Department of Energy
Western Area Power Administration
Watertown Operations Office
P.O. Box 790
1330 41st Street SE
Watertown, South Dakota 57201-0790

September 3, 2010

Dear Transmission Customers and Other Interested Parties:

Summarized below are the Integrated System (IS) Transmission and Ancillary Services Rates which will be effective January 1, 2011. Western will host a meeting to provide customers an opportunity to discuss and comment on these recalculated rates on September 21, 2010, at 8:00 a.m. CDT at the Holiday Inn City Center, 100 W 8th Street, Sioux Falls, South Dakota. This meeting provides an opportunity to discuss the proper application of data in the formula rate, not the rate formula itself. The data used in calculating these rates can be found at either of the following web sites http://www.wapa.gov/ugp/rates/default.htm or http://www.oatioasis.com/wapa/index.html. The recalculated rates are as follows:

Service	Rate Schedule	Rate
Network Transmission	UGP-NT1	Load-ratio share of 1/12 of the Annual Revenue Requirement for IS Transmission Service of $157,866,363.
Firm Point-to-Point Transmission	UGP-FPT1	Maximum of $2.83/kWmonth
Non-Firm Point-to-Point Transmission	UGP-NFPT1	Maximum of 3.88 mills/kWh
Scheduling, System Control and Dispatch	UGP-AS1	$43.11/tag/day
Reactive Supply and Voltage Control from Generation Sources	UGP-AS2	$0.05/kWmonth
Regulation and Frequency Response	UGP-AS3	$0.04/kWmonth
Energy Imbalance	UGP-AS4	i) For deviations within +/- 1.5% (minimum of 2 MW) of the scheduled transaction, 100% of average incremental cost;

		ii) For deviations greater than +/- 1.5% up to 7.5% (or greater than 2 MW up to 10 MW) of the scheduled transaction, 110% of incremental cost when energy taken is greater than energy scheduled and 90% of incremental cost when energy taken is less than scheduled; iii) For deviations greater than +/- 7.5% (or 10 MW) of the scheduled transaction, 125% of incremental cost when energy taken is greater than energy scheduled and 75% of incremental cost when energy taken is less than scheduled.
Spinning/Supplemental Reserves	UGP-AS5 and 6	$0.20/kWmonth of customer load
Generator Imbalance	UGP-AS7	i) For deviations within +/- 1.5% (minimum of 2 MW) of the scheduled transaction, 100% of the average incremental cost; ii) For deviations greater than +/- 1.5% up to 7.5% (or greater than 2 MW up to 10 MW) of the scheduled transaction, 110% of incremental cost when energy delivered is less than generation scheduled and 90% of incremental cost when energy delivered is greater than scheduled; iii) For deviations greater than +/- 7.5% (or 10 MW)of the scheduled transaction, 125% of incremental cost when energy delivered is less than energy scheduled and 75% of incremental cost when energy delivered is greater than scheduled. As an exception, an intermittent resource will be exempt from this deviation band and will pay the deviation band charges for all deviations greater than the larger of 1.5% or 2 MW.

Penalty Rate for Unreserved Use of Transmission Service	UGP-TSP1	200% of the transmission service rate for point-to-point service assessed as follows: the penalty for a single hour will be based upon the rate for daily firm point-to-point service; the penalty for more than one assessment of a given duration (e.g. daily) will increase to the next longest duration (e.g. weekly); the penalty charge for multiple instances of unreserved use within a day will be based on the rate for daily firm point-to-point service; the penalty charge for multiple instances of unreserved use isolated to 1 calendar week would result in a penalty based on the charge for weekly firm point-to-point service; and the penalty charge for multiple instances of unreserved use during more than 1 week during a calendar month is based on the charge for monthly firm point-to-point service.

The IS Transmission Loss Factor effective January 1, 2011, is 4 percent and unchanged from the previous 4-year period.

These new rates shall be used in transmission bills calculated on or after February 1, 2011.

If you have any questions concerning the IS Transmission and Ancillary Services Rate Calculation, please telephone Lloyd Linke at (605) 882-7500.

Sincerely,

Lloyd A. Linke
Operations Manager

for

Integrated System Transmission and Ancillary Services Rate Calculation

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

Effective January 1, 2011

Integrated System
Transmission and Ancillary Services
Rate Calculation

Effective January 1, 2011

Integrated System Transmission and Ancillary Service Rates

INTEGRATED SYSTEM
ANNUAL REVENUE REQUIREMENT
FOR TRANSMISSION SERVICE
Effective Janaury 1, 2011

Line No.			Notes
1			
2			
3	**Annual IS Transmission Costs**		
4	Basin Electric	$46,388,310	Basin Electric Revenue Requirement Template
5	Western	$101,723,683	Western Revenue Requirement Template
6	Heartland	$1,010,268	Heartland Revenue Requirement Template
7		$149,122,261	L4 + L5 + L6
8			
9			
10	**Transmission Customer Facility Credits**		
11		$6,394,624	MRES Revenue Requirement Template
12		$2,349,478	NWPS Revenue Requirement Template
13		$8,744,102	
14			
15			
16	**Annual Revenue Requirement for IS Transmission Service**		
17			
18		$157,866,363	L7 + L13

INTEGRATED SYSTEM
FIRM POINT-TO-POINT RATE DESIGN
Effective Janaury 1, 2011

Line No.			Notes
1			
2			
3	**Annual Revenue Requirement for IS Transmission Service**		**Notes**
4			
5		$157,866,363	IS Annual Revenue Requirement for
6			Transmission Service Worksheet, L33
7			
8	**IS Transmission System Total Load**		
9			
10		4,646,000 KW	IS Transmission System Total Load Worksheet, C5L14
11			
12			
13	**Maximum Firm Point-to-Point Transmission Rate in $/KW-Mo**		
14			
15	**$2.83 / KW-Mo**		L5 / L10 / 12 months

INTEGRATED SYSTEM
NON-FIRM POINT-TO-POINT RATE DESIGN
Effective Janaury 1, 2011

Line No.			
1			
2			
3	Firm Point-to-Point Transmission Rate in $/KW-Mo		Notes
4			
5		$2.83 / KW-Mo	IS Firm Point-to-Point Rate Design Worksheet, L15
6			
7			
8			
9	Maximum Non-Firm Point-to-Point Transmission Rate		
10		**3.88 Mills/KWh**	(L5 * 1000) / 730 hours per month

RATE FOR SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE FOR 2011

A.	Fixed Charge Rate	21.867%	(1)
B.	Scheduling, System Control and Dispatch Net Plant Costs ($)	$16,124,034	(2)
C.	Annual Revenue Requirement for Scheduling, System Control and Dispatch Service	$3,525,843	(A x B)
D.	2009 Number of Daily Tags	81,780	
E.	Rate for Scheduling, System Control and Dispatch Service ($/tag/day)	**$43.11**	(C / D)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual IS Transmission Costs", for 2011 Rate.

(2) Scheduling, System Control and Dispatch Plant Costs include the portion of Watertown Operations Office plant (40.473%) and communication facilities plant (68.33%) associated with Scheduling, System Control and Dispatch Service for transmission less total depreciation associated with this plant. (Reference FY 2009 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 2011
(INTEGRATED SYSTEM)

A.	WAPA Reactive Service Revenue Requirement	$2,750,130	(1)
B.	Paid to Others for Reactive Service	$0	(2)
C.	Total Reactive Revenue Requirement	$2,750,130	(A+B)
D.	2009 IS Transmission System Total Load (kW-Yr)	4,593,000	(3)
E.	Annual Reactive Charge ($/kW-Yr)	$0.60	(C/D)
F.	Monthly Reactive Charge ($/kW-Mo)	$0.05	(E/12)

(1) Reactive Service Revenue Requirement from "Reactive Supply and Voltage Control from Generation Sources For 2011, Western's Costs".

(2) Charges for Reactive Service Operation Outside the Bandwidth

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

RATE FOR REGULATION AND FREQUENCY RESPONSE FOR 2011

A.	Western Regulation Revenue Requirement	$1,258,814	(1)
B.	BEPC & HCPD Regulation Revenue Requirement	$84,204	(2)
C.	Total Regulation Revenue Requirement	$1,343,018	(A + B)
D.	Load in Control Area(s) (kW-Yr)	2,699,000	(3)
E.	Regulation Charge ($/kW-Yr)	$0.50	(C / D)
F.	Regulation Charge ($/kW-Mo)	$0.04	(E / 12 months)

(1) Regulation and Frequency Response Service from "Regulation and Frequency Response for 2011, Western's Costs".

(2) Basin Electric cost support data.

(3) Average of monthly peaks for 2009 Watertown Control Area.

Rate for Reserves for 2011

A.	Fixed Charge Rate	15.541%	(1)
B.	Generation Net Plant Costs	$ 509,970,151	(2)
C.	Annual Cost of Generation	$ 79,254,461	(A x B)
D.	Plant Capacity (kW)	2,473,000	
E.	Cost/kW ($/kW-Yr)	$ 32.05	(C / D)
F.	Monthly Charge ($/kW-mo)	$ 2.67	(E / 12 months)
G.	Western's Load (kW-Yr)	1,587,000	(3)
H.	Capacity used for Reserves (kW)	118,000	(4)
I.	Annual Reserves Revenue Requirement	$ 3,781,900	(E x H)
J.	Annual Charge ($/kW-Yr)	$ 2.38	(I /G)
K.	Monthly Charge ($/kW-mo)	$ 0.20	(J/12)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Generation Revenue Requirement", for 2011 Rate.

(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 2009.

(4) Southwest Power Pool Reserve Sharing System.

Integrated System Load Data

2011 IS Transmission System Total Load Estimate
Transmission Rate
(MW)

4,646

8

2009 IS Transmission System Total Load
Ancillary Services
(MW)

Line No.	(1) Date	(2) Hour Ending	(3) Network Load	(4) Added Network Load - Cornbelt/NIMEC	(5) Long-Term Firm Point-to-Point	Total
1	01/15/09	800	4,314		489	4803
2	02/03/09	800	4,088		499	4587
3	03/12/09	800	4,081		495	4576
4	04/07/09	800	3,435		501	3936
5	05/29/09	1700	3,151		498	3649
6	06/25/09	1700	3,910		492	4402
7	07/27/09	1500	4,082		486	4568
8	08/13/09	1800	4,263		497	4760
9	09/17/09	1700	3,426	209	500	4135
10	10/28/09	2000	3,239	272	492	4003
11	11/30/09	1900	3,679	277	501	4457
12	12/15/09	800	4,337	293	501	5131
13						
14	12 CP		3,834	263	496	4,593

2009 IS Network Customer Control Area Load

Date	Hr End	East Control Area Load (1)	West Control Area Load (2)	Total Load
January 15, 2009	8:00	3005 MW	82 MW	3087 MW
February 3, 2009	8:00	2767 MW	72 MW	2839 MW
March 12, 2009	8:00	2784 MW	91 MW	2875 MW
April 7, 2009	8;00	2251 MW	65 MW	2316 MW
May 29, 2009	17:00	1868 MW	83 MW	1951 MW
June 25, 2009	17:00	2413 MW	95 MW	2508 MW
July 27, 2009	15:00	2311 MW	94 MW	2405 MW
August 13, 2009	18:00	2534 MW	86 MW	2620 MW
September 17, 2009	17:00	2532 MW	95 MW	2627 MW
October 28, 2009	20:00	2616 MW	79 MW	2695 MW
November 30, 2009	19:00	2897 MW	79 MW	2976 MW
December 15, 2009	8:00	3391 MW	96 MW	3487 MW
Total		**31,369**	**1017**	**32,386**
			Average Control Area Load	**2,699**

(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

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

Est for 12 Months Ending 9/30/2011

Western Area Power Administration - UGPR & RMR

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$ 119,276,574
	REVENUE CREDITS	(Note R)				
2	Short-Term Firm Point-to-Point Transmission Service Credit		0	NA	1.00000	0
3	Non-Firm Point-to-Point Transmission Service Credit		14,714,615	NA	1.00000	14,714,615
4	Revenue from Existing Transmission Agreements		2,654,630	NA	1.00000	2,654,630
5	Scheduling, System Control, and Dispatch Service Credit		104,564	NA	1.00000	104,564
6	Account No. 454	(page 3, line 36)	79,082	TP	1.00000	79,082
7	Account No. 456	(page 3, line 39)	0	TP	1.00000	0
8	TOTAL REVENUE CREDITS					17,552,891
9	NET REVENUE REQUIREMENT	(line 1 minus line 8)				$ 101,723,683

Revenue Requirement - Non-Levelized

Revenue Requirement Template
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Est for 12 Months Ending 9/30/2011

Western Area Power Administration - UGPR & RMR

Line No.	(1) RATE BASE:	(2) ROOs Reference	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	GROSS PLANT IN SERVICE (Note A)					
1	Production	Schedule 1A Total	18,907,591	NA		
2	Transmission	Schedule 1A Total	1,029,534,571	TP	1.00000	1,029,534,571
3	Distribution	Schedule 1A Total	31,115,560	NA		
4	General & Intangible	Bal Sheet - Other Assets - SGL 175002		W/S	1.00000	0
5	Common		0	CE	0.00000	0
6	TOTAL GROSS PLANT (sum lines 1-5)		1,079,557,722	GP=	95.366%	1,029,534,571
	ACCUMULATED DEPRECIATION					
7	Production	Schedule 4	9,200,671	NA		
8	Transmission	Schedule 4	500,465,475	TP	1.00000	500,465,475
9	Distribution	Schedule 4	15,141,223	NA		
10	General & Intangible	Bal Sheet - Other Assets - SGL 175902	0	W/S	1.00000	0
11	Common		0	CE	0.00000	0
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		524,807,369			500,465,475
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	9,706,920			
14	Transmission	(line 2- line 8)	529,069,096			529,069,096
15	Distribution	(line 3 - line 9)	15,974,337			
16	General & Intangible	(line 4 - line 10)	0			0
17	Common	(line 5 - line 11)	0			0
18	TOTAL NET PLANT (sum lines 13-17)		554,750,353	NP=	95.371%	529,069,096
	ADJUSTMENTS TO RATE BASE (Note B)					
19	Account No. 281 (enter negative)		0		zero	0
20	Account No. 282 (enter negative)		0	NP	0.95371	0
21	Account No. 283 (enter negative)		0	NP	0.95371	0
22	Account No. 190		0	NP	0.95371	0
23	Account No. 255 (enter negative)		0	NP	0.95371	0
24	TOTAL ADJUSTMENTS (sum lines 19 - 23)		0			0
25	LAND HELD FOR FUTURE USE	(Note C)	0	TP	1.00000	0
	WORKING CAPITAL (Note D)					
26	CWC	calculated	14,384,418			0
27	Materials & Supplies (Note C)	Bal Sheet - Other Assets - SGL 151191	0	TE	0.00000	0
28	Prepayments	Bal Sheet Other Assets	0	GP	0.95366	0
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		14,384,418			0
30	RATE BASE (sum lines 18, 24, 25, and 29)		569,134,771			529,069,096

Western Area Power Administration
Integrated System

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

Est for 12 Months Ending 9/30/2011

Western Area Power Administration - UGPR & RMR

Line No.	(1)	(2) Results of Operation Reference	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission (Note E)	Schedule 11				
1a	Western UGP		51,039,778	PTP/UGP	0.95339	48,660,814
1b	Western RMR		36,317,427	PTP/RMR	0.00991	359,906
2	Less Account 565 (Note E)			NA	1.00000	0
3	A&G (Note F)	Schedule 11				
3a	Western UGP		18,082,350	PTP/UGP	0.95339	17,239,532
3b	Western RMR		9,635,791	PTP/RMR	0.00991	95,491
4	Less FERC Annual Fees		0	W/S	1.00000	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad (Note G)		0	W/S	1.00000	0
5a	Plus Transmission Related Reg. Comm. Exp (Note G)		0	TE	0.00000	0
6	Common		0	CE	0.00000	0
7	Transmission Lease Payments		0	NA	1.00000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)		115,075,346			66,355,743
	DEPRECIATION EXPENSE					
9	Transmission (Note E)	Schedule 4				
9a	Western UGP		26,830,121	PTP/UGP	0.95339	25,579,569
9b	Western RMR		14,844,626	PTP/RMR	0.00991	147,110
10	General		0	W/S	1.00000	0
11	Common		0	CE	0.00000	0
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		41,674,747			25,726,679
	TAXES OTHER THAN INCOME TAXES (Note H)					
	LABOR RELATED					
13	Payroll		0	W/S	1.00000	0
14	Highway and vehicle		0	W/S	1.00000	0
15	PLANT RELATED					
16	Property		0	GP	0.95366	0
17	Gross Receipts		0		zero	0
18	Other		0	GP	0.95366	0
19	Payments in lieu of taxes		0	GP	0.95366	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		0			0
	INCOME TAXES	(Note I)		NA		
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) = where WCLTD=(page 4, line 27) and R= (page 4, line30) and FIT, SIT & p are as given in footnote I.		0.00%			
23	1 / (1 - T) = (from line 21)		0.0000			
24	Amortized Investment Tax Credit (enter negative)		0			
25	Income Tax Calculation = line 22 * line 28		0	NA		0
26	ITC adjustment (line 23 * line 24)		0	NP	0.95371	0
27	Total Income Taxes	(line 25 plus line 26)	0			0
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		29,253,527	NA		27,194,152
29	REV. REQUIREMENT (sum lines 8, 12,20,27,28)		186,003,620			119,276,574

Western Area Power Administration
Integrated System

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

Est for 12 Months Ending 9/30/2011

Western Area Power Administration - UGPR & RMR

SUPPORTING CALCULATIONS AND NOTES

Line No.							
	TRANSMISSION PLANT INCLUDED IN IS RATES						
1	Total transmission plant (page 2, line 2, column 3)						1,029,534,571
2	Less transmission plant excluded from IS rates (Note K)						
3	Less transmission plant included in OATT Ancillary Services (Note L)						0
4	Transmission plant included in IS rates (line 1 less lines 2 & 3)						1,029,534,571
5	Percentage of transmission plant included in IS Rates (line 4 divided by line 1)					TP=	1.00000
	TRANSMISSION EXPENSES						
6	Total transmission expenses (page 3, line 1, column 3)						
7	Less transmission expenses included in OATT Ancillary Services (Note J)						0
8	Included transmission expenses (line 7 less line 6)						0
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)						0.00000
10	Percentage of transmission plant included in IS Rates (line 5)					TP	1.00000
11	Percentage of transmission expenses included in IS Rates (line 9 times line 10)					TE=	0.00000

WAGES & SALARY ALLOCATOR (W&S)

Line No.		$	TP	Allocation		W&S Allocator ($ / Allocation)
12	Production	0	0.00	0		
13	Transmission	19,388,138	1.00	19,388,138		
14	Distribution	0	0.00	0		
15	Other		0.00	0		
16	Total (sum lines 12-15)	19,388,138		19,388,138	=	1.00000

PERCENTAGE OF TOTAL PLANT ALLOCATOR PTP (Note M)

Line No.		$			
17	Transmission Plant in Service UGP	1,023,181,684			
18	Total Plant in Service UGP	1,073,204,835			
19	UGP Percentage of Transmission Plant to Total Plant (line 17 divided by line 18)		PTP/UGP	=	0.95339
20	Transmission Plant in Service RMR	6,352,887			
21	Total Plant in Service RMR	640,798,643			
22	RMR Percentage of Transmission Plant to Total Plant (line 20 divided by line 22)		PTP/RMR	=	0.00991

COMMON PLANT ALLOCATOR (CE) (Note N)

Line No.		$	% Electric (line 17 / line 20)		Labor Ratio (line 16)		CE
23	Electric	0					
24	Gas	0	0.00000	*	1.00000	=	0.00000
25	Water	0					
26	Total (sum lines 17-19)	0					

RETURN (R)

Line No.		$
27	Long Term Interest Schedule 5	$34,313,681

Line No.		HFD Sch's 21RX & 21X Col 8 Lines	$	%	Cost (Note O)	Weighted	
28	Long Term Debt	23,25,26,29,30	667,509,943	100%	0.0514	0.0514	=WCLTD
29	Proprietary Capital			0%	0.1238	0.0000	
30	Total (sum lines 22-23)		667,509,943	100%		0.0514	=R
31					Proprietary Capital Cost Rate =	12.38%	
32					TIER =	1.00	

REVENUE CREDITS

Line No.			Load
	ACCOUNT 447 (SALES FOR RESALE)		
33	a. Bundled Non-RQ Sales for Resale	(Note P)	0
34	b. Bundled Sales for Resale included in Divisor on page 1		0
35	Total of (a)-(b)		0
36	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note Q)		79,082
	ACCOUNT 456 (OTHER ELECTRIC REVENUES)		
37	a. Transmission charges for all transmission transactions		
38	b. Transmission charges for all transmission transactions included in Divisor on page 1		
39	Total of (a)-(b)		$0

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

Est for 12 Months Ending 9/30/2011

Western Area Power Administration - UGPR & RMR

General Note: References to Results of Operations in this revenue requirement template indicate the Financial Statement Results of Operations (ROOs) Schedule where data is located

Note Letter	
	To the extent the references to ROOs data are missing, the entity will include a "Notes" section to provide this data.
A	Combines plant data for both the Upper Great Plains Region and Rocky Mountain Region.
B	Does not apply to Western. For others, the balances in Accounts 190, 281, 282 and 283, as adjusted by any contra accounts identified as regulatory assets amounts in 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.
C	Transmission related only.
D	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 in the Other Assets Section of the Balance Sheet
E	For O&M Expense, Calculated as Total O&M from Results of Operations less Purchase Power, Transmission Service Provided by Others (FERC 565), O&M Expense Fort Peck Powerhouse, Prior Year Adjustments, A&G Expense from Schedule 11, plus CME and Warehouse Interest from Schedule 5. Depreciation Expense from Results of Operations Schedule 4.
F	Totals of Results of Operations Schedule 11A Object Classes 1411, 1412, 1415, 1416, 1421, 1422, 1425, 1426, 1431, 1432, 1441, 1442
G	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.
H	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.
I	Western is not subject to Federal or State Income Tax.

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

J	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Acct No. 561. Western does not include transmission expenses in ancillary service rates.
K	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).
L	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.
M	Percentage of Total Plant Allocators are developed separately for the Upper Great Plains Region and Rocky Mountain Region to allocate O&M, A&G, and Depreciation Expenses between Transmission and Generation.
N	Western does not have Common Plant.
O	Debt cost rate = long-term interest (line 21) / long term debt (line 22). The Proprietary Capital Cost rate is implicit, a residual calculation after TIER is determined. TIER will be supported in the filing and no change in TIER may be made absent a filing with the ISO and the FERC, if the entity is under FERC's jurisdiction.
P	Line 29 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.
Q	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
R	The revenues credited on page 1 lines 2-5 shall include only the amounts received directly reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, facilities not inlcuded in this template (e.g., direct assignment facilites and GSUs) which are not recovered under this Revenue Requirement Template.

Western's Ancillary Services Cost Data

REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES FOR 2011
(WESTERN'S COSTS)

A. Fixed Charge Rate	15.541%	(1)
B. Generation Net Plant Costs ($)	$509,970,151	(2)
C. Annual Cost of Generation ($)	$79,254,461	(A x B)
D. Capability Used for Reactive Support (%)	3.47%	(3)
E. Reactive Service Revenue Requirement	$2,750,130	(C x D)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Generation Revenue Requirement", for 2011 Rate.

(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 2005-2009.

REGULATION AND FREQUENCY RESPONSE FOR 2011
(Western's Costs)

A.	Fixed Charge Rate	12.594%	(1)
B.	Corps Generation Net Plant Costs ($)	173,487,614	(2)
C.	Annual Corps Generation Cost ($)	21,849,030	(A x B)
D.	Plant Capacity (kW)	937,000	
E.	Cost/kW ($/kW)	23.32	(C / D)
F.	Capacity Used for Regulation (kW)	53,980	(J x 2%)
G.	Regulation Revenue Requirement ($) - Capacity	$1,258,814	(E x F)
H.	Regulation Revenue Requirement ($) - Purchases	$0	(3)
I.	Total Regulation Revenue Requirement ($)	$1,258,814	
J.	Load in Control Area(s) (kW-Yr)	2,699,000	(4)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Corps Revenue Requirement", for 2011 Rate.

(2) Corps Generation Net Plant is Electric Plant in Service for Oahe and Fort Peck less less Depreciation Reserve as of 9/30/09.

(3) Cost of Purchases Required to Regulate for Intermittent Resources

(4) Average of monthly peaks for 2009 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
43			
44	**G. Generation Fixed Charge Rate**		
45			
46	Operation and Maintenance Expense	8.902%	L8
47			
48	A&G Expense	0.042%	L17
49			
50	Depreciation Expense	2.754%	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	3.843%	L41
57			
58	Total	15.541%	
59			
60			
61	**H. Generation Revenue Requirement**		
62			
63	Generation Fixed Charge Rate	15.541%	L59
64			
65	Net Generation Plant Investment	$644,373,587	L6
66			
67	Western Annual Generation Revenue Requirement	$100,142,099	L63 * L65
68			

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	$17,746,903	Depreciation Expense Worksheet, C6L6
23			
24	Net Generation Plant Investment	$644,373,587	L6
25			
26	Depreciation as a % of Net Generation Plant Investment	2.754%	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	3.843%	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
1			
2	**A. Operation and Maintenance Expense for Generation**		
3			
4	Generation O&M Expense	$57,363,003	O&M Expenses Worksheet, C6L19
5			
6	Net Generation Plant Investment	$644,373,587	Net Plant Investment Worksheet, C6L12
7			
8	O&M as % of Net Generation Plant Investment	8.902%	L4/L6
9			
10			
11	**B. A&G Expense for Generation**		
12			
13	Generation A&G Expense	$270,400	A&G Expenses Worksheet, C6L17
14			
15	Net Generation Plant Investment	$644,373,587	L6
16			
17	A&G as % of Net Generation Plant Investment	0.042%	L13/L15
18			
19			

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

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Notes
1			
2	**A. Operation and Maintenance Expense for Corps Generation**		
3			
4	Corps Generation O&M Expense	$23,797,237	O&M Expenses Worksheet, C4L19
5			
6	Net Corps Generation Plant Investment	$427,039,348	Net Plant Investment Worksheet, C4L12
7			
8	O&M as % of Net Generation Plant Investment	5.573%	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	$427,039,348	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	$13,571,913	Depreciation Expense, C4L6
23			
24	Net Corps Generation Plant Investment	$427,039,348	L6
25			
26	Depreciation as a % of Net Generation Plant Investment	3.178%	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	3.843%	Cost of Capital Worksheet, C6L11
42			

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

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Notes
43			
44	**G. Corps Generation Fixed Charge Rate**		
45			
46	Operation and Maintenance Expense	5.573%	L8
47			
48	A&G Expense	0.000%	L17
49			
50	Depreciation Expense	3.178%	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	3.843%	L41
57			
58	Total	12.594%	
59			
60			
61	**H. Corps Generation Revenue Requirement**		
62			
63	Corps Generation Fixed Charge Rate	12.594%	L69
64			
65	Net Corps Generation Plant Investment	$427,039,348	L6
66			
67	Western Annual Corps Generation Revenue Requirement	$53,781,335	L63 * L65
68			

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	$45,937,864	O&M Expenses Worksheet, C6L17
5	Transmission of Electricity by Others	$0	
6	Total O&M Expense for Transmission	$45,937,864	L4 + L5
7			
8	Net Transmission Plant Investment	$505,697,544	Net Plant Investment Worksheet, C6L11
9			
10	O&M as % of Net Transmission Plant Investment	9.084%	L6/L8
11			
12			
13	**B. A&G Expense for Transmission**		
14			
15	Transmission A&G Expense	$14,717,153	A&G Expenses Worksheet, C6L12
16			
17	Net Transmission Plant Investment	$505,697,544	L8
18			
19	A&G as % of Net Transmission Plant Investment	2.910%	L15/L17
20			
21			
22	**C. Depreciation Expense for Transmission**		
23			
24	Transmission Depreciation Expense	$22,139,465	Depreciation Expense Worksheet, C6L4
25			
26	Net Transmission Plant Investment	$505,697,544	L8
27			
28	Depreciation as a % of Net Transmission Plant Investment	4.378%	L24/L26

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

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Source/Notes
29			
30			
31	**D. Taxes Other than Income Taxes for Transmission**		
32			
33	Not applicable.		
34			
35			
36	**E. Allocation of General Plant to Transmission**		
37			
38	No General Plant identified at this time, all plant is identified as either generation or transmission related.		
39			
40			
41	**F. Cost of Capital**		
42			
43	Weighted Transmission Composite Interest Rate	5.495%	Cost of Capital Worksheet, C6L9
44			
45			
46	**G. Transmission Fixed Charge Rate**		
47			
48	Operation and Maintenance Expense	9.084%	L10
49			
50	A&G Expense	2.910%	L19
51			
52	Depreciation Expense	4.378%	L28
53			
54	Taxes Other than Income Taxes	0.000%	
55			
56	Allocation of General Plant to Transmission	0.000%	

	DETERMINATION OF PICK-SLOAN MISSOURI BASIN PROGRAM, EASTERN DIVISION		
	ANNUAL IS TRANSMISSION COSTS		
	Western Area Power Administration		
	Upper Great Plains Region		
Line No.	**Description**	**Amount**	**Source/Notes**
57			
58	Cost of Capital	5.495%	L43
59			
60	Total	21.867%	

O&M Expenses - Ancillary Services
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	282,225,951	99,665,355			381,891,306
3						
4	Less:					
5	Other Power Supply Expenses	219,858,889	54,925,483			274,784,372
6	A&G Expenses	15,347,921	8,546,884			23,894,805
7	Sunflower Payment		0			0
8	Prior Year Adjustments	0	0			0
9						
10	Plus:					
11	Moveable Property Interest	660,076	264,245			924,321
12	Warehouse Stores Interest	125,115	82,168			207,283
13						
14	COE/BOR Total			23,797,237	32,723,549	56,520,786
15	PS Total O&M	47,804,332	36,539,401	23,797,237	32,723,549	140,864,519
16						
17	PS-ED Transmission O&M 5/	45,576,124	361,740	0	0	45,937,864
18						
19	PS-ED Generation O&M 6/	842,217	0	23,797,237	32,723,549	57,363,003

1/ All Western UGPR O&M Expenses are from the FY 2009 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 2009 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 2009 Corps of Engineers Financial Statements

4/ Total BOR O&M Expenses are from the FY 2009 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.

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

Line No.	(1) Object Class	(2) WESTERN UGPR 1/	(3) WESTERN RMR 2/	(4) COE 3/	(5) BOR 3/	(6) Total
1						
2	1411	2,141,248	1,572,009	0	0	3,713,257
3	1412	1,715,250	2,413,725	0	0	4,128,975
4	1415	7,280	4,303	0	0	11,583
5	1416	26,795	37,847	0	0	64,642
6	1421	1,018,275	737,395			1,755,670
7	1422	1,830,597	4,958			1,835,555
8	1425	5,903	3,711			9,614
9	1426	21,456	(97)			21,359
10	1431	0	0	0	0	0
11	1432	0	0	0	0	0
12	1441	4,755,224	2,774,113	0	0	7,529,337
13	1442	3,825,893	998,920	0	0	4,824,813
14	PS Total A&G	15,347,921	8,546,884	0	0	23,894,805
15						
16	PS-ED Transmission A&G 4/	14,632,539	84,614	0	0	14,717,153
17						
18	PS-ED Generation A&G 5/	270,400	0	0	0	270,400

1/ Western UGPR A&G Expenses are from the FY 2009 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 2009 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 11A.

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

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

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

DEPRECIATION EXPENSE - Ancillary Services
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	23,067,712 1/	14,844,626 2/	13,571,913 3/	3,768,583 4/	55,252,834
3						
4	PS-ED Transmission Depreciation 5/	21,992,503	146,962	0	0	22,139,465
5						
6	PS-ED Generation Depreciation 6/	406,407	0	13,571,913	3,768,583	17,746,903

1/ FY 2009 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 4.

2/ FY 2009 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 4.

3/ FY 2009 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.

COST OF CAPITAL - Ancillary Services
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 2009 Balances	629,769,146	1/	370,641,141	1/	527,623,995	1/	97,704,004	1/	1,625,738,286	
4											
5	**Interest Expenses:**										
6	FY 2009 Simple Interest	34,548,141	2/	25,139,992	2/	18,167,179	2/	4,565,736	2/	82,421,048	
7	Average Interest Rate	5.486%	L6/L3	6.783%	L6/L3	3.443%	L6/L3	4.673%	L6/L3		
8	Transmission Plant Factor	0.9934	3/	0.0066	4/	0.0000	5/	0.0000	6/		
9	Weighted Trans. Composite Rate									5.495%	7/
10	Generation Plant Factor	0.0128	8/	0.0000	9/	0.6834	10/	0.3038	11/		
11	Weighted Gen. Composite Rate									3.843%	12/

1/ FY 2009 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedules 21X and 21RX.
2/ FY 2009 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).

NET PLANT INVESTMENT - Ancillary Services
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	1,007,955,730	1/	640,798,643	2/	951,706,242	3/	423,102,811	12/	3,023,563,426
3	PS-ED Transmission Plant-in-Service	960,973,825	4/	6,352,887	5/	0	6/	0		967,326,712
4	PS-ED Generation Plant-in-Service	17,758,071	7/	0		951,706,242	L2-L3	423,102,811	L2-L3	1,392,567,124
5	Generation Plant to Total Plant	0.017618	L4/L2	0.0000	L4/L2	1.0000	L4/L2	1.0000	L4/L2	
6	Transmission Plant to Total Plant	0.953389	L3/L2	0.0099	L3/L2	0.0000	L3/L2	0.0000	L3/L2	
7										
8	PS Accumulated Depreciation	481,499,959	8/	259,838,836	9/	524,666,894	10/	215,043,577	11/	1,481,049,266
9	PS-ED Trans. Accumulated Depreciation	459,056,764	L6*L8	2,572,404	L6*L8	0	13/	0	L6*L8	461,629,168
10	PS-ED Gen. Accumulated Depreciation	8,483,066	L5*L8	0	L5*L8	524,666,894	L8-L9	215,043,577	L5*L8	748,193,537
11	PS-ED Net Transmission Plant	501,917,061	L3-L9	3,780,483	L3-L9	0	L3-L9	0	L3-L9	505,697,544
12	PS-ED Net Generation Plant	9,275,005	L4-L10	0	L4-L10	427,039,348	L4-L10	208,059,234	L4-L10	644,373,587

1/ Transmission Plant-in-Service Worksheet, C2L516
2/ FY 2009 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 1.
3/ FY 2009 Corps of Engineers Financial Statements, Electric and Power Multi-Purpose Plant in Service.
4/ Transmission Plant-in-Service Worksheet, C5L516.
5/ Transmission Plant-in-Service Worksheet, C5L525.
6/ Transmission Plant-in-Service Worksheet, C5L529.
7/ Transmission Plant-in-Service Worksheet, C4L516.
8/ FY 2009 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 4.
9/ FY 2009 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 4.
10/ FY 2009 Corps of Engineers Financial Statements, Statement of Assets and Liabilities.
11/ FY 2009 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 15.
12/ FY 2009 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 17.
13/ Formerly used to account for transmission related accumulated depreciation on the COE switchyards. All COE facilities moved to generation so no transmission depreciation.

Line No.	(1) DESCRIPTION a	(2) FY2009 TOTALS TOTALS b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS c	(4) GENERATION ADJUSTMENTS GEN ADJ d	(5) TRANSMISSION TOTALS TRANS TOTAL e	(6) SOURCE/NOTES
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	5,099,232			5,099,232	
9	BROOKINGS-SIOUX FALLS	1,174,861			1,174,861	
10	BROOKINGS-WATERTOWN NO. 1	1,718,240			1,718,240	
11	BROOKINGS-WATERTOWN NO. 2	3,318,558			3,318,558	
12	BROOKINGS-WHITE 115/230KV	2,952,237			2,952,237	
13	CARRINGTON-JAMESTOWN	1,273,088			1,273,088	
14	CHARLIE CREEK-BELFIELD	14,655,950			14,655,950	
15	CONRAD-SHELBY #2	5,804,318			5,804,318	
16	CRESTON-MARYVILLE	1,366,481			1,366,481	
17	DAWSON COUNTY - MILES CITY	2,605,678			2,605,678	
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	918,676			918,676	
22	DAWSON-WILLISTON	1,258,900			1,258,900	
23	DENISON-CRESTON	11,497,529			11,497,529	
24	DEVILS LAKE-CARRINGTON	7,408,621			7,408,621	
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	6,914,811			6,914,811	
31	FORMAN-SUMMIT (BISMARCK)	922,098			922,098	
32	FORMAN-SUMMIT (HURON)	487,534			487,534	
33	FORT PECK-DAWSON #1	481,450			481,450	
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	157,876			157,876	
37	FORT PECK-WILLISTON	10,004,221			10,004,221	
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	1,151,719			1,151,719	
41	FORT RANDALL-GREGORY	777,327			777,327	
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	5,033,030			5,033,030	
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	1,540,944			1,540,944	
52	GAVINS POINT-BELDEN	455,727			455,727	
53	GAVINS POINT-SIOUX FALLS	1,813,500			1,813,500	
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	2,010,227			2,010,227	
58	GROTON-HURON	1,212,199			1,212,199	
59	GROTON-SUMMIT	3,176,751			3,176,751	
60	HAVRE-RAINBOW	6,720,551			6,720,551	

Line No.	(1) DESCRIPTION a	(2) FY2009 TOTALS TOTALS b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS c	(4) GENERATION ADJUSTMENTS GEN ADJ d	(5) TRANSMISSION TOTALS TRANS TOTAL 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	10,808,503			10,808,503	
64	HURON-MT VERNON	617,623			617,623	
65	HURON-WATERTOWN 230KV 1&3	5,792,955			5,792,955	
66	JAMESTOWN-EDGELEY	324,360			324,360	
67	JAMESTOWN-FARGO NO. 1	4,941,649			4,941,649	
68	JAMESTOWN-FARGO NO. 2	3,155,850			3,155,850	
69	JAMESTOWN-GRAND FORKS	16,016,353			16,016,353	
70	JAMESTOWN-VALLEY CITY	1,055,414			1,055,414	
71	LEEDS-DEVILS LAKE	2,323,057			2,323,057	
72	LEEDS-ROLLA	1,815,333			1,815,333	
73	MALLARD-RUGBY	1,282,436			1,282,436	
74	MARTIN-MISSION	1,816,904			1,816,904	
75	MARTIN-PHILIP	1,790,108			1,790,108	
76	MAURINE-RAPID CITY	4,592,789			4,592,789	
77	MILES CITY-BAKER	8,470,654			8,470,654	
78	MILES CITY-CUSTER	3,750,704			3,750,704	
79	NEW UNDERWOOD-PHILIP	2,116,605			2,116,605	
80	NEW UNDERWOOD-RAPID CITY NO. 1	1,067,598			1,067,598	
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	2,511,409			2,511,409	
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	2,263,096			2,263,096	
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	4,629,316			4,629,316	
108	YELLOWTAIL-CUSTER	2,265,163			2,265,163	
109	Subtotal	412,025,231	0	0	412,025,231	
110						
111	Substations					
112	ARMOUR SUBSTATION	1,868,644	(82,000)		1,786,644	
113	ASH SUBSTATION	63,325			63,325	
114	AURORA SUBSTATION	2,899,881			2,899,881	
115	BELDEN SUBSTATION	164,986.20			164,986	
116	BELFIELD SUBSTATION	10,138,776			10,138,776	
117	BERESFORD SUBSTATION	3,494,954	(594,142)		2,900,812	17% of the costs of this facility have been allocated to distribution.
118	BISBEE SUBSTATION	272,529	(136,265)		136,264	50% of the costs of this facility have been allocated to distribution
119	BISMARK SUBSTATION	8,110,398			8,110,398	
120	BISON	12,472			12,472	
121	BOLE SUB (BEFP)	92,092			92,092	
122	BOLE SUB (BEPS)	3,111,717			3,111,717	
123	BONESTEEL SUBSTATION	3,442,909	(1,721,454)		1,721,455	50% of the costs of this facility have been allocated to distribution.

Line No.	(1) DESCRIPTION a	(2) FY2009 TOTALS TOTALS b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS c	(4) GENERATION ADJUSTMENTS GEN ADJ d	(5) TRANSMISSION TOTALS TRANS TOTAL e	(6) SOURCE/NOTES
124	BROOKINGS SUBSTATION	3,880,456			3,880,456	
125	CARPENTER SUBSTATION	2,398,390			2,398,390	
126	CARRINGTON SUBSTATION	3,756,722	(488,374)		3,268,348	13% of the costs of this facility have been allocated to distribution.
127	CIRCLE SUBSTATION	1,507,470			1,507,470	
128	CONRAD SUB	311,656			311,656	
129	CONRAD SUB (BEPS)	5,008,913			5,008,913	
130	CRESTON SUBSTATION	4,941,437	(55,000)		4,886,437	
131	CROSSOVER SUB (BEFP)	267,232			267,232	
132	CROSSOVER SUB	10,955,346			10,955,346	
133	CUSTER SUBSTATION (BEFP)	3,189,683			3,189,683	
134	CUSTER SUBSTATION	1,322,622			1,322,622	
135	CUSTER TRAIL SUBSTATION	1,475,222	(737,611)		737,611	50% of the costs of this facility have been allocated to distribution
136	DAWSON COUNTY SUBSTATION	10,804,980	(864,398)		9,940,582	8% of the costs of this facility have been allocated to distribution.
137	DENISON SUBSTATION	15,717,046			15,717,046	
138	DEVAUL SUBSTATION	905,869	(543,522)		362,347	60% of the costs of this facility have been allocated to distribution
139	DEVILS LAKE SUBSTATION	2,591,935	(285,113)		2,306,822	11% of the costs of this facility have been allocated to distribution
140	EAGLE BUTTE SUBSTATION	1,252,804			1,252,804	
141	EDGELEY SUBSTATION	3,477,612	(486,866)		2,990,746	14% of the costs of this facility have been allocated to distribution
142	ELK CREEK SUBSTATION	2,078,657			2,078,657	
143	ELLENDALE SUBSTATION	579 43	(579)		0	
144	ENDERLIN TAP STATION	730,428			730,428	
145	EXIRA SWITCHING STATION	5,500,776			5,500,776	
146	FAITH SUBSTATION	1,212,383	(606,191)		606,192	50% of the costs of this facility have been allocated to distribution.
147	FARGO SUBSTATION	20,561,012	(47,000)		20,514,012	
148	FLANDREAU SUBSTATION	3,393,392	(576,877)		2,816,515	17% of the costs of this facility have been allocated to distribution
149	FORMAN SUBSTATION	5,456,548	(709,351)		4,747,197	13% of the costs of this facility have been allocated to distribution.
150	FORT RANDALL	253,710			253,710	
151	FORT THOMPSON #2	8,472,673			8,472,673	
152	FORT THOMPSON SUBSTATION	14,537,019	(354,000)		14,183,019	
153	GLENDIVE SUBSTATION	1,725,310			1,725,310	
154	GRAND FORKS SUBSTATION	9,329,992			9,329,992	
155	GRAND ISLAND SUBSTATION	11,912,281			11,912,281	
156	GRANITE FALLS SUBSTATION	18,720,615	(57,000)		18,663,615	
157	GREAT FALLS SUB (BEFP)	87,834			87,834	
158	GREAT FALLS SUB	470,826			470,826	
159	GREGORY SUBSTATION	1,526,856	(305,371)		1,221,485	20% of the costs of this facility have been allocated to distribution
160	GROTON SUBSTATION	3,880,549			3,880,549	
161	HAVRE SUBSTATION	5,668,800	(963,696)		4,705,104	17% of the costs of this facility have been allocated to distribution.
162	HILKEN SUSTATION	3,874,407			3,874,407	
163	HURON SUBSTATION	10,935,738			10,935,738	
164	JAMESTOWN SUBSTATION	18,212,205	(1,821,221)		16,390,984	10% of the costs of this facility have been allocated to distribution.
165	KILLDEER SUBSTATION	434,273			434,273	
166	LAKOTA SUBSTATION	2,756,210	(909,549)		1,846,661	33% of the costs of this facility have been allocated to distribution
167	LEEDS SUBSTATION	1,465,204	(205,129)		1,260,075	14% of the costs of this facility have been allocated to distribution
168	LETCHER SUBSTATION	10,097,632			10,097,632	
169	MARTIN SUBSTATION	1,533,848			1,533,848	
170	MAURINE SUBSTATION	5,662,288			5,662,288	
171	MIDLAND SUBSTATION	672,772			672,772	
172	MILES CITY #2	4,634,218			4,634,218	
173	MILES CITY #2 (BEFP)	986,001			986,001	
174	MILES CITY SUB #3	1,669,005			1,669,005	
175	MILES CITY SUB #3 (BEFP)	226,697			226,697	
176	MILES CITY SUBSTATION (BEFP)	160,336			160,336	
177	MILES CITY SUBSTATION	714,993			714,993	
178	MISSION SUBSTATION	3,156,994			3,156,994	
179	MORRIS SUBSTATION	7,114,391			7,114,391	
180	MT VERNON SUBSTATION	1,896,247			1,896,247	
181	NEW UNDERWOOD SUBSTATION	7,296,806	(802,649)		6,494,157	11% of the costs of this facility have been allocated to distribution.
182	NEWELL SUBSTATION	1,154,996			1,154,996	
183	Non-Facility	412,629			412,629	
184	O'FALLON CREEK SUBSTATION	1,986,758	(993,379)		993,379	50% of the costs of this facility have been allocated to distribution.
185	PHILIP SUBSTATION	1,974,602			1,974,602	
186	PIERRE SUBSTATION	4,471,691	(2,235,846)		2,235,845	50% of the costs of this facility have been allocated to distribution

Line No.	(1) DESCRIPTION a	(2) FY2009 TOTALS TOTALS b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS c	(4) GENERATION ADJUSTMENTS GEN ADJ d	(5) TRANSMISSION TOTALS TRANS TOTAL e	(6) SOURCE/NOTES
187	RAINBOW SUBSTATION	723,556			723,556	
188	RAPID CITY SUBSTATION	4,804,631			4,804,631	
189	RICHLAND SUBSTATION	1,555,034	(1,244,027)		311,007	80% of the costs of this facility have been allocated to distribution.
190	ROLLA SUBSTATION	830,427	(207,607)		622,820	25% of the costs of this facility have been allocated to distribution
191	RUDYARD SUBSTATION	2,585,060	(439,460)		2,145,600	17% of the costs of this facility have been allocated to distribution
192	RUGBY SUBSTATION	5,885,813	(824,014)		5,061,799	14% of the costs of this facility have been allocated to distribution
193	SAVAGE SUB	74,403			74,403	
194	SHELBY SUBSTATION	1,086,199			1,086,199	
195	SHELBY SUBSTATION #2 (BEFP)	286,340			286,340	
196	SHELBY SUBSTATION #2 (BEPS)	4,134,102			4,134,102	
197	SIOUX CITY #2	9,444,471			9,444,471	
198	SIOUX CITY SUBSTATION	15,655,346	(57,000)		15,598,346	
199	SIOUX FALLS SUBSTATION	6,520,157			6,520,157	
200	SPENCER	3,240,715			3,240,715	
201	SULLY BUTTES	74,428			74,428	
202	SUMMIT SUBSTATION	2,873,211			2,873,211	
203	TYNDALL SUBSTATION	842,578			842,578	
204	UTICA JCT.	13,007,047			13,007,047	
205	VALLEY CITY SUBSTATION	3,066,265			3,066,265	
206	VERONA	25,210			25,210	
207	VIRGIL FODNESS SUBSTATION	3,206,763			3,206,763	
208	WALL SUBSTATION	1,609,013	(804,506)		804,507	50% of the costs of this facility have been allocated to distribution.
209	WARD SUBSTATION	3,451,262			3,451,262	
210	WASHBURN SUBSTATION	1,972,344			1,972,344	
211	WATERTOWN #2	2,965,204			2,965,204	
212	WATERTOWN STATIC VAR SYSTEM	11,703,689			11,703,689	
213	WATERTOWN SUBSTATION	13,118,030			13,118,030	
214	WATFORD CITY SUB	1,539,705	(30,000)		1,509,705	
215	WESSINGTON SPRINGS SUBSTATION	4,051,147			4,051,147	
216	WHATELY (NORTHERN)	40,860			40,860	
217	WHATELY SUBSTATION	109,910	(54,955)		54,955	50% of the costs of this facility have been allocated to distribution
218	WHITE 345/115 SUB	9,658,497			9,658,497	
219	WICKSVILLE SUBSTATION	683,282	(341,641)		341,641	50% of the costs of this facility have been allocated to distribution.
220	WILLISTON SUBSTATION	6,684,168			6,684,168	
221	WINNER SUBSTATION	3,361,424	(1,680,712)		1,680,712	50% of the costs of this facility have been allocated to distribution.
222	WOLF POINT SUBSTATION	7,230,798	(2,169,239)		5,061,559	30% of the costs of this facility have been allocated to distribution.
223	WOONSOCKET SUBSTATION	2,378,168			2,378,168	
224	YANKTON SUBSTATION	53,583			53,583	
225	Subtotal	466,992,099	(24,435,744)	0	442,556,355	
226						
227	Line Taps & Related Equipment					
228	ANITA	6,259			6,259	
229	ASSINNIBOINE	35,005			35,005	
230	BAKER (BEFP)	133,554			133,554	
231	BAKER	97,832			97,832	
232	CANYON FERRY (BEFP)	15,145			15,145	
233	CANYON FERRY	30,065			30,065	
234	CHARLIE CREEK	1,121,015			1,121,015	
235	COTTON	1,399			1,399	
236	DENBIGH TAP	848,872			848,872	
237	DICKINSON	63,736			63,736	
238	E. J. MANNING	49,112			49,112	
239	EAGLE	156,285			156,285	
240	FORSYTH	32,070			32,070	
241	FORSYTH	273,368			273,368	
242	HARLEM	174,745			174,745	
243	HARLEM (BEFP)	16,015			16,015	
244	HETTINGER	4,451			4,451	
245	HIGHWOOD	22,896			22,896	
246	MALLARD	29,969			29,969	
247	MALTA	151,936			151,936	
248	NASHUA SUB	72,368			72,368	
249	O'NEILL SUB (NPP)	115,790			115,790	

Line No.	(1) DESCRIPTION a		(2) FY2009 TOTALS TOTALS b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS c	(4) GENERATION ADJUSTMENTS GEN ADJ d	(5) TRANSMISSION TOTALS TRANS TOTAL e	(6) SOURCE/NOTES
250	PENN TAP		890,607			890,607	
251	POPLAR (MDU)		3,758			3,758	
252	SHIRLEY TAP		22,102			22,102	
253	STANLEY		49,735			49,735	
254	TERRY TAP		78,497			78,497	
255	TERRY TAP		345,850	(172,925)		172,925	50% of the costs of this facility have been allocated to distribution
256	TIBER TAP		166,306	(83,153)		83,153	50% of the costs of this facility have been allocated to distribution
257	VETAL TAP		232,375			232,375	
258	V. T. HANLON		5,553			5,553	
259	WM. J. NEAL		166,336			166,336	
260	YANKTON JCT.		28,526			28,526	
261	ZENITH		2,047			2,047	
262		Subtotal	5,443,580	(256,078)	0	5,187,502	
263							
264	**O&M Service & Maintenance Centers**						
265	ARMOUR O&M SER. CEN.		3,488,667			3,488,667	
266	BISMARCK O&M SER. CEN.		8,969,071			8,969,071	
267	DAWSON SER. CEN.		22,545			22,545	
268	DEVILS LAKE O&M SER. CEN.		3,852,064			3,852,064	
269	Fargo Line Maintenance Facility		964,929			964,929	
270	FARGO O&M SER. CEN.		794,673			794,673	
271	FORT PECK SER. CEN		5,793,310			5,793,310	
272	FORT THOMPSON O&M S. C.		315,000			315,000	
273	HAVRE SERVICE CENTER		249,377			249,377	
274	HURON O&M SER. CEN.		2,447,467			2,447,467	
275	JAMESTOWN O&M SER. CEN		3,841,398			3,841,398	
276	MILES CITY MTCE FAC.		21,817			21,817	
277	MILES CITY MTCE FAC.		1,003,437			1,003,437	
278	NEW UNDERWOOD SER. CEN.		96,884			96,884	
279	PHILIP O&M SER. CENT.		1,690,034			1,690,034	
280	PIERRE O&M SER. CEN.		1,047,818			1,047,818	
281	RAPID CITY GARAGE & STOR.		2,055,932			2,055,932	
282	SIOUX CITY O&M SER. CEN.		3,007,882			3,007,882	
283	SIOUX FALLS O&M SER. CEN.		313,280			313,280	
284	WATERTOWN MAINT. CEN.		934,402			934,402	
285		Subtotal	40,909,988	0	0	40,909,988	
286							
287	**Operation Centers**						
288	WATERTOWN OPERATIONS CENT		861,149		(269,109)	592,040	
289	WATERTOWN OPER CTR (BFPS)		10,862,172		(3,394,429)	7,467,743	Column 4 shows 31.25% of the Watertown Operations Center that
290		Subtotal	11,723,321	0	(3,663,538)	8,059,783	was prorated to generation based on FTE associated with generation
291							
292	**Mobile Equipment**						
293	MOB 115KV SWITCH TRAILER		12,328			12,328	
294	MOB 115KV SWITCH TRAILER		57,413			57,413	
295	MOB TRANSF 111KV 15MVA		213,000			213,000	
296	MOB TRANSF 115KV 10MVA		76,258			76,258	
297	MOB TRANSF 115KV 10MVA		142,235			142,235	
298	MOB TRANSF 115KV 25MVA		556,464			556,464	
299	MOB TRANSF 115KV 40MVA		499,220			499,220	
300	MOB TRANSF 230KV 1-33MVA		170,278			170,278	
301	MOB TRANS		248,943			248,943	
302	MOBILE BY PASS KIT (BISMARCK)		35,071			35,071	
303	MOBILE BY PASS KIT (HURON)		163,695			163,695	
304	MOBILE CAPACITOR BANK		19,075			19,075	
305	MOBILE SUB 110KV		127,144			127,144	
306	MOBILE SUB 115KV 20MVA		404,166			404,166	
307	MOBILE SUB 41.8 KV		192,498			192,498	
308	MOBILE SUB 69KV		71,118			71,118	
309	MOB SH.REACTOR		179,328			179,328	
310		Subtotal	3,168,233	0	0	3,168,233	
311							
312	**Transmission-Related Generation Facilities**						

Line No.	(1) DESCRIPTION a	(2) FY2009 TOTALS TOTALS b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS c	(4) GENERATION ADJUSTMENTS GEN ADJ d	(5) TRANSMISSION TOTALS TRANS TOTAL e	(6) SOURCE/NOTES
313	BIG BEND-FORT THOMPSON (LOW VOLTAGE)	81,944		(81,944)	0	
314	CANYON FERRY-EAST HELENA "A"	141,044		(141,044)	0	
315	CANYON FERRY-EAST HELENA "B"	141,044		(141,044)	0	
316	FORT PECK POWERPLANT (COE)	8,380		(8,380)	0	
317	FORT THOMPSON-BIG BEND NO. 1	922,164		(922,164)	0	
318	FORT THOMPSON-BIG BEND NO. 2	690,735		(690,735)	0	
319	Subtotal	1,985,311	0	(1,985,311)	0	
320						
321	Communication Facilities					
322	ATLANTIC COMMUNICATION SITE	17,199		(5,447)	11,752	Column 4 shows 31.67% of the Communication Facilities that were prorated to generation based on the number of communication channels dedicated to generation.
323	BAKER RELAY	27,791		(8,801)	18,990	
324	BANTRY	268,530		(85,044)	183,486	
325	BARRETT	244,695		(77,495)	167,200	
326	BATTLE MT. MICROWAVE	470,739		(149,083)	321,656	
327	BELLE PRAIRIE	16,111		(5,102)	11,009	
328	BELLE PRAIRIE	577,323		(182,838)	394,485	
329	BENEDICT	36,772		(11,646)	25,126	
330	BEULAH	10,679		(3,382)	7,297	
331	BIG BEND	113,362		(35,902)	77,460	
332	BIJOU REPEATER	603,315		(191,070)	412,245	
333	BISMARCK REPEATER	405,324		(128,366)	276,958	
334	BISON REPEATER	204,957		(64,910)	140,047	
335	BOLE NORTH REPEATER	149,228		(47,260)	101,968	
336	BRINSMADE	237,551		(75,232)	162,319	
337	BRISTOL	11,441		(3,623)	7,818	
338	BRUNSVILLE REPEATER	92,595		(29,325)	63,270	
339	BUFFALO	255,051		(80,775)	174,276	
340	CAHOON	240,466		(76,156)	164,310	
341	CARRINGTON REPEATER	726,855		(230,195)	496,660	
342	CHARTER OAK REPEATER	12,546		(3,973)	12,546	
343	CHARTER OAK REPEATER	3,121		(988)	3,121	
344	CHINOOK (BEFP)	284,048		(89,958)	194,090	
345	CHINOOK REPEATER	15,293		(4,843)	10,450	
346	CLARK MW REPEATER	588,027		(186,228)	401,799	
347	CLEVELAND REPEATER, N D	263,617		(83,488)	180,129	
348	COLEMAN REPEATER	105,281		(33,342)	71,939	
349	COLOME REPEATER	469,005		(148,534)	320,471	
350	CONRAD BUTTE REPEATER	371,283		(117,585)	253,698	
351	CONRAD BUTTE REPEATER	84,384		(26,725)	57,659	
352	CRESTON REPEATER	11,107		(3,517)	7,590	
353	CROW LAKE REPEATER	311,803		(98,748)	213,055	
354	CROWN BUTTE	202,445		(64,114)	138,331	
355	CULBERTSON RADIO RELAY SITE	1,926		(610)	1,316	
356	CUSTER LOOKOUT	194,017		(61,445)	132,572	
357	DALTON (WES)	198,021		(62,713)	135,308	
358	DEVILS LAKE REPEATER	467,927		(148,192)	319,735	
359	DODSON REPEATER	276,812		(87,666)	189,146	
360	DOGDEN BUTTE	281,286		(89,083)	192,203	
361	DRISCOLL	196,774		(62,318)	134,456	
362	DUPREE REPEATER	1,821		(577)	1,244	
363	DUTTON REPEATER	315,739		(99,995)	215,744	
364	EAST RAINY BUTTE	287,339		(91,000)	196,339	
365	ECKELSON	288,401		(91,337)	197,064	
366	ELKTON	146,696		(46,459)	100,237	
367	ELLENDALE REPEATER	319,122		(101,066)	218,056	
368	ELLSWORTH AIR BASE	59,669		(18,897)	40,772	
369	ERHARD	301,774		(95,572)	206,202	
370	EXIRA REPEATER	2,527		(800)	1,727	
371	F. L. BLAIR	103,372		(32,738)	70,634	
372	FAIRPOINT REPEATER	339,030		(107,371)	231,659	
373	FALLON REPEATER	271,939		(86,123)	185,816	
374	FERGUS FALLS COMMUNICATIONS SITE	485,567		(153,779)	331,788	
375	FLOWING WELLS	68,762		(21,777)	46,986	

Line No.	(1) DESCRIPTION a	(2) FY2009 TOTALS TOTALS b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS c	(4) GENERATION ADJUSTMENTS GEN ADJ d	(5) TRANSMISSION TOTALS TRANS TOTAL e	(6) SOURCE/NOTES
376	FORBES COMMUNICATION SITE	45,316		(14,352)	30,964	
377	FORT PECK RELAY (WES)	250,960		(79,479)	171,481	
378	FORT THOMPSON REPEATER	306,861		(97,183)	209,678	
379	FORT THOMPSON REPEATER (EAST RIVER)	301,614		(95,521)	206,093	
380	FOX CREEK MICROWAVE	579,063		(183,389)	395,674	
381	FRYBURG SUB & MICROWAVE	210,967		(66,813)	144,154	
382	GARRISON	249,702		(79,081)	170,621	
383	GARY REPEATER	228,494		(72,364)	156,130	
384	GAVIN'S POINT	46,061		(14,588)	31,473	
385	GAVINS POINT REPEATER	411,445		(130,305)	281,140	
386	GETTYSBURG REPEATER	296,476		(93,894)	202,582	
387	GLENHAM	293,701		(93,015)	200,686	
388	GRAND FORKS MINNKOTA (MPC)	23,847		(7,552)	16,295	
389	HAILSTONE BUTTE	188,523		(59,705)	128,818	
390	HALLOWAY REPEATER	266,614		(84,437)	182,177	
391	HATHAWAY	17,314		(5,483)	11,831	
392	HATHAWAY	191,777		(60,736)	131,041	
393	HERMOSA MICROWAVE	302,701		(95,865)	206,836	
394	HIGHLAND REPEATER	177,964		(56,361)	121,603	
395	HIGHMORE REPEATER	251,511		(79,654)	171,857	
396	HINSDALE	201,837		(63,922)	137,915	
397	HINSDALE REPEATER	25,153		(7,966)	17,187	
398	HOPEWELL REPEATER	391,934		(124,126)	267,808	
399	HUNTER MICROWAVE	307,546		(97,400)	210,146	
400	HURON DISTRICT OFFICE	747,055		(236,592)	510,463	
401	HYSHAM	250,143		(79,220)	170,923	
402	JAMESTOWN REPEATER	46,981		(14,879)	32,102	
403	JONES CREEK	251,034		(79,502)	171,532	
404	KELLY CREEK	15,210		(4,817)	10,393	
405	KELLY CREEK	300,278		(95,098)	205,180	
406	KILLDEER REPEATER	369,183		(116,920)	252,263	
407	KNEE HILL MW	308,285		(97,634)	210,651	
408	KNEE HILL MW	119,303		(37,783)	81,520	
409	KONES CORNER REPEATER	470,207		(148,915)	321,292	
410	LAC QUI PARLE	747,619		(236,771)	510,848	
411	LAKE ANDES REPEATER	648,460		(205,367)	443,093	
412	LEFOR	186,943		(59,205)	127,738	
413	LINDSAY RIDGE	235,489		(74,579)	160,910	
414	LINTON COMMUNICATIONS SITE	339,867		(107,636)	232,231	
415	LODGEPOLE REPEATER	186,559		(59,083)	127,476	
416	MALTA REPEATER	289,599		(91,716)	197,883	
417	MANDAN MICROWAVE SITE	69,988		(22,165)	47,823	
418	MAPLE RIVER	172,792		(54,723)	118,069	
419	MARTIN REPEATER	287,916		(91,183)	196,733	
420	MAYVILLE	331,361		(104,942)	226,419	
421	MIDLAND REPEATER	660,339		(209,129)	451,210	
422	MILES CITY SUB (BEFP)	305,418		(96,726)	208,692	
423	MOE REPEATER	129,266		(40,939)	88,327	
424	MOORHEAD	251,422		(79,625)	171,797	
425	MORRIS REPEATER & MICROWAVE	331,303		(104,924)	226,379	
426	NEWCASTLE REPEATER	216,330		(68,512)	147,818	
427	OAHE	558,997		(177,034)	381,963	
428	O'KREEK REPEATER	508,754		(161,122)	347,632	
429	ORCHARD REPEATER	43,642		(13,821)	29,821	
430	OTO MICROWAVE	16,445		(5,208)	11,237	
431	OTTUMWA ROAD REPEATER SITE	7,685		(2,434)	5,251	
432	PAGE N.D.	1,646		(521)	1,125	
433	PAHOJA SUB	66,444		(21,043)	45,401	
434	PEAK	264,351		(83,720)	180,631	
435	PHILIP JCT. REPEATER	545,125		(172,641)	372,484	
436	PINE RIDGE	15,766		(4,993)	10,773	
437	PINE RIDGE	273,894		(86,742)	187,152	
438	PRIMGHAR REPEATER	11,990		(3,797)	8,193	

Line No.	(1) DESCRIPTION a	(2) FY2009 TOTALS TOTALS b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS c	(4) GENERATION ADJUSTMENTS GEN ADJ d	(5) TRANSMISSION TOTALS TRANS TOTAL e	(6) SOURCE/NOTES
439	PUKWANNA REPEATER	258,360		(81,823)	176,537	
440	RAPID CITY REPEATER	354,281		(112,201)	242,080	
441	RICHARDSON COULEE	214,752		(68,012)	146,740	
442	RICHARDSON COULEE REPEATER	24,536		(7,771)	16,765	
443	RICHLAND MW REPEATER (BEPS)	532,827		(168,746)	364,081	
444	ROCKY RIDGE REPEATER	226,934		(71,870)	155,064	
445	ROLLAG	172,922		(54,764)	118,158	
446	RUGBY REPEATER	276,659		(87,618)	189,041	
447	RUTLAND	388,869		(123,155)	265,714	
448	SACO	1,237		(392)	845	
449	SENTINEL BUTTE	215,321		(68,192)	147,129	
450	SHEEP COULEE REPEATER	475,744		(150,668)	325,076	
451	SIOUX CITY REPEATER	576,462		(182,566)	393,896	
452	SIOUX FALLS REPEATER	367,833		(116,493)	251,340	
453	SIOUX PASS	1,366		(433)	933	
454	SNAKE BUTTE REPEATER	729,560		(231,052)	498,508	
455	SPALDING REPEATER	38,651		(12,241)	26,410	
456	SPIRIT MOUND	226,293		(71,667)	154,626	
457	STRASBERG	17,870		(5,659)	12,211	
458	SUMMIT REPEATER	50,053		(15,852)	34,201	
459	TAPPEN COMMUNICATIONS SITE	291,767		(92,403)	199,364	
460	TAPPEN REPEATER	272,393		(86,267)	186,126	
461	TENNANT COMMUNICATIONS SITE	8,782		(2,781)	6,001	
462	TORONTO REPEATER	106,096		(33,601)	72,495	
463	TRIPP REPEATER	232,264		(73,558)	158,706	
464	TURKEY RIDGE REPEATER	631,991		(200,152)	431,839	
465	TYLER REPEATER	449,771		(142,443)	307,328	
466	VICTOR (EREC)	35,530		(11,252)	24,278	
467	VIDA	14,357		(4,547)	9,810	
468	VIDA	323,156		(102,343)	220,813	
469	WALL REPEATER	461,034		(146,010)	315,024	
470	WATERTOWN REPEATER	699,939		(221,671)	478,268	
471	WAYSIDE	118,156		(37,420)	80,736	
472	WESSINGTON SPGS. REPEATER	623,475		(197,455)	426,020	
473	WESTFIELD	19,003		(6,018)	12,985	
474	WHITE SWAN	116,529		(36,905)	79,624	
475	WHITLOCK (BCPS)	165,594		(52,444)	113,150	
476	WOLBACH REPEATER	52,848		(16,737)	36,111	
477	YELLOWTAIL SWITCHYARD (BEPS)	271,476		(85,976)	185,500	
478	Subtotal	38,235,629	0	(12,109,223)	26,126,406	
479						
480	Miles City Converter Station					
481	MILES CITY CONVERTER STATION	22,557,875			22,557,875	
482	MILES CITY CONVERTER STATION	382,455			382,455	
483	Subtotal	22,940,330	0	0	22,940,330	
484						
485	Distribution Facilities					
486	BUFORD TRENTON TAP - BUFORD TRENTON P P	650,001	(650,001)		0	
487	BUFORD TRENTON PUMP SUB	184,827	(184,827)		0	These facilities have been determined to be used solely for distribution
488	FALLON PUMPING PLANT SUBS	223,594	(223,594)		0	and are therefore not recovered in the transmission rate
489	FALLON RELIFT PUMPING PLA	171,257	(171,257)		0	
490	FALLON-GLENDIVE PUMP #4	25,506	(25,506)		0	
491	FORT PECK-WOLF POINT	190,500	(190,500)		0	
492	FRAZER PUMP SUB	253,597	(253,597)		0	
493	GARRISON-SNAKE CREEK	569,241	(569,241)		0	
494	GLENDIVE P.P. #1 SUB	425,706	(425,706)		0	
495	INTAKE SUBSTATION	108,040	(108,040)		0	
496	INTAKE-INTAKE PUMP	6,494	(6,494)		0	
497	SAVAGE PUMPING PLANT SUBS	102,283	(102,283)		0	
498	SHIRLEY PUMP SUBSTATION	127,053	(127,053)		0	
499	SNAKE CREEK PUMP SUBSTATI	662,435	(662,435)		0	
500	TERRY PUMPING PLANT SWITC	474,404	(474,404)		0	
501	TIBER DAM SUBSTATION	318,568	(318,568)		0	

Line No.	(1) DESCRIPTION a	(2) FY2009 TOTALS TOTALS b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS c	(4) GENERATION ADJUSTMENTS GEN ADJ d	(5) TRANSMISSION TOTALS TRANS TOTAL e	(6) SOURCE/NOTES
502	WIOTA SUBSTATION	38,507	(38,507)		0	
503	Subtotal Distribution Facilities	4,532,013	(4,532,013)	0	0	
504						
505	**Subtotal Upper Great Plains Region Facilities**	1,007,955,735	(29,223,835)	(17,758,072)	960,973,828	
506						
507						
508						
509	**Rocky Mountain Region Facilities**					
510	NEW UNDERWOOD-STEGALL	287,835			287,835	Column 2 includes plant-in-service from FY 2008 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.
511	STEGALL SUBSTATION	8,932,477.75	(8,629,869)		302,609	
512	STEGALL-WAYSIDE	2,978,205			2,978,205	
513	YELLOWTAIL SWITCHYARD	11,136,950	(8,352,713)		2,784,237	
514		23,335,469	(16,982,582)	0	6,352,887	
515						
516	**Corps of Engineers Facilities**					
517	CORPS SWITCHYARD FACILITIES	29,782,666		(29,782,666)	0	
518		29,782,666	0	(29,782,666)	0	
519						
520	**TOTAL FACILITIES**	1,061,073,870	(46,206,417)	(47,540,738)	967,326,715	

Basin Electric's Transmission Cost Data

Line No.			Total	Allocator	Total Transmission	IS Transmission	West (MBPP) Transmission	Other Transmission
1	GROSS REVENUE REQUIREMENT (page 3, line 28)				$ 80,809,944	$ 46,018,647	$ 9,169,061	$ 25,622,237
	(MBPP West Excluded - 1-.065997)						$ 8,563,930	
	REVENUE CREDITS							
2	Third Party Receipts			TP 1.00000		$ (333,000)	$ -	$ -
3								
4	Third Party Payments			TP 1.00000		$ 97,532		
5		(line 2 + 4)				$ (235,466)	$ -	$ -
6	NET REVENUE REQUIREMENT	(line 1+ 5)				$ 45,783,179	$ 605,131	$ 25,622,237
7	TOTAL REVENUE REQUIREMENT WITH MBPP EAST					$ 46,388,310		

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

Projections for 2011

Line	(1)	(2) Worksheets	(3)	(4) Allocator A		(5) Total Trans	(4a) Allocator B		(6) IS Transmission	(7) West (MBPP) Transmission	(8) Other Transmission
	GROSS PLANT IN SERVICE (Note A)										
1	Production	Worksheet 1, L 1, C. e	3,089,817,764	NA	0.000%	-	NA	0.000%	-	-	-
2	Transmission	Worksheet 1, L 2, C.e	695,243,629	DA	100.000%	695,243,629	DA	100.000%	400,036,379	92,267,804	202,939,446
3	Distribution		-	NA	0.000%	-	NA	0.000%	-	-	-
4	General	Worksheet 1, L.3.C. e	137,063,124								
4a	Direct Assign - Transmission (Note B)		40,535,706	DA	100.000%	40,535,706	DA	100.000%	26,264,758	3,235,492	11,035,456
4b	Direct Assign - Production		38,388,859	NA	0.000%	-	NA	0.000%	-	-	-
4c	Other		58,138,559	WS	11.263%	6,548,146	GP	Gross Plant	3,767,738	869,004	1,911,404
5	Intangible	Worksheet 1, L.4. C. e	72,508,060	DA	100.000%	69,100,565	DA	100.000%	32,120,916	2,617,629	34,362,020
6	TOTAL GROSS PLANT (sum lines 1,2,4,5)	Worksheet 1, L. 5. C. e	$ 3,994,632,577			$ 811,428,046			$ 462,189,791	$ 98,989,929	$ 250,248,326
				GP			GP	Gross Plant	57.539%	13.271%	29.190%
	ACCUMULATED DEPRECIATION										
7	Production	Worksheet 1, L.6. C. e	1,125,038,825	NA	0.000%	-	NA	0.000%	-	-	-
8	Transmission	Worksheet 1, L, 7, C. e	280,597,227	DA	100.000%	280,597,227	DA	100.000%	185,526,380	53,539,881	41,530,966
9	Distribution		-	NA	0.000%		NA	0.000%			
10	General	Worksheet 1, L. 8. C. e	104,800,140								
10a	Direct Assign - Transmission		28,760,846	DA	100.000%	28,760,846	DA	100.000%	19,294,997	2,573,181	6,892,668
10b	Direct Assign - Production		27,790,909	NA	0.000%		NA	0.000%			
10c	Other		48,248,385	WS	11.263%	5,434,216	GP	Gross Plant	3,126,794	721,175	1,586,246
11	Intangible	Worksheet 1, L. 9. C. e	46,230,724	DA	100.000%	45,700,724	DA	100.000%	21,659,035	1,919,605	22,112,084
12	TOTAL ACCUM. DEPR (sum lines 7,8,10,11)	Worksheet 1, L. 10. C. e	$ 1,556,656,916			$ 360,493,013			$ 229,617,206	$ 58,753,842	$ 72,121,966
	NET PLANT IN SERVICE										
13	Production	(line 1- line 7)	1,964,778,939	AUTO		-	AUTO		-	-	-
14	Transmission	(line 2- line 8)	414,646,402	AUTO		414,646,402	AUTO		214,509,999	38,727,923	161,408,480
15	Distribution	(line 3 - line 9)	-	AUTO		-	AUTO				
16	General	(line 4 - line 10)	32,262,984	AUTO		-	AUTO				
16a	Direct Assign	(line 4a - line 10a)	11,774,860	AUTO		11,774,860	AUTO		6,969,761	662,311	4,142,768
16b	Production	(line 4b - line 10b)	10,597,950	AUTO		-	AUTO				
16c	Other	(line 4c - line 10c)	9,890,174	AUTO		1,113,930	AUTO		640,944	147,829	325,156
17	Intangible	(line 5 - line 11)	26,277,336	AUTO		23,399,841	AUTO		10,451,861	698,024	12,249,936
18	TOTAL NET PLANT (sum lines 13, 14, 16, 17)		$ 2,437,965,661			$ 450,935,033			$ 232,572,585	$ 40,236,087	$ 178,126,360
	WORKING CAPITAL										
19	CWC (Note C)	one eighth of line 9, page 3	9,642,672	DA	100.000%	4,098,749	DA	100.000%	2,396,437	613,941	1,088,371
20	Materials & Supplies Transmission	RUS 2009.12h, Section G, L.4 L.5. C.d	6,155,586	GP	100.000%	6,155,586	GP	Gross Plant	3,541,863	816,908	1,796,816
21	Prepayments (Note C)		-	GP	Gross Plant	-	GP	Gross Plant	-	-	-
22	TOTAL WORKING CAPITAL (sum lines 19-21)		$ 15,798,258			$ 10,254,335			$ 5,938,300	$ 1,430,849	$ 2,885,187
23	Rate Base		$ 2,453,763,919			$ 461,189,368			$ 238,510,885	$ 41,666,936	$ 181,011,547

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

Projections for 2011

Line No	(1)	(2) Reference	(3) Company Total	(4) Allocator A		(5) Total Transmission	(4a) Allocator B		(6) IS Transmission	(7) West (MBPP) Transmission	(8) Other Transmission
	O&M										
1	Transmission less Account 565	Expense Worksheet #3, L 7&16, C.b	25,243,853								
2	Direct Assignment (Note D)	Accounting Records	13,065,544	DA	100.000%	13,065,544	DA	100.000%	8,532,473	3,456,185	1,076,887
3	Other	Accounting Records	12,178,309	TPW	100.000%	12,178,309	TPW	(page 4)	6,893,654	-	5,284,655
4	A&G	Expense Worksheet #3, L.11, C.b	51,897,524			-					
5	Less Regulatory Fees (Note E)	Accounting Records	224,000	NA	0.000%	-	NA	0.000%			
6	Production	Accounting Records	2,178,219	NA	0.000%	-	NA	0.000%			
7	Transmission (Note F)	Accounting Records	1,454,410	DA		1,454,410	DA	100.000%	240,250	646,910	567,250
8	Headquarters		48,040,895	WS	11.263%	6,091,731	GP	Gross Plant	3,505,121	808,434	1,778,176
9	TOTAL O&M (sum lines 1 and 4)		$ 77,141,377			$ 32,789,994			$ 19,171,498	$ 4,911,529	$ 8,705,968
	DEPRECIATION & AMORTIZATION EXPENSE										
10	Depreciation and Amortization Expense	Accounting Records	79,000,000								
11	Transmission	Accounting Records	10,526,040	DA	100.000%	10,526,040	DA	100.000%	5,970,093	1,191,436	3,364,511
12	Production	Accounting Records	68,473,960	NA	0.000%		NA	0.000%			
13	General Plant	Accounting Records	11,962,070	NA	0.000%		NA	0.000%			
14	Transmission	Accounting Records	1,623,851	DA	100.000%	1,623,851	DA	100.000%	1,083,302	193,311	347,238
15	Production	Accounting Records	6,500,000	NA	0.000%	-	NA	0.000%			
16	Other General Plant		3,838,219	WS	11.263%	432,299	GP	Gross Plant	248,741	57,370	126,188
17	Other Amortization		1,927,673	DA	100.000%	1,899,262	DA	100.000%	903,295	65,397	930,570
18	TOTAL (Sum lines 10,13,17)	Expense Worksheet #3, L.20, C.b	$ 92,889,743			$ 14,481,452			$ 8,205,431	$ 1,507,514	$ 4,768,507
	TAXES OTHER THAN INCOME TAXES										
19	PLANT RELATED										
20	Property total										
21	Tax Reclassification	Accounting Records		NA	0.000%	-	NA	0.000%			
22	Gross Receipts (Note G)	Based on 2009 actual	3,100,000	DA	100.000%	3,100,000	DA	Estimated	2,900,000	-	200,000
23	Production			NA	0.000%	-	NA	0.000%	-	-	-
24	TOTAL OTHER TAXES		$ 3,100,000			$ 3,100,000			$ 2,900,000	$ -	$ 200,000
25	TOTAL OPERATING EXPENSES (Sum 9+18+24)		$ 173,131,120			$ 50,371,446			$ 30,276,929	$ 6,419,043	$ 13,675,475
26	Return		$ 161,948,419	WCC	Rate Base	$ 30,438,498	WCC	Rate Base	$ 15,741,718	$ 2,750,018	$ 11,946,762
27	REV. REQUIREMENT (sum lines 25+26)		$ 335,079,539			$ 80,809,944			$ 46,018,647	$ 9,169,061	$ 25,622,237

A & G Allocation

WAGES AND SALARY ALLOCATOR (W/S)

Line #	(1) From Accounting Report	(2)	(3) TOTAL	(4) Allocator		(5) Percent		(6) IS Transmission	(7) West (MBPP) Transmission	(8) Other Transmission
1	Production	Accounting Records	40,196,392					$2,729,706	$446,402	$1,925,629
2	Transmission-East	Accounting Records	217,789							
3	Transmission-West	Accounting Records	446,402	WS	Trans % of total wages	11.263%	Gross Plant	57.539%	13.271%	29.190%
4	Transmission-Allocated	Accounting Records	4,437,546							
5	Distribution		-	TPW	Trans % excluding West			55.606%	0.000%	43.394%
6	Other Transmission		-							
7	Total Wages and Salaries (sum lines 1-6) (exclude adm)		$45,298,129							

Transmission Wage and Salary Dollar Split

8	IS transmission Plant (p.2.c.6.L.14, 16a, 17)		231,931,641	
9	West (MBPP) Transmission Plant (p.2..c.7.L14, 16a, 17		40,088,258	
10	Other transmission Plant (p.2.c.8 L.14, 16a.17)		177,801,204	
11	Total (sum lines 8 -10)		$449,821,103	
12	Percent of IS to Total Transmission (Note H)	(Line 8/Line 11-9)		56.606%
13	Percent of Other to total Transmission	(Line 10/Line 11-9)		43.394%
14	IS Trans Wage & Salary Dollar (L 4 times L 12)		2,511,917	100.000%
15	West Trans Wage & Salary Dollar (no allocation)		-	
16	Other Transmission Wage & Salary (L 4 times L 13)		1,925,629	
17	Total Transmission Wage and Salary Allocated (L.4)		$4,437,546	

Note I — Weighted Cost of Capital

			Percent	Rate	Weighted cost
Wksht #1	LTD	2,778,453,149	73.58%	5.07%	3.73%
Wksht #1	Equity	997,471,699	26.42%	10.85%	2.87%
		3,775,924,848	100.00%		6.60%

Note
A RUS form 12h plus new investment averaged over 13 months.
B General Plant directly assigned to transmission includes the transmission maintenance buildings and microwave assigned to transmission.
C Cash working capital assigned to transmission is one eighth of O&M allocated to transmission on page 3, line 9, column 6-8.
Prepayments are the electric related prepayments booked to Account No. 165 and reported on Section B, line 24, in the RUS 12.
D Includes Lease payments of $4,260,600 for member facilities in the IS system and O&M that is charged to specific lines or substations.
E Line 5 - Regulatory Commission expenses directly related to transmission service, ISO filings, or transmission sitings.
F A&G costs directly allocated to MBPP - Costs split between MBPP Production and MBPP Transmission based on MBPP Wages.
Includes OASIS costs for West Side and Common Use System plus A&G costs allocated to MBPP Transmission.
G SD Gross receipts taxes paid in lieu of property with a portion directly assigned to other transmission.
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.
H West (MBPP) net plant ($40,088,257) is excluded in the percentage calculations on line 12 and 13 as costs for transmission and A&G are directly allocated to MBPP.
I Equity percent as a percent of total estimated long term debt plus current portion of long term debt plus equity.

Basin Electric Power Cooperative

Worksheet #1

Work Paper

Line		b Estimated Budget Year 2009	c Average Budget Year 2010	d Estimated Budget Year 2011	e Transmission Adjusted for 2011 Average Balance
	GROSS PLANT IN SERVICE				
1	Production	1,962,496,218	2,446,635,528	3,733,000,000	3,089,817,764
2	Transmission	612,385,875	673,787,258	716,700,000	695,243,629
3	General	129,598,947	131,354,247	142,772,000	137,063,124
4	Intangible	71,683,380	71,683,380	73,332,740	72,508,060
5	TOTAL GROSS PLANT	$ 2,776,164,420	$ 3,323,460,413	$ 4,665,804,740	$ 3,994,632,577
	ACCUMULATED DEPRECIATION				
6	Production	1,040,313,954	1,085,942,527	1,164,135,124	1,125,038,825
7	Transmission	260,994,369	275,397,227	285,797,227	280,597,227
8	General	91,176,582	101,075,646	108,524,633	104,800,140
9	Intangible	44,835,727	45,750,724	46,710,724	46,230,724
10	TOTAL ACCUM. DEPR	$ 1,437,320,632	$ 1,508,166,123	$ 1,605,167,708	$ 1,556,666,916
	NET PLANT IN SERVICE				
11	Production	922,182,264	1,360,693,002	2,568,864,876	1,964,778,939
12	Transmission	351,391,506	398,390,031	430,902,773	414,646,402
13	General	38,422,365	30,278,601	34,247,367	32,262,984
14	Intangible	26,847,653	25,932,656	26,622,016	26,277,336
15	TOTAL NET PLANT	$ 1,338,843,788	$ 1,815,294,289	$ 3,060,637,032	$ 2,437,965,661

	2011 Estimate
Long-term Liabilities	
Long-term debt, net of current portion	$ 2,689,478,705
Obligations under capital lease	
Total Long-term Liabilities	$ 2,689,478,705
Current Liabilities	
Current portion of long-term debt	$ 88,974,444
Total LTD	2,778,453,149
Equity	997,471,699

Basin Electric Power Cooperative
Integrated System Facilities (IS)

IS Facilities Worksheet #2
Average Balances

IS Facilities			12/31/09 Gross Plant	12/31/09 ACCUM DEPR	12/31/09 Net Book Value	2009 Depreciation Expense	12/31/10 Gross Plant	12/31/10 ACCUM DEPR	12/31/10 Net Book Value	2010 Depreciation Expense	12/31/11 Gross Plant	12/31/11 ACCUM DEPR	12/31/11 Net Book Value	2011 Depreciation Expense
IS Lines			221,153,263	128,649,988	94,503,275	2,621,181	222,604,721	129,271,169	93,333,552	2,621,181	222,604,721	130,581,759	92,022,962	2,621,181
IS Substations			94,958,174	56,538,657	38,419,517	1,186,002	103,286,328	58,006,856	45,279,472	1,411,722	103,286,328	58,712,717	44,573,611	1,411,722
IS Trans Mntnce Bldgs			17,692,990	12,416,986	5,276,004	663,198	17,692,990	13,080,184	4,612,806	663,198	17,692,990	13,411,783	4,281,208	663,198
IS Microwave			7,322,537	5,312,223	2,010,315	374,813	7,322,537	5,687,035	1,635,502	374,813	7,322,537	5,874,442	1,448,096	374,813
Intangible			30,470,606	20,257,615	10,212,991	857,912	30,470,606	21,115,527	9,355,079	857,912	30,470,606	21,544,483	8,926,123	857,912
Accum Depr Adjustment				(5,522,430)				(5,522,430)				(5,522,430)		
Total			371,587,570	215,653,039	155,944,531	5,703,105	381,377,182	221,638,341	159,738,841	5,928,825	381,377,182	224,602,754	156,774,428	5,928,825
					-									
T3 Neset Sub	10/01/09	9,858,301	8,207,990	56,477	8,151,513	56,477	1,650,311	101,861	1,548,450	45,384	1,650,311	124,552	1,525,758	45,384
Rhame Substation	04/01/10	6,977,217	120,163	-	120,163	-	6,857,054	141,427	6,715,627	141,427	6,857,054	235,711	6,621,343	188,569
Comm-Belfield Rhame Project	04/01/10	1,290,889	-	-	-	-	1,290,889	26,625	1,264,264	26,625	1,290,889	44,374	1,246,514	35,499
Belfield-Rhame 230 kV Line	04/01/10	26,254,111	1,010,576	-	1,010,576	-	25,243,535	520,648	24,722,887	520,646	25,243,535	867,747	24,375,788	694,197
Belfield Substation Addition	04/01/10	1,290,889					1,290,889	26,625	1,264,264	26,625	1,290,889	44,374	1,246,514	35,499
Williston-Tioga 230 kV Line	12/31/10	24,400,000	440,882	-	440,882	-	23,959,118	-	23,959,118	-	23,959,118	335,500	23,623,618	671,000
Williston Substation Transformers	12/31/10	2,200,000					169,231	-	169,231	-	2,200,000	30,250	2,169,750	60,500
Miscellaneous Additions/replacements	2010	5,500,000					2,961,538	27,147	2,934,391	88,229	5,500,000	102,772	5,397,228	151,250
Sully Buttes Reactor	01/25/11	3,000,000									1,846,154	34,904	1,811,250	20,625
Watford City 230/115 kV Transformer	06/01/11	200,000									123,077	987	122,090	1,375
C Creek Sub CP & 345/230 kV Transformer	11/01/11	8,850,000									2,042,308	4,680	2,037,627	40,563
Glenham Shunt Reactor	02//01/11	4,500,000									2,769,231	52,356	2,716,875	30,938
Miscellaneous General Plant Additions	2011	1,100,000									592,308	7,404	584,904	27,500
TransCanada Charlie Creek Cap Banks	12/01/11	3,000,000									461,538	529	461,010	6,875
TransCanada-Philip SB CAP BANK	12/31/11	5,600,000									430,769	-	430,769	-
ND/SD Microwave	12/01/11	4,270,000									656,923	1,369	655,554	17,792
Miscellaneous Upgrades	12/01/11	1,700,000									130,769	150	130,619	300
			9,779,611	56,477	9,723,134	56,477	63,422,564	844,331	62,578,232	848,936	77,044,872	1,887,659	75,157,213	2,027,865
GRAND TOTAL			381,377,182	215,709,516	165,667,666	5,759,582	444,799,746	222,482,673	222,317,073	6,777,761	458,422,054	226,490,413	231,931,641	7,956,690

West (MBPP)			12/31/09 Gross Plant	12/31/09 ACCUM DEPR	12/31/09 Net Book Value	2009 Depreciation Expense	12/31/10 Gross Plant	12/31/10 ACCUM DEPR	12/31/10 Net Book Value	2010 Depreciation Expense	12/31/11 Gross Plant	12/31/11 ACCUM DEPR	12/31/11 Net Book Value	2011 Depreciation Expense
West (MBPP) Lines			70,749,575	40,778,311	29,971,264	910,642	70,749,575	41,688,952	29,060,622	910,642	70,749,575	42,144,273	28,605,301	910,642
West (MBPP) Substations			20,718,536	12,522,623	8,195,913	264,719	20,718,536	12,787,342	7,931,194	264,719	20,718,536	12,919,701	7,798,835	264,719
West (MBPP) Trans Mntnce Bldgs			1,254,372	1,007,662	246,711	90,694	1,254,372	1,098,355	156,017	90,694	1,254,372	1,143,702	110,670	90,694
West (MBPP) Microwave			1,981,120	1,275,553	705,567	102,618	1,981,120	1,378,170	602,949	102,618	1,981,120	1,429,479	551,641	102,618
Intangible			2,617,629	1,821,510	796,119	65,397	2,617,629	1,886,907	730,722	65,397	2,617,629	1,919,605	698,024	65,397
Accum Depr Adjustment				(1,531,443)				(1,531,443)				(1,531,443)		
Total			97,321,232	55,874,215	41,447,017	1,434,069	97,321,232	57,308,284	40,012,948	1,434,069	97,321,232	58,025,318	39,295,914	1,434,069
Miscellaneous Additions/replacements	12/01/11	3,051,200					-	-	-	-	469,415	538	468,876	6,992
Miscellaneous Additions/replacements	2010						330,278	2,271	328,007	4,541	330,278	6,812	323,466	9,083
GRAND TOTAL			97,321,232	55,874,215	41,447,017	1,434,069	97,651,510	57,310,554	40,340,956	1,438,610	98,120,925	58,032,668	40,088,257	1,450,144

Basin Electric Power Cooperative

Expense Worksheet #3

		(a) 2010 Estimate	(b) 2011 Estimate
	Expenses - Operations:		
1	Production - Excluding Fuel	88,223,378	87,903,501
2	Production - Fuel	214,573,127	215,572,718
3	Production - Rents	38,282,932	38,996,062
4	Other Power Supply	314,679,436	321,273,588
5	**Sub-Total Operations Exp.**	655,758,873	663,745,869
6			
7	Transmission Operations	18,703,461	20,512,300
8	Transmission Wheeling	15,805,065	36,643,475
9	Subtotal - Transmission	34,508,526	57,155,775
10			
11	Administration	57,409,775	51,897,524
12	**Total Operations Expense**	747,677,174	772,799,168
13			
14	**Expenses - Maintenance:**		
15	Production	98,550,641	136,108,310
16	Transmission	2,301,050	4,731,553
17	General Plant	0	0
18	**Total Maintenance Expense**	100,851,691	140,839,863
19			
20	Depreciation & Amortization	76,978,176	92,889,743
21	Taxes	3,092,889	2,576,472
22	Interest & Other Deductions	89,943,575	72,248,181
		170,014,640	167,714,396
	Total Cost of Electric Service	**1,018,543,505**	**1,081,353,427**

Basin Electric Power Cooperative

Expense Worksheet #3

		(a) 2010 Estimate	(b) 2011 Estimate
	Expenses - Operations:		
1	Production - Excluding Fuel	88,223,378	87,903,501
2	Production - Fuel	214,573,127	215,572,718
3	Production - Rents	38,282,932	38,996,062
4	Other Power Supply	314,679,436	321,273,588
5	**Sub-Total Operations Exp.**	655,758,873	663,745,869
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7	Transmission Operations	18,703,461	20,512,300
8	Transmission Wheeling	15,805,065	36,643,475
9	Subtotal - Transmission	34,508,526	57,155,775
10			
11	Administration	57,409,775	51,897,524
12	**Total Operations Expense**	747,677,174	772,799,168
13			
14	**Expenses - Maintenance:**		
15	Production	98,550,641	136,108,310
16	Transmission	2,301,050	4,731,553
17	General Plant	0	0
18	**Total Maintenance Expense**	100,851,691	140,839,863
19			
20	Depreciation & Amortization	76,978,176	92,889,743
21	Taxes	3,092,889	2,576,472
22	Interest & Other Deductions	89,943,575	72,248,181
		170,014,640	167,714,396
	Total Cost of Electric Service	**1,018,543,505**	**1,081,353,427**

Basin Electric's Ancillary Services Cost Data

Basin Electric Power Cooperative
IS Ancillary Services
Regulation and Frequency Response - 2009

Summary

A	Total LOS and AVS Net Plant Investment	$	539,449,310	(ancillary worksheet 1)
B	Facilities with AGC (LOS 1 & AVS)	$	429,935,564	(Ancillary worksheet 1 less LOS 2)
C	B/A		79.6990%	
D	AGC Facilities	$	57,035	
E	AGC Facilities Percentage (D/B)		0.0133%	
F	Generation Revenue Requirement	$	204,800,743	(Generation revenue require * line C percent)
G	Plant Allocated to AGC	$	27,169	(E x F)
H	**Regulation Revenue Requirement**	$	**84,204**	(D + G)

Basin Electric Power Cooperative
Generation Plant
December 31, 2009

Worksheet #2

	LO #1	LO #2	SM #4	AVS #065	AVS #066	Groton	Trans Groton	LRS #006	LRS #007	LRS #008	DFS	Other 340-347	Total
Gross Plant - Production	100,276,515	223,817,050	24,930,271	643,814,063	210,180,828	125,897,561	1,922,004	186,328,836	174,364,115	206,521,050	646,747	65,719,183	1,964,418,222
Accum Depr - Production	(65,463,807)	(114,252,668)	(23,070,199)	(350,183,446)	(109,382,358)	(8,737,404)	(216,340)	(118,619,152)	(109,556,849)	(126,485,382)	-	(15,024,074)	(1,041,011,680)
Accum Depr - Adjustment	50,352	(50,637)	56,378	414,700	248,719	20,746		(100,282)	(90,603)	(85,772)		17,785	481,386
Net Book	34,843,059	109,513,745	1,916,450	294,045,316	101,047,189	117,180,902	1,705,664	67,609,402	64,716,663	79,949,896	646,747	50,712,895	923,887,928
Gross General Plant	4,176,457	4,176,457	251,844	5,500,977	5,500,977	520,915		2,310,318	2,310,318	2,310,388		387,203	27,455,856
G/P Gross Microwave Alloc	1,629,977	1,629,977	102,192	2,146,908	2,146,908	54,051		53,737	53,737	53,739	431,879	2,629,900	10,933,004
Accum Depr	(2,615,076)	(2,615,076)	(228,813)	(3,476,096)	(3,476,096)	(97,903)		(1,658,543)	(1,658,543)	(1,658,593)		(52,446)	(17,537,184)
Microwave Accum Depr	(1,180,524)	(1,180,524)	(74,013)	(1,554,915)	(1,554,915)	(48,430)		(34,599)	(34,599)	(34,600)	(121,042)	(893,355)	(6,711,516)
Accum Depr Adjust	(538,824)	(538,824)	(33,782)	(709,707)	(709,707)	(67,206)	-	(298,065)	(298,065)	(298,074)	-	(49,955)	(3,542,209)
Net Book	1,472,010	1,472,010	61,210	1,907,167	1,907,167	361,427		372,849	372,849	372,860	310,837	2,021,347	10,597,951
Gross Plant Intangible	-	-	-	524,573	524,573	-		-	-	-		3,181,710	4,230,855
Accum Depr				(107,013)	(107,013)	-						(293,904)	(507,930)
Net Book	-	-	-	417,560	417,560	-		-	-	-		2,887,806	3,722,925
Total Net Plant	36,315,069	110,985,756	1,977,660	296,370,043	103,371,915	117,542,329	1,705,664	67,982,251	65,089,511	80,322,756	957,584	55,622,048	938,208,804

Basin Electric Power Cooperative
Generation Plant
December 31, 2009

Worksheet #7

	LO #1	LO #2	SM #4	AVS #065	AVS #066	Groton	Trans Groton	LRS #006	LRS #007	LRS #008	DFS	Other 340-347	Total
Gross Plant - Production	100,276,515	223,817,050	24,930,271	643,814,063	210,180,828	125,897,561	1,922,004	186,328,836	174,364,115	206,521,050	646,747	65,719,183	1,964,418,222
Accum Depr - Production	(65,483,807)	(114,252,668)	(23,070,199)	(350,183,446)	(109,382,358)	(8,737,404)	(216,340)	(118,619,152)	(109,556,849)	(126,485,382)	-	(15,024,074)	(1,041,011,680)
Accum Depr - Adjustment	50,352	(50,637)	56,378	414,700	248,719	20,746		(100,282)	(90,603)	(85,772)		17,785	481,386
Net Book (RUS 310-347)	34,843,059	109,513,745	1,916,450	294,045,316	101,047,189	117,180,902	1,705,664	67,609,402	64,716,663	79,949,896	646,747	50,712,895	923,887,928

Heartland's
Transmission Cost Data

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Annual Transmission Revenue Requirement

Heartland Consumers Power District

For the 12 months ending 12/31/2010

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$ 1,045,250
	REVENUE CREDITS	(Note P)				
2	Account No. 454	(page 4, line 30)	24,869	TP	0.52203	$12,982
3	Account No. 456.1	(page 4, line 33)	0	TP	0.52203	0
4	Revenue From Existing Transmission Agreements		22,000	NA	1.00000	22,000
5	Transmission Service Credits		0	NA	1.00000	0
6	TOTAL REVENUE CREDITS					34,982
	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 1,010,268

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Annual Transmission Revenue Requirement

For the 12 months ending 12/31/2010

Heartland Consumers Power District

Line No.	(1)	(2) Reference	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
1	Production	Schedule A	41,719,984	NA		
2	Transmission	Schedule A	14,599,061	TP	0.52203	7,621,180
3	Distribution		0	NA		
4	General & Intangible	Schedule A	6,352,713	W/S	0.06786	431,123
5	Common		0	CE	0.06786	0
6	TOTAL GROSS PLANT (sum lines 1-5)		62,671,758	GP=	12.848%	8,052,303
	ACCUMULATED DEPRECIATION					
7	Production		30,738,402	NA		
8	Transmission		10,538,880	TP	0.52203	5,501,635
9	Distribution		0	NA		
10	General & Intangible		2,932,975	W/S	0.06786	199,045
11	Common		0	CE	0.06786	0
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		44,210,257			5,700,679
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	10,981,582			
14	Transmission	(line 2- line 8)	4,060,181			2,119,545
15	Distribution	(line 3 - line 9)	0			
16	General & Intangible	(line 4 - line 10)	3,419,738			232,079
17	Common	(line 5 - line 11)	0			0
18	TOTAL NET PLANT (sum lines 13-17)		18,461,501	NP=	12.738%	2,351,624
	ADJUSTMENTS TO RATE BASE (Note A)					
19	Account No. 281 (enter negative)		0		zero	0
20	Account No. 282 (enter negative)		0	NP	0.12738	0
21	Account No. 283 (enter negative)		0	NP	0.12738	0
22	Account No. 190		0	NP	0.12738	0
23	Account No. 255 (enter negative)		0	NP	0.12738	0
24	TOTAL ADJUSTMENTS (sum lines 19 - 23)		0			0
25	LAND HELD FOR FUTURE USE (Note B)		0	TP	0.52203	0
	WORKING CAPITAL (Note C)					
26	CWC		420,744			49,567
27	Materials & Supplies (Note B)		0	TE	1.00000	0
28	Prepayments		114,025	GP	0.12848	14,650
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		534,769			64,217
30	RATE BASE (sum lines 18, 24, 25, and 29)		18,996,270			2,415,841

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Annual Transmission Revenue Requirement

For the 12 months ending 12/31/2010

Heartland Consumers Power District

Line No.	(1)	(2) Reference	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	Schedule A	251,518	TE	1.00000	251,518
1a	Less LSE Expenses included in Transmission O&M Accounts (Note D)		0		1.00000	0
2	Less Account 565		71,173	NA	1.00000	71,173
3	A&G (Note G)	Schedule A	3,185,604	W/S	0.06786	216,189
4	Less FERC Annual Fees		0	W/S	0.06786	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad(Note E)		0	W/S	0.06786	0
5a	Plus Transmission Related Reg. Comm. Exp. (Note E)		0	TE	1.00000	0
6	Common		0	CE	0.06786	0
7	Transmission Lease Payments		0	NA	1.00000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less 2, 4, 5)		3,365,949			396,534
	DEPRECIATION EXPENSE					
9	Transmission		848,400	TP	0.52203	442,892
10	General		230,242	W/S	0.06786	15,625
11	Common		0	CE	0.06786	0
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		1,078,642			458,517
	TAXES OTHER THAN INCOME TAXES (Note F)					
	LABOR RELATED					
13	Payroll		77,700	W/S	0.06786	5,273
14	Highway and vehicle		0	W/S	0.06786	0
15	PLANT RELATED					
16	Property		160,866	GP	0.12848	20,669
17	Gross Receipts		0	NA	zero	0
18	Other		0	GP	0.12848	0
19	Payments in lieu of taxes		0	GP	0.12848	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		238,566			25,942
	INCOME TAXES (Note G)			NA		
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		0.00%			
	where WCLTD=(page 4, line 27) and R= (page 4, line30)					
	and FIT, SIT & p are as given in footnote G.					
23	1 / (1 - T) = (from line 21)		0.0000			
24	Amortized Investment Tax Credit (enter negative)		0			
25	Income Tax Calculation = line 22 * line 28		0	NA		0
26	ITC adjustment (line 23 * line 24)		0	NP	0.12738	0
27	Total Income Taxes	(line 25 plus line 26)	0			0
28	RETURN		1,291,586	NA		164,257
	[Rate Base (page 2, line 30) * Rate of Return (page 4, line 24)]					
29	REV. REQUIREMENT (sum lines 8, 12,20,27,28)		5,974,743			1,045,250

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Annual Transmission Revenue Requirement

For the 12 months ending 12/31/2010

Heartland Consumers Power District

SUPPORTING CALCULATIONS AND NOTES

Line No.	TRANSMISSION PLANT INCLUDED IN IS RATES		
1	Total transmission plant (page 2, line 2, column 3)		14,599,061
2	Less transmission plant excluded from IS rates (Note H)		6,752,305
3	Less transmission plant included in OATT Ancillary Services (Note I)		225,576
4	Transmission plant included in IS rates (line 1 less lines 2 & 3)		7,621,180
5	Percentage of transmission plant included in IS Rates (line 4 divided by line 1)	TP=	0.52203

Line No.	TRANSMISSION EXPENSES		
6	Total transmission expenses (page 3, line 1, column 3)		251,518
7	Less transmission expenses included in OATT Ancillary Services (Note J)		0
8	Included transmission expenses (line 7 less line 6)		251,518
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)		1.00000
10	Percentage of transmission plant included in IS Rates (line 5)	TP	0.52203
11	Percentage of transmission expenses included in IS Rates (Note K)	TE=	1.00000

Line No.	WAGES & SALARY ALLOCATOR (W&S)	$	TP	Allocation		W&S Allocator ($ / Allocation)	
12	Production	924,498	0.00	0			
13	Transmission	138,144	0.52	72,116			
14	Distribution	0	0.00	0			
15	Other	0	0.00	0			
16	Total (sum lines 12-15)	1,062,642		72,116	=	0.06786	= W/S

Line No.	COMMON PLANT ALLOCATOR (CE) (Note L)	$	% Electric (line 17 / line 20)		Labor Ratio (line 16)		CE
17	Electric	62,671,758	1.00000	*	0.06786	=	0.06786
18	Gas	0					
19	Water	0					
20	Total (sum lines 17-19)	62,671,758					

Line No.	RETURN (R)		$
21	Long Term Interest	Schedule A	$1,975,956

Line No.			$	%	Cost (Note M)	Weighted	
22	Long Term Debt	Schedule A	36,522,482	80%	5.41%	0.0433	=WCLTD
23	Proprietary Capital	Schedule A	9,089,404	20%	12.38%	0.0247	
24	Total (sum lines 22, 23)		45,611,886	100%		0.0680	=R
25					Proprietary Capital Cost Rate =	12.38%	
26					TIER =	1.26	

Line No.	REVENUE CREDITS		Load
	ACCOUNT 447 (SALES FOR RESALE)		
27	a. Bundled Non-RQ Sales for Resale	(Note N)	0
28	b. Bundled Sales for Resale included in Divisor on page 1		0
29	Total of (a)-(b)		0
30	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note O)		$24,869
	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES)		
31	a. Transmission charges for all transmission transactions		$0
32	b. Transmission charges for all transmission transactions included in Divisor on page 1		$0
33	Total of (a)-(b)		$0

Heartland Consumers Power District

General Note: References to pages in this revenue requirement template are indicated as: (page#, line#, col.#)

Note Letter

A Does not apply to Heartland. For others, 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.

B Transmission related only.

C 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 as shown on Schedule I of EIA Form 412.

D Account Nos. 561.4, 561.8, and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.

E 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.

F 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.

G Heartland is not subject to Federal or State Income Tax

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

H Removes transmission plant determined to be state-jurisdictional by Commission order according to the seven-factor test (until EIA 412 balances are adjusted to reflect applicaton of seven-factor test).

I 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.

J Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.

K All O&M expense included in Page 3 line 1 column 3 is associated with transmission plant in IS rates. The O&M expense for non-qualifying facilities (Page 4 lines 2,3) is the responsibility of others.

L Heartland has no common plant.

M Debt cost rate = long-term interest (line 21) / long term debt (line 22). The Proprietary Capital Cost rate is implicit, a residual calculation after TIER is determined. TIER will be supported in the filing and no change in TIER may be made absent a filing with the ISO and the FERC, if the entity is under FERC's jurisdiction.

N Line 29 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 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 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 IS (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.

Transmission Customer Facility Credits

Confidential

Formula Rate - Cash Flow

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/09

Missouri River Energy Services

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT	(page 2, line 23, col. 5)				$ 12,222,916
	REVENUE CREDITS	(Note Q)				
2	Account No. 454	(page 3, line 34)	0	TP	1.00000	0
3	Account No. 456.1	(page 3, line 37)	202,947	TP	1.00000	202,947
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)					202,947
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 12,019,969

Allocation of Net Revenue Requirements by Pricing Zones:	Irv Simmons	OTP	MBPP	Marshall Wind Circuit	Total
Transmission Plant Investment	$ 1,957,786	$ 27,514,314	$ 29,358,631	$ -	$ 58,830,731
% of Total Transmission Plant	3.3%	46.8%	49.9%	0.0%	100.0%
Net Transmission Revenue Requirement (Allocated on Transmission Plant)	$ 396,659	$ 5,621,572	$ 5,997,965	$ -	$ 12,019,969

Line No.	DIVISOR		
8	Average of 12 coincident system peaks for requirements (RQ) service	(Note A)	625,690
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)		625,690

Line No.			Peak Rate		Off-Peak Rate
16	Annual Cost ($/kW/Yr)	(line 7/ line 15)	$ 19.211		
17	Network & P-to-P Rate ($/kW/Mo)	(line 11/ 12)	$ 1.601		
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16/ 52)	0.369		$0.369
19	Point-To-Point Rate ($/kW/Day)	(line 18/ 5; line 18/ 7)	0.074	Capped at weekly rate	$0.053
20	Point-To-Point Rate ($/MWh)	(line 19/ 16; line 19/ 24 times 1,000)	4.618	Capped at weekly and daily rates	$2.199
21	FERC Annual Charge($/MWh)	(Note E)	$0.000	Short Term	$0.000 Short Term
22			$0.000	Long Term	$0.000 Long Term

Formula Rate - Cash Flow

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/09

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)		18,645,820	TE	1.0000	18,645,820
1a	Less LSE Expenses included in Transmission O&M Accounts (N		0		1.0000	0
2	Less Account 565		15,124,840		1.0000	15,124,840
3	A&G	VII.13.d	8,801,617	W/S	0.1942	1,709,404
4	Less FERC Annual Fees		0	W/S	0.1942	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad (Note F)		896,335	W/S	0.1942	174,081
5a	Plus Transmission Related Reg. Comm. Exp. (Note F)		862,219	TE	1.0000	862,219
6	Common		0	CE	0.1942	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)		12,288,481			5,918,521
	DEBT SERVICE					
9a	Debt Service - Transmission Bond Resolution (Note T)		2,214,606		1.0000	2,214,606
9b	Debt Service- Excluding Transmission Bond Resolution (Note U)		23,799,538	GP 2	0.1068	2,542,562
10	Amortization of premium or discount (Note V)		0	GP	0.1748	0
11	TOTAL DEBT SERVICE (Sum lines 9 - 10)		26,014,144			4,757,169
	TAXES OTHER THAN INCOME TAXES (Note G)					
	LABOR RELATED					
13	Payroll		0	W/S	0.1942	0
14	Highway and vehicle		0	W/S	0.1942	0
15	PLANT RELATED					
16a	Property- Transmission Only (Note G)		400,985		1.0000	400,985
16b	Property- General Plant		55,372	GP	0.1748	9,677
17	Gross Receipts		0		0.0000	0
18	Other		0	GP	0.1748	0
19	Payments in lieu of taxes		0	GP	0.1748	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		456,357			410,662
21	SUBTOTAL (sum lines 8, 11, 20)		38,758,982			11,086,352
22	MARGIN REQUIREMENT (Note H)		6,503,536	GP	0.1748	1,136,564
23	REV. REQUIREMENT (sum lines 21 22)		45,262,518			12,222,916

Formula Rate - Cash Flow

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/09

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	280,322,814	NA	0.0000	0
2a	Transmission, excluding separate 1	IV.7.f	31,316,417	TP	1.0000	31,316,417
2b	Separate Transmission Project (No	IV.7.f	27,514,314	TP	1.0000	27,514,314
3	Distribution	IV.8.f	0	NA	0.0000	0
4	General & Intangible	IV.9.f	22,621,953	W/S	0.1942	4,393,517
5	Common		0	CE	0.1942	0
6	TOTAL GROSS PLANT (sum lines 1-5)		361,775,498	GP	0.1748	63,224,248
6a	Gross Plant Allocator, excluding Separate Transmission Project		334,261,184	GP 2	0.1068	35,709,934

TRANSMISSION PLANT INCLUDED IN ISO RATES

Line No.			
7	Total transmission plant (line 2)		58,830,731
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)		58,830,731
11	Percentage of transmission plant included in ISO Rates (line 10 divided by line 7)	TP=	1.00000

TRANSMISSION EXPENSES

Line No.			
12	Total transmission expenses (page 2, line 1, column 3)		18,645,820
13	Less transmission expenses included in OATT Ancillary Services (Note I)		0
14	Included transmission expenses (line 12 less line 13)		18,645,820
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)

Line No.		$		Allocation		W&S Allocator ($ / Allocation)
18	Production	2,260,156	0.00	0		
19	Transmission	566,753	1.00	566,753		
20	Distribution	0	0.00	0		
21	Other	91,269		0		
22	Total (sum lines 18-21)	2,918,179		566,753	=	0.1942

COMMON PLANT ALLOCATOR (CE) (Note M)

Line No.		$	% Electric (line 23 / line 26)		Labor Ratio (line 22)		CE
23	Electric	361,775,498					
24	Gas	0	1.00000	*	0.1942	=	0.1942
25	Water	0					
26	Total (sum lines 23-25)	361,775,498					

FINANCING DATA

Line No.			$
27	Long Term Debt	II.33.b +34.b	$216,666,942
28	Debt Service		26,014,144
29	Interest on Long Term Debt	III.16.b + III.17.b (Note R)	11,934,781
30	Bond Principal Amortization (line 28 less line 29)		14,079,363

REVENUE CREDITS

Line No.			Load
	ACCOUNT 447 (SALES FOR RESALE)		
31	a. Bundled Non-RQ Sales for Resale	(Note N)	
32	b. Bundled Sales for Resale included in Divisor on page 1		
33	Total of (a)-(b)		0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note O)		$0
	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES)		
35	a. Transmission charges for all transmission transactions		$202,947
36	b. Transmission charges for all transmission transactions included in Divisor on page 1		$0
37	Total of (a)-(b)		$202,947

Formula Rate - Cash Flow

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/09

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 <u>not</u> 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.
V	The amortization of debt discounts and premiums are excluded since amortization is a non-cash item that does not affect debt service cash flow. The principal and interest payments already reflect all discounts or premiums when the debt was originally issued.
W	Represents only transmission assets that can be directly assigned to the Transmission Service Agreements and no other types of assets. These transmission assets were financed under the Transmission Bond Resolution. Work papers will be provided.
X	Transmission Expense will be the sum of (a) Form 412 VII.8.d and (b) facility credits for the Irv Simmons project in the Integrated System (IS).

Formula Rate - Non-Levelized	Rate Formula Template Utilizing FERC Form 1 Data	For the 12 months ended 12/31/09

Utilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT, joint Plant Transmission Facilities

		Total	Allocator			Allocated Amount
GROSS REVENUE REQUIREMENT	(page 3, line 29)					$ 2,553,769
REVENUE CREDITS	(Note T)					
Account No. 454	(page 4, line 34)	165,720	TP	0.81036		134,293
Account No. 456	(page 4, line 37)	86,380	TP	0.81030		69,998
Revenues from Grandfathered Interzonal Transactions		0	TP	0.81036		0
Revenues from service provided by the ISO at a discount		0	TP	0.81036		0
TOTAL REVENUE CREDITS (sum lines 2-5)						204,291
NET REVENUE REQUIREMENT	(line 1 minus line 6)					$ 2,349,478
DIVISOR						
Average of 12 coincident system peeks for requirements (RQ) service					(Note A)	235,917
Plus 12 CP of firm bundled sales over one year not in line 8					(Note B)	14,000
Plus 12 CP of Network Load not in line 8					(Note C)	0
Less 12 CP of firm P-T-P over one year (enter negative)					(Note D)	0
Plus Contract Demand of firm P-T-P over one year						0
Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)						0
Less Contract Demands from service over one year provided by ISO at a discount (enter negative)						0
Divisor (sum lines 8-14)						249,917
Annual Cost ($/kW/Yr)	(line 7 / line 15)	9.401				
Network & P-to-P Rate ($/kW/Mo)	(line 16 / 12)	0.783				

		Peak Rate		Off-Peak Rate	
Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	0.181		$0.181	
Point-To-Point Rate ($/kW/Day)	(line 18 / 5; line 18 / 7)	0.036	Capped at weekly rate	$0.026	
Point-To-Point Rate ($/MWh)	(line 19 / 16; line 19 / 24 times 1,000)	2.260	Capped at weekly and daily rates	$1.076	
FERC Annual Charge($/MWh)	(Note E)	$0.000	Short Term	$0.000	Short Term
		$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 12/31/09

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

(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					
Production	206.42.g	158,992,136	NA		
Transmission	206.53.g	32,799,950	TP	0.81036	26,579,708
Distribution	206.69.g	219,701,382	NA		
General & Intangible	206.5.g & 83.g	9,835,101	W/S	0.04261	419,102
Common	356.1	20,915,117	CE	0.02601	543,941
TOTAL GROSS PLANT (sum lines 1-5)		442,243,776	GP=	6.228%	27,542,749
ACCUMULATED DEPRECIATION					
Production	219.18-22.c	102,313,590	NA		
Transmission	219.23.c	20,718,080	VEst.	72.913%	15,106,085
Distribution	219.24.c	87,301,009	NA		
General & Intangible	219.25.c	2,464,070	W/S	0.04261	105,000
Common	356.1	4,729,590	CE	0.02601	123,003
TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		217,526,338			15,334,088
NET PLANT IN SERVICE					
Production	(line 1 - line 7)	56,678,546			
Transmission	(line 2 - line 8)	12,081,871			11,473,621
Distribution	(line 3 - line 9)	132,400,373			
General & Intangible	(line 4 - line 10)	7,371,121			314,102
Common	(line 5 - line 11)	16,185,527			420,938
TOTAL NET PLANT (sum lines 13-17)		224,717,438	NP=	5.433%	12,208,661
ADJUSTMENTS TO RATE BASE (Note F)					
Account No. 281 (enter negative)	273.8.k	0	NA	zero	0
Account No. 282 (enter negative)	275.2.k	-41,774,514	NP	0.05433	-2,269,565
Account No. 283 (enter negative)	277.9.k	1,065,318	NP	0.05433	57,878
Account No. 190	234.8.c	-14,654,666	NP	0.05433	-796,173
Account No. 255 (enter negative)	267.8.h	-2,183,567	NP	0.05433	-118,631
TOTAL ADJUSTMENTS (sum lines 19-23)		-57,547,429			-3,126,491
LAND HELD FOR FUTURE USE	214.x.d (Note G)	0	VEst.	0.72913	0
WORKING CAPITAL (Note H)					
CWC	calculated	755,467			53,052
Materials & Supplies (Note G)	227.8.c & .15.c	0		1.00000	0
Prepayments (Account 165)	111.46.d	0	GP	0.06228	0
TOTAL WORKING CAPITAL (sum lines 26 - 28)		755,467			53,052
RATE BASE (sum lines 18, 24, 25, & 29)		167,925,475			9,135,223

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/09

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

(1)	(2)	(3)	(4)		(5)
	Form No. 1 Page, Line, Col.	Company Total	Allocator		Transmission (Col 3 times Col 4)
O&M					
Transmission	321.100.b	6,033,541	TE	0.81036	5,068,928
Less Account 565	321.88.b	5,092,828		1.00000	5,892,828
A&G	323.168.b	5,703,019	W/S	0.02601	148,319
Less FERC Annual Fees		0	W/S	0.02601	0
Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		0	W/S	0.02601	0
Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.81036	0
Common	356.1	0	CE	0.02601	0
Transmission Lease Payments		0		1.00000	0
TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)		6,043,733			424,419
DEPRECIATION EXPENSE					
Transmission	336.7.b	1,072,558	VRB00	0.72913	871,644
General	336.9.b	626,662	W/S	0.02601	16,298
Common	336.10.b	948,471	CE	0.02601	24,667
TOTAL DEPRECIATION (Sum lines 9 - 11)		2,647,691			912,609
TAXES OTHER THAN INCOME TAXES (Note J)					
LABOR RELATED					
Payroll	262.i	732,029	W/S	0.02601	19,038
Highway and vehicle	262.i	44,426	W/S	0.02601	1,155
PLANT RELATED					
Property	262.i	3,359,658	GP	0.06228	209,238
Gross Receipts	262.i	161,272	NA	zero	0
Other	262.i	207,624	GP	0.06228	12,931
Payments in lieu of taxes		0	GP	0.06228	0
TOTAL OTHER TAXES (sum lines 13 - 19)		4,505,009			242,362
INCOME TAXES	(Note K)				
T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		35.00%			
CIT=(T/1-T) * (1-(WCLTD/R)) =		32.42%			
where WCLTD=(page 4, line 27) and R= (page 4, line30) and FIT, SIT & p are as given in footnote K.					
1 / (1 - T) = (from line 21)		1.5385			
Amortized Investment Tax Credit (266.8f) (enter negative)		-456,492			
Income Tax Calculation = line 22 * line 28		4,557,239	NA		247,916
ITC adjustment (line 23 * line 24)		-702,295	NP	0.05433	-38,155
Total Income Taxes	(line 25 plus line 26)	3,854,944			209,761
RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		14,055,362	NA		764,618
REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		31,106,739			2,553,769

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

SUPPORTING CALCULATIONS AND NOTES

TRANSMISSION PLANT INCLUDED IN ISO RATES

Total transmission plant (page 2, line 2, column 3)		32,799,950
Less transmission plant excluded from ISO rates (Note M)		6,220,244
Less transmission plant included in OATT Ancillary Services (Note N)		0
Transmission plant included in ISO rates (line 1 less lines 2 & 3)		26,579,706
Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)	TP=	0.81036

TRANSMISSION EXPENSES

Total transmission expenses (page 3, line 1, column 3)		6,033,541
Less transmission expenses included in OATT Ancillary Services (Note L)		0
Included transmission expenses (line 6 less line 7)		6,033,541
Percentage of transmission expenses after adjustment (line 8 divided by line 6)		1.00000
Percentage of transmission plant included in ISO Rates (line 5)	TP	0.81036
Percentage of transmission expenses included in ISO Rates (line 9 times line 10)	TE=	0.81036

WAGES & SALARY ALLOCATOR (W&S)

	Form 1 Reference	$	TP	Allocation		W&S Allocator ($ / Allocation)		
Production	354.18.b	470,641	0.00	0				
Transmission	354.19.b	288,963	0.81	234,164				
Distribution	354.20.b	4,198,950	0.00	0				
Other	354.21,22,23.b	1,822,621	0.00	0				
Total (sum lines 12-15)		6,781,176		234,164	=	0.03453	=	WS
						0.04261	=	Wsact

COMMON PLANT ALLOCATOR (CE) (Note O)

		$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
Electric	200.3.c	421,377,251	0.75314	*	0.03453	=	0.02601
Gas	200.3.d	138,114,915					
Water	200.3.e	0					
Total (sum lines 17 - 19)		559,492,166					

RETURN (R)

		$
Long Term Interest (117, sum of 56c through 60c)		$0
Preferred Dividends (118.29c) (positive number)	$	-
Development of Common Stock:		
Proprietary Capital (112.14d)		0
Less Preferred Stock (line 28)		0
Less Account 216.1 (112.12d) (enter negative)		0
Common Stock (sum lines 23-25)		0

	$	%		Cost (Note P)		Weighted	
Long Term Debt (112, sum of 16d through 19d)	971,001,062	0.5523	0.0000	0.0603	0.0000	0.0333	=WCLTD
Preferred Stock (112.3d)	0	0.0000	0.0000	0.0000	0.0000	0.0000	
Common Stock (line 26)	787,025,027	0.4477	0.0000	0.1125	0.0000	0.0504	
Total (sum lines 27-29)	1,758,026,089		0.0000	0.0000	0.0000	0.0837	=R

REVENUE CREDITS

			Load
ACCOUNT 447 (SALES FOR RESALE)	(310-311)	(Note Q)	
a. Bundled Non-RQ Sales for Resale (311.x.h)			216,524
b. Bundled Sales for Resale included in Divisor on page 1			216,524
Total of (a)-(b)			0
ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			$165,720
ACCOUNT 456 (OTHER ELECTRIC REVENUES)	(330.x.n)		
a. Transmission charges for all transmission transactions			$211,908
b. Transmission charges for all transmission transactions included in Divisor on Page 1			$125,529
Total of (a)-(b)			$86,380

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)

Peak as would be reported on page 401, column d of Form 1 at the time of the ISO coincident monthly peaks.
Labeled LF, LU, IF, IU on pages 310-311 of Form 1at the time of the ISO coincident monthly peaks.
Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.
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.
Identified in Form 1 as being only transmission related.
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.
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.
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.
The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

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

Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.
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).
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.
Enter dollar amounts
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.
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.
Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
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.
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.