SEP 0 7 2012

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, 2013.

Western Area Power Administration (Western) will host a meeting to provide customers an opportunity to discuss and comment on these rates on October 15, 2012, at 1:30 p.m. MDT at Western's offices located at 2900 4th Avenue North, 6th Floor, Billings, MT. The meeting will also be available via WebEx. For those desiring to attend the meeting via WebEx, please contact Stan Bayley at (406) 255-2923 or bayley@wapa.gov before September 28, 2012, for access information. If you will attend in person, please e-mail your intention to do so to UGPISRate@wapa.gov prior to September 28, 2012.

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 $176,723,580.
Firm Point-to-Point Transmission	UGP-FPT1	Maximum of $2.81/kWmonth
Non-Firm Point-to-Point Transmission	UGP-NFPT1	Maximum of 3.85 mills/kWh
Scheduling, System Control and Dispatch	UGP-AS1	$42.42/tag/day
Reactive Supply and Voltage Control from Generation Sources	UGP-AS2	$0.04/kWmonth

Regulation and Frequency Response	UGP-AS3	\$0.06/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	\$0.17/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, 2013, is 4 percent and unchanged from the previous 5-year period.

These new rates shall be used in transmission bills calculated on or after February 1, 2013. Please refer to the IS OASIS page (http://www.oatioasis.com/wapa/index.html) for information regarding the implementation status for Western charging Transmission Customers under the Energy Imbalance and Generator Imbalance rates.

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

Lloyd A. Linke
Operations Manager

Integrated System
Transmission and Ancillary Services
Rate Calculation

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

Effective January 1, 2013

Integrated System
Transmission and Ancillary Services
Rate Calculation

Effective January 1, 2013

Integrated System Transmission and Ancillary Service Rates

INTEGRATED SYSTEM
ANNUAL REVENUE REQUIREMENT
FOR TRANSMISSION SERVICE
Effective Janaury 1, 2013

Line No.			Notes
1			
2			
3	**Annual IS Transmission Costs**		**Notes**
4	Basin Electric	$53,400,797	Basin Electric Revenue Requirement Template
5	Western	$118,668,270	Western Revenue Requirement Template
6	Heartland	$814,373	Heartland Revenue Requirement Template
7		$172,883,440	L4 + L5 + L6
8			
9			
10	**Transmission Customer Facility Credits**		
11		$3,547,194	MRES Revenue Requirement Template
12		$3,635,778	NWPS Revenue Requirement Template
13		$7,182,972	L11 + L12
14			
15			
16	**Annual Revenue Requirement for IS Transmission Service**		
17			
18		$180,066,412	L7 + L13
19			
20	**2011 True-up Amount**		
21		($3,336,488)	2011 Rate True-up Worksheet
22			
23	**2011 Unreserved Use of Transmission Service Penalties**		
24			
25		($6,344)	2011 Unreserved Use Penalty Worksheet
26			
27	**Annual Revenue Requirement for IS Transmission Service after True-up**		
28			
29		$176,723,580	L18 - L21 - L25

INTEGRATED SYSTEM
FIRM POINT-TO-POINT RATE DESIGN
Effective Janaury 1, 2013

Line No.			Notes
1			
2			
3	**Annual Revenue Requirement for IS Transmission Service**		**Notes**
4			
5		$176,723,580	IS Annual Revenue Requirement for
6			Transmission Service Worksheet, L29
7			
8	**IS Transmission System Total Load**		
9			
10		5,249,000 KW	IS Transmission System Total Load Estimate
11			
12			
13	**Maximum Firm Point-to-Point Transmission Rate in $/KW-Mo**		
14			
15	**$2.81 / KW-Mo**		L5 / L10 / 12 months

INTEGRATED SYSTEM
NON-FIRM POINT-TO-POINT RATE DESIGN
Effective Janaury 1, 2013

Line No.		
1		
2		
3	**Firm Point-to-Point Transmission Rate in $/KW-Mo**	**Notes**
4		
5	$2.81 / KW-Mo	IS Firm Point-to-Point Rate Design Worksheet, L15
6		
7		
8		
9	**Maximum Non-Firm Point-to-Point Transmission Rate**	
10	**3.85 Mills/KWh**	(L5 * 1000) / 730 hours per month

RATE FOR SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE FOR 2013

A.	Fixed Charge Rate	22.258%	(1)
B.	Scheduling, System Control and Dispatch Net Plant Costs ($)	$16,636,553	(2)
C.	Annual Revenue Requirement for Scheduling, System Control and Dispatch Service	$3,702,964	(A x B)
D.	2011 Number of Daily Tags	87,292	
E.	Rate for Scheduling, System Control and Dispatch Service ($/tag/day)	**$42.42**	(C / D)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual IS Transmission Costs", for 2013 Rate.

(2) Scheduling, System Control and Dispatch Plant Costs include the portion of Watertown Operations Office plant (34.704%) and communication facilities plant (68.14%) associated with Scheduling, System Control and Dispatch Service for transmission less total depreciation associated with this plant. (Reference FY 2011 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 2013
(INTEGRATED SYSTEM)

A.	WAPA Reactive Service Revenue Requirement	$2,630,304	(1)
B.	Paid to Others for Reactive Service	$0	(2)
C.	Total Reactive Revenue Requirement	$2,630,304	(A + B)
D.	Over Collection for 2011	($74,773)	(3)
E.	Total Reactive Revenue Requirement with 2011 True-up	$2,555,531	(C + D)
F.	2011 IS Transmission System Total Load (kW-Yr)	4,918,000	(4)
G.	Annual Reactive Charge ($/kW-Yr)	$0.52	(E / F)
H.	Monthly Reactive Charge ($/kW-Mo)	$0.04	(G / 12)

(1) Reactive Service Revenue Requirement from "Reactive Supply and Voltage Control from Generation Sources For 2013, Western's Costs".

(2) Charges for Reactive Service Operation Outside the Bandwidth.

(3) True-up Required for 2011 "True-up for 2011 Reactive Supply and Voltage Control from Generation Sources."

RATE FOR REGULATION AND FREQUENCY RESPONSE FOR 2013

A.	Western Regulation Revenue Requirement	$1,813,770	(1)
B.	BEPC & HCPD Regulation Revenue Requirement	$65,242	(2)
C.	Total Regulation Revenue Requirement	$1,879,012	(A + B)
D.	Under Collection - 2011 Regulation Revenue Rqmt	$317,306	(3)
E.	Total Regulation Revenue Rqmt with True-up	2,196,318	(C + D)
F.	Load in Control Area(s) (kW-Yr)	3,150,000	(4)
G.	Regulation Charge ($/kW-Yr)	$0.70	(E / F)
H.	Regulation Charge ($/kW-Mo)	$0.06	(G / 12 months)

(1) Regulation and Frequency Response Service from "Regulation and Frequency Response for 2013, Western's Costs".

(2) Basin Electric cost support data.

(3) Over/Under Collection "True-up of Regulation and Frequency Response Rate for 2011"

(4) Average of monthly peaks for 2011 IS Customer Control Area.

Rate for Reserves for 2013

A.	Fixed Charge Rate		17.846%	(1)
B.	Generation Net Plant Costs	$	473,919,619	(2)
C.	Annual Cost of Generation	$	84,575,695	(A x B)
D.	Plant Capacity (kW)		2,420,000	
E.	Cost/kW ($/kW-Yr)	$	34.95	(C / D)
F.	Monthly Charge ($/kW-mo)	$	2.91	(E / 12 months)
G.	Western's Load (kW-Yr)		1,578,000	(3)
H.	Capacity used for Reserves (kW)		91,000	(4)
I.	Annual Reserves Revenue Requirement	$	3,180,450	(E x H)
J.	Annual Charge ($/kW-Yr)	$	2.02	(I /G)
K.	Monthly Charge ($/kW-mo)	$	0.17	(J /12)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Generation Revenue Requirement", for 2013 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 2011.

(4) Southwest Power Pool Reserve Sharing System.

Integrated System Load Data

2013 IS Transmission System Total Load Estimate
Transmission Rate
(MW)

5,249

2011 IS Transmission System Total Load
Ancillary Services
(MW)

Line No.	(1) Date	(2) Hour Ending	(3) Network Load	(4) Long-Term Firm Point-to-Point Reservations	(5) Total
1	**01/31/11**	1900	4,685	476	5,161
2	**02/08/11**	800	4,802	476	5,278
3	**03/02/11**	800	4,500	476	4,976
4	**04/04/11**	900	3,788	476	4,264
5	**05/10/11**	1700	3,584	476	4,060
6	**06/30/11**	1700	4,470	476	4,946
7	**07/19/11**	1700	5,257	476	5,733
8	**08/01/11**	1700	5,166	476	5,642
9	**09/01/11**	1700	4,402	476	4,878
10	**10/27/11**	800	3,787	476	4,263
11	**11/21/11**	800	4,216	476	4,692
12	**12/06/11**	800	4,641	476	5,117
13					
14	**12 CP**		4,442	476	4,918

2011 IS Network Customer Control Area Load

Date	Hr End	East Control Area Load (1)	West Control Area Load (2)	Total Load
January 31, 2011	19:00	3295 MW	102 MW	3397 MW
February 8, 2011	8:00	3445 MW	106 MW	3551 MW
March 2, 2011	8:00	3254 MW	99 MW	3353 MW
April 4, 2011	9:00	2617 MW	68 MW	2685 MW
May 10, 2011	17:00	2357 MW	58 MW	2415 MW
June 30, 2011	17:00	2923 MW	78 MW	3001 MW
July 19, 2011	17:00	3376 MW	111 MW	3487 MW
August 1, 2011	17:00	3362 MW	78 MW	3440 MW
September 1, 2011	17:00	3052 MW	71 MW	3123 MW
October 27, 2011	8:00	2748 MW	67 MW	2815 MW
November 21, 2011	8:00	3017 MW	86 MW	3103 MW
December 6, 2011	8:00	3354 MW	79 MW	3433 MW
Total		36,800	1003	37,803
			Average Control Area Load	3,150

(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

Western Area Power Administration

Est for 12 Months Ending 9/30/2013

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$ 130,477,556
	REVENUE CREDITS	(Note R)				
2	Short-Term Firm Point-to-Point Transmission Service Credit		1,574,074	NA	1.00000	1,574,074
3	Non-Firm Point-to-Point Transmission Service Credit		9,475,189	NA	1.00000	9,475,189
4	Revenue from Existing Transmission Agreements		598,647	NA	1.00000	598,647
5	Scheduling, System Control, and Dispatch Service Credit		82,260	NA	1.00000	82,260
6	Account No. 454	(page 3, line 36)	79,116	TP	1.00000	79,116
7	Account No. 456	(page 3, line 39)	0	TP	1.00000	0
8	TOTAL REVENUE CREDITS					11,809,286
9	NET REVENUE REQUIREMENT	(line 1 minus line 8)				$ 118,668,270

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

Est for 12 Months Ending 9/30/2013

Western Area Power Administration

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	993,733,424	NA		
2	Transmission	Schedule 1A Total	1,176,531,143	TP	1.00000	1,176,531,143
3	Distribution	Schedule 1A Total	31,758,678	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)		2,202,023,245	GP=	53.430%	1,176,531,143
	ACCUMULATED DEPRECIATION					
7	Production	Schedule 4	560,415,683	NA		
8	Transmission	Schedule 4	556,486,226	TP	1.00000	556,486,226
9	Distribution	Schedule 4	15,036,150	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)		1,131,938,059			556,486,226
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	433,317,741			
14	Transmission	(line 2- line 8)	620,044,917			620,044,917
15	Distribution	(line 3 - line 9)	16,722,528			
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)		1,070,085,186	NP=	57.944%	620,044,917
	ADJUSTMENTS TO RATE BASE (Note B)					
19	Account No. 281 (enter negative)		0		zero	0
20	Account No. 282 (enter negative)		0	NP	0.57944	0
21	Account No. 283 (enter negative)		0	NP	0.57944	0
22	Account No. 190		0	NP	0.57944	0
23	Account No. 255 (enter negative)		0	NP	0.57944	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	20,164,610			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	0.53430	0
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		20,164,610			0
30	RATE BASE (sum lines 18, 24, 25, and 29)		1,090,249,796			620,044,917

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

Est for 12 Months Ending 9/30/2013

Western Area Power Administration

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		55,235,787	PTP/UGP	0.95426	52,709,302
1b	Western RMR		38,012,112	PTP/RMR	0.00931	353,893
1c	COE	COE Financial Stmts	38,925,000	PTP/COE	0.03504	1,363,932
2	Less Account 565 (Note E)			NA	1.00000	0
3	A&G (Note F)	Schedule 11				
3a	Western UGP		19,307,091	PTP/UGP	0.95426	18,423,985
3b	Western RMR		9,836,889	PTP/RMR	0.00931	91,581
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)		161,316,879			72,942,693
	DEPRECIATION EXPENSE					
9	Transmission (Note E)	Schedule 4				
9a	Western UGP		28,545,821	PTP/UGP	0.95426	27,240,135
9b	Western RMR		16,633,433	PTP/RMR	0.00931	154,857
9c	COE		10,779,525	PTP/COE	0.03504	377,715
10	General		0	W/S	1.00000	0
11	Common		0	CE	0.00000	0
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		55,958,779			27,772,707
	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	0.53430	0
17	Gross Receipts		0		zero	0
18	Other		0	GP	0.53430	0
19	Payments in lieu of taxes		0	GP	0.53430	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)) =		0.00%			
	where WCLTD=(page 4, line 27) and R= (page 4, line30)					
	and FIT, SIT & p are as given in footnote I.					
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	0.57944	0
27	Total Income Taxes	(line 25 plus line 26)	0			0
28	RETURN		52,331,990	NA		29,762,156
	[Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]					

29	REV. REQUIREMENT (sum lines 8, 12,20,27,28)	269,607,648	130,477,556

Western Area Power Administration
Integrated System

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

Est for 12 Months Ending 9/30/2013

Western Area Power Administration

SUPPORTING CALCULATIONS AND NOTES

Line No.			
	TRANSMISSION PLANT INCLUDED IN IS RATES		
1	Total transmission plant (page 2, line 2, column 3)		1,176,531,143
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)		1,176,531,143
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	19,447,924	1.00	19,447,924		
14	Distribution	0	0.00	0		
15	Other		0.00	0		
16	Total (sum lines 12-15)	19,447,924		19,447,924	=	1.00000

PERCENTAGE OF TOTAL PLANT ALLOCATOR PTP (Note M)

Line No.		$			
17	Transmission Plant in Service UGP	1,134,918,307			
18	Total Plant in Service UGP	1,189,317,699			
19	UGP Percentage of Transmission Plant to Total Plant (line 17 divided by line 18)		PTP/UGP	=	0.95426
20	Transmission Plant in Service RMR	6,345,466			
21	Total Plant in Service RMR	681,620,527			
22	RMR Percentage of Transmission Plant to Total Plant (line 20 divided by line 22)		PTP/RMR	=	0.00931
23	Transmission Plant in Service COE	35,267,370			
24	Total Plant in Service COE	1,006,360,081			
25	COE Percentage of Transmission Plant to Total Plant (line 23 divided by line 24)		PTP/COE	=	0.03504

COMMON PLANT ALLOCATOR (CE) (Note N)

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

RETURN (R)

Line No.		$
30	Long Term Interest Schedule 5	$39,181,653

Line No.			$	%	Cost (Note O)	Weighted	=WCLTD
31	Long Term Debt	HFD Sch's 21RX & 21X Col 8 Lines 23,25,26,29,30	816,480,009	100%	0.0480	0.0480	=R
32	Proprietary Capital			0%	0.1238	0.0000	
33	Total (sum lines 22-23)		816,480,009	100%		0.0480	
34					Proprietary Capital Cost Rate =	12.38%	
35					TIER =	1.00	

REVENUE CREDITS

Line No.			Load
	ACCOUNT 447 (SALES FOR RESALE)		
36	a. Bundled Non-RQ Sales for Resale	(Note P)	0
37	b. Bundled Sales for Resale included in Divisor on page 1		0
38	Total of (a)-(b)		0

39	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note Q)	79,116
	ACCOUNT 456 (OTHER ELECTRIC REVENUES)	
40	a. Transmission charges for all transmission transactions	
41	b. Transmission charges for all transmission transactions included in Divisor on page 1	
42	Total of (a)-(b)	$0

Western Area Power Administration
Integrated System

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

Est for 12 Months Ending 9/30/2013

Western Area Power Administration

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 2013
(WESTERN'S COSTS)

A.	Fixed Charge Rate	17.846%	(1)
B.	Generation Net Plant Costs ($)	$473,919,619	(2)
C.	Annual Cost of Generation ($)	$84,575,695	(A x B)
D.	Capability Used for Reactive Support (%)	3.11%	(3)
E.	Reactive Service Revenue Requirement	$2,630,304	(C x D)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Generation Revenue Requirement", for 2013 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 2007-2011.

TRUE-UP FOR 2011 REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES (INTEGRATED SYSTEM)

A.	WAPA 2011 Rate Reactive Service Revenue Requirement	$2,750,130	(1)
B.	WAPA 2011 Actual Reactive Service Revenue Requirement	$2,630,304	(2)
C.	Under Collection of Revenue Requirement	$119,826	(A - B)
D.	2011 Rate IS Transmission System Total Load (kW-Yr)	4,593,000	(3)
E.	2011 Actual IS Transmission System Total Load (kW-Yr)	4,918,000	(4)
F.	Difference 2011 Rate Load to 2011 Actual Load	(325,000)	(D - E)
G.	Under collection of revenue requirement	$119,826	(C)
H.	Over collection due to volume	$194,599	(F * [A / D] * -1)
I.	Net Over Collection	$74,773	(H - G)

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

(2) Reactive Service Revenue Requirement from "Reactive Supply and Voltage Control from Generation Sources For 2013, Western's Costs" (uses 2011 actual costs).

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

(4) Reactive Service Revenue Requirement from "Rate for Reactive Supply and Voltage Control from Generation Sources For 2013, Western's Costs".

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.

REGULATION AND FREQUENCY RESPONSE FOR 2013
(Western's Costs)

A.	Fixed Charge Rate	15.972%	(1)
B.	Corps Generation Net Plant Costs ($)	$168,890,532.00	(2)
C.	Annual Corps Generation Cost ($)	$26,975,195.77	(A x B)
D.	Plant Capacity (kW)	937,000	
E.	Cost/kW ($/kW)	$28.79	(C / D)
F.	Capacity Used for Regulation (kW)	63,000	(J x 2%)
G.	Regulation Revenue Requirement ($) - Capacity	$1,813,770	(E x F)
H.	Regulation Revenue Requirement ($) - Purchases	$0	(3)
I.	Total Regulation Revenue Requirement ($)	$1,813,770	
J.	Load in Control Area(s) (kW-Yr)	3,150,000	(4)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Corps Revenue Requirement", for 2013 Rate.

(2) Corps Generation Net Plant is Electric Plant in Service for Oahe and Fort Peck less less Depreciation Reserve as of 9/30/11.

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

(4) Average of monthly peaks for 2011.

TRUE-UP OF REGULATION AND FREQUENCY RESPONSE FOR 2011 RATE
(INTEGRATED SYSTEM)

A.	2011 Rate Regulation Service Revenue Requirement	$1,343,018	(1)
B.	2011 Actual Regulation Service Revenue Requirement	$1,884,741	(2)
C.	Under Collection of Revenue Requirement	($541,723)	(A - B)
D.	2011 Rate Load in Control Area(s) (kW-Yr)	2,699,000	(3)
E.	2011 Actual Load in Control Area(s)(kW-Yr)	3,150,000	(4)
F.	Difference 2011 Rate Load to 2011 Actual Load	(451,000)	(D - E)
G.	Under collection of revenue requirement	($541,723)	(C)
H.	Over collection due to volume	$224,417	(F * [A / D] * -1)
I.	Net Under Collection	($317,306)	(G + H)

(1) Regulation Service Revenue Requirement from "Rate for Regulation and Frequency Response for 2011".

(2) Regulation Service Revenue Requirement from "Rate for Regulation and Frequency Response for 2013".

(3) Regulation Service Revenue Requirement from "Rate for Regulation and Frequency Response for 2011".

(4) Regulation Service Revenue Requirement from "Rate for Regulation and Frequency Response for 2013".

RATE FOR REGULATION AND FREQUENCY RESPONSE FOR 2011

		2011 Rate	
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 2011.

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	$78,351,000	O&M Expenses Worksheet, C6L19
5			
6	Net Generation Plant Investment	$654,099,613	Net Plant Investment Worksheet, C6L12
7			
8	O&M as % of Net Generation Plant Investment	11.978%	L4/L6
9			
10			
11	**B. A&G Expense for Generation**		
12			
13	Generation A&G Expense	$308,351	A&G Expenses Worksheet, C6L18
14			
15	Net Generation Plant Investment	$654,099,613	L6
16			
17	A&G as % of Net Generation Plant Investment	0.047%	L13/L15
18			
19			

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

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Notes
20	**C. Depreciation Expense for Generation**		
21			
22	Generation Depreciation Expense	$15,137,195	Depreciation Expense Worksheet, C6L6
23			
24	Net Generation Plant Investment	$654,099,613	L6
25			
26	Depreciation as a % of Net Generation Plant Investment	2.314%	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	3.507%	Cost of Capital Worksheet, C6L11
42			

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

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Notes
43			
44	**G. Generation Fixed Charge Rate**		
45			
46	Operation and Maintenance Expense	11.978%	L8
47			
48	A&G Expense	0.047%	L17
49			
50	Depreciation Expense	2.314%	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	3.507%	L41
57			
58	Total	17.846%	
59			
60			
61	**H. Generation Revenue Requirement**		
62			
63	Generation Fixed Charge Rate	17.846%	L58
64			
65	Net Generation Plant Investment	$654,099,613	L6
66			
67	Western Annual Generation Revenue Requirement	$116,730,617	L63 * L65
68			

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

Western Area Power Administration
Upper Great Plains Region

Line No.	Description	Amount	Notes
1			
2	**A. Operation and Maintenance Expense for Corps Generation**		
3			
4	Corps Generation O&M Expense	$41,886,497	O&M Expenses Worksheet, C4L19
5			
6	Net Corps Generation Plant Investment	$421,473,130	Net Plant Investment Worksheet, C4L12
7			
8	O&M as % of Net Generation Plant Investment	9.938%	L4/L6
9			
10			
11	**B. A&G Expense for Corps Generation**		
12			
13	Corps Generation A&G Expense	$0	A&G Expenses Worksheet, C4L18
14			
15	Net Corps Generation Plant Investment	$421,473,130	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	$10,650,544	Depreciation Expense, C4L6
23			
24	Net Corps Generation Plant Investment	$421,473,130	L6
25			
26	Depreciation as a % of Net Generation Plant Investment	2.527%	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	3.507%	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	9.938%	L8
47			
48	A&G Expense	0.000%	L17
49			
50	Depreciation Expense	2.527%	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	3.507%	L41
57			
58	Total	15.972%	
59			
60			
61	**H. Corps Generation Revenue Requirement**		
62			
63	Corps Generation Fixed Charge Rate	15.972%	L58
64			
65	Net Corps Generation Plant Investment	$421,473,130	L6
66			
67	Western Annual Corps Generation Revenue Requirement	$67,317,688	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	$54,494,799	O&M Expenses Worksheet, C6L17
5	Transmission of Electricity by Others	$0	
6	Total O&M Expense for Transmission	$54,494,799	L4 + L5
7			
8	Net Transmission Plant Investment	$560,291,527	Net Plant Investment Worksheet, C6L11
9			
10	O&M as % of Net Transmission Plant Investment	9.726%	L6/L8
11			
12			
13	**B. A&G Expense for Transmission**		
14			
15	Transmission A&G Expense	$15,823,815	A&G Expenses Worksheet, C6L16
16			
17	Net Transmission Plant Investment	$560,291,527	L8
18			
19	A&G as % of Net Transmission Plant Investment	2.824%	L15/L17
20			
21			
22	**C. Depreciation Expense for Transmission**		
23			
24	Transmission Depreciation Expense	$26,033,383	Depreciation Expense Worksheet, C6L4
25			
26	Net Transmission Plant Investment	$560,291,527	L8
27			
28	Depreciation as a % of Net Transmission Plant Investment	4.646%	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	5.062%	Cost of Capital Worksheet, C6L9
44			
45			
46	**G. Transmission Fixed Charge Rate**		
47			
48	Operation and Maintenance Expense	9.726%	L10
49			
50	A&G Expense	2.824%	L19
51			
52	Depreciation Expense	4.646%	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	5.062%	L43
59			
60	Total	22.258%	
61			
62			
63	**H. Transmission Revenue Requirement**		
64			
65	Transmission Fixed Charge Rate	22.258%	L60
66			
67	Net Transmission Plant Investment	$560,291,527	L8
68			
69	Annual Western-UGPR Transmission Cost	$124,709,688	L65 * L67
70			
71			
72			
73			

30

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**	178,068,563	73,349,578			251,418,141
3						
4	**Less:**					
5	**Other Power Supply Expenses**	106,987,870	28,826,020			135,813,890
6	**A&G Expenses**	16,498,178	8,621,240			25,119,418
7	**Sunflower Payment**		0			0
8	**Prior Year Adjustments**	16,909	0			16,909
9						
10	**Plus:**					
11	**Moveable Property Interest**	785,418	233,800			1,019,218
12	**Warehouse Stores Interest**	84,533	84,307			168,840
13						
14	**COE/BOR Total**			43,144,149	35,428,412	78,572,561
15	**PS Total O&M**	55,435,557	36,220,425	43,144,149	35,428,412	170,228,543
16						
17	**PS-ED Transmission O&M 5/**	52,899,935	337,212	1,257,652	0	54,494,799
18						
19	**PS-ED Generation O&M 6/**	1,036,091	0	41,886,497	35,428,412	78,351,000

1/ All Western UGPR O&M Expenses are from the FY 2011 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 2011 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 2011 Corps of Engineers Financial Statements.

4/ Total BOR O&M Expenses are from the FY 2011 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 (with Switchyard Plant).

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 (with Switchyard Plant).

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	2,799,231	1,788,829	0	0	4,588,060
3	1412	1,831,962	2,191,075	0	0	4,023,037
4	1415	171,123	106,732	0	0	277,855
5	1416	151,181	95,059	0	0	246,240
6	1421	1,283,527	825,252	0	0	2,108,779
7	1422	1,578,533	2,704	0	0	1,581,237
8	1425	85,562	53,366	0	0	138,928
9	1426	117,585	133	0	0	117,718
10	1431	0	0	0	0	0
11	1432	0	0	0	0	0
12	1441	4,858,931	2,784,504	0	0	7,643,435
13	1442	3,620,543	773,586	0	0	4,394,129
14	**PS Total A&G**	16,498,178	8,621,240	0	0	25,119,418
15						
16	**PS-ED Transmission A&G 4/**	15,743,551	80,264	0	0	15,823,815
17						
18	**PS-ED Generation A&G 5/**	308,351	0	0	0	308,351

1/ Western UGPR A&G Expenses are from the FY 2011 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 2011 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 (with Switchyard Plant

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 (with Switchyard Plant

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	26,783,834	1/	16,633,433	2/	10,970,329	3/	3,986,061	4/	58,373,657
3										
4	PS-ED Transmission Depreciation 5/	25,558,741		154,857		319,785		0		26,033,383
5										
6	PS-ED Generation Depreciation 6/	500,590		0		10,650,544		3,986,061		15,137,195

1/ FY 2011 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 4.

2/ FY 2011 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 4.

3/ FY 2011 Corps of Engineers Statement of Revenues and Expenses.

4/ From data provided by BOR.

5/ For UGPR, RMR, COE, 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 (with Switchyard Plant).

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 (with Switchyard Plant). 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 2011 Balances	706,934,618	1/	408,570,525	1/	529,055,775	1/	112,409,726	1/	1,756,970,644	
4											
5	**Interest Expenses:**										
6	FY 2011 Interest	35,139,060	13/	26,043,687	13/	16,480,562	2/	4,925,238	2/	82,588,547	
7	Average Interest Rate	4.971%	L6/L3	6.374%	L6/L3	3.115%	L6/L3	4.382%	L6/L3		
8	Transmission Plant Factor	0.9939	3/	0.0061	4/	0.0265	5/	0.0000	6/		
9	Weighted Trans. Composite Rate									5.062%	7/
10	Generation Plant Factor	0.0142	8/	0.0000	9/	0.6753	10/	0.3041	11/		
11	Weighted Gen. Composite Rate									3.507%	12/

1/ FY 2011 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedules 21X and 21RX.
2/ FY 2011 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 33, 33A and ROOs Schedule 5.
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).
13/ Interest from Results of Operations Schedule 5

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	1,090,678,595	1/	681,620,527	2/	978,765,461	3/	436,565,875	12/	3,187,630,458
3	PS-ED Transmission Plant-in-Service	1,040,791,262	4/	6,345,466	5/	28,526,500	6/	0		1,075,663,228
4	PS-ED Generation Plant-in-Service	20,389,409	7/	0		950,238,961	L2-L3	436,565,875	L2-L3	1,407,194,245
5	Generation Plant to Total Plant	0.01869	L4/L2	0.00000	L4/L2	0.97085	L4/L2	1.00000	L4/L2	
6	Transmission Plant to Total Plant	0.95426	L3/L2	0.00931	L3/L2	0.02915	L3/L2	0.00000	L3/L2	
7										
8	PS Accumulated Depreciation	520,655,924	8/	285,097,697	9/	544,642,150	10/	214,597,742	11/	1,564,993,513
9	PS-ED Trans. Accumulated Depreciation	496,841,122	L6*L8	2,654,260	L6*L8	15,876,319	L6*L8	0	L6*L8	515,371,701
10	PS-ED Gen. Accumulated Depreciation	9,731,059	L5*L8	0	L5*L8	528,765,831	L8-L9	214,597,742	L5*L8	753,094,632
11	PS-ED Net Transmission Plant	543,950,140	L3-L9	3,691,206	L3-L9	12,650,181	L3-L9	0	L3-L9	560,291,527
12	PS-ED Net Generation Plant	10,658,350	L4-L10	0	L4-L10	421,473,130	L4-L10	221,968,133	L4-L10	654,099,613

1/ Transmission Plant-in-Service Worksheet, C2L516
2/ FY 2011 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 1.
3/ FY 2011 Corps of Engineers Financial Statements, Electric and Power Multi-Purpose Plant in Service.
4/ Transmission Plant-in-Service Worksheet, C5L514.
5/ Transmission Plant-in-Service Worksheet, C5L523.
6/ Transmission Plant-in-Service Worksheet, C5L527.
7/ Transmission Plant-in-Service Worksheet, C4L514.
8/ FY 2011 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 4.
9/ FY 2011 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 4.
10/ FY 2011 Corps of Engineers Financial Statements, Statement of Assets and Liabilities.
11/ FY 2011 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 15.
12/ FY 2011 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 17.

Line No.	(1) DESCRIPTION	(2) FY2011 TOTALS	(3) MISCELLANEOUS ADJUSTMENTS	(4) GENERATION ADJUSTMENTS	(5) TRANSMISSION TOTALS	(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	351,685			351,685	
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	7,245,050			7,245,050	
9	BROOKINGS-SIOUX FALLS	2,004,921			2,004,921	
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	1,259,668			1,259,668	
14	CHARLIE CREEK-BELFIELD	14,513,308			14,513,308	
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	15,568,431			15,568,431	
24	DEVILS LAKE-CARRINGTON	7,359,165			7,359,165	
25	DEVILS LAKE-LAKOTA	1,872,142			1,872,142	
26	EDGELEY-FORMAN	375,316			375,316	
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	10,096,097			10,096,097	
38	FORT PECK-WOLF POINT #2	7,554,492			7,554,492	
39	FORT RANDALL-FORT THOMPSON 1&2	7,326,839			7,326,839	
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	8,505,957			8,505,957	
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	10,035,508			10,035,508	
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	12,747,013			12,747,013	
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	8,757,087			8,757,087	

2011 FACILITIES

Line No.	(1) DESCRIPTION	(2) FY2011 TOTALS	(3) MISCELLANEOUS ADJUSTMENTS	(4) GENERATION ADJUSTMENTS	(5) TRANSMISSION TOTALS	(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	19,035,261			19,035,261	
70	JAMESTOWN-VALLEY CITY	1,055,414			1,055,414	
71	LEEDS-DEVILS LAKE	4,896,674			4,896,674	
72	LEEDS-ROLLA	1,609,492			1,609,492	
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	5,946,731			5,946,731	
77	MILES CITY-BAKER (BEPS)	8,205,790			8,205,790	
78	MILES CITY-BAKER (BEFP)	2,363,548			2,363,548	
79	MILES CITY-CUSTER	3,750,704			3,750,704	
80	NEW UNDERWOOD-PHILIP	2,302,158			2,302,158	
81	NEW UNDERWOOD-RAPID CITY NO. 1	1,132,486			1,132,486	
82	NEW UNDERWOOD-RAPID CITY NO. 2	309,991			309,991	
83	NEW UNDERWOOD-STEGALL (HURON)	2,672,947			2,672,947	
84	OAHE-FORT THOMPSON 230KV 1&2	3,149,034			3,149,034	
85	OAHE-FORT THOMPSON 230KV 3&4	5,119,119			5,119,119	
86	OAHE-GLENHAM	5,768,280			5,768,280	
87	OAHE-MAURINE	1,967,901			1,967,901	
88	OAHE-NEW UNDERWOOD	6,447,607			6,447,607	
89	OAHE-PIERRE	388,816			388,816	
90	O'FALLON CREEK-MILES CITY	2,488,318			2,488,318	
91	PIERRE-PHILIP	1,187,034			1,187,034	
92	RAPID CITY-ELK CREEK 115-kV T/L	52,064			52,064	
93	RUGBY-LEEDS	2,235,655			2,235,655	
94	SHELBY-SHELBY#2	576,090			576,090	
95	SIOUX CITY-DENISON	1,661,311			1,661,311	
96	SIOUX CITY-SPENCER	1,938,353			1,938,353	
97	SIOUX FALLS- SIOUX CITY	3,217,192			3,217,192	
98	SIOUX FALLS-VIRGIL FODNESS 230KV T-LINE	277,897			277,897	
99	SUMMIT-WATERTOWN	6,743,203			6,743,203	
100	TIBER TAP-TIBER	1,084,858			1,084,858	
101	UTICA JCT-SIOUX FALLS	3,485,236			3,485,236	
102	VALLEY CITY-FORMAN	1,527,895			1,527,895	
103	VIRGIL FODNESS-UTICA JUNCTION-FT RANDALL/RASM	312,931			312,931	
104	WATERTOWN-GRANITE FALLS 1&2	5,269,587			5,269,587	
105	WATERTOWN-SIOUX CITY	26,679,769			26,679,769	
106	WATFORD CITY-BEULAH	1,399,798			1,399,798	
107	WILLISTON-WATFORD CITY	17,233,741			17,233,741	
108	WM. J. NEAL-RUGBY	4,629,316			4,629,316	
109	YELLOWTAIL-CUSTER	2,265,163			2,265,163	
110	**Subtotal**	447,768,430	0	0	447,768,430	
111						
112	**Substations**					
113	ARMOUR SUBSTATION	1,974,125.83	(82,000)		1,892,126	
114	ASH SUBSTATION	63,325			63,325	
115	AURORA SUBSTATION	2,899,881			2,899,881	
116	BELDEN SUBSTATION	164,986			164,986	
117	BELFIELD SUBSTATION	9,998,416.43			9,998,416	
118	BERESFORD SUBSTATION	3,671,464.25	(624,149)		3,047,315	17% of the costs of this facility have been allocated to distribution.
119	BISBEE SUBSTATION	272,529	(136,265)		136,264	50% of the costs of this facility have been allocated to distribution.
120	BISMARK SUBSTATION	8,135,623			8,135,623	
121	BISON	12,472			12,472	
122	BOLE SUB (BEFP)	92,092			92,092	
123	BOLE SUB (BEPS)	3,111,717			3,111,717	

2011 FACILITIES

Line No.	(1) DESCRIPTION	(2) FY2011 TOTALS	(3) MISCELLANEOUS ADJUSTMENTS	(4) GENERATION ADJUSTMENTS	(5) TRANSMISSION TOTALS	(6) SOURCE/NOTES
124	BONESTEEL SUBSTATION	3,442,909	(1,721,454)		1,721,455	50% of the costs of this facility have been allocated to distribution.
125	BROOKINGS SUBSTATION	4,595,774.00			4,595,774	
126	CARPENTER SUBSTATION	2,463,312			2,463,312	
127	CARRINGTON SUBSTATION	3,782,443.70	(491,718)		3,290,726	13% of the costs of this facility have been allocated to distribution.
128	CIRCLE SUBSTATION	1,632,954.70			1,632,955	
129	CONRAD SUB	311,656			311,656	
130	CONRAD SUB (BEPS)	5,008,913			5,008,913	
131	CRESTON SUBSTATION	4,941,437	(55,000)		4,886,437	
132	CROSSOVER SUB (BEFP)	313,924.45			313,924	
133	CROSSOVER SUB	10,785,373			10,785,373	
134	CULBERTSON EAST SWITCHING STATION	2,389,949.38			2,389,949	
135	CUSTER SUBSTATION (BEFP)	3,189,684			3,189,684	
136	CUSTER SUBSTATION	1,401,908			1,401,908	
137	CUSTER TRAIL SUBSTATION	1,475,222	(737,611)		737,611	50% of the costs of this facility have been allocated to distribution.
138	DAWSON COUNTY SUBSTATION	10,533,867.89	(842,709)		9,691,159	8% of the costs of this facility have been allocated to distribution.
139	DENISON SUBSTATION	15,717,046			15,717,046	
140	DEVAUL SUBSTATION	882,270.59	(529,362)		352,909	60% of the costs of this facility have been allocated to distribution.
141	DEVILS LAKE SUBSTATION	2,610,604.73	(287,167)		2,323,438	11% of the costs of this facility have been allocated to distribution.
142	EAGLE BUTTE SUBSTATION	1,179,875.43			1,179,875	
143	EDGELEY SUBSTATION	3,477,612	(486,866)		2,990,746	14% of the costs of this facility have been allocated to distribution.
144	ELK CREEK SUBSTATION	2,086,660.26			2,086,660	
145	ELLENDALE SUBSTATION	579			579	
146	ENDERLIN TAP STATION	749,768			749,768	
147	EXIRA SWITCHING STATION	5,500,776			5,500,776	
148	FAIRVIEW WEST SWITCHING STATION	4,296,873			4,296,873	
149	FAITH SUBSTATION	1,212,383	(606,191)		606,192	50% of the costs of this facility have been allocated to distribution.
150	FARGO SUBSTATION	20,555,543.38	(47,000)		20,508,543	
151	FLANDREAU SUBSTATION	4,254,672.61	(723,294)		3,531,379	17% of the costs of this facility have been allocated to distribution.
152	FORMAN SUBSTATION	5,568,535	(723,910)		4,844,625	13% of the costs of this facility have been allocated to distribution.
153	FORT RANDALL	253,710			253,710	
154	FORT THOMPSON #2	10,929,453.55			10,929,454	
155	FORT THOMPSON SUBSTATION	15,464,906	(354,000)		15,110,906	
156	GLENDIVE SUBSTATION	1,725,310			1,725,310	
157	GRAND FORKS SUBSTATION	9,410,371.06			9,410,371	
158	GRAND ISLAND SUBSTATION	12,137,790.61			12,137,791	
159	GRANITE FALLS SUBSTATION	19,940,352.45	(57,000)		19,883,352	
160	GREAT FALLS SUB (BEFP)	122,532.68			122,533	
161	GREAT FALLS SUB	456,557.05			456,557	
162	GREGORY SUBSTATION	1,557,813.89	(311,563)		1,246,251	20% of the costs of this facility have been allocated to distribution.
163	GROTON SUBSTATION	5,105,701.14			5,105,701	
164	HAVRE SUBSTATION	5,593,215.47	(950,847)		4,642,368	17% of the costs of this facility have been allocated to distribution.
165	HILKEN SUSTATION	3,874,407			3,874,407	
166	HURON SUBSTATION	11,109,282.00			11,109,282	
167	JAMESTOWN SUBSTATION	18,437,113.88	(1,843,711)		16,593,403	10% of the costs of this facility have been allocated to distribution.
168	KILLDEER SUBSTATION	6,220,775.21			6,220,775	
169	LAKOTA SUBSTATION	2,873,871.83	(948,378)		1,925,494	33% of the costs of this facility have been allocated to distribution.
170	LEEDS SUBSTATION	1,435,823.23	(201,015)		1,234,808	14% of the costs of this facility have been allocated to distribution.
171	LETCHER SUBSTATION	11,030,118.50			11,030,119	
172	MARTIN SUBSTATION	1,533,848			1,533,848	
173	MAURINE SUBSTATION	7,960,676.88			7,960,677	
174	MIDLAND SUBSTATION	673,869.22			673,869	
175	MILES CITY SUB #2	4,280,430			4,280,430	
176	MILES CITY #2 (BEFP)	1,783,939.53			1,783,940	
177	MILES CITY SUB #3	1,669,004.93			1,669,005	
178	MILES CITY SUB #3 (BEFP)	226,697			226,697	
179	MILES CITY SUBSTATION (BEFP)	160,336			160,336	
180	MILES CITY SUBSTATION	714,993			714,993	
181	MISSION SUBSTATION	3,529,331.66			3,529,332	
182	MORRIS SUBSTATION	7,216,905.70			7,216,906	
183	MT VERNON SUBSTATION	2,058,763.13			2,058,763	
184	NELSON SUBSTATION	1,944,816.97			1,944,817	
185	NEW UNDERWOOD SUBSTATION	9,578,255.83	(1,053,608)		8,524,648	11% of the costs of this facility have been allocated to distribution.
186	NEWELL SUBSTATION	1,149,585			1,149,585	

Line No.	(1) DESCRIPTION	(2) FY2011 TOTALS	(3) MISCELLANEOUS ADJUSTMENTS	(4) GENERATION ADJUSTMENTS	(5) TRANSMISSION TOTALS	(6) SOURCE/NOTES
187	Non-Facility	263,535.44			263,535	
188	O'FALLON CREEK SUBSTATION	2,185,525	(1,092,762)		1,092,763	50% of the costs of this facility have been allocated to distribution.
189	PHILIP SUBSTATION	1,770,883.04			1,770,883	
190	PIERRE SUBSTATION	4,210,602.99	(2,105,301)		2,105,302	50% of the costs of this facility have been allocated to distribution.
191	RAINBOW SUBSTATION	723,556			723,556	
192	RAPID CITY SUBSTATION	4,790,249.76			4,790,250	
193	RICHLAND SUBSTATION	1,574,590.28	(1,259,672)		314,918	80% of the costs of this facility have been allocated to distribution.
194	ROLLA SUBSTATION	623,513	(155,878)		467,635	25% of the costs of this facility have been allocated to distribution.
195	RUDYARD SUBSTATION	2,585,060	(439,460)		2,145,600	17% of the costs of this facility have been allocated to distribution.
196	RUGBY SUBSTATION	5,886,039	(824,045)		5,061,994	14% of the costs of this facility have been allocated to distribution.
197	SAVAGE SUB	74,403			74,403	
198	SHELBY SUBSTATION	1,084,272			1,084,272	
199	SHELBY SUBSTATION #2 (BEFP)	286,340			286,340	
200	SHELBY SUBSTATION #2 (BEPS)	4,134,102			4,134,102	
201	SIOUX CITY #2	10,392,071.21			10,392,071	
202	SIOUX CITY SUBSTATION	15,705,258.75	(57,000)		15,648,259	
203	SIOUX FALLS SUBSTATION	7,461,167.71			7,461,168	
204	SPENCER	3,240,715			3,240,715	
205	SULLY BUTTES	74,428			74,428	
206	SUMMIT SUBSTATION	2,750,088.24			2,750,088	
207	TYNDALL SUBSTATION	846,557.29			846,557	
208	UTICA JCT.	12,863,876			12,863,876	
209	VALLEY CITY SUBSTATION	3,112,850.60			3,112,851	
210	VERONA	25,210			25,210	
211	VIRGIL FODNESS SUBSTATION	3,206,763			3,206,763	
212	WALL SUBSTATION	1,467,544.18	(733,772)		733,772	50% of the costs of this facility have been allocated to distribution.
213	WARD SUBSTATION	3,456,032			3,456,032	
214	WASHBURN SUBSTATION	2,082,998.77			2,082,999	
215	WATERTOWN #2	3,011,746.66			3,011,747	
216	WATERTOWN STATIC VAR SYSTEM	11,727,833.41			11,727,833	
217	WATERTOWN SUBSTATION	14,261,022.31			14,261,022	
218	WATFORD CITY SUB	1,516,413	(30,000)		1,486,413	
219	WESSINGTON SPRINGS SUBSTATION	5,141,440.25			5,141,440	
220	WHATELY (NORTHERN)	40,860			40,860	
221	WHATELY SUBSTATION	109,910	(54,955)		54,955	50% of the costs of this facility have been allocated to distribution.
222	WHITE 345/115 SUB	9,658,399			9,658,399	
223	WICKSVILLE SUBSTATION	689,471.76	(344,736)		344,736	50% of the costs of this facility have been allocated to distribution.
224	WILLISTON 2 SUBSTATION	5,931,177.07			5,931,177	
225	WILLISTON SUBSTATION	6,684,168			6,684,168	
226	WINNER SUBSTATION	3,256,387.88	(1,628,194)		1,628,194	50% of the costs of this facility have been allocated to distribution.
227	WOLF POINT SUBSTATION	7,230,797.7	(2,169,239)		5,061,559	30% of the costs of this facility have been allocated to distribution.
228	WOONSOCKET SUBSTATION	2,303,184.96			2,303,185	
229	YANKTON SUBSTATION	53,583			53,583	
230	Subtotal	505,414,344	(24,709,832)	0	480,704,512	
231						
232	**Line Taps & Related Equipment**					
233	ANITA	6,259			6,259	
234	ASSINNIBOINE	35,005			35,005	
235	BAKER (BEFP)	320,386			320,386	
236	BAKER	97,832			97,832	
237	CANYON FERRY (BEFP)	15,145			15,145	
238	CANYON FERRY	30,065			30,065	
239	CHARLIE CREEK	1,121,015			1,121,015	
240	COTTON	1,399			1,399	
241	DENBIGH TAP	848,872			848,872	
242	DICKINSON	63,736			63,736	
243	E. J. MANNING	49,112			49,112	
244	EAGLE	156,285			156,285	
245	FORSYTH	32,070			32,070	
246	FORSYTH	273,368			273,368	
247	HARLEM	174,745			174,745	
248	HARLEM (BEFP)	192,512			192,512	
249	HIGHWOOD	22,896			22,896	

2011 FACILITIES

Line No.	(1) DESCRIPTION	(2) FY2011 TOTALS	(3) MISCELLANEOUS ADJUSTMENTS	(4) GENERATION ADJUSTMENTS	(5) TRANSMISSION TOTALS	(6) SOURCE/NOTES
250	MALLARD	29,969			29,969	
251	MALTA	358,088			358,088	
252	NASHUA SUB	72,368			72,368	
253	O'NEILL SUB (NPP)	115,790			115,790	
254	PENN TAP	890,607			890,607	
255	PLEASANT LAKE TAP	992,415			992,415	
256	POPLAR (MDU)	3,758			3,758	
257	SHIRLEY TAP	22,102			22,102	
258	STANLEY	49,735			49,735	
259	TERRY TAP	78,497			78,497	
260	TERRY TAP	345,850	(172,925)		172,925	50% of the costs of this facility have been allocated to distribution.
261	TIBER TAP	166,306	(83,153)		83,153	50% of the costs of this facility have been allocated to distribution.
262	VETAL TAP	232,375			232,375	
263	V. T. HANLON	5,553			5,553	
264	WM. J. NEAL	156,417			156,417	
265	YANKTON JCT.	28,526			28,526	
266	ZENITH	2,047			2,047	
267	Subtotal	6,991,105	(256,078)	0	6,735,027	6,735,027
268						
269	**O&M Service & Maintenance Centers**					
270	ARMOUR O&M SER. CEN.	3,488,667			3,488,667	
271	BISMARCK O&M SER. CEN.	9,816,108			9,816,108	
272	DAWSON SER. CEN.	22,545			22,545	
273	DEVILS LAKE O&M SER. CEN.	3,852,064			3,852,064	
274	FARGO LINE MAINTENANCE FACILITY	2,040,287			2,040,287	
275	FARGO O&M SER. CEN.	794,673			794,673	
276	FORT PECK SER. CEN.	5,692,728			5,692,728	
277	FORT THOMPSON O&M S. C.	315,000			315,000	
278	HAVRE SERVICE CENTER	249,377			249,377	
279	HURON O&M SER. CEN.	2,419,849			2,419,849	
280	JAMESTOWN O&M SER. CEN.	3,841,398			3,841,398	
281	MILES CITY MTCE FAC.	21,817			21,817	
282	MILES CITY MTCE FAC.	1,003,437			1,003,437	
283	NEW UNDERWOOD SER. CEN.	96,884			96,884	
284	PHILIP O&M SER. CENT.	1,690,034			1,690,034	
285	PIERRE O&M SER. CEN.	1,051,383			1,051,383	
286	RAPID CITY GARAGE & STOR.	2,064,165			2,064,165	
287	SIOUX CITY O&M SER. CEN.	3,007,882			3,007,882	
288	SIOUX FALLS O&M SER. CEN.	239,920			239,920	
289	WATERTOWN MAINT. CEN.	934,402			934,402	
290	Subtotal	42,642,620	0	0	42,642,620	
291						
292	**Operation Centers**					
293	WATERTOWN ALTERNATE OPERATIONS CENTER	6,128,823		(2,126,947)	4,001,876	
294	WATERTOWN OPERATIONS CENT	876,061		(304,028)	572,033	Column 4 shows 34.704% of the Watertown Operations Center that
295	WATERTOWN OPER CTR (BFPS)	11,299,013		(3,921,209)	7,377,804	was prorated to generation based on FTE associated with generation.
296	Subtotal	18,303,896	0	(6,352,184)	11,951,712	
297						
298	**Mobile Equipment**					
299	MOB 115KV SWITCH TRAILER	12,328			12,328	
300	MOB 115KV SWITCH TRAILER	57,413			57,413	
301	MOB TRANSF 111KV 15MVA	213,000			213,000	
302	MOB TRANSF 115KV 10MVA	76,258			76,258	
303	MOB TRANSF 115KV 10MVA	142,235			142,235	
304	MOB TRANSF 115KV 25MVA	556,464			556,464	
305	MOB TRANSF 115KV 40MVA	499,220			499,220	
306	MOB TRANSF 230KV 1-33MVA	170,278			170,278	
307	MOBILE BY PASS KIT (BISMARCK)	35,071			35,071	
308	MOBILE BY PASS KIT (HURON)	163,695			163,695	
309	MOBILE CAPACITOR BANK	19,075			19,075	
310	MOBILE SUB 110KV	127,144			127,144	
311	MOBILE SUB 115KV 20MVA	404,166			404,166	
312	MOBILE SUB 41.8 KV	192,498			192,498	

Line No.	(1) DESCRIPTION	(2) FY2011 TOTALS	(3) MISCELLANEOUS ADJUSTMENTS	(4) GENERATION ADJUSTMENTS	(5) TRANSMISSION TOTALS	(6) SOURCE/NOTES
313	MOBILE SUB 69KV	71,118			71,118	
314	MOB SH REACTOR	179,328			179,328	
315	Subtotal	2,919,291	0	0	2,919,291	
316						
317	**Transmission-Related Generation Facilities**					
318	BIG BEND-FORT THOMPSON (LOW VOLTAGE)	81,944		(81,944)	0	
319	CANYON FERRY-EAST HELENA "A"	141,044		(141,044)	0	
320	CANYON FERRY-EAST HELENA "B"	141,044		(141,044)	0	
321	FORT PECK POWERPLANT (COE)	146,652.26		(146,652)	0	
322	FORT THOMPSON-BIG BEND NO. 1	922,164		(922,164)	0	
323	FORT THOMPSON-BIG BEND NO. 2	690,735		(690,735)	0	
324	Subtotal	2,123,583	0	(2,123,583)	0	
325						
326	**Communication Facilities**					
327	ATLANTIC COMMUNICATION SITE	17,199		(5,480)	11,719	Column 4 shows 31.86% of the Communication Facilities that were prorated to generation based on the number of communication channels dedicated to generation.
328	BAKER RELAY	27,791		(8,854)	18,937	
329	BANTRY	268,530		(85,554)	182,976	
330	BARRETT	244,695		(77,960)	166,735	
331	BATTLE MT. MICROWAVE	324,151.14		(103,275)	220,876	
332	BELLE PRAIRIE	16,111		(5,133)	10,978	
333	BELLE PRAIRIE	577,323		(183,935)	393,388	
334	BENEDICT	36,772		(11,715)	25,057	
335	BEULAH	10,679		(3,402)	7,277	
336	BIG BEND	113,362		(36,117)	77,245	
337	BIJOU REPEATER	562,952		(179,357)	383,595	
338	BISMARCK REPEATER	405,324		(129,136)	276,188	
339	BISON REPEATER	204,957		(65,299)	139,658	
340	BOLE NORTH REPEATER	149,228		(47,544)	101,684	
341	BRINSMADE	237,551		(75,684)	161,867	
342	BRISTOL	11,441		(3,645)	7,796	
343	BRUNSVILLE REPEATER	92,595		(29,501)	63,094	
344	BUFFALO	255,051		(81,259)	173,792	
345	CAHOON	337,215.45		(107,437)	229,778	
346	CARRINGTON REPEATER	726,855		(231,576)	495,279	
347	CHARTER OAK REPEATER	12,546		(3,997)	8,549	
348	CHARTER OAK REPEATER	3,121		(994)	2,127	
349	CHINOOK (BEFP)	284,048		(90,498)	193,550	
350	CHINOOK REPEATER	15,293		(4,872)	10,421	
351	CLARK MW REPEATER	619,405.78		(197,343)	422,063	
352	CLEVELAND REPEATER, N.D.	263,617		(83,988)	179,629	
353	COLEMAN REPEATER	105,281		(33,543)	71,738	
354	COLOME REPEATER	469,005		(149,425)	319,580	
355	CONRAD BUTTE REPEATER	371,283		(118,291)	252,992	
356	CONRAD BUTTE REPEATER	84,384		(26,885)	57,499	
357	CRESTON REPEATER	11,107		(3,539)	7,568	
358	CROW LAKE REPEATER	311,803		(99,341)	212,462	
359	CROWN BUTTE	202,445		(64,499)	137,946	
360	CULBERTSON RADIO RELAY SITE	1,926		(614)	1,312	
361	CUSTER LOOKOUT	194,017		(61,814)	132,203	
362	DALTON (WES)	198,021		(63,089)	134,932	
363	DEVILS LAKE REPEATER	465,879.32		(148,429)	317,450	
364	DODSON REPEATER	276,812		(88,192)	188,620	
365	DOGDEN BUTTE	281,286		(89,618)	191,668	
366	DRISCOLL	196,774		(62,692)	134,082	
367	DUPREE REPEATER	1,821		(580)	1,241	
368	DUTTON REPEATER (BEPS)	18,529.82		(5,904)	12,626	
369	DUTTON REPEATER (BEFP)	315,739		(100,594)	215,145	
370	EAST RAINY BUTTE	287,339		(91,546)	195,793	
371	ECKELSON	231,893.37		(73,881)	158,012	
372	ELKTON	146,696		(46,737)	99,959	
373	ELLENDALE REPEATER	644,579		(205,363)	439,216	
374	ELLSWORTH AIR BASE	59,669		(19,010)	40,659	
375	ERHARD	301,774		(96,145)	205,629	

Line No.	(1) DESCRIPTION	(2) FY2011 TOTALS	(3) MISCELLANEOUS ADJUSTMENTS	(4) GENERATION ADJUSTMENTS	(5) TRANSMISSION TOTALS	(6) SOURCE/NOTES
376	EXIRA REPEATER	2,527		(805)	1,722	
377	F. L. BLAIR	76,407.48		(24,343)	52,064	
378	FAIRPOINT REPEATER	339,030		(108,015)	231,015	
379	FALLON REPEATER	367,717.58		(117,155)	250,563	
380	FERGUS FALLS COMMUNICATIONS SITE	485,567		(154,702)	330,865	
381	FLOWING WELLS	68,763		(21,908)	46,855	
382	FORBES COMMUNICATION SITE	45,316		(14,438)	30,878	
383	FORT PECK RELAY (WES)	250,959.50		(79,956)	171,004	
384	FORT PECK COMMUNICATIONS BUILDING	380,212.21		(121,136)	259,076	
385	FORT PECK REPEATER	109,068.74		(34,749)	74,320	
386	FORT THOMPSON REPEATER	99,222.88		(31,612)	67,611	
387	FORT THOMPSON REPEATER (EAST RIVER)	301,614		(96,094)	205,520	
388	FOX CREEK MICROWAVE	579,063		(184,490)	394,573	
389	FRYBURG SUB & MICROWAVE	210,967		(67,214)	143,753	
390	GARRISON	267,755.36		(85,307)	182,448	
391	GARY REPEATER	80,798.66		(25,742)	55,057	
392	GAVIN'S POINT	148,752.31		(47,392)	101,360	
393	GAVINS POINT REPEATER	411,445		(131,086)	280,359	
394	GETTYSBURG REPEATER	290,839		(92,661)	198,178	
395	GLENHAM	293,701		(93,573)	200,128	
396	GRAND FORKS MINNKOTA (MPC)	23,847		(7,598)	16,249	
397	HAILSTONE BUTTE	188,523		(60,063)	128,460	
398	HALLOWAY REPEATER	109,706.08		(34,952)	74,754	
399	HATHAWAY	17,314		(5,516)	11,798	
400	HATHAWAY	191,777		(61,100)	130,677	
401	HERMOSA MICROWAVE	302,701		(96,441)	206,260	
402	HIGHLAND REPEATER	177,964		(56,699)	121,265	
403	HIGHMORE REPEATER	145,723.24		(46,427)	99,296	
404	HINSDALE	201,837		(64,305)	137,532	
405	HINSDALE REPEATER	25,153		(8,014)	17,139	
406	HOPEWELL REPEATER	231,172.47		(73,652)	157,520	
407	HUNTER MICROWAVE	307,546		(97,984)	209,562	
408	HURON DISTRICT OFFICE	747,055		(238,012)	509,043	
409	HYSHAM	250,143		(79,696)	170,447	
410	JAMESTOWN REPEATER	46,981		(14,968)	32,013	
411	JONES CREEK	251,034		(79,979)	171,055	
412	KELLY CREEK (BEFP)	76,047.96		(24,229)	51,819	
413	KELLY CREEK	300,278		(95,668)	204,610	
414	KILLDEER REPEATER	395,542		(126,020)	269,522	
415	KNEE HILL MW	308,285		(98,220)	210,065	
416	KNEE HILL MW	119,303		(38,010)	81,293	
417	LAC QUI PARLE	747,619		(238,191)	509,428	
418	LAKE ANDES REPEATER	648,460		(206,599)	441,861	
419	LEFOR	186,943		(59,560)	127,383	
420	LINDSAY RIDGE	235,489		(75,027)	160,462	
421	LINTON COMMUNICATIONS SITE	339,867		(108,282)	231,585	
422	LITTLE MISSOURI SUBSTATION	35,123.76		(11,190)	23,934	
423	LODGEPOLE REPEATER	186,559		(59,438)	127,121	
424	MALTA REPEATER	289,599		(92,266)	197,333	
425	MANDAN MICROWAVE SITE	69,988		(22,298)	47,690	
426	MAPLE RIVER	172,792		(55,052)	117,740	
427	MARTIN REPEATER	287,916		(91,730)	196,186	
428	MAYVILLE	331,361		(105,572)	225,789	
429	MIDLAND REPEATER	516,514.50		(164,562)	351,953	
430	MILES CITY SUB (BEFP)	305,418		(97,306)	208,112	
431	MOE REPEATER	129,266		(41,184)	88,082	
432	MOORHEAD	251,422		(80,103)	171,319	
433	MORRIS REPEATER & MICROWAVE	327,191.48		(104,243)	222,948	
434	NEWCASTLE REPEATER	216,330		(68,923)	147,407	
435	OAHE	564,580		(179,875)	384,705	
436	O'KREEK REPEATER	367,629.89		(117,127)	250,503	
437	ORCHARD REPEATER	43,642		(13,904)	29,738	
438	OTO MICROWAVE	16,445		(5,239)	11,206	

Line No.	(1) DESCRIPTION	(2) FY2011 TOTALS	(3) MISCELLANEOUS ADJUSTMENTS	(4) GENERATION ADJUSTMENTS	(5) TRANSMISSION TOTALS	(6) SOURCE/NOTES
439	OTTUMWA ROAD REPEATER SITE	7,685		(2,448)	5,237	
440	PAGE N.D.	1,646		(524)	1,122	
441	PAHOJA SUB	66,444		(21,169)	45,275	
442	PEAK	83,843.78		(26,713)	57,131	
443	PHILIP JCT. REPEATER	545,125		(173,677)	371,448	
444	PINE RIDGE	15,766		(5,023)	10,743	
445	PINE RIDGE	273,894		(87,262)	186,632	
446	PRIMGHAR REPEATER	11,990		(3,820)	8,170	
447	PUKWANNA REPEATER	258,360		(82,313)	176,047	
448	RAPID CITY REPEATER	347,278.59		(110,643)	236,636	
449	RICHARDSON COULEE	214,752		(68,420)	146,332	
450	RICHARDSON COULEE REPEATER	186,301.08		(59,356)	126,945	
451	RICHLAND MW REPEATER (BEPS)	444,616		(141,655)	302,961	
452	ROCKY RIDGE REPEATER	226,934		(72,301)	154,633	
453	ROLLAG	172,922		(55,093)	117,829	
454	RUGBY REPEATER	276,659		(88,143)	188,516	
455	RUTLAND	388,869		(123,894)	264,975	
456	SACO	1,237		(394)	843	
457	SENTINEL BUTTE	215,321		(68,601)	146,720	
458	SHEEP COULEE REPEATER	475,744		(151,572)	324,172	
459	SIOUX CITY REPEATER	531,829.33		(169,441)	362,388	
460	SIOUX FALLS REPEATER	330,717.93		(105,367)	225,351	
461	SIOUX PASS	1,366		(435)	931	
462	SNAKE BUTTE REPEATER	729,560		(232,438)	497,122	
463	SPALDING REPEATER	38,651		(12,314)	26,337	
464	SPIRIT MOUND	226,293		(72,097)	154,196	
465	STRASBERG	17,870		(5,693)	12,177	
466	SUMMIT REPEATER	50,053		(15,947)	34,106	
467	TAPPEN COMMUNICATIONS SITE	291,767		(92,957)	198,810	
468	TAPPEN REPEATER	272,393		(86,785)	185,608	
469	TENNANT COMMUNICATIONS SITE	8,782		(2,798)	5,984	
470	TORONTO REPEATER	106,096		(33,802)	72,294	
471	TRIPP REPEATER	114,817		(36,581)	78,236	
472	TURKEY RIDGE REPEATER	664,768.09		(211,795)	452,973	
473	TYLER REPEATER	449,771		(143,297)	306,474	
474	VICTOR (EREC)	35,530		(11,320)	24,210	
475	VIDA	14,357		(4,574)	9,783	
476	VIDA	323,156		(102,957)	220,199	
477	WALL REPEATER	461,034		(146,885)	314,149	
478	WATERTOWN REPEATER	699,939		(223,000)	476,939	
479	WAYSIDE	17,781.11		(5,665)	12,116	
480	WESSINGTON SPGS. REPEATER	624,746		(199,044)	425,702	
481	WESTFIELD	19,003		(6,054)	12,949	
482	WHITE SWAN	116,529		(37,126)	79,403	
483	WHITLOCK (BCPS)	165,594		(52,758)	112,836	
484	WOLBACH REPEATER	28,280		(9,010)	19,270	
485	YELLOWTAIL SWITCHYARD (BEPS)	343,984		(109,593)	234,391	
486	Subtotal	37,393,748	0	(11,913,642)	25,480,106	
487						
488	**Miles City Converter Station**					
489	MILES CITY CONVERTER STATION - BEPS	20,610,613			20,610,613	
490	MILES CITY CONVERTER STATION - BEFP	1,978,951			1,978,951	
491	Subtotal	22,589,564	0	0	22,589,564	
492						
493	**Distribution Facilities**					
494	BUFORD TRENTON TAP - BUFORD TRENTON P.P.	650,001	(650,001)		0	
495	BUFORD TRENTON PUMP SUB	184,827	(184,827)		0	These facilities have been determined to be used solely for distribution
496	FALLON PUMPING PLANT SUBS	223,594	(223,594)		0	and are therefore not recovered in the transmission rate.
497	FALLON RELIFT PUMPING PLA	171,257	(171,257)		0	
498	FALLON-GLENDIVE PUMP #4	25,506	(25,506)		0	
499	FORT PECK-WOLF POINT	190,500	(190,500)		0	
500	FRAZER PUMP SUB	253,597	(253,597)		0	
501	GARRISON-SNAKE CREEK	569,241	(569,241)		0	

2011 FACILITIES

Line No.	(1) DESCRIPTION	(2) FY2011 TOTALS	(3) MISCELLANEOUS ADJUSTMENTS	(4) GENERATION ADJUSTMENTS	(5) TRANSMISSION TOTALS	(6) SOURCE/NOTES
502	GLENDIVE P.P. #1 SUB.	425,706	(425,706)		0	
503	INTAKE SUBSTATION	108,040	(108,040)		0	
504	INTAKE-INTAKE PUMP	6,494	(6,494)		0	
505	SAVAGE PUMPING PLANT SUBS	102,283	(102,283)		0	
506	SHIRLEY PUMP SUBSTATION	127,053	(127,053)		0	
507	SNAKE CREEK PUMP SUBSTATI	662,436	(662,436)		0	
508	TERRY PUMPING PLANT SWITC	474,404	(474,404)		0	
509	TIBER DAM SUBSTATION	318,568	(318,568)		0	
510	WIOTA SUBSTATION	38,507	(38,507)		0	
511	**Subtotal Distribution Facilities**	4,532,014	(4,532,014)	0	0	
512						
513	**Subtotal Upper Great Plains Region Facilities**	1,090,678,595	(29,497,924)	(20,389,409)	1,040,791,262	
514						
515						
516						
517	**Rocky Mountain Region Facilities**					
518	NEW UNDERWOOD-STEGALL	287,835			287,835	Column 2 includes plant-in-service from FY 2011 RMCSR - Pick-
519	STEGALL SUBSTATION	8,928,770	(8,626,161)		302,609	Sloan Missouri River Basin Results of Operations, Schedule 1. These
520	STEGALL-WAYSIDE	2,978,205			2,978,205	are RMR facilities utilized by both RMR and UGPR. The amount in
521	YELLOWTAIL SWITCHYARD	11,107,263	(8,330,447)		2,776,816	Column 5 will be recovered by UGPR.
522		23,302,074	(16,956,608)	0	6,345,466	
523						
524	**Corps of Engineers Facilities**					
525	CORPS SWITCHYARD FACILITIES	40,712,191		(12,185,691)	28,526,500	
526		40,712,191	0	(12,185,691)	28,526,500	
527						
528	**TOTAL FACILITIES**	1,154,692,860	(46,454,532)	(32,575,100)	1,075,663,228	

Basin Electric's Transmission Cost Data

Revenue Requirement Worksheet
RUS Form 12 Data
BASIN ELECTRIC POWER COOPERATIVE

Projection for 2013

Line No.			Total		Allocator	Total Transmission	IS Transmission	West (MBPP) Transmission	Other Transmission
1	**GROSS REVENUE REQUIREMENT (page 3, line 28)**					$ 83,986,430	$ 53,089,809	$ 8,431,697	$ 22,464,924
	(MBPP West Excluded - 1-.065997)							$ (7,875,230)	
	REVENUE CREDITS								
2	Third Party Receipts		$ (350,472)	TP	1.00000		**$ (350,472)**		
3									
4	Third Party Payments			TP	1.00000		**$ 104,993**		
5		(line 2 + 4)					$ (245,479)	$ -	$ -
6	**NET REVENUE REQUIREMENT**	(line 1+ 5)					**52,844,330**	**556,467**	**22,464,924**
7	**TOTAL REVENUE REQUIREMENT WITH MBPP EAST**						**$ 53,400,797**		

Revenue Requirement Worksheet
RUS form 12 Data
BASIN ELECTRIC POWER COOPERATIVE

Projection for 2013

	(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										
1	Production (Note A)	12h.A.6.e	4,413,943,130	NA	0.000%		NA	0.000%	-	-	-
2	Transmission (Note B)	12h.A.11.e & 12h.A.23.e	729,400,000	DA	100.000%	729,400,000	DA	100.000%	448,363,369	94,742,815	186,293,816
3	Distribution	12h.A.16.e	-	NA	0.000%		NA	0.000%			
4	General	12h.A.18.e	158,272,000								
4a	Direct Assign - Transmission (Note C)		37,423,227	DA	100.000%	37,423,227	DA	100.000%	27,312,980	3,147,763	6,962,484
4b	Direct Assign - Production		41,860,630	NA	0.000%		NA	0.000%			
4c	Other		78,988,143	WS	10.025%	7,918,561	WS	Gross Plant	4,867,539	1,028,542	2,022,480
5	Intangible	12h.A.1.e	75,689,531	DA	0.000%	66,336,542	DA	0.000%	30,836,079	2,512,924	32,987,539
6	TOTAL GROSS PLANT (sum lines 1,2,4,5)	12h.A.18.e & 12h.A.24.e	$ 5,377,304,661			$ 841,078,330			$ 511,379,967	$ 101,432,044	$ 228,266,319
							GP1	Gross Plant	61.470%	12.989%	25.541%
	ACCUMULATED DEPRECIATION										
7	Production	12h.B.1-4.f	1,291,805,060	NA	0.000%		NA	0.000%	-		
8	Transmission	12h.B.5.f & 12h.B.15.f	305,250,584	DA	100.000%	305,250,584	DA	100.000%	203,317,667	53,811,448	48,121,469
9	Distribution	12h.B.6.f	-	NA	0.000%		NA	0.000%			-
10	General	12h.B.7.f	122,467,345								-
10a	Direct Assign - Transmission		26,009,533	DA	100.000%	26,009,533	DA	100.000%	19,746,769	3,040,788	3,221,977
10b	Direct Assign - Production		38,025,928	NA	0.000%		NA	0.000%			
10c	Other		48,450,170	WS	10.025%	4,857,130	GP1	Gross Plant	2,985,678	630,893	1,240,560
11	Intangible	12h.B.12.f	52,715,095	DA		51,985,925	DA	100.000%	23,934,148	2,083,098	25,968,679
12	TOTAL ACCUM. DEPR (sum lines 7,8,10,11)	12h.B.18.f less 12h.B.14.f	$ 1,772,238,084			$ 388,103,172			$ 249,984,262	$ 59,566,227	$ 78,552,685
	NET PLANT IN SERVICE										
13	Production	(line 1- line 7)	3,122,138,070	AUTO		-	AUTO		-	-	-
14	Transmission	(line 2- line 8)	424,149,416	AUTO		424,149,416	AUTO		245,045,702	40,931,367	138,172,347
15	Distribution	(line 3 - line 9)	-	AUTO		-	AUTO		-	-	-
16	General	(line 4 - line 10)	35,804,655	AUTO		-	AUTO		-	-	-
16a	Direct Assign	(line 4a - line 10a)	11,413,694	AUTO		11,413,694	AUTO		7,566,211	106,975	3,740,507
16b	Production	(line 4b - line 10b)	3,834,702	AUTO		-	AUTO		-	-	-
16c	Other	(line 4c - line 10c)	30,537,973	AUTO		3,061,431	AUTO		1,881,861	397,649	781,920
17	Intangible	(line 5 - line 11)	22,974,436	AUTO		14,350,617	AUTO		6,901,931	429,826	7,018,860
18	TOTAL NET PLANT (sum lines 13, 14, 16, 17)		$ 3,605,066,577			$ 452,975,158			$ 261,395,705	$ 41,865,817	$ 149,713,634
	WORKING CAPITAL										
19	CWC (Note D)	one eighth of line 9, page 3	10,909,314	DA	100.000%	4,482,285	DA	100.000%	3,104,214	539,504	838,567
20	Materials & Supplies Transmission	12h. G, L.4. L.5. C.d.	7,116,367	GP1	100.000%	7,116,367	GP1	Gross Plant	4,374,431	924,345	1,817,591
21	Prepayments (Note D)	12a.B.25	-	GP1	10.025%	-	GP1	Gross Plant			
22	TOTAL WORKING CAPITAL (sum lines 19-21)		$ 18,025,681			$ 11,598,652			$ 7,478,645	$ 1,463,849	$ 2,656,158
23	Rate Base		$ 3,623,092,258			$ 464,573,810			$ 268,874,350	$ 43,329,666	$ 152,369,792

Revenue Requirement Worksheet
RUS form 12 Data
BASIN ELECTRIC POWER COOPERATIVE

Projection for 2013

Line No.	(1)	(2) Reference		(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	**29,429,423**								
2	Direct Assignment (Note E)	Accounting Records	13,243,240	DA	100.000%	13,243,240	DA	100.000%	9,359,373	3,560,000	323,867
3	Other	Accounting Records	16,186,183	TPW	100.000%	16,186,183	GP2	page 4	11,435,053	-	4,751,130
4	A&G	Expense Worksheet #3	**57,845,091**			-					
5	Less Regulatory Fees (Note F)	Accounting Records	155,664	NA	0.000%	-	NA	0.000%			
6	Production	Accounting Records	2,429,453	NA	0.000%	-	NA	0.000%			
7	Transmission (Note G)	Accounting Records	988,101	DA		988,101	DA	page 4	195,557	756,031	36,513
8	Headquarters		54,271,873	WS	10.025%	5,440,755	GP2	Gross Plant	3,843,730	-	1,597,025
9	**TOTAL O&M (sum lines 1 and 4)**		**$ 87,274,514**			**$ 35,858,279**			**$ 24,833,713**	**$ 4,316,031**	**$ 6,708,535**
	DEPRECIATION & AMORTIZATION EXPENSE										
10	Depreciation and Amortization Expense	Accounting Records	**123,334,677**								
11	Transmission	Accounting Records	13,445,160	DA	100.000%	13,445,160	DA	100.000%	7,238,919	1,250,309	4,955,932
12	Production	Accounting Records	109,889,517	NA	0.000%		NA	0.000%			
13	General Plant	Accounting Records	**12,000,000**	NA	0.000%		NA	0.000%			
14	Transmission	Accounting Records	2,005,000	DA	100.000%	2,005,000	DA	100.000%	1,264,420	198,000	542,580
15	Production	Accounting Records	6,500,000	NA	0.000%		NA	0.000%			
16	Hdqtrs General Plant		3,495,000	WS	10.025%	350,374	GP1	Gross Plant	215,375	45,510	89,489
17	Other Amortization		**2,257,826**	DA	0.000%	1,917,762	DA	0.000%	921,795	65,397	930,570
18	**TOTAL (Sum lines 10,13,17)**	Expense Worksheet, L.20. C.b	**$ 137,592,503**			**$ 17,718,296**			**$ 9,640,509**	**$ 1,559,216**	**$ 6,518,571**
	TAXES OTHER THAN INCOME TAXES										
19	PLANT RELATED										
20	Property total	2011 12a.A.21 (less income tax)									
21	Tax Reclassification	Accounting Records		NA	0.000%	-	NA	0.000%			
22	Gross Receipts (Note I)	2010 RUS Form 12	3,000,000	DA	100.000%	**3,000,000**	DA	100.000%	2,752,000		248,000
23	Production			NA	0.000%		NA	0.000%			
24	**TOTAL OTHER TAXES**		**$ 3,000,000**			**$ 3,000,000**			**$ 2,752,000**	**$ -**	**$ 248,000**
25	**TOTAL OPERATING EXPENSES (Sum 9+18+24)**					**$ 56,576,575**					
26	Return		**$ 213,762,443**	WCC	Rate Base	**$ 27,409,855**	WCC	Rate Base	**$ 15,863,587**	**$ 2,556,450**	**$ 8,989,818**
27	**REV. REQUIREMENT (sum lines 25+26)**		**$ 441,629,460**			**$ 83,986,430**			**$ 53,089,809**	**$ 8,431,697**	**$ 22,464,924**

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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	51,451,302								
2	Transmission-East	Accounting Records	239,133								
3	Transmission-West	Accounting Records	431,290	WS	Trans % of total wages	10.025%		GP1	61.4700%	12.9890%	25.5410%
4	Transmission-Allocated	Accounting Records	5,062,297								
5	Distribution			TPW	Trans % excluding MBPP West		Note H	GP2	70.647%	0.000%	29.353%
6	Other Transmission		-								
7	Total Wages and Salaries (sum lines 1-6) (exclude adm)		$57,184,022								

Note J Estimated Weighted Cost of Capital

			Percent	Rate	cost
Estimated wksht #1	LTD	3,215,026,187	74.23%	4.18%	3.10%
Estimated wksht #1	Equity	1,116,018,211	25.77%	10.85%	2.80%
		4,331,044,398	100.00%		5.90%

Notes

A RUS form 12h plus new investment averaged over 13 months.
B Transmission capital lease for $40,296,830 is excluded from transmission plant investment. Lease payments of $3,859.923 are included in Transmisson O&M.
C General Plant directly assigned to transmission includes the transmission maintenance buildings and microwave assigned to transmission.
Prepayments are the electric related prepayments booked to Account No. 165 and reported on Section B, line 24, in the RUS 12.
D Cash working capital assigned to transmission is one eighth of O&M allocated to transmission on page 3 , line 9, column 6-8.
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Prepayments are the electric related prepayments booked to Account No. 165 and reported on Section B, line 24, on the RUS 12 form.
E Includes Lease payments of $3,859,923 for member facilities in the IS system and O&M that is charged to specific lines or substations.
F Line 5 - Regulatory Commission expenses directly related to transmission service, ISO filings, or transmission sitings.
G 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.
H West (MBPP) plant investment on page 2, line, column 7 is excluded in the percentage calculations on page 4, GP2, columns 6-8for A&G and transmission O&M allocation as these are directly allocated to MBPP through the project billing.
I SD Gross receipts taxes paid in lieu of property with a portion directly assigned to Common Use System (CUS).
Payroll taxes are included in the RUS 500 series of accounts along with the labor costs. ND Trans Line tax is included in O&M, line 2.
J Equity percent as a percent of total long term debt plus current portion of long term debt plus equity. See Worksheet #1.

Basin Electric Power Cooperative

Worksheet #1

Work Paper

Line		a Actual 2011	b Estimated Budget Year 2012	c Estimated Budget Year 2013	d Transmission Adjusted for 2013 Average Balance
	GROSS PLANT IN SERVICE				
1	Production	3,365,502,527	4,293,686,260	4,534,200,000	4,413,943,130
2	Transmission	688,758,703	718,000,000	740,800,000	729,400,000
3	General	146,146,916	152,772,000	163,772,000	158,272,000
4	Intangible	78,046,322	73,332,740	78,046,322	75,689,531
5	**TOTAL GROSS PLANT**	**$ 4,278,454,467**	**$ 5,237,791,000**	**$ 5,516,818,322**	**$ 5,377,304,661**
	ACCUMULATED DEPRECIATION				
6	Production	1,115,579,864	1,259,827,412	1,323,782,708	1,291,805,060
7	Transmission	284,358,449	300,157,227	310,343,940	305,250,584
8	General	104,269,150	118,034,690	126,900,000	122,467,345
9	Intangible	49,339,867	51,574,671	53,855,519	52,715,095
10	**TOTAL ACCUM. DEPR**	**$ 1,553,547,330**	**$ 1,729,594,000**	**$ 1,814,882,167**	**$ 1,772,238,084**
	NET PLANT IN SERVICE				
11	Production	2,249,922,663	3,033,858,848	3,210,417,292	3,122,138,070
12	Transmission	404,400,254	417,842,773	430,456,060	424,149,417
13	General	41,877,766	34,737,310	36,872,000	35,804,655
14	Intangible	28,706,454	21,758,069	24,190,803	22,974,436
15	**TOTAL NET PLANT**	**$ 2,724,907,137**	**$ 3,508,197,000**	**$ 3,701,936,155**	**$ 3,605,066,578**

	2013 Estimate
Long-term Liabilities	
Long-term debt, net of current portion	$ 3,095,391,019
Obligations under capital lease	$ 39,560,451
Total Long-term Liabilities	**$ 3,134,951,470**
Current Liabilities	
Current portion of long-term debt	$ 119,635,168
Total LTD	**3,254,586,638**
Equity	**1,116,018,211**

Basin Electric Power Cooperative

Integrated System Facilities (IS)

IS Facilities - Worksheet #2

			Actual 2011				Updated Estimated 2012				Estimated 2013			
			12/31/11	12/31/11	12/31/11	2011 Depreciation	12/31/12	12/31/12	12/31/12	2012 Depreciation	12/31/13	12/31/13	12/31/13	2013 Depreciation
IS Facilities			Gross Plant	ACCUM DEPR	Net Book Value	Expense	Gross Plant	Accum Depr	Net Book Value	Expense	Gross Plant	Accum Depr	Net Book Value	Expense
IS Lines			273,952,358	133,844,790	140,107,568	4,042,149	273,952,358	137,886,939.09	114,861,477.69	4,042,149	273,952,358	139,908,014	134,044,345	4,042,149
IS Substations			125,246,384	63,438,096	61,808,288	1,918,936	125,021,946	65,354,973.01	54,976,729.75	1,916,877	125,021,946	66,315,471	58,706,476	1,916,877
IS Trans Mntnce Bldgs			18,530,996	13,800,776	4,730,219	737,644	18,530,996	14,538,419.86	3,723,339.00	737,644	18,530,996	14,907,242	3,623,754	737,644
Microwave			12,947,556	10,322,367	2,625,189	592,794	12,947,556	10,915,161.55	1,862,067.35	592,794	12,947,556	11,211,559	1,735,997	592,794
Intangible			32,120,916	22,090,558	10,030,358	921,795	32,120,916	23,012,353.31	9,585,430.76	921,795	32,120,916	23,473,251	8,647,666	921,795
Accum Depr Adjustment				(10,025,313)				(10,025,313)				(10,025,313)		
Total			462,798,210	233,471,274	219,301,623	8,213,319	462,573,772	241,682,534	220,891,238	8,211,260	462,573,772	245,790,222	216,783,550	8,211,259
Martin Substation Capacitors	12/01/11	948,362	948,362	2,634	945,727	2,634	948,362	34,246	914,115	31,612	948,362	50,052	898,309	31,612
Mission Area Capacitors	09/01/11	1,794,141	1,794,141	19,935	1,774,206	19,935	1,794,141	79,740	1,714,401	59,805	1,794,141	109,643	1,684,499	59,805
Watford City 230/115 kV Transformer	06/01/11	200,000					200,000	5,500	194,500	5,500	200,000	8,250	191,750	5,500
C Creek Sub & 345/230 kV Transformer	'07/01/12	10,700,000					10,700,000	147,125	10,552,875	147,125	10,700,000	294,250	10,405,750	294,250
230/115 Transformer, Caps, etc. Philip	01/31/12	5,100,000					5,100,000	133,604	4,966,396	133,604	5,100,000	203,729	4,896,271	140,250
Switches - Witten	01/01/12	200,000					200,000	5,500	194,500	5,500	200,000	8,250	191,750	5,500
Western ND capacitors	01/01/12	4,000,000					3,692,308	110,000	3,582,308	110,000	4,000,000	165,000	3,835,000	110,000
Blaisdell 230/115 Sub	08/31/12	14,350,000					3,395,959	85,708	3,310,251	85,708	14,350,000	283,021	14,066,979	394,625
Lonesome Creek - clutch	04/30/13	2,000,000									1,384,615	18,333	1,366,282	36,667
Pioneer Station Clutch	04/30/13	2,000,000									1,384,615	18,333	1,366,282	36,667
115 KV Line Blaisdell to Berthold	06/30/13	4,800,000									2,584,615	33,000	2,551,615	66,000
Williston 230/115 KV Transformer # 2	06/30/13	2,400,000									1,292,308	16,500	1,275,808	33,000
			-	-	-	-	26,030,769	601,424	25,429,345	578,855	43,938,657	1,208,362	42,730,295	1,213,875
			462,798,210	233,471,274	219,301,623	8,213,319	488,604,541	242,283,958	246,320,583	8,790,114	506,512,429	246,998,584	259,513,845	9,425,134
						2011				2012				2013
West (MBPP)			12/31/11	12/31/11	12/31/11	Depreciation	12/31/12	12/31/12	12/31/12	Depreciation	12/31/13	12/31/13	12/31/13	Depreciation
			Gross Plant	ACCUM DEPR	Net Book Value	Expense	Gross Plant	ACCUM DEPR	Net Book Value	Expense	Gross Plant	Accum Depr	Net Book Value	Expense
West (MBPP) Lines			70,749,575	42,599,595	28,149,980	910,642	70,749,575	43,510,237	28,149,980	910,642	70,749,575	43,965,558	26,784,017	910,642
West (MBPP) Substations			19,778,012	12,067,333	7,710,679	264,284	19,778,012	12,326,338	7,718,353	259,005	19,778,012	12,455,840	7,322,172	259,005
West (MBPP) Trans Mntnce Bldgs			2,362,545	1,855,324	507,221	109,628	2,362,545	1,948,490	458,075	93,165	2,362,545	1,995,072	367,473	93,165
West (MBPP) Microwave			1,844,541	1,372,833	471,707	95,055	1,844,541	1,467,429	468,458	94,596	1,844,541	1,514,728	329,813	94,596
Intangible			2,617,629	1,952,304	665,325	65,397	2,617,629	2,017,701	665,325	65,397	2,617,629	2,050,400	567,229	65,397
Accum Depr Adjustment				(1,433,224)			-	(1,443,108)		-	-	(1,443,108)		
Total			97,352,302	58,414,165	37,504,912	1,445,006	97,277,032	58,373,733	38,903,299	1,422,805	97,352,302	60,538,490	36,813,813	1,422,805
Miscellaneous Add/replace			-	-	-	-	3,051,200	48,946	3,002,254	90,900	3,051,200	94,397	2,956,804	90,900
GRAND TOTAL MBPP			97,352,302	58,414,165	37,504,912	1,445,006	100,328,232	58,422,680	41,905,553	1,513,706	100,403,502	60,632,886	39,770,616	1,513,706

Basin Electric Power Cooperative
Estimated 2013 Expenses

Expense Worksheet #3

		(a) 2012 Estimate	(b) 2013 Estimated
	Expenses - Operations:		
1	Production - Excluding Fuel	108,356,465	115,136,131
2	Production - Fuel	244,630,035	263,128,686
3	Production - Rents	39,854,657	40,540,858
4	Other Power Supply	310,883,506	314,164,287
5	**Sub-Total Operations Exp.**	**703,724,663**	**732,969,962**
6			
7	Transmission Operations	22,903,038	24,330,702
8	Trans of Electricity by others	22,672,810	38,142,100
9	Subtotal - Transmission	**45,575,848**	**60,360,024**
10			
11	Administration	56,564,713	57,845,091
12	**Total Operations Expense**	**749,300,511**	**851,175,077**
13			
14	**Expenses - Maintenance:**		
15	Production	127,010,329	128,506,184
16	Transmission	4,873,500	5,098,721
17	General Plant	0	0
18	**Total Maintenance Expense**	**131,883,829**	**133,604,905**
19			
20	Depreciation & Amortization	115,455,209	137,592,503
21	Taxes	3,581,591	2,957,826
22	Interest & Other Deductions	140,147,864	153,853,440
		259,184,664	294,403,769
	Total Cost of Electric Service	**1,889,669,515**	**2,072,513,737**

Basin Electric Power Cooperative
Lines
December 31, 2011

cpx	Type	Description	BookBasisAmount	AccumDepr_LTD	NetBookAmount	Depr_YTD
012	L	230kv LO#1 DC Line to Washburn	1,485,282.43	1,450,404.36	34,878.07	-
021	L	345 kv line Stanton to SD Border	9,297,594.49	8,240,894.79	1,056,699.70	26,841.62
022	L	345 kv line - SD to Ft Thompson	9,134,431.34	7,874,276.66	1,260,154.68	25,088.93
023	L	345 kv line Stanton to SD Border	11,511,849.83	10,083,334.14	1,428,515.69	31,822.23
024	L	345 kv line SD to Watertown	10,164,503.88	8,699,935.00	1,464,568.88	32,442.63
025	L	230 kv line LOS#1 to Logan	5,181,912.49	3,864,063.61	1,317,848.88	31,077.94
026	L	230 kv line-230/115/69-sub (16)	289,131.92	251,375.91	37,756.01	1,259.11
031	L	115 kv line Logan to Kenmare	3,115,809.17	2,237,622.07	878,187.10	15,613.59
032	L	115 kv line Logan to Mallard	632,973.09	439,732.23	193,240.86	3,051.83
034	L	230 kv line Philip Tap-Philip Sub	853,709.18	770,034.98	83,674.20	2,418.96
127	L	345 kv N line #1 dbl circ	12,390,820.64	5,268,575.34	7,122,245.30	217,946.24
128	L	345 kv S line #2 dbl circ	11,215,380.84	5,706,991.88	5,508,388.96	161,915.74
129	L	500 kv AVS switchyd to SD bdr	57,926,564.63	30,122,971.31	27,803,593.32	852,932.22
130	L	500 kv SD bdr to Broadland sub	53,098,065.54	27,499,683.57	25,598,381.97	778,666.40
134	L	345 kv dbl circ line	942,053.08	651,519.04	290,534.04	10,018.42
141	L	230 kv line Broadland to Huron	1,068,624.71	582,658.54	485,966.17	16,505.22
150	L	230 kv line Estavan to Sask bdr	15,071,877.15	10,636,145.06	4,435,732.09	119,132.20
152	L	345 kv line AVS to Charlie Creek	11,657,031.39	6,269,656.88	5,387,374.51	156,830.94
181	L	230 KV Line - Rhame to Belfield	28,337,329.04	1,303,649.69	27,033,679.35	751,228.20
185	L	230 kv line MC-Bowman-NU	9,481,899.87	8,013,385.42	1,468,514.45	271,110.36
234	L	115Kv Line-Char Ck-Sqw Gab Sub	1,218,283.33	104,177.13	1,114,106.20	33,506.95
235	L	115Kv Line-Sqw Gap-ND/MT Bordr	375,853.37	31,248.78	344,604.59	10,416.26
236	L	115Kv Line-ND/MT Brd-Richld Sb	281,423.71	23,882.30	257,541.41	7,745.61
296	L	230 kv line - Williston to Tioga	24,513,172.61	671,189.85	23,841,982.76	671,189.85
311	L	115 kv tie line to Groton sub	136,010.38	94,508.46	41,501.92	1,431.10
361	L	69KV Line Cornbelt	41,112.46	9,352.87	31,759.59	1,200.43
411	L	230 KV Line RC to New Underwood	6,010,877.21	1,184,734.48	4,826,142.73	142,952.21
		Subtotal Lines	**285,433,577.78**	**142,086,004.35**	**143,347,573.43**	**4,374,345.19**

Basin Electric Power Cooperative
Substations
December 31, 2011

013	S	230KV LO Washburn Substation	71,594.00	70,297.54	1,296.46	-
016	S	230/115/69KV LO Substation	1,234,995.25	1,148,124.52	86,870.73	2,799.70
036	S	345KV FT Thompson Substation	2,374,698.58	2,066,395.64	308,302.94	10,631.16
039	S	230/115KV Storla, SD Substation	2,207,566.00	1,849,601.55	357,964.45	12,086.64
040	S	230/115KV Philip, SD Substation	862,864.55	747,632.47	115,232.08	3,973.56
042	S	230KV Philip,SD Tap Substation	214,957.34	196,026.69	18,930.65	612.88
046	S	Martin, SD USBR Sub Capacitor Installed	200,286.98	154,660.37	45,626.61	1,573.35
047	S	Armour, SD USBR Sub Capacitor Installed	137,378.51	125,211.30	12,167.21	419.60
058	S	115KV Williston, ND Substation	643,258.54	480,194.41	163,064.13	5,622.91
060	S	230/115KV Dickinson, ND Substation	1,204,038.19	1,092,667.78	111,370.41	3,650.56
061	S	115KV Spirit Mound Switchyard	1,570,210.37	1,216,196.54	354,013.83	18,628.66
063	S	Static VAR Suppt-Victory Hill Sub-Sctbluff	1,647,966.90	1,526,257.45	121,709.45	52,163.04
126	S	500KV Broadland SD, Substation	12,470,253.59	6,787,401.58	5,682,852.01	194,671.81
142	S	230KV USBR Huron Substation Addition	1,682,292.13	903,020.47	779,271.66	26,871.45
145	S	Manning,ND Sub Capacitor Installed	186,622.67	156,391.17	30,231.50	1,591.12
153	S	345/115KV Charlie Creek Substation	5,342,496.23	3,787,554.30	1,554,941.93	52,055.01
179	S	Little Missouri Tap 115 kv Capacitor Bank	1,244,508.58	74,213.82	1,170,294.76	34,252.53
182	S	230 kv Belfield Substation	25,732.14	1,239.03	24,493.11	708.08
183	S	230 kv Rhame Substation	6,014,030.40	329,036.61	5,684,993.79	175,508.54
194	S	Bowman Sub -230 KV breakers	1,393,433.08	343,248.78	1,050,184.30	36,213.25
195	S	Hettinger Capacitors	827,734.55	183,944.70	643,789.85	22,789.02
196	S	Baker Capacitors	827,734.58	183,944.70	643,789.88	22,789.02
278	S	230 kV Sully Butte Sub (Shunt)	1,435,657.18	33,156.06	1,402,501.12	33,156.06
279	S	230 kV Glenham Sub (Shunt)	2,768,063.80	25,395.14	2,742,668.66	25,395.14
295	S	230/115kV Blaisdell Substation	200,195.00	-	200,195.00	-
297	S	230 kv Neset (Tioga) Substation (T3)	9,577,299.17	608,785.56	8,968,513.61	282,032.08
299	S	230Kv Willistn Sub Transformer	2,736,411.38	6,276.17	2,730,135.21	6,276.17
310	S	345/115KV Groton Substation Addition	5,019,758.71	3,316,731.52	1,703,027.19	56,452.43
314	S	Groton 115kv Capacitor Banks	2,284,013.51	157,115.33	2,126,898.18	73,341.32
325	S	230 mw Miles City DC Tie	18,989,385.85	13,732,225.20	5,257,160.65	525,716.06
362	S	69KV Substation - Cornbelt	1,557,920.14	356,577.17	1,201,342.97	45,765.46
408	S	RC Tie East Interconnect	1,060,552.13	241,849.60	818,702.53	29,152.61
470	S	Groton Clutch	2,004,077.40	344,693.75	1,659,383.65	59,432.05
550	S	115 kV Ordway Substation	2,244,766.81	89,151.06	2,155,615.75	57,196.66
711	S	230KV LO #1 Switchyard and AVS Addition	5,087,828.39	4,313,146.71	774,681.68	26,713.20
720	S	345/230KV LO#2 Switchyard and AVS Add	16,128,277.37	10,937,642.09	5,190,635.28	178,987.46
734	S	Tioga substation - Capacitor bank	387,866.07	200,827.41	187,038.66	6,449.61
735	S	345/230KV Watertown Substation	2,871,896.05	2,614,172.04	257,724.01	8,887.05
737	S	230/115KV Logan Substation & Sask Addition	4,115,005.36	3,138,616.72	976,388.64	30,453.32
767	S	345KV AVS Switchyard & Charlie Creek Add't	24,808,017.77	13,745,758.00	11,062,259.77	381,457.30
		Subtotal Substation	**145,661,645.25**	**77,285,380.95**	**68,376,264.30**	**2,506,475.87**

Basin Electric Power Cooperative
Maintenance Buildings and Microwave
December 31, 2011

070	TSM	Mandan Transmission Maint Bldg	7,935,672.66	5,422,957.09	2,512,715.57	307,050.73
071	TSM	Gettysburg Trans Maint Bldg	1,212,753.85	1,078,829.17	133,924.68	46,169.95
072	TSM	Groton Trans Maint Bldg	2,238,314.05	1,611,455.97	626,858.08	167,606.55
109	TSM	Logan Trans Maint Bldg	1,698,373.57	1,218,679.52	479,694.05	86,286.25
119	TSM	Broadland Trans Maint Bldg	1,213,203.72	1,068,604.62	144,599.10	18,884.94
120	TSM	AVS Plantsite Trans Maint Bldg	4,232,677.74	3,400,249.73	832,428.01	111,645.34
		Subtotal TSM	**18,530,995.59**	**13,800,776.10**	**4,730,219.49**	**737,643.76**
043	M	Microwave - North Dakota	10,619,075.55	7,985,093.46	2,633,982.09	496,628.28
044	M	Microwave -South Dakota	4,913,744.26	4,171,483.27	742,260.99	236,474.16
136	M	Microwave - SD AVS	897,056.02	835,481.25	61,574.77	32,871.70
137	M	Microwave - AVS	2,175,315.11	1,434,539.71	740,775.40	105,124.72
139	M	Microwave - ND Sask	1,340,021.64	1,282,313.09	57,708.55	50,493.60
155	M	Microwave - ND CC	1,061,358.36	1,010,019.38	51,338.98	40,166.83
308	M	Microwave - SD Groton	143,258.75	142,654.01	604.74	6,570.12
		Subtotal Microwave	**21,149,829.69**	**16,861,584.17**	**4,288,245.52**	**968,329.41**
		Microwave Adjustment	(8,202,273.50)	(6,539,216.96)	(1,663,056.54)	(375,535.06)
		Total Microwave	**12,947,556.19**	**10,322,367.21**	**2,625,188.98**	**592,794.35**
		Accumulated Depreciation Adjustment		(10,025,312.70)		
		TOTAL IS TRANSMISSION	**462,573,774.81**	**233,469,215.91**	**229,104,558.90**	**8,211,259.17**

Basin Electric's Ancillary Services Cost Data

Basin Electric Power Cooperative
IS Ancillary Services
Regulation and Frequency Response - Estimate 2013

Summary

A	Total LOS and AVS Net Plant Investment	528,761,766	(ancillary worksheet 1)
B	Facilities with AGC (LOS 1 & AVS)	419,658,693	(Ancillary worksheet 1 less LOS 2)
C	B/A	79.366%	
D	AGC Facilities	42,952	
E	AGC Facilities Percentage (D/B)	0.0102%	
F	Generation Revenue Requirement	218,525,866	(Generation revenue require LO#1 and AVS)
G	Plant Allocated to AGC	22,290	(E x F)
H	Regulation Revenue Requirement	**65,242**	(D + G)

Basin Electric Power Cooperative
Generation Plant
December 31, 2011

	LO #1	LO #2	AVS #065	AVS #066	LRS #006	LRS #007	LRS #008	DFS	SM	Groton	Other 340-347	Total
Gross Plant - Production	102,169,104	230,438,230	653,101,292	220,039,191	186,743,387	180,196,490	207,738,240	1,272,336,964	24,930,271	125,969,639	161,839,717	3,365,502,525
Accum Depr - Production	(69,111,481)	(123,130,931)	(376,796,256)	(117,966,848)	(125,784,209)	(116,467,374)	(134,032,684)	(6,573,128)	(23,282,958)	(16,280,433)	(21,740,445)	(1,131,166,748)
Accum Depr - Adjustment	1,007,940	1,795,773	5,495,293	1,720,459	1,834,469	1,698,590	1,954,767				79,593	15,586,884
Net Book (RUS 310-349)	**34,065,563**	**109,103,072**	**281,800,329**	**103,792,802**	**62,793,647**	**65,427,706**	**75,660,323**	**1,265,763,836**	**1,647,313**	**109,689,206**	**140,178,865**	**2,249,922,661**

Revenue Requirement Worksheet
RUS Form 12
BASIN ELECTRIC POWER COOPERATIVE

For the twelve months ended 12/31/2011

	East	Other
GROSS REVENUE REQUIREMENT	$ 276,108,823	$ 203,508,698
Percent of revenue requirement to Net Plant	42.365%	

Total Production	(6) LO #1	(7) LO #2	(8) AVS #065	(9) AVS #066	(10) SMS	(11) Groton	(12) Other
$479,617,521	$ 32,183,884	$ 41,377,806	$106,208,511	$ 80,133,471	$ 1,397,340	$ 14,807,811	$ 203,508,698

Revenue Requirement Worksheet
RUS Form 12
BASIN ELECTRIC POWER COOPERATIVE

For the twelve months ended 12/31/2011

Line #	(1)	(2) Worksheets	(3)	(4) Allocator A		(5) Total Production	(4a) Allocator B		(6) LO #1	(7) LO #2	(8) AVS #065	(9) AVS #066	(10) SMS	(11) Groton	(12) Other
	GROSS PLANT IN SERVICE														
1	Production (Note A)	12h.A.6.e	3,365,502,527	NA	100.000%	3,365,502,527	NA	100.000%	102,169,104	230,438,230	653,101,292	220,039,191	24,930,271	125,969,639	2,008,854,799
2	Transmission	12h.A.11.e & 12h.A.23.e	688,758,703	DA	N/A	-	DA	N/A	-	-	-	-			-
3	Distribution	12h.A.16.e	-	NA	0.000%	-	NA	0.000%	-	-	-	-			-
4	General	12h.A.18.e	146,146,916			-			-	-	-	-			-
4a	Direct Assign - Transmission (Note B)		36,293,606	DA	N/A	-	DA	N/A	-	-	-	-			-
4b	Direct Assign - Production		41,860,630	NA	100.000%	41,860,630	NA	100.000%	7,326,449	7,326,449	6,256,741	6,256,741	261,844	544,648	13,887,759
4c	Other		67,992,679	WS	88.549%	60,206,688	WS	Gross Plant	1,827,740	4,122,393	11,683,565	3,936,360	445,987	2,253,516	35,937,128
5	Intangible	12h.A.1.e	78,046,322	DA	100.000%	8,945,757	DA	100.000%	-	-	524,573	524,573	-	-	7,896,612
6	TOTAL GROSS PLANT (sum lines 1,2,4,5)	12h.A.18.e & 12h.A.24.e	$ 4,278,454,467			$ 3,476,515,602			111,323,293	241,887,072	671,566,170	230,756,864	25,638,102	128,767,804	2,066,576,298
							GP1	Gross Plant	3.036%	6.847%	19.406%	6.538%	0.741%	3.743%	59.690%
	ACCUMULATED DEPRECIATION														
7	Production	12h.B.1-4.f	1,115,579,864	NA	100.000%	1,115,579,864	NA	0.000%	68,103,541	121,335,158	371,300,963	116,246,389	23,282,958	16,280,433	399,030,421
8	Transmission	12h.B.5.f & 12h.B.15.f	284,358,449	DA	100.000%	-	DA	100.000%	-	-	-	-			-
9	Distribution	12h.B.6.f	-	NA	0.000%	-	NA	0.000%	-	-	-	-			-
10	General	12h.B.7.f	104,269,150			-			-	-	-	-			-
10a	Direct Assign - Transmission		23,086,020	DA	0.000%	-	DA	0.000%	-	-	-	-			-
10b	Direct Assign - Production		32,732,960	NA	100.000%	32,732,960	DA	100.000%	5,782,114	5,782,114	5,995,852	5,995,852	243,355	240,484	8,693,189
10c	Other		48,450,170	WS	88.549%	42,902,034	GP1	Gross Plant	1,302,409	2,937,531	8,325,465	2,804,969	317,801	1,605,809	25,608,050
11	Intangible	12h.B.12.f	49,339,867	DA	100.000%	1,189,465	DA	100.000%	-	-	157,372	157,372	-	-	874,721
12	TOTAL ACCUM. DEPR (sum lines 7,8,10,11)	12h.B.18.f less 12h.B.14.f	$ 1,553,547,330			$ 1,192,404,323			75,188,065	130,054,803	385,779,653	125,204,582	23,844,113	18,126,726	434,206,382
	NET PLANT IN SERVICE														
13	Production	(line 1- line 7)	2,249,922,663	AUTO		2,249,922,663	AUTO		34,065,563	109,103,073	281,800,328	103,792,802	1,647,313	109,689,206	1,609,824,378
14	Transmission	(line 2- line 8)	404,400,254	AUTO		-	AUTO		-	-	-	-		-	-
15	Distribution	(line 3 - line 9)	-	AUTO		-	AUTO		-	-	-	-		-	-
16	General	(line 4 - line 10)	41,877,766	AUTO		-	AUTO		-	-	-	-		-	-
16a	Direct Assign	(line 4a - line 10a)	13,207,587	AUTO		-	AUTO		-	-	-	-		-	-
16b	Production	(line 4b - line 10b)	9,127,669	AUTO		9,127,669	AUTO		1,544,335	1,544,335	260,888	260,888	18,490	304,164	5,194,570
16c	Other	(line 4c - line 10c)	19,542,510	AUTO		17,304,654	AUTO		525,330	1,184,861	3,358,099	1,131,392	128,186	647,707	10,329,078
17	Intangible	(line 5 - line 11)	28,706,454	AUTO		7,756,292	AUTO		-	-	367,201	367,201	-	-	7,021,890
18	TOTAL NET PLANT (sum lines 13, 14, 16, 17)		$ 2,724,907,137			$ 2,284,111,279			$ 36,135,228	$ 111,832,269	$ 285,786,517	$ 105,552,283	$ 1,793,989	$ 110,641,077	$ 1,632,369,916
	WORKING CAPITAL														
19	CWC (Note C)	one eighth of line 9, page 3	37,436,847	DA	100.000%	36,479,860	DA	100.000%	3,439,624	3,728,927	9,582,947	8,606,201	140,068	532,548	10,449,545
20	Materials & Supplies Production	12h, Section G, L3, C.d.	42,280,575	DA	100.000%	42,280,575	GP1	Gross Plant	1,283,543	2,894,980	8,204,866	2,764,337	313,197	1,582,548	25,237,104
21	Prepayments (Note C)	12a Section B. L 25		GP1	0.000%	-	GP1	Gross Plant							
22	TOTAL WORKING CAPITAL (sum lines 19-21)		$ 79,717,422			$ 78,760,435			$ 4,723,167	$ 6,623,907	$ 17,787,813	$ 11,370,538	$ 453,265	$ 2,115,096	$ 35,686,649
23	Rate Base		$ 2,804,624,559			$ 2,362,871,714			$ 40,858,395	$ 118,456,175	$303,574,330	$ 116,922,821	$ 2,247,254	$112,756,173	$1,668,056,565

Revenue Requirement Worksheet
RUS Form 12
BASIN ELECTRIC POWER COOPERATIVE

For the twelve months ended 12/31/2011

Line No	(1)	(2) Reference	(3) Company Total	(4) Allocator A		(5) Total Production	(4a) Allocator B		(6) LO #1	(7) LO #2	(8) AVS #065	(9) AVS #066	(10) SMS	(11) Groton	(12) Other
	O&M														
1	Production Plant (Note D)	RUS 12a, L5 & L16	239,053,138	DA	100.000%	239,053,138	DA	100.000%	25,673,502	25,673,502	64,879,329	64,879,329	670,714	1,987,449	55,289,312
2	Direct Assignment	Accounting Records	-	NA	0.000%	-	NA	0.000%	-	-	-	-			
3	Other	Accounting Records	-	TPW	100.000%	-	GP1	Gross Plant	-	-	-	-			-
4	A&G	RUS 12a, Section A, L.13 C.b.	60,441,639			-									
5	Less Regulatory Fees (Note E)	Accounting Records	155,664	NA	0.000%	-	NA	0.000%	-	-	-	-			-
6	Production	Accounting Records	2,429,453	DA	100.000%	2,429,453	NA	0.000%	-	-	-	-			2,429,453
7	Transmission (Note F)	Accounting Records	988,101	N/A	0.000%	-	N/A	page 4	-	-	-	-			
8	Headquarters (Note G)		56,868,420	WS	88.549%	50,356,292	GP2	Gross Plant	1,843,490	4,157,917	11,784,245	3,970,281	449,830	2,272,936	25,877,594
9	TOTAL O&M (sum lines 1 and 4)	Expense Worksheet	$ 299,494,777			$ 291,838,884			$ 27,516,992	$ 29,831,419	$ 76,663,575	$ 68,849,611	$ 1,120,544	$ 4,260,385	$ 83,596,359
	DEPRECIATION & AMORTIZATION EXPENSE														
10	Depreciation and Amortization Expense	12a, Section A, L22 C.b.	55,918,563												
11	Transmission	Accounting Records	12,146,615	NA	0.000%	-	NA	0.000%							
12	Production	Accounting Records	43,771,948	DA	100.000%	43,771,948	DA	100.000%	1,497,643	3,756,376	10,782,736	3,745,883	117,105	3,825,250	20,046,955
13	General Plant	Accounting Records	8,786,591	NA	0.000%	-	NA	0.000%							-
14	Transmission	Accounting Records	2,003,622	NA	0.000%	-	NA	0.000%							-
15	Production	Accounting Records	3,438,691	DA	100.000%	3,438,691	DA	100.000%	705,758	705,758	526,771	526,771	7,205	60,976	905,450
16	Other General Plant		3,344,278	WS	88.549%	2,961,317	GP1	Gross Plant	89,899	202,763	574,666	193,613	21,936	110,841	1,767,598
17	Other Amortization		2,257,826	DA	100.000%	340,064	DA	100.000%			25,180	25,180	-	-	289,705
18	TOTAL (Sum lines 10,13,17)	12a, Section A, L22 C.b.	$ 66,952,980			$ 50,512,020			$ 2,293,300	$ 4,664,697	$ 11,909,352	$ 4,491,447	$ 146,246	$ 3,997,067	$ 23,009,709
	TAXES OTHER THAN INCOME TAXES														
19	PLANT RELATED														
20	Property total	2011 12a A 21 (less income tax)													
21	Tax Reclassification	Accounting Records		NA	0.000%	-	NA	0.000%							
22	Gross Receipts (Note H)	2010 RUS Form 12	2,827,042	NA	0.000%	-	DA	100.000%	-	-	-	-			-
23	Production			NA	0.000%		NA	0.000%	-	-	-	-			-
24	TOTAL OTHER TAXES		$ 2,827,042			$ -			$ -	$ -	$ -	$ -			$ -
25	TOTAL OPERATING EXPENSES (Sum 9+18+24)		$ 369,284,799			$ 342,350,903			$ 29,810,292	$ 34,496,316	$ 88,572,927	$ 73,341,058	$ 1,266,790	$ 8,257,452	$ 106,606,068
26	Return		$ 162,929,423	WCC	Rate Base	$ 137,266,617	WCC	Rate Base	$ 2,410,645	$ 6,988,914	$ 17,910,885	$ 6,898,446	$ 132,588	$ 6,652,614	$ 98,415,337
27	REV. REQUIREMENT (sum lines 25+26)		$ 532,214,222			$ 479,617,521			$ 32,183,884	$ 41,377,806	$ 106,208,511	$ 80,133,471	$ 1,397,340	$ 14,807,811	$ 203,508,698

A & G Allocation

WAGES AND SALARY ALLOCATOR (W/S)

Line #	(1) From Accounting Report	(2)	(3) TOTAL	(4) Allocator	(5) Percent
1	Production	Accounting Records	43,138,062	WS	88.549%
2	Transmission-East	Accounting Records	233,300	GP2	
3	Transmission-West	Accounting Records	406,532		
4	Transmission-Allocated	Accounting Records	4,938,826		
5	Distribution				
6	Other Transmission		-		
7	Total Wages and Salaries (sum lines 1-6) (exclude adm)		$48,716,721		

			(6) LO #1	(7) LO #2	(8) AVS #065	(9) AVS #066	(10) SMS	(11) Groton	(12) Other
Gross Plant		GP1	3.036%	6.847%	19.406%	6.538%	0.741%	3.743%	59.690%
(No MBPP)	%	GP2	3.661%	8.257%	23.402%	7.884%	0.893%	4.514%	51.389%

Note I	Weighted Cost of Capital		Percent	Rate	Weighted cost
12a. B L 46 & L 52	LTD	3,215,026,187	74.23%	4.18%	3.11%
12a. B L 39	Equity	1,116,018,211	25.77%	10.85%	2.80%
		4,331,044,398	100.00%		5.90%

Note
A Line 1, page 2 excludes $1,922,004 and is included in line 2, page 2.
Accumulated Depreciation for 275,097, associated with the $1,922,004 is excluded in line 7 and added to line 8.
B General Plant directly assigned to production includes the common facilities and microwave assigned to production
C Cash working capital assigned to production is one eighth of O&M allocated to production on page 3 , line 9, column 6-10
Prepayments are the electric related prepayments booked to Account No. 165 and reported on Section B, line 24, on the RUS 12 form.
D Costs assigned to plant based on RUS Forms 12 D and 12 F.
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.
G MBPP plant is excluded in the percentage calculations on page 4, GP2, as A&G costs on page 2 line 8 are directly allocated to MBPP.
H SD Gross receipts taxes paid in lieu of property with a portion directly assigned to Common Use System (CUS).
Payroll taxes are included in the RUS 500 series of accounts along with the labor costs.
I Equity percent as a percent of total long term debt plus current portion of long term debt plus equity.

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 12/31/2013

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$ 827,565
	REVENUE CREDITS	(Note P)				
2	Account No. 454	(page 4, line 30)	24,879	TP	0.53026	$13,192
3	Account No. 456.1	(page 4, line 33)	0	TP	0.53026	0
4	Revenue From Existing Transmission Agreements		0	NA	1.00000	0
5	Transmission Service Credits		0	NA	1.00000	0
6	TOTAL REVENUE CREDITS					13,192
	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 814,373

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Annual Transmission Revenue Requirement

For the 12 months ending 12/31/2013

Heartland Consumers Power District

Line No.	(1) RATE BASE:		(2) Reference	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	GROSS PLANT IN SERVICE						
1	Production	Schedule A		43,846,047	NA		
2	Transmission	Schedule A		14,855,074	TP	0.53026	7,877,052
3	Distribution			0	NA		
4	General & Intangible	Schedule A		6,637,865	W/S	0.06890	457,349
5	Common			0	CE	0.06890	0
6	TOTAL GROSS PLANT (sum lines 1-5)			65,338,986	GP=	12.756%	8,334,401
	ACCUMULATED DEPRECIATION						
7	Production	Schedule A		32,585,675	NA		
8	Transmission	Schedule A		11,697,162	TP	0.53026	6,202,537
9	Distribution			0	NA		
10	General & Intangible	Schedule A		2,978,814	W/S	0.06890	205,240
11	Common			0	CE	0.06890	0
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)			47,261,651			6,407,777
	NET PLANT IN SERVICE						
13	Production	(line 1- line 7)		11,260,372			
14	Transmission	(line 2- line 8)		3,157,912			1,674,515
15	Distribution	(line 3 - line 9)		0			
16	General & Intangible	(line 4 - line 10)		3,659,051			252,109
17	Common	(line 5 - line 11)		0			0
18	TOTAL NET PLANT (sum lines 13-17)			18,077,335	NP=	10.658%	1,926,624
	ADJUSTMENTS TO RATE BASE (Note A)						
19	Account No. 281 (enter negative)			0		zero	0
20	Account No. 282 (enter negative)			0	NP	0.10658	0
21	Account No. 283 (enter negative)			0	NP	0.10658	0
22	Account No. 190			0	NP	0.10658	0
23	Account No. 255 (enter negative)			0	NP	0.10658	0
24	TOTAL ADJUSTMENTS (sum lines 19 - 23)			0			0
25	LAND HELD FOR FUTURE USE (Note B)			0	TP	0.53026	0
	WORKING CAPITAL (Note C)						
26	CWC			472,153			52,361
27	Materials & Supplies (Note B)			0	TE	1.00000	0
28	Prepayments	Schedule A		366,803	GP	0.12756	46,789
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)			838,956			99,150
30	RATE BASE (sum lines 18, 24, 25, and 29)			18,916,291			2,025,774

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Annual Transmission Revenue Requirement

For the 12 months ending 12/31/2013

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	230,905	TE	1.00000	230,905
1a	Less LSE Expenses included in Transmission O&M Accounts (Note D)		0		1.00000	0
2	Less Account 565	Schedule A	60,533	NA	1.00000	60,533
3	A&G (Note G)	Schedule A	3,606,855	W/S	0.06890	248,512
4	Less FERC Annual Fees		0	W/S	0.06890	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad(Note E)		0	W/S	0.06890	0
5a	Plus Transmission Related Reg. Comm. Exp. (Note E)		0	TE	1.00000	0
6	Common		0	CE	0.06890	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)		3,777,227			418,884
	DEPRECIATION EXPENSE					
9	Transmission	Schedule A	394,344	TP	0.53026	209,105
10	General	Schedule A	156,003	W/S	0.06890	10,749
11	Common		0	CE	0.06890	0
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		550,347			219,854
	TAXES OTHER THAN INCOME TAXES (Note F)					
	LABOR RELATED					
13	Payroll	Schedule A	92,114	W/S	0.06890	6,347
14	Highway and vehicle		0	W/S	0.06890	0
15	PLANT RELATED					
16	Property	Schedule A	199,770	GP	0.12756	25,483
17	Gross Receipts		0	NA	zero	0
18	Other		0	GP	0.12756	0
19	Payments in lieu of taxes		0	GP	0.12756	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		291,884			31,830
	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	0.10658	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 24)]		1,466,013	NA		156,997
29	REV. REQUIREMENT (sum lines 8, 12,20,27,28)		6,085,471			827,565

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Annual Transmission Revenue Requirement

For the 12 months ending 12/31/2013

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)							14,855,074	
2	Less transmission plant excluded from IS rates (Note H)							6,752,305	
3	Less transmission plant included in OATT Ancillary Services (Note I)							225,659	
4	Transmission plant included in IS rates (line 1 less lines 2 & 3)							7,877,110	
5	Percentage of transmission plant included in IS Rates (line 4 divided by line 1)						TP=	0.53026	
	TRANSMISSION EXPENSES								
6	Total transmission expenses (page 3, line 1, column 3)							230,905	
7	Less transmission expenses included in OATT Ancillary Services (Note J)							0	
8	Included transmission expenses (line 7 less line 6)							230,905	
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	0.53026	
11	Percentage of transmission expenses included in IS Rates (Note K)						TE=	1.00000	
	WAGES & SALARY ALLOCATOR (W&S)		$	TP	Allocation				
12	Production		1,155,783	0.00	0				
13	Transmission		172,703	0.53	91,533				
14	Distribution		0	0.00	0			W&S Allocator	
15	Other		0	0.00	0			($ / Allocation)	
16	Total (sum lines 12-15)		1,328,486		91,533		=	0.06890	= W/S
	COMMON PLANT ALLOCATOR (CE) (Note L)		$		% Electric (line 17 / line 20)			Labor Ratio (line 16)	CE
17	Electric	Schedule A	65,338,986		1.00000	*		0.06890 =	0.06890
18	Gas		0						
19	Water		0						
20	Total (sum lines 17-19)		65,338,986						
	RETURN (R)		$						
21	Long Term Interest	Schedule A	$2,217,394						
			$	%	Cost (Note M)			Weighted	
22	Long Term Debt	Schedule A	32,255,351	84%	6.87%			0.0577	=WCLTD
23	Proprietary Capital	Schedule A	5,953,799	16%	12.38%			0.0198	
24	Total (sum lines 22, 23)		38,209,150	100%				0.0775	=R
25					Proprietary Capital Cost Rate =			12.38%	
26					TIER =			1.13	
	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)							$24,879	
	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	

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Annual Transmission Revenue Requirement

For the 12 months ending 12/31/2013

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

Missouri River Energy Services
Facility Credits

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

First Revised Sheet No. 2634
Superseding Original Sheet No. 2634

Attachment O-MRES
Page 1 of 5

Formula Rate - Non-Levelized
Clean Version

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/2013

MRES

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 31)					$ 6,774,112
	REVENUE CREDITS	(Note T)				
2	Account No. 454	(page 4, line 34)	135,156	TP	1.00000	135,156
3	Account No. 456.1	(page 4, line 37)	0	TP	1.00000	0
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)					135,156
6a	Historic Year Actual ATRR					-
6b	Historic Year Projected ATRR					-
6c	Historic Year ATRR True-Up	(line 6a - line 6b)				-
6d	Historic Year Actual Divisor					-
6e	Historic Year Projected Divisor					-
6f	Difference in Divisor	(line 6e- line 6d)				-
6g	Historic Year Projected Annual Cost ($/kW/Yr)					-
6h	Historic Year Divisor True-Up	(line 6f * line 6g)				-
6i	Interest on Historic Year True-Up					-
7	NET REVENUE REQUIREMENT	(line1 - line 6 + Line 6c+ line 6h+ line 6i)				$ 6,638,956
	DIVISOR					
8	Average of 12 coincident system peaks for requirements (RQ) service			(Note A)		674,154
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 S)					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)					674,154
16	Annual Cost ($/kW/Yr)	(line 7 / line 15)	9.848			
17	Network & P-to-P Rate ($/kW/Mo) (line 11 / 12)		0.821			
			Peak Rate			Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	0.189			$0.189
19	Point-To-Point Rate ($/kW/Day)	(line 16 / 260; line 16 / 365)	0.038	Capped at weekly rate		$0.027
20	Point-To-Point Rate ($/MWh)	(line 16 / 4,160; line 16 / 8,760 times 1,000)	2.367	Capped at weekly and daily rates		$1.124
21	FERC Annual Charge ($/MWh)	(Note E)	$0.000 Short Term			$0.000 Short Term
			$0.000 Long Term			$0.000 Long Term
22						

Issued by: Stephen G. Kozey, Issuing Officer
Issued on: January 15, 2009
Midwest ISO
FERC Electric Tariff, Fourth Revised Volume No. 1

Effective: January 6, 2009

First Revised Sheet No. 2635
Superseding Original Sheet No. 2635

Attachment O-MRES
Page 2 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/2013

MRES

Line No.	(1) RATE BASE:	(2) EIA 412 Reference	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	GROSS PLANT IN SERVICE (Note AA and Note GG)					
1	Production	IV.6.e	290,996,829	NA		
2	Transmission	IV.7.e less Line 2a	67,249,702	TP	1.00000	67,249,702
2a	Transmission for projects with FERC approved incentives (Note EE)		3,276,290	TP	1.00000	3,276,290
3	Distribution	IV.8.e	0	NA		
4	General & Intangible	IV.1e and IV.9.e	24,421,984	W/S	0.14706	3,591,497
5	Common		0	CE	0.14706	0
6	TOTAL GROSS PLANT (sum lines 1-5)		385,944,805	GP=	19.204%	74,117,489
	ACCUMULATED DEPRECIATION (Note AA and Note GG)					
7	Production		180,261,837	NA		
8	Transmission		34,427,321	TP	1.00000	34,427,321
8a	Transmission for projects with FERC approved incentives (Note EE)		0	TP	1.00000	0
9	Distribution		0	NA		
10	General & Intangible		15,046,472	W/S	0.14706	2,212,734
11	Common		0	CE	0.14706	0
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		229,735,630			36,640,055
	NET PLANT IN SERVICE (Note GG)					
13	Production	(line 1- line 7)	110,734,992			
14	Transmission	(line 2- line 8)	32,822,381			32,822,381
14a	Transmission for projects with FERC approved incentives (Line 2a - line 8a) (Note EE)		3,276,290			3,276,290
15	Distribution	(line 3 - line 9)	0			
16	General & Intangible	(line 4 - line 10)	9,375,512			1,378,763
17	Common	(line 5 - line 11)	0			0
18	TOTAL NET PLANT (sum lines 13-17)		156,209,175	NP=	23.992%	37,477,434
18a	CWIP for projects with FERC approved incentives (Note CC and Note GG)		45,928,852	NA	1.00000	45,928,852
	ADJUSTMENTS TO RATE BASE (Note F)					
19	Account No. 281 (enter negative)		0		zero	0
20	Account No. 282 (enter negative)		0	NP	0.23992	0
21	Account No. 283 (enter negative)		0	NP	0.23992	0
22	Account No. 190		0	NP	0.23992	0
23	Account No. 255 (enter negative)		0	NP	0.23992	0
23a	Unamortized balance of Abandoned Plant (Note DD and Note GG)		0	NA	1.00000	0
24	TOTAL ADJUSTMENTS (sum lines 19 - 23)		0			0
25	LAND HELD FOR FUTURE USE (Note GG)	IV.12.e (Note G)	0	TP	1.00000	0
	WORKING CAPITAL	(Note H)				
26	CWC		1,523,723			667,084
27	Materials & Supplies (Note GG)	(Note G)	286,000	TE	0.98515	281,753
28	Prepayments (Note GG)	II.20.b	2,000,000	GP	0.19204	384,080
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		3,809,723			1,332,917
30	RATE BASE earning ACSR (lines 18+24+25+29-14a-23a)		156,742,608			35,534,061
30a	RATE BASE earning HCSR (lines 14a+18a+23a)		49,205,142			49,205,142

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Issued on: January 15, 2009

Effective: January 6, 2009

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

Third Revised Sheet No. 2636
Superseding Second Revised Sheet No. 2636
Attachment O-MRES
Page 3 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/2013

Line No.	(1)	(2) EIA 412 Reference	MRES (3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M (Note BB)					
1	Transmission	VII.8.d	25,674,952	TE	0.98515	25,293,679
1a	Less LSE Expenses included in Transmission O&M Accounts (Note V)		0		1.00000	0
2	Less Account 565		21,646,236	TE	0.98515	21,324,789
3	A&G	VII.13.d	8,351,066	W/S	0.14706	1,228,108
4	Less FERC Annual Fees		0	W/S	0.14706	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		390,000	W/S	0.14706	57,353
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		200,000	TE	0.98515	197,030
6	Common		0	CE	0.14706	0
7	Transmission Lease Payments		0	NA	1.00000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less 1a, 2, 4, 5)		12,189,782			5,336,675
	DEPRECIATION AND AMORTIZATION EXPENSE (Note AA)					
9	Transmission		905,984	TP	1.00000	905,984
9a	Abandoned Plant Amortization (Note DD)		0	NA	1.00000	0
10	General & Intangible		675,156	W/S	0.14706	99,288
11	Common		0	CE	0.14706	0
12	TOTAL DEPRECIATION (sum lines 9 - 11)		1,581,140			1,005,272
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll		0	W/S	0.14706	0
14	Highway and vehicle		0	W/S	0.14706	0
15	PLANT RELATED					
16	Property		1,697,067	GP	0.19204	325,905
17	Gross Receipts		0	NA	zero	0
18	Other		0	GP	0.19204	0
19	Payments in lieu of taxes		0	GP	0.19204	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		1,697,067			325,905
	INCOME TAXES	(Note K)		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 22) and R= (page 4, line 24)					
	and FIT, SIT & p are as given in footnote K.					
23	1 / (1 - T) = (from line 21)		0.0000			
24	Amortized Investment Tax Credit (266.8f) (enter negative)		0			
25	Income Tax Calculation = line 22 * line 28		0	NA		0
26	ITC adjustment (line 23 * line 24)		0	NP	0.23992	0
27	Total Income Taxes	(line 25 plus line 26)	0			0
28	RETURN from ACSR [Rate Base (page 2, line 30 + 30a) * Rate of Return (page 4, line 24)]		15,857,977	NA		6,524,919
28a	RETURN from HCSR [Rate Base (page 2, line 30a) * Rate of Return (page 4, line 30)]		496,972	NA		496,972
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28 and 28a)		31,822,938			13,689,743
30	LESS ATTACHMENT GG ADJUSTMENT [Attachment GG, page 2, line 3, column 10] (Note W) [Revenue Requirement for facilities included on page 2, line 2, and also included in Attachment GG]		4,935,431			4,935,431
30a	LESS ATTACHMENT MM ADJUSTMENT [Attachment MM, page 2, line 3 column 14] (Note Y) [Revenue Requirement for facilities included on page 2, line 2 and also included in Attachment MM]		1,980,200			1,980,200
31	REVENUE REQUIREMENT TO BE COLLECTED UNDER ATTACHMENT O (line 29 - line 30 - line 30a)		24,907,307			6,774,112

Issued by: Stephen G. Kozey, Issuing Officer
Issued on: September 30, 2009

Effective: January 1, 2010

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

First Revised Sheet No. 2637
Superseding Original Sheet No. 2637
Attachment O-MRES
Page 4 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing EIA Form 412 Data

MRES

For the 12 months ended 12/31/2013

SUPPORTING CALCULATIONS AND NOTES

Line No.	Description	Reference	$	TP / %	Allocation / Cost		Amount	
	TRANSMISSION PLANT INCLUDED IN ISO RATES							
1	Total transmission plant (page 2, line 2 and 2a, column 3)						67,249,702	
2	Less transmission plant excluded from ISO rates (Note M)						0	
3	Less transmission plant included in OATT Ancillary Services (Note N)						0	
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)						67,249,702	
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)					TP=	1.00000	
	TRANSMISSION EXPENSES							
6	Total transmission expenses (page 3, line 1, column 3)						25,674,952	
7	Less transmission expenses included in OATT Ancillary Services (Note L)						381,355	
8	Included transmission expenses (line 6 less line 7)						25,293,597	
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)						0.98515	
10	Percentage of transmission plant included in ISO Rates (line 5)					TP	1.00000	
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)					TE=	0.98515	
	WAGES & SALARY ALLOCATOR (W&S)		$	TP	Allocation			
12	Production		2,474,341	0.00	0			
13	Transmission		449,120	1.00	449,120			
14	Distribution		0	0.00	0		W&S Allocator	
15	Other		130,507	0.00	0		($ / Allocation)	
16	Total (sum lines 12-15)		3,053,968		449,120	=	0.14706	= W/S
	COMMON PLANT ALLOCATOR (CE) (Note O)		$		% Electric (line 17 / line 20)		Labor Ratio (line 16)	CE
17	Electric		385,944,804		1.00000	*	0.14706 =	0.14706
18	Gas		0					
19	Water		0					
20	Total (sum lines 17-19)		385,944,804					
	ACTUAL CAPITAL STRUCTURE RETURN (ACSR)		$					
21	Long Term Interest	III.16.b + III.17.b (Note U)	$16,534,606					
			$	%	Cost (Note P)		Weighted	
22	Long Term Debt (Note GG)	II 37.b	290,141,538	70%	5.70%		0.0399	=WCLTD
23	Proprietary Capital (Note GG)	II.32.b	121,834,155	30%	0.1238		0.0371	
24	Total (sum lines 22, 23)		411,975,693	100%			0.0770	=R
25					Proprietary Capital Cost Rate =		12.38%	
26					TIER =		1.35	
	HYPOTHETICAL CAPITAL STRUCTURE RETURN (HCSR) (NOTE FF)			%	Cost (Note P)		Weighted	
27	Long Term Debt 9 (Cost of Long-term Debt from page 4, line 22)			55%	5.70%		0.0314	=WCLTD
28	Proprietary Capital (Cost of Proprietary Capital from page 4, line 25)			45%	12.38%		0.0557	
29	Total (sum lines 27, 28)			100%			0.0871	=R
30	Annual Allocation Factor for Incentive Return (line 29 minus line 24)						1.010%	
	REVENUE CREDITS						Load	
	ACCOUNT 447 (SALES FOR RESALE)							
31	a. Bundled Non-RQ Sales for Resale			(Note Q)			0	
32	b. Bundled Sales for Resale included in Divisor on page 1						0	
33	Total of (a)-(b)						0	
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)						$135,156	
	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES)							
35	a. Transmission charges for all transmission transactions						$17,821,593	
36	b. Transmission charges for all transmission transactions included in Divisor on page 1						$17,821,593	
36a	c. Transmission charges associated with Schedules 26 and 37 (Note X)						$0	
36b	d.Transsmission charges associated with Schedule 26-A (Note Z)						$0	
37	Total of (a)-(b)-(c)-(d)						$0	

Issued by: Stephen G. Kozey, Issuing Officer
Issued on: January 15, 2009
Midwest ISO
FERC Electric Tariff, Fourth Revised Volume No. 1

Effective: January 6, 2009

Second Revised Sheet No. 2638
Superseding First Revised Sheet No. 2638
Attachment O-MRES
Page 5 of 5
For the 12 months ended 12/31/2013

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing EIA Form 412 Data
MRES

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 412 to provide this data.

Note Letter	
A	The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of applicable pricing zone 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 applicable pricing zone coincident monthly peaks.
C	LF as defined above at time of applicable pricing zone coincident monthly peaks.
D	LF as defined above at time of applicable pricing zone coincident monthly peaks.
E	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any
F	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
G	Transmission related only.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 as shown on Schedule I of EIA Form 412.
I	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.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit. multiplied by (1/1-T) (page 3, line 26).

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)

L	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.
M	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 application of seven-factor test).
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts
P	Debt cost rate = long-term interest (line 21) / long term debt (line 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.
Q	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.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4, page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.
T	The revenues credited on page 1, lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.
U	From Reference III.17.b include only the amount from accounts 428, 429, and 430.
V	Account Nos. 561.4 and 561.8 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.
W	Pursuant to Attachment GG of the Midwest ISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment GG and recovered under Schedule 26 of the Midwest ISO Tariff.
X	Removes from revenue credits revenues that are distributed pursuant to Schedules 26 and 37 of the Midwest ISO Tariff, since the Transmission Owner's Attachment O revenue requirements have already been reduced by the Attachment GG revenue requirements.
Y	Pursuant to Attachment MM of the Midwest ISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment MM and recovered under Schedule 26-A of the Midwest ISO Tariff.
Z	Removes from revenue credits revenues that are distributed pursuant to Schedule 26-A of the Midwest ISO Tariff, since the Transmission Owner's Attachment O revenue requirements have already been reduced by the Attachment MM revenue requirements.
AA	Plant in Service, Accumulated Depreciation and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.
BB	Schedule 10-FERC charges should not be included in O&M recovered under this Attachment O.
CC	The CWIP balance on Page 2, Line 18a is the 13 month average for the transmission projects approved for included CWIP in rate base by FERC. The projects approved for 100% CWIP recovery do not include any AFUDC in the CWIP balances.
DD	Page 2, Line 23a includes any unamortized balances related to the recovery of abandoned plant costs for the projects approved by FERC. Page 3, Line 9a is the annual amortization expense of abandoned plant costs for the projects approved by FERC. No abandoned plant costs will be included until approved by FERC under a separate docket.
EE	Includes the transmission gross plant in-service (line 2a, page 2 of 5), accumulated depreciation (line 8a, page 2 of 5) and net transmission plant in-service (line 14a, page 2 of 5) for the transmission projects granted a hypothetical capital structure of 55% debt and 45% equity by FERC. These transmission plant balances do not include any AFUDC.
FF	The Hypothetical Capital Structure Return (HCSR) calculation is only applicable to the projects approved by FERC that use a hypothetical capital structure of 55% debt and 45% equity.
GG	Calculated using 13 month average balance.

Issued by: Stephen G. Kozey, Issuing Officer
Issued on: June 18, 2010

Effective: June 19, 2010

NWPS
Facility Credits

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

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT	(page 3, line 29)				$ 3,961,914
	REVENUE CREDITS	(Note T)				
2	Account No. 454	(page 4, line 34)	185,992	TP	0.85953	159,865
3	Account No. 456	(page 4, line 37)	193,445	TP	0.85953	166,271
4	Revenues from Grandfathered Interzonal Transactions		0	TP	0.85953	0
5	Revenues from service provided by the ISO at a discount		0	TP	0.85953	0
6	TOTAL REVENUE CREDITS (sum lines 2-5)					326,136
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 3,635,778
	DIVISOR					
8	Average of 12 coincident system peaks for requirements (RQ) service				(Note A)	267
9	Plus 12 CP of firm bundled sales over one year not in line 8				(Note B)	14,000
10	Plus 12 CP of Network Load not in line 8				(Note C)	0
11	Less 12 CP of firm P-T-P over one year (enter negative)				(Note D)	0
12	Plus Contract Demand of firm P-T-P over one year					0
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)					0
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)					0
15	Divisor (sum lines 8-14)					14,267
16	Annual Cost ($/kW/Yr)	(line 7 / line 15)	254.834			
17	Network & P-to-P Rate ($/kW/Mo)	(line 16 / 12)	21.236			
			Peak Rate			Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	4.901			$4.901
19	Point-To-Point Rate ($/kW/Day)	(line 18 / 5; line 18 / 7)	0.980	Capped at weekly rate		$0.700
20	Point-To-Point Rate ($/MWh)	(line 19 / 16; line 19 / 24 times 1,000)	61.258	Capped at weekly and daily rates		$29.171
21	FERC Annual Charge($/MWh)	(Note E)	$0.000	Short Term		$0.000 Short Term
22			$0.000	Long Term		$0.000 Long Term

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

Line No.	(1) RATE BASE:	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	GROSS PLANT IN SERVICE					
1	Production	206.42.g	161,113,959	NA		
2	Transmission	206.53.g	44,280,597	TP	0.85953	38,060,352
3	Distribution	206.69.g	242,808,257	NA		
4	General & Intangible	206.5.g & 83.g	12,281,284	W/S	0.08520	1,046,390
5	Common	356.1	22,410,882	CE	0.05520	1,236,981
6	TOTAL GROSS PLANT (sum lines 1-5)		482,894,979	GP=	8.355%	40,343,723
	ACCUMULATED DEPRECIATION					
7	Production	219.18-22.c	111,025,033	NA		
8	Transmission	219.23.c	23,999,288	VEst.	74.942%	17,985,465
9	Distribution	219.24.c	96,132,385	NA		
10	General & Intangible	219.25.c	2,938,423	W/S	0.08520	250,360
11	Common	356.1	6,338,969	CE	0.05520	349,883
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		240,434,097			18,585,708
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	50,088,927			
14	Transmission	(line 2- line 8)	20,281,309			20,074,887
15	Distribution	(line 3 - line 9)	146,675,872			
16	General & Intangible	(line 4 - line 10)	9,342,861			796,031
17	Common	(line 5 - line 11)	16,071,913			887,098
18	TOTAL NET PLANT (sum lines 13-17)		242,460,881	NP=	8.974%	21,758,015
	ADJUSTMENTS TO RATE BASE (Note F)					
19	Account No. 281 (enter negative)	273.8.k	0	NA	zero	0
20	Account No. 282 (enter negative)	275.2.k	-44,552,839	NP	0.08974	-3,998,094
21	Account No. 283 (enter negative)	277.9.k	0	NP	0.08974	0
22	Account No. 190	234.8.c	3,973,603	NP	0.08974	356,584
23	Account No. 255 (enter negative)	267.8.h	-1,404,221	NP	0.08974	-126,012
24	TOTAL ADJUSTMENTS (sum lines 19- 23)		-41,983,457			-3,767,522
25	LAND HELD FOR FUTURE USE	214.x.d (Note G)	0	VEst.	0.74942	0
	WORKING CAPITAL (Note H)					
26	CWC	calculated	281,655			45,651
27	Materials & Supplies (Note G)	227.6.c & .15.c	0		1.00000	0
28	Prepayments (Account 165)	111.46.d	0	GP	0.08355	0
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		281,655			45,651
30	RATE BASE (sum lines 18, 24, 25, & 29)		200,759,079			18,036,144

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

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.100.b	1,648,286	TE	0.85953	1,606,225
2	Less Account 565	321.88.b	1,348,861		1.00000	1,348,861
3	A&G	323.168.b	1,953,816	W/S	0.05520	107,842
4	Less FERC Annual Fees		0	W/S	0.05520	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		0	W/S	0.05520	0
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.85953	0
6	Common	356.1	0	CE	0.05520	0
7	Transmission Lease Payments		0		1.00000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)		2,253,241			365,206
	DEPRECIATION EXPENSE					
9	Transmission	336.7.b	1,447,976	VRB00	0.74942	1,247,062
10	General	336.9.b	720,480	W/S	0.05520	39,767
11	Common	336.10.b	1,417,010	CE	0.05520	78,213
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		3,585,465			1,365,042
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll	262.i	773,391	W/S	0.05520	42,688
14	Highway and vehicle	262.i	54,102	W/S	0.05520	2,986
15	PLANT RELATED					
16	Property	262.i	3,391,246	GP	0.08355	283,323
17	Gross Receipts	262.i	156,307	GP	0.08355	13,059
18	Other	262.i	239,415	GP	0.08355	20,002
19	Payments in lieu of taxes		0	GP	0.08355	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		4,614,461			362,058
	INCOME TAXES (Note K)					
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		35.00%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		34.76%			
	where WCLTD=(page 4, line 27) and R= (page 4, line30) and FIT, SIT & p are as given in footnote K.					
23	1 / (1 - T) = (from line 21)		1.5385			
24	Amortized Investment Tax Credit (266.8f) (enter negative)		-1,404,221			
25	Income Tax Calculation = line 22 * line 28		5,923,937	NA		532,205
26	ITC adjustment (line 23 * line 24)		-2,160,340	NP	0.08974	-193,865
27	Total Income Taxes	(line 25 plus line 26)	3,763,597			338,340
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		17,044,446	NA		1,531,269
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		31,261,210			3,961,914

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

SUPPORTING CALCULATIONS AND NOTES

Line No.	TRANSMISSION PLANT INCLUDED IN ISO RATES		
1	Total transmission plant (page 2, line 2, column 3)		44,280,597
2	Less transmission plant excluded from ISO rates (Note M)		6,220,244
3	Less transmission plant included in OATT Ancillary Services (Note N)		0
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)		38,060,352
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)	TP=	0.85953

Line No.	TRANSMISSION EXPENSES		
6	Total transmission expenses (page 3, line 1, column 3)		1,648,286
7	Less transmission expenses included in OATT Ancillary Services (Note L)		0
8	Included transmission expenses (line 6 less line 7)		1,648,286
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)		1.00000
10	Percentage of transmission plant included in ISO Rates (line 5)	TP	0.85953
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)	TE=	0.85953

WAGES & SALARY ALLOCATOR (W&S)

Line No.		Form 1 Reference	$	TP	Allocation		W&S Allocator ($ / Allocation)	
12	Production	354.18.b	2,077,203	0.00	0			
13	Transmission	354.19.b	3,379,526	0.86	2,904,793			
14	Distribution	354.20.b	26,664,340	0.00	0			
15	Other	354.21,22,23.b	7,543,789	0.00	0			
16	Total (sum lines 12-15)		39,664,858		2,904,793	=	0.07323	= WS
							0.08520	= Wsact

COMMON PLANT ALLOCATOR (CE) (Note O)

Line No.			$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	460,538,538					
18	Gas	200.3.d	150,503,744	0.75369	*	0.07323	=	0.05520
19	Water	200.3.e	0					
20	Total (sum lines 17 - 19)		611,042,283					

RETURN (R)

Line No.			$
21	Long Term Interest (117, sum of 56c through 60c)		$0
22	Preferred Dividends (118.29c) (positive number)		$ -
	Development of Common Stock:		
23	Proprietary Capital (112.14d)		0
24	Less Preferred Stock (line 28)		0
25	Less Account 216.1 (112.12d) (enter negative)		0
26	Common Stock	(sum lines 23-25)	0

Line No.		$	%		Cost (Note P)		Weighted
27	Long Term Debt (112, sum of 16d through 19d)	905,205,000	0.5131	0.0000	0.0586	0.0000	0.0301 =WCLTD
28	Preferred Stock (112.3d)	0	0.0000	0.0000	0.0000	0.0000	0.0000
29	Common Stock (line 26)	859,112,942	0.4869	0.0000	0.1125	0.0000	0.0548
30	Total (sum lines 27-29)	1,764,317,942		0.0000	0.0000	0.0000	0.0849 =R

REVENUE CREDITS

Line No.				Load
	ACCOUNT 447 (SALES FOR RESALE)	(310-311)	(Note Q)	
31	a. Bundled Non-RQ Sales for Resale (311.x.h)			106,032
32	b. Bundled Sales for Resale included in Divisor on page 1			106,032
33	Total of (a)-(b)			0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			$185,992
	ACCOUNT 456 (OTHER ELECTRIC REVENUES)	(330.x.n)		
35	a. Transmission charges for all transmission transactions			$193,445
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1			$0
37	Total of (a)-(b)			$193,445

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

Note Letter	
A	Peak as would be reported on page 401, column d of Form 1 at the time of the ISO coincident monthly peaks.
B	Labeled LF, LU, IF, IU on pages 310-311 of Form 1at the time of the ISO coincident monthly peaks.
C	Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
D	Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
E	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.
F	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 100-111 line 46 in the Form 1.
I	Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

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

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts
P	Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
Q	Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have <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	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.