975.36***
52							
53							
54							
55							
56							
57							
58							
59							

	R	S	T	U	V	W	X
60		HCPD TRANSMISSION & GENERAL PLANT (WEST SIDE)					
61		December 31, 2007					
62		Page 6 of 6	Investment	Accum Depr	Accum IDC	Net Book	Annual Depr
63							
64		HEARTLAND TRANSMISSION					
65		TP-I Irv Simmons	$0.00	$0.00	$0.00	$0.00	$0.00
66		TP-II	$0.00	$0.00	$0.00	$0.00	$0.00
67		TP-II Marshall	$0.00	$0.00	$0.00	$0.00	$0.00
68		TP-III Groton Sub	$0.00	$0.00	$0.00	$0.00	$0.00
69							
70		*Total HCPD Transmission-West Side*	*$0.00*	*$0.00*	*$0.00*	*$0.00*	*$0.00*
71							
72		HEARTLAND GENERAL PLANT					
73		General Plant Improvement	$0.00	$0.00	$0.00		$0.00
74		Furniture & Equipment	$0.00	$0.00	$0.00		$0.00
75		Furniture & Equipment-EPD	$0.00		$0.00		
76		Transportation Equipment	$0.00	$0.00	$0.00		$0.00
77		Headquarter's Improvement	$0.00		$0.00		
78							
79		*Total HCPD General Plant-West Side*	*$0.00*	*$0.00*	*$0.00*	*$0.00*	*$0.00*
80							
81		*TOTAL WEST SIDE TRANSMISSION*					
82		*& GENERAL PLANT*	*$3,962,355.74*	*$2,611,067.32*	*$1,064,303.20*	*$286,985.22*	*$224,975.36*
83							
84							
85							
86							
87							
88							
89							
90							
91							
92							
93							
94							
95							
96							
97							
98							
99							
100							
101							

NWPS
Transmission Revenue Requirement Adjustment

Breakdown of Northwestern's IS Costs:

	Financial Statement Date	12/31/2002	12/31/2003	12/31/2004	
1	Transmission Gross Plant in Service	$ 29,827,890	$ 29,884,782	$ 29,894,838	
2	Distribution Gross Plant in Service	$ 161,885,283	$ 167,335,302	$ 175,073,436	
3	Transmission Accumulated Depreciation	$ 18,332,089	$ 19,237,371	$ 20,144,084	
4	Distribution Accumulated Depreciation	$ 52,676,927	$ 57,894,559	$ 62,352,847	
5	Percentage of Transmission Gross Plant Allocated to IS	77.51%	77.56%	77.56%	
6	Total Gross Plant Allocated to IS	$ 29,827,890	$ 29,884,782	$ 29,894,838	
7	Total Accumulated Depreciation Allocated to IS				
8	Total IS Net Plant	$ 29,827,890	$ 29,884,782	$ 29,894,838	
9	Northwestern Revenue Requirements:				
10	Total O&M	$ 760,626	$ 807,386	$ 504,512	
11	Depreciation	738,743	781,459	784,646	
12	Total Other Taxes	552,219	472,510	387,643	
13	Income Taxes	126,777	228,670	448,222	
14	Return	963,458	988,694	1,077,700	
15	Revenue Credits	(282,875)	(220,628)	(241,516)	
16	Total Revenue Requirements	$ 2,858,948	$ 3,058,092	$ 2,961,207	
	Rate Base - Revenue Requirement	$ 12,679,790	$ 11,895,269	$ 10,398,468	
17	Rate Base - 7 factor	$ 14,350,032	$ 14,426,023	$ 11,662,784	
18	Return	7.60%	8.31%	10.36%	
19	% Debt Financed	81%	65%	24%	
20	Debt Cost	6.78%	6.87%	8.37%	
21	Equity Cost	11.00%	11.00%	11.00%	
	Original Revenue Requirement	$ 2,281,647	$ 3,685,308	$ 1,900,607	
	Difference	$ 577,301	$ (627,216)	$ 1,060,600	$ 1,010,685

Transmission Customer Facility Credits

Midwest ISO
FERC Electric Tariff, Third Revised Volume No. 1

First Revised Sheet No.

Attachment O
Page 1 of 4

Formula Rate - Cash Flow

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/07

Missouri River Energy Services

Line No.						Allocated Amount
1	GROSS REVENUE REQUIREMENT	(page 2, line 23, col. 5)				$ 11,884,430
	REVENUE CREDITS	(Note Q)	Total	Allocator		
2	Account No. 454	(page 3, line 34)	0	TP	1.00000	0
3	Account No. 456.1	(page 3, line 37)	41,025	TP	1.00000	41,025
4	Revenues from Grandfathered Interzonal Transactions		0	TP	1.00000	0
5	Revenues from service provided by the ISO at a discount		0	TP	1.00000	0
6	TOTAL REVENUE CREDITS (sum lines 2-5)					41,025
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				**$ 11,843,405**

Allocation of Net Revenue Requirements by Pricing Zones:

	Irv Simmons	OTP	MBPP	Marshall Wind Circuit	Total
Transmission Plant Investment	$ 1,957,786	$ 26,938,415	$ 28,968,344	$ 1,984,245	$ 59,848,790
% of Total Transmission Plant	3.27%	45.01%	48.40%	3.32%	100.0%
Net Transmission Revenue Requirement (Allocated on Transmission Plant)	**$ 387,424**	**$ 5,330,810**	**$ 5,732,510**	**$ 392,660**	**$ 11,843,405**

	DIVISOR			
8	Average of 12 coincident system peaks for requirements (RQ) service		(Note A)	675,337
9	Plus 12 CP of firm bundled sales over one year not in line 8		(Note B)	0
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 P)	0
14	Less 12 CP or Contract Demands from service over one year provided by ISO at a discount (enter negative)			0
15	Divisor (sum lines 8-14)			675,337
16	Annual Cost ($/kW/Yr)	(line 7/ line 15)	$ 17.537	
17	Network & P-to-P Rate ($/kW/Mo)	(line 11/ 12)	**$ 1.461**	

			Peak Rate		Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16/ 52)	0.337		$0.337
19	Point-To-Point Rate ($/kW/Day)	(line 18/ 5; line 18/ 7)	0.067	Capped at weekly rate	$0.048
20	Point-To-Point Rate ($/MWh)	(line 19/ 16; line 19/ 24 times 1,000)	4.216	Capped at weekly and daily rates	$2.007
21	FERC Annual Charge($/MWh)	(Note E)	$0.000	Short Term	$0.000 Short Term
22			$0.000	Long Term	$0.000 Long Term

Midwest ISO
FERC Electric Tariff, Third Revised Volume No. 1

First Revised Sheet No.

Attachment O
Page 2 of 4

Formula Rate - Cash Flow

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/07

Missouri River Energy Services

Line No.	(1)	(2) EIA 412 Reference	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission (Note X)		15,866,691	TE	1.0000	15,866,691
1a	Less LSE Expenses included in Transmission O&M Accounts (I		0		1.0000	0
2	Less Account 565		12,606,281		1.0000	12,606,281
3	A&G	VII.13.d	8,143,587	W/S	0.2621	2,134,339
4	Less FERC Annual Fees		0	W/S	0.2621	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad (Note F)		0	W/S	0.2621	0
5a	Plus Transmission Related Reg. Comm. Exp. (Note F)		0	TE	1.0000	0
6	Common		0	CE	0.2621	0
7	Transmission Lease Payments		0		1.0000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less 1a, 2, 4, 5)		11,403,997			5,394,749
	DEBT SERVICE					
9a	Debt Service - Transmission Bond Resolution (Note T)		2,220,036		1.0000	2,220,036
9b	Debt Service- Excluding Transmission Bond Resolution (Note U)		23,207,223	GP 2	0.1142	2,651,378
10	Amortization of premium or discount (Note V)		0	GP	0.1834	0
11	TOTAL DEBT SERVICE (Sum lines 9 - 10)		25,427,259			4,871,415
	TAXES OTHER THAN INCOME TAXES (Note G)					
	LABOR RELATED					
13	Payroll		0	W/S	0.2621	0
14	Highway and vehicle		0	W/S	0.2621	0
15	PLANT RELATED					
16a	Property- Transmission Only (Note G)		443,661		1.0000	443,661
16b	Property- General Plant		48,634	GP	0.1834	8,918
17	Gross Receipts		0		0.0000	0
18	Other		0	GP	0.1834	0
19	Payments in lieu of taxes		0	GP	0.1834	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		492,295			452,579
21	SUBTOTAL (sum lines 8, 11, 20)		37,323,551			10,718,743
22	MARGIN REQUIREMENT (Note H)		6,356,815	GP	0.1834	1,165,687
23	REV. REQUIREMENT (sum lines 21 22)		43,680,366			11,884,430

Midwest ISO
FERC Electric Tariff, Third Revised Volume No. 1

First Revised Sheet No.

Attachment O
Page 3 of 4

Formula Rate - Cash Flow

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/07

Missouri River Energy Services

SUPPORTING CALCULATIONS AND NOTES

Line No.		EIA 412 Reference	Company Total	Allocator		Transmission
	GROSS PLANT IN SERVICE					
1	Production	IV.6.f	272,168,356	NA	0.0000	0
2a	Transmission, excluding separate	IV.7.f	32,910,375	TP	1.0000	32,910,375
2b	Separate Transmission Project (Nc	IV.7.f	26,938,415	TP	1.0000	26,938,415
3	Distribution	IV.8.f	0	NA	0.0000	0
4	General & Intangible	IV.9.f	13,151,035	W/S	0.2621	3,446,733
5	Common		0	CE	0.2621	0
6	TOTAL GROSS PLANT (sum lines 1-5)		345,168,181	GP	0.1834	63,295,523
6a	Gross Plant Allocator, excluding Separate Transmission Project		318,229,766	GP 2	0.1142	36,357,108
	TRANSMISSION PLANT INCLUDED IN ISO RATES					
7	Total transmission plant (line 2)					59,848,790
8	Less transmission plant excluded from ISO rates (Note J)					0
9	Less transmission plant included in OATT Ancillary Services (Note K)					0
10	Transmission plant included in ISO rates (line 7 less lines 8 & 9)					59,848,790
11	Percentage of transmission plant included in ISO Rates (line 10 divided by line 7)				TP=	1.00000
	TRANSMISSION EXPENSES					
12	Total transmission expenses (page 2, line 1, column 3)					15,866,691
13	Less transmission expenses included in OATT Ancillary Services (Note I)					0
14	Included transmission expenses (line 12 less line 13)					15,866,691
15	Percentage of transmission expenses after adjustment (line 14 divided by line 12)					1.00000
16	Percentage of transmission plant included in ISO Rates (line 11)				TP	1.00000
17	Percentage of transmission expenses included in ISO Rates (line 15 times line 16)				TE=	1.00000
	WAGES & SALARY ALLOCATOR (W&S) (Note L)		$		Allocation	
18	Production		1,612,292	0.00	0	
19	Transmission		572,647	1.00	572,647	
20	Distribution		0	0.00	0	W&S Allocator
21	Other		0		0	($ / Allocation)
22	Total (sum lines 18-21)		2,184,939		572,647 =	0.2621
	COMMON PLANT ALLOCATOR (CE) (Note M)		$		% Electric (line 23 / line 26)	Labor Ratio (line 22) CE
23	Electric		345,168,181		1.00000 *	0.2621 = 0.2621
24	Gas		0			
25	Water		0			
26	Total (sum lines 23-25)		345,168,181			
	FINANCING DATA		$			
27	Long Term Debt	II.33.b +34.b	$ 246,723,895			
28	Debt Service		25,427,259			
29	Interest on Long Term Debt	III.16.b + III.17.b (Note R)	12,012,259			
30	Bond Principal Amortization (line 28 less line 29)		13,415,000			
	REVENUE CREDITS					Load
	ACCOUNT 447 (SALES FOR RESALE)					
31	a. Bundled Non-RQ Sales for Resale		(Note N)			0
32	b. Bundled Sales for Resale included in Divisor on page 1					0
33	Total of (a)-(b)					
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note O)					$0
	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES)					
35	a. Transmission charges for all transmission transactions					41,025
36	b. Transmission charges for all transmission transactions included in Divisor on page 1					0
37	Total of (a)-(b)					$41,025

Formula Rate - Cash Flow | Rate Formula Template | For the 12 months ended 12/31/07

Utilizing EIA Form 412 Data

Missouri River Energy Services

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from EIA Form 412 are indicated as: x.y.z (section, line, column)

To the extent the page references to EIA Form 412 are missing, the entity will include a "Notes" section in the EIA Form 412 to provide this data.

Note Letter	
A	The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of ISO coincident monthly peaks. RQ service is service which the supplier plans to provide on an on-going basis (i.e., the supplier includes projected load for this service in its system resource planning).
B	Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions), and long-term (duration of at least five years); does not meet definition of RQ service. IF is "firm service" for a term longer than one but less than five years. LU is service from a designated generating unit, of a term no less than five years. LI is service from a designated generating unit for a term between one and five years. Measured at time of ISO coincident monthly peaks.
C	LF as defined above at time of ISO coincident monthly peaks.
D	LF as defined above at time of ISO coincident monthly peaks.
E	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any
F	Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting.
G	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. MRES segregates property taxes between generation, transmission, and general plant based on internal accounting records. Therefore, MRES transmission property taxes are directly assigned to the revenue requirement and general property taxes will be allocated based on the GP allocator. Work papers will be provided."
H	The Margin Requirement is the margin the utility uses in calculating rates applicable to its native load sales. The Margin Requirement as a percent of interest expense yields a TIER (times interest earned ratio), and the Margin Requirement as a percent of debt service is the DSR (debt service ratio), either of which may be referred to as a Margin Ratio (MR). Some utilities have MRs required by bond covenants and/or MRs that include expenses additional to interest or debt service (for example, an MR equal to a percentage of the sum of DS+O&M). The ISO will review such party's filings to assure that the MRs are consistent with those applicable to native load or required by bond covenants and utility must provide workpapers showing derivation of margin. The margin requirement will be allocated on GP.
I	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.
J	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until RUS 12 balances are adjusted to reflect application of seven-factor test).
K	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.
L	If the utility has more employees assigned to A&G than to the sum of production, transmission, and distribution, set the W&S allocator at page 3, line 22 equal to the gross plant allocator (GP) at page 3, line 6.
M	Enter dollar amounts.
N	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.
O	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
P	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.
Q	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.

R From Reference II.17.b include only the amount from Account 430.

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 Represents only Debt Service that can be directly assigned to transmission assets and no other types of assets. Work papers will be provided.

U Represents all Debt Service, other than transmission debt service included in line 9a, page 2. Work papers will be provided.

NWPS Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/06

Utilizing FERC Form 1 Data With 7-Factor Changes - EXCLUDES EXT. Joint Plant Transmission Facilities

Line No.						Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$ 2,772,504
	REVENUE CREDITS	(Note T)	Total	Allocator		
2	Account No. 454	(page 4, line 34)	76,731	TP	0.77673	59,599
3	Account No. 456	(page 4, line 37)	102,710	TP	0.77673	79,778
4	Revenues from Grandfathered Interzonal Transactions		0	TP	0.77673	0
5	Revenues from service provided by the ISO at a discount		0	TP	0.77673	0
6	TOTAL REVENUE CREDITS (sum lines 2-5)					139,377
7	NET REVENUE REQUIREMENT (line 1 minus line 6)					$ 2,633,127
						$0.3843
	DIVISOR					
8	Average of 12 coincident system peaks for requirements (RQ) service				(Note A)	215,250
9	Plus 12 CP of firm bundled sales over one year not in line 8				(Note B)	14,000
10	Plus 12 CP of Network Load not in line 8				(Note C)	0
11	Less 12 CP of firm P-T-P over one year (enter negative)				(Note D)	0
12	Plus Contract Demand of firm P-T-P over one year					0
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)					0
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)					0
15	Divisor (sum lines 8-14)					229,250
16	Annual Cost ($/kW/Yr)	(line 7 / line 15)	11.486			
17	Network & P-to-P Rate ($/kW/Mo	(line 16 / 12)	0.957			
			Peak Rate			Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	0.221			$0.221
19	Point-To-Point Rate ($/kW/Day)	(line 18 / 5; line 18 / 7)	0.044	Capped at weekly rate		$0.032
20	Point-To-Point Rate ($/MWh)	(line 19 / 16; line 19 / 24 times 1,000)	2.761	Capped at weekly and daily rates		$1.315
21	FERC Annual Charge($/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 12/31/06

Utilizing FERC Form 1 Data With 7-Factor Changes - EXCLUDES EXT. Joint Plant Transmission Facilities

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	149,310,703	NA		
2	Transmission	206.53.g	30,041,076	TP	0.77673	23,334,607
3	Distribution	206.69.g	231,063,580	NA		
4	General & Intangible	206.5.g & 83.g	9,008,972	W/S	0.04212	378,287
5	Common	356.1	28,109,411	CE	0.02556	720,647
6	TOTAL GROSS PLANT (sum lines 1-5)		409,934,870	GP=	5.960%	24,433,541
	ACCUMULATED DEPRECIATION					
7	Production	219.18-22.c	51,067,827	NA		
8	Transmission	219.23.c	21,557,621	VEst.	75.067%	16,183,455
9	Distribution	219.24.c	123,230,076	NA		
10	General & Intangible	219.25.c	3,239,938	W/S	0.04212	136,861
11	Common	356.1	10,355,036	CE	0.02556	258,973
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		197,645,227			16,879,288
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	55,545,426			
14	Transmission	(line 2- line 8)	8,083,829			6,851,152
15	Distribution	(line 3 - line 9)	124,863,728			
16	General & Intangible	(line 4 - line 10)	5,732,308			241,426
17	Common	(line 5 - line 11)	18,064,353			461,674
18	TOTAL NET PLANT (sum lines 13-17)		212,289,643	NP=	3.558%	7,554,253
	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	-8,281,040	VEst.	0.06446	527,040
21	Account No. 283 (enter negative	277.9.k	-274,274,031	NP	0.03558	-8,174,703
22	Account No. 190	234.8.c	9,104,701	NP	0.03558	9,104,701
23	Account No. 255 (enter negative	267.8.h	-1,826,286	VEst.	0.06446	-141,709
24	TOTAL ADJUSTMENTS (sum lines 19-23)		-5,995,492			315,329
25	LAND HELD FOR FUTURE USE	214.x.d (Note G)	0	VEst.	0.75067	0
	WORKING CAPITAL (Note H)					
26	CWC	calculated				60,392
27	Materials & Supplies (Note G)	227.8.c & .15.c	4,885,580		1.00000	1,358,581
28	Prepayments (Account 165)	111.46.d	1,103,107	GP	0.05960	276,030
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		5,989,688			1,695,004
30	RATE BASE (sum lines 18, 24, 25, & 29)		212,283,839			9,564,585

Accumulated Depreciation of Joint Pl
Transmission Facilities
5,474,705

Amount related to Exclusions

	Accumulated Deferred Income Taxes
527,040	Accumulated Deferred Income Taxes
	Accumulated Deferred Income Taxes
	Accumulated Deferred Income Taxes
117,954	Accumulated Deferred Investment Ta

Excluded transmission maintained and supplied by others

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/06

Utilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT. Joint Plant Transmission Facilities

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	4,264,563	TE	0.77673	4,183,890	Reduce non-565 by TE Ratio
2	Less Account 565	321.88.b	3,903,237		1.00000	3,903,237	
3	A&G	323.168.b	7,922,752	W/S	0.02556	202,483	
4	Less FERC Annual Fees		0	W/S	0.02556	0	
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		0	W/S	0.02556	0	
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.77673	0	
6	Common	356.1	0	CE	0.02556	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)		8,284,078			483,137	
	DEPRECIATION EXPENSE						Excluded
9	Transmission	336.7.b	900,067	VRB00	0.75067	699,500	200,567
10	General	336.9.b	371,766	W/S	0.02556	9,501	
11	Common	336.10.b	1,801,140	CE	0.02556	46,032	
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		3,072,973			755,034	
	TAXES OTHER THAN INCOME TAXES (Note J)						
	LABOR RELATED						
13	Payroll	262.i	1,715,505	W/S	0.02556	43,844	
14	Highway and vehicle	262.i	0	W/S	0.02556	0	
15	PLANT RELATED						
16	Property	262.i	5,520,675	GP	0.05960	329,000	
17	Gross Receipts	262.i	224,433	NA	zero	0	
18	Other	262.i	341,008	GP	0.05960	20,325	
19	Payments in lieu of taxes		0	GP	0.05960	0	
20	TOTAL OTHER TAXES (sum lines 13 - 19)		7,810,821			393,769	
	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)) =		34.66%				
	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)		-494,034				
25	Income Tax Calculation = line 22 * line 28		6,617,500	NA		298,156	
26	ITC adjustment (line 23 * line 24)		761,437	NP	0.03558	-17,723	From detail on VRBase00t w/ exclusions
27	Total Income Taxes	(line 25 plus line 26)	7,378,937			280,433	
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		19,090,452	NA		860,133	
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		45,637,261			2,772,504	

Formula Rate - Non-Levelized — Rate Formula Template Utilizing FERC Form 1 Data — For the 12 months ended 12/31/06

Utilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT. Joint Plant Transmission Facilities

SUPPORTING CALCULATIONS AND NOTES

Line No.	TRANSMISSION PLANT INCLUDED IN ISO RATES			
1	Total transmission plant (page 2, line 2, column 3)		30,042,078	Transmission Plant Grandfathered wit Joint Plants from VRB00t 6,707,471
2	Less transmission plant excluded from ISO rates (Note M)		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)		23,334,607	
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)	TP=	0.77673	
	TRANSMISSION EXPENSES			
6	Total transmission expenses (page 3, line 1, column 3)		4,264,563	
7	Less transmission expenses included in OATT Ancillary Services (Note L)		0	
8	Included transmission expenses (line 6 less line 7)		4,264,563	
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	0.77673	
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)	TE=	0.77673	

WAGES & SALARY ALLOCATOR (W&S)

		Form 1 Reference	$	TP	Allocation		W&S Allocator ($ / Allocation)			
12	Production	354.18.b	[redacted]	0.00	0					
13	Transmission	354.19.b	[redacted]	0.78	185,748					
14	Distribution	354.20.b	[redacted]	0.00	0					
15	Other	354.21,22,23.b	[redacted]	0.00	0					
16	Total (sum lines 12-15)		5,078,055		185,748	=	0.03271	=	WS	Wages & salaries by others for excluded facilities MEC, OTP, MDU
							0.04212	=	Wsact	

COMMON PLANT ALLOCATOR (CE) (Note O)

			$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	[redacted]	0.78125	*	0.03271	=	0.02558
18	Gas	200.3.d	[redacted]					
19	Water	200.3.e	[redacted]					
20	Total (sum lines 17 - 19)		488,625,960					

	RETURN (R)	$
21	Long Term Interest (117, sum of 62c through 66c)	$0
22	Preferred Dividends (118.29c) (positive number)	0
23	Proprietary Capital (112.16c)	0
24	Less Preferred Stock (line 22)	0
25	Less Account 216.1 (112.12c) (enter negative)	0

26	Common Stock	(sum lines 23-25)					0	
		$	%		Cost (Note P)		Weighted	
27	Long Term Debt (112, sum of 16d through 19d)	0.0000	0.4854	0.0000	0.0660	0.0000	0.0320	=WCLTD
28	Preferred Stock (112.3d)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
29	Common Stock (line 26)	0.0000	0.5146	0.0000	0.1125	0.0000	0.0579	
30	Total (sum lines 27-29)	0.0000		0.0000	0.0000	0.0000	0.0899	=R

REVENUE CREDITS

				Load
	ACCOUNT 447 (SALES FOR RESALE)	(310-311)	(Note Q)	
31	a. Bundled Non-RQ Sales for Resale (311.x.h)			247,403
32	b. Bundled Sales for Resale included in Divisor on page 1			247,403
33	Total of (a)-(b)			0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY)	(Note R)		$76,731
	ACCOUNT 456 (OTHER ELECTRIC REVENUES)	(330.x.n)		
35	a. Transmission charges for all transmission transactions			$243,923
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1			$141,213
37	Total of (a)-(b)			$102,710

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/06

Utilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT. Joint Plant Transmission Facilities

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= 11.00% (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.