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

SEP 1 3 2013

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, 2014.

Western Area Power Administration (Western) will host a meeting to provide customers an opportunity to discuss and comment on these rates on October 15, 2013, 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 Sara Baker at (406) 255-2924 or sbaker@wapa.gov before September 27, 2013, for access information. If you will attend in person, please e-mail your intention to do so to UGPISRate@wapa.gov prior to September 27, 2013.

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 $199,293,972
Firm Point-to-Point Transmission	UGP-FPT1	Maximum of $3.02/kWmonth
Non-Firm Point-to-Point Transmission	UGP-NFPT1	Maximum of 4.14 mills/kWh
Scheduling, System Control and Dispatch	UGP-AS1	$43.38/tag/day
Reactive Supply and Voltage Control from Generation Sources	UGP-AS2	$0.03/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	$0.20/kWmonth of customer load
Generator Imbalance	UGP-AS7	i) For deviations within +/- 1.5% (minimum of 2 MW) of the scheduled transaction, 100% of the average incremental cost; ii) For deviations greater than +/- 1.5% up to 7.5% (or greater than 2 MW up to 10 MW) of the scheduled transaction, 110% of incremental cost when energy delivered is less than generation scheduled and 90% of incremental cost when energy delivered is greater than scheduled; iii) For deviations greater than +/- 7.5% (or 10 MW) of the scheduled transaction, 125% of incremental cost when energy delivered is less than energy scheduled and 75% of incremental cost when energy delivered is greater than scheduled.

		As an exception, an intermittent resource will be exempt from this deviation band and will pay the deviation band charges for all deviations greater than the larger of 1.5% or 2 MW.
Penalty Rate for Unreserved Use of Transmission Service	UGP-TSP1	200% of the transmission service rate for point-to-point service assessed as follows: the penalty for a single hour will be based upon the rate for daily firm point-to-point service; the penalty for more than one assessment of a given duration (e.g. daily) will increase to the next longest duration (e.g. weekly); the penalty charge for multiple instances of unreserved use within a day will be based on the rate for daily firm point-to-point service; the penalty charge for multiple instances of unreserved use isolated to 1 calendar week would result in a penalty based on the charge for weekly firm point-to-point service; and the penalty charge for multiple instances of unreserved use during more than 1 week during a calendar month is based on the charge for monthly firm point-to-point service.

The IS Transmission Loss Factor effective January 1, 2014, 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, 2014. 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,

for Lloyd A. Linke
Operations Manager

Integrated System
Transmission and Ancillary Services
Rate Calculation

Effective January 1, 2014

Integrated System Transmission and Ancillary Services

2012 Rate True-up Calculation

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

Integrated System
Transmission and Ancillary Services
Rate Calculation

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

Integrated System Transmission and Ancillary Services Rate Calculation

Integrated System Transmission and Ancillary Service Rates

INTEGRATED SYSTEM
ANNUAL REVENUE REQUIREMENT
FOR TRANSMISSION SERVICE
Effective January 1, 2014

Line No.			Notes
1			
2			
3	**Annual IS Transmission Costs**		**Notes**
4	Basin Electric	$63,407,302	Basin Electric Revenue Requirement Template
5	Western	$123,008,724	Western Revenue Requirement Template
6	Heartland	$876,901	Heartland Revenue Requirement Template
7		$187,292,927	L4 + L5 + L6
8			
9			
10	**Transmission Customer Facility Credits**		
11		$3,274,840	MRES Revenue Requirement Template
12		$5,188,854	NWPS Revenue Requirement Template
13		$8,463,694	L11 + L12
14			
15			
16	**Annual Revenue Requirement for IS Transmission Service**		
17			
18		$195,756,621	L7 + L13
19			
20	**2012 True-up Amount**		
21		$3,542,941	2012 Rate True-up Worksheet
22			
23	**2012 Unreserved Use of Transmission Service Penalties**		
24			
25		($5,590)	2012 Unreserved Use Penalty Worksheet
26			
27	**Annual Revenue Requirement for IS Transmission Service after True-up**		
28			
29		$199,293,972	L18 + L21 + L25

INTEGRATED SYSTEM
FIRM POINT-TO-POINT RATE DESIGN
Effective January 1, 2014

Line No.				Notes
1				
2				
3	**Annual Revenue Requirement for IS Transmission Service**			**Notes**
4				
5		$199,293,972		IS Annual Revenue Requirement for
6				Transmission Service Worksheet, L29
7				
8	**IS Transmission System Total Load**			
9				
10		5,496,000	KW	IS Transmission System Total Load Estimate
11				
12				
13	**Maximum Firm Point-to-Point Transmission Rate in $/KW-Mo**			
14				
15		**$3.02 / KW-Mo**		L5 / L10 / 12 months

INTEGRATED SYSTEM
NON-FIRM POINT-TO-POINT RATE DESIGN
Effective January 1, 2014

Line No.			Notes
1			
2			
3	**Firm Point-to-Point Transmission Rate in $/KW-Mo**		**Notes**
4			
5		$3.02 / KW-Mo	IS Firm Point-to-Point Rate Design Worksheet, L15
6			
7			
8			
9	**Maximum Non-Firm Point-to-Point Transmission Rate**		
10		**4.14 Mills/KWh**	(L5 * 1000) / 730 hours per month

RATE FOR SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE FOR 2014

A.	Fixed Charge Rate	22.770%	(1)
B.	Scheduling, System Control and Dispatch Net Plant Costs ($)	$16,273,778	(2)
C.	Annual Revenue Requirement for Scheduling, System Control and Dispatch Service	$3,705,539	(A x B)
D.	2012 Number of Daily Tags	85,416	
E.	Rate for Scheduling, System Control and Dispatch Service ($/tag/day)	**$43.38**	(C / D)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual IS Transmission Costs", for 2014 Rate.

(2) Scheduling, System Control and Dispatch Plant Costs include the portion of Watertown Operations Office plant (35.417%) and communication facilities plant (66.78%) associated with Scheduling, System Control and Dispatch Service for transmission less total depreciation associated with this plant. (Reference FY 2012 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 2014
(INTEGRATED SYSTEM)

A.	WAPA Reactive Service Revenue Requirement	$2,289,895	(1)
B.	Paid to Others for Reactive Service	$0	(2)
C.	Total Reactive Revenue Requirement	$2,289,895	(A + B)
D.	Over Collection for 2012	($800,877)	(3)
E.	Total Reactive Revenue Requirement with 2012 True-up	$1,489,018	(C + D)
F.	2012 IS Transmission System Total Load (kW-Yr)	4,973,000	(4)
G.	Annual Reactive Charge ($/kW-Yr)	$0.30	(E / F)
H.	Monthly Reactive Charge ($/kW-Mo)	$0.03	(G / 12)

(1) Reactive Service Revenue Requirement from "Reactive Supply and Voltage Control from Generation Sources For 2014, Western's Costs".

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

(3) True-up Required for 2012 "True-up for 2012 Reactive Supply and Voltage Control from Generation Sources."

(4) IS Peak Transmission System Load.

RATE FOR REGULATION AND FREQUENCY RESPONSE FOR 2014

A.	Western Regulation Revenue Requirement	$2,099,496	(1)
B.	BEPC & HCPD Regulation Revenue Requirement	$50,249	(2)
C.	Total Regulation Revenue Requirement	$2,149,745	(A + B)
D.	Under Collection - 2012 Regulation Revenue Rqmt	$242,324	(3)
E.	Total Regulation Revenue Rqmt with True-up	2,392,069	(C + D)
F.	Load in Control Area(s) (kW-Yr)	3,229,000	(4)
G.	Regulation Charge ($/kW-Yr)	$0.74	(E / F)
H.	Regulation Charge ($/kW-Mo)	$0.06	(G / 12 months)

(1) Regulation and Frequency Response Service from "Regulation and Frequency Response for 2014, Western's Costs".

(2) Basin Electric cost support data.

(3) Over/Under Collection "True-up of Regulation and Frequency Response Rate for 2012"

(4) Average of monthly peaks for 2012 IS Customer Control Area.

Rate for Reserves for 2014

A.	Fixed Charge Rate		18.508%	(1)
B.	Generation Net Plant Costs	$	474,040,718	(2)
C.	Annual Cost of Generation	$	87,735,456	(A x B)
D.	Plant Capacity (kW)		2,372,000	
E.	Cost/kW ($/kW-Yr)	$	36.99	(C / D)
F.	Monthly Charge ($/kW-mo)	$	3.08	(E / 12 months)
G.	Western's Load (kW-Yr)		1,522,000	(3)
H.	Capacity used for Reserves (kW)		99,500	(4)
I.	Annual Reserves Revenue Requirement	$	3,680,505	(E x H)
J.	Annual Charge ($/kW-Yr)	$	2.42	(I /G)
K.	Monthly Charge ($/kW-mo)	$	0.20	(J /12)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Generation Revenue Requirement", for 2014 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 2012.

(4) Southwest Power Pool Reserve Sharing System.

Integrated System Load Data

2014 IS Transmission System Total Load Estimate
Transmission Rate
(MW)

5,496

2012 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	01/19/12	800	4,892	476	5,368
2	02/10/12	800	4,588	476	5,064
3	03/01/12	800	4,157	476	4,633
4	04/11/12	800	3,620	476	4,096
5	05/18/12	1600	3,925	426	4,351
6	06/27/12	1700	5,012	426	5,438
7	07/19/12	1800	5,449	426	5,875
8	08/01/12	1700	5,185	426	5,611
9	09/04/12	1700	4,427	426	4,853
10	10/25/12	2000	3,938	426	4,364
11	11/26/12	1900	4,429	426	4,855
12	12/26/12	1900	4,738	426	5,164
13					
14	**12 CP**		4,530	443	4,973

2012 IS Network Customer Control Area Load

Date	Hr End	East Control Area Load (1)	West Control Area Load (2)	Total Load
January 19, 2012	19:00	3500 MW	95 MW	3595 MW
February 10, 2012	8:00	3303 MW	79 MW	3382 MW
March 1, 2012	8:00	3060 MW	75 MW	3135 MW
April 11, 2012	8:00	2631 MW	60 MW	2691 MW
May 18, 2012	16:00	2665 MW	57 MW	2722 MW
June 27, 2012	17:00	3122 MW	92 MW	3214 MW
July 19, 2012	18:00	3373 MW	122 MW	3495 MW
August 1, 2012	17:00	3322 MW	107 MW	3429 MW
September 4, 2012	17:00	3178 MW	70 MW	3248 MW
October 25, 2012	8:00	2885 MW	81 MW	2966 MW
November 26, 2012	19:00	3103 MW	89 MW	3192 MW
December 26, 2012	19:00	3551 MW	126 MW	3677 MW
Total		**37,693**	**1053**	**38,746**
			Average Control Area Load	**3,229**

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

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

Western's
Transmission Cost Data

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

Est for 12 Months Ending 9/30/2014

Western Area Power Administration

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$ 137,965,146
	REVENUE CREDITS	(Note R)				
2	Short-Term Firm Point-to-Point Transmission Service Credit		113,015	NA	1.00000	113,015
3	Non-Firm Point-to-Point Transmission Service Credit		14,030,944	NA	1.00000	14,030,944
4	Revenue from Existing Transmission Agreements		651,694	NA	1.00000	651,694
5	Scheduling, System Control, and Dispatch Service Credit		81,739	NA	1.00000	81,739
6	Account No. 454	(page 4, line 39)	79,030	TP	1.00000	79,030
7	Account No. 456	(page 4, line 42)	0	TP	1.00000	0
8	TOTAL REVENUE CREDITS					14,956,422
9	NET REVENUE REQUIREMENT	(line 1 minus line 8)				$ 123,008,724

Western Area Power Administration
Integrated System

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

Est for 12 Months Ending 9/30/2014

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	1,026,417,173	NA		
2	Transmission	Schedule 1A Total	1,239,165,422	TP	1.00000	1,239,165,422
3	Distribution	Schedule 1A Total	31,898,125	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)		2,297,480,720	GP=	53.936%	1,239,165,422
	ACCUMULATED DEPRECIATION					
7	Production	Schedule 4	560,526,625	NA		
8	Transmission	Schedule 4	582,933,186	TP	1.00000	582,933,186
9	Distribution	Schedule 4	15,182,927	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)		1,158,642,738			582,933,186
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	465,890,548			
14	Transmission	(line 2- line 8)	656,232,236			656,232,236
15	Distribution	(line 3 - line 9)	16,715,198			
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)		1,138,837,982	NP=	57.623%	656,232,236
	ADJUSTMENTS TO RATE BASE (Note B)					
19	Account No. 281 (enter negative)		0		zero	0
20	Account No. 282 (enter negative)		0	NP	0.57623	0
21	Account No. 283 (enter negative)		0	NP	0.57623	0
22	Account No. 190		0	NP	0.57623	0
23	Account No. 255 (enter negative)		0	NP	0.57623	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	20,738,760			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	0.53936	0
29	TOTAL WORK NG CAPITAL (sum lines 26 - 28)		20,738,760			0
30	RATE BASE (sum lines 18, 24, 25, and 29)		1,159,576,742			656,232,236

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

Est for 12 Months Ending 9/30/2014

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		59,651,887	PTP/UGP	0.95563	57,005,133
1b	Western RMR		29,072,322	PTP/RMR	0.00930	270,373
1c	COE	COE Financial Stmts	47,388,198	PTP/COE	0.06234	2,954,180
2	Less Account 565 (Note E)			NA	1.00000	0
3	A&G (Note F)	Schedule 11				
3a	Western UGP		19,693,223	PTP/UGP	0.95563	18,819,435
3b	Western RMR		10,104,447	PTP/RMR	0.00930	93,971
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)		165,910,077			79,143,092
	DEPRECIATION EXPENSE					
9	Transmission (Note E)	Schedule 4				
9a	Western UGP		29,281,360	PTP/UGP	0.95563	27,982,146
9b	Western RMR		20,038,251	PTP/RMR	0.00930	186,356
9c	COE		10,647,088	PTP/COE	0.06234	663,739
10	General		0	W/S	1.00000	0
11	Common		0	CE	0.00000	0
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		59,966,699			28,832,241
	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	0.53936	0
17	Gross Receipts		0		zero	0
18	Other		0	GP	0.53936	0
19	Payments in lieu of taxes		0	GP	0.53936	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	0.57623	0
27	Total Income Taxes	(line 25 plus line 26)	0			0
28	RETURN		52,992,657	NA		29,989,813
	[Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]					
29	REV. REQUIREMENT (sum lines 8, 12,20,27,28)		278,869,433			137,965,146

Revenue Requirement - Non-Levelized | Revenue Requirement Template | Est for 12 Months Ending 9/30/2014

Utilizing Financial Statement Results of Operations

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)		1,239,165,422
2	Less transmission plant excluded from IS rates (Note K)		0
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)		1,239,165,422
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	19,610,555	1 00	19,610,555		
14	Distribution	0	0 00	0		
15	Other	0	0 00	0		
16	Total (sum lines 12-15)	19,610,555		19,610,555	=	1.00000

PERCENTAGE OF TOTAL PLANT ALLOCATOR PTP (Note M)

Line No.		$			
17	Transmission Plant in Service UGP	1,165,920,694			
18	Total Plant in Service UGP	1,220,056,679			
19	UGP Percentage of Transmission Plant to Total Plant (line 17 divided by line 18)		PTP/UGP	=	0.95563
20	Transmission Plant in Service RMR	6,476,901			
21	Total Plant in Service RMR	696,161,474			
22	RMR Percentage of Transmission Plant to Total Plant (line 20 divided by line 22)		PTP/RMR	=	0.00930
23	Transmission Plant in Service COE	66,767,827			
24	Total Plant in Service COE	1,070,947,140			
25	COE Percentage of Transmission Plant to Total Plant (line 23 divided by line 24)		PTP/COE	=	0.06234

COMMON PLANT ALLOCATOR (CE) (Note N)

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

RETURN (R)

Line No.			$
30	Long Term Interest Schedule 5		$39,304,293

Line No.			$	%	Cost (Note O)	Weighted	=WCLTD
31	Long Term Debt	HFD Sch's 21RX & 21X Col 8 Lines 23,25,26,29,30	859,995,409	100%	0 0457	0.0457	=R
32	Proprietary Capital			0%	0.1238	0.0000	
33	Total (sum lines 22-23)		859,995,409	100%		0.0457	
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)		79,030
	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

Revenue Requirement - Non-Levelized | Revenue Requirement Template | Est for 12 Months Ending 9/30/2014

Utilizing Financial Statement Results of Operations

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. T ER 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 2014
(WESTERN'S COSTS)

A.	Fixed Charge Rate	18.508%	(1)
B.	Generation Net Plant Costs ($)	$474,040,718	(2)
C.	Annual Cost of Generation ($)	$87,735,456	(A x B)
D.	Capability Used for Reactive Support (%)	2.61%	(3)
E.	Reactive Service Revenue Requirement	$2,289,895	(C x D)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Generation Revenue Requirement", for 2014 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 2008-2012.

TRUE-UP FOR 2012 REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES (INTEGRATED SYSTEM)

A.	WAPA 2012 Rate Reactive Service Revenue Requirement	$2,874,486	(1)
B.	WAPA 2012 Actual Reactive Service Revenue Requirement	$2,289,895	(2)
C.	Over Collection of Revenue Requirement	$584,591	(A - B)
D.	2012 Rate IS Transmission System Total Load (kW-Yr)	4,625,000	(3)
E.	2012 Actual IS Transmission System Total Load (kW-Yr)	4,973,000	(4)
F.	Difference 2012 Rate Load to 2012 Actual Load	(348,000)	(D - E)
G.	Over collection of revenue requirement	$584,591	(C)
H.	Over collection due to volume	$216,286	(F * [A / D] * -1)
I.	Net Over Collection	$800,877	(H + G)

(1) Reactive Service Revenue Requirement from "Rate for Reactive Supply and Voltage Control from Generation Sources For 2012, Western's Costs".

(2) Reactive Service Revenue Requirement from "Reactive Supply and Voltage Control from Generation Sources For 2014, Western's Costs" (uses 2012 actual costs).

(3) Reactive Service Revenue Requirement from "Rate for Reactive Supply and Voltage Control from Generation Sources For 2012, Western's Costs".

(4) Reactive Service Revenue Requirement from "Rate for Reactive Supply and Voltage Control from Generation Sources For 2014, Western's Costs".

RATE FOR REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES FOR 2012 (INTEGRATED SYSTEM)

A.	WAPA Reactive Service Revenue Requirement	$2,874,486	(1)
B.	Paid to Others for Reactive Service	$0	(2)
C.	Total Reactive Revenue Requirement	$2,874,486	(A + B)
D.	2010 IS Transmission System Total Load (kW-Yr)	4,625,000	(3)
E.	Annual Reactive Charge ($/kW-Yr)	$0.68	(C / D)
F.	Monthly Reactive Charge ($/kW-Mo)	$0.06	(E / 12)

(1) Reactive Service Revenue Requirement from "Reactive Supply and Voltage Control from Generation Sources For 2012, 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 2014
(Western's Costs)

A.	Fixed Charge Rate	17.639%	(1)
B.	Corps Generation Net Plant Costs ($)	$172,688,021	(2)
C.	Annual Corps Generation Cost ($)	$30,460,440.02	(A x B)
D.	Plant Capacity (kW)	937,000	
E.	Cost/kW ($/kW)	$32.51	(C / D)
F.	Capacity Used for Regulation (kW)	64,580	(J x 2%)
G.	Regulation Revenue Requirement ($) - Capacity	$2,099,496	(E x F)
H.	Regulation Revenue Requirement ($) - Purchases	$0	(3)
I.	Total Regulation Revenue Requirement ($)	$2,099,496	
J.	Load in Control Area(s) (kW-Yr)	3,229,000	(4)

(1) Page 3 of 3, "Determination of Pick-Sloan Missouri Basin Program, Eastern Division Annual Corps Revenue Requirement", for 2014 Rate.

(2) Corps Generation Net Plant is Electric Plant in Service for Oahe and Fort Peck less less Depreciation Reserve as of 9/30/12.

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

(4) Average of monthly peaks for 2012.

TRUE-UP OF REGULATION AND FREQUENCY RESPONSE FOR 2012 RATE
(INTEGRATED SYSTEM)

A.	2012 Rate Regulation Service Revenue Requirement	$1,748,600	(1)
B.	2012 Actual Regulation Service Revenue Requirement	$2,154,356	(2)
C.	Under Collection of Revenue Requirement	($405,756)	(A - B)
D.	2012 Rate Load in Control Area(s) (kW-Yr)	2,953,000	(3)
E.	2012 Actual Load in Control Area(s)(kW-Yr)	3,229,000	(4)
F.	Difference 2012 Rate Load to 2012 Actual Load	(276,000)	(D - E)
G.	Under collection of revenue requirement	($405,756)	(C)
H.	Over collection due to volume	$163,432	(F * [A / D] * -1)
I.	Net Under Collection	($242,324)	(G + H)

(1) Regulation Service Revenue Requirement from "Rate for Regulation and Frequency Response for 2012".

(2) Regulation Service Revenue Requirement from "Rate for Regulation and Frequency Response for 2014".

(3) Regulation Service Revenue Requirement from "Rate for Regulation and Frequency Response for 2012".

(4) Regulation Service Revenue Requirement from "Rate for Regulation and Frequency Response for 2014".

RATE FOR REGULATION AND FREQUENCY RESPONSE FOR 2012

		2012 Rate	
A.	Western Regulation Revenue Requirement	$1,682,619	(1)
B.	BEPC & HCPD Regulation Revenue Requirement	$65,981	(2)
C.	Total Regulation Revenue Requirement	$1,748,600	(A + B)
D.	Load in Control Area(s) (kW-Yr)	2,953,000	(3)
E.	Regulation Charge ($/kW-Yr)	$0.61	(C / D)
F.	Regulation Charge ($/kW-Mo)	$0.05	(E / 12 months)

(1) Regulation and Frequency Response Service from "Regulation and Frequency Response for 2012, Western's Costs".

(2) Basin Electric cost support data.

(3) Average of monthly peaks for 2012.

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	$84,709,813	O&M Expenses Worksheet, C6L19
5			
6	Net Generation Plant Investment	$676,471,782	Net Plant Investment Worksheet, C6L12
7			
8	O&M as % of Net Generation Plant Investment	12.522%	L4/L6
9			
10			
11	**B. A&G Expense for Generation**		
12			
13	Generation A&G Expense	$300,418	A&G Expenses Worksheet, C6L18
14			
15	Net Generation Plant Investment	$676,471,782	L6
16			
17	A&G as % of Net Generation Plant Investment	0.044%	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	$16,805,427	Depreciation Expense Worksheet, C6L6
23			
24	Net Generation Plant Investment	$676,471,782	L6
25			
26	Depreciation as a % of Net Generation Plant Investment	2.484%	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	3.458%	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	12.522%	L8
47			
48	A&G Expense	0.044%	L17
49			
50	Depreciation Expense	2.484%	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	3.458%	L41
57			
58	Total	18.508%	
59			
60			
61	**H. Generation Revenue Requirement**		
62			
63	Generation Fixed Charge Rate	18.508%	L58
64			
65	Net Generation Plant Investment	$676,471,782	L6
66			
67	Western Annual Generation Revenue Requirement	$125,201,397	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	$48,467,286	O&M Expenses Worksheet, C4L19
5			
6	Net Corps Generation Plant Investment	$421,137,377	Net Plant Investment Worksheet, C4L12
7			
8	O&M as % of Net Generation Plant Investment	11.509%	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	$421,137,377	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	$11,251,124	Depreciation Expense, C4L6
23			
24	Net Corps Generation Plant Investment	$421,137,377	L6
25			
26	Depreciation as a % of Net Generation Plant Investment	2.672%	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	3.458%	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	11.509%	L8
47			
48	A&G Expense	0.000%	L17
49			
50	Depreciation Expense	2.672%	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	3.458%	L41
57			
58	Total	17.639%	
59			
60			
61	**H. Corps Generation Revenue Requirement**		
62			
63	Corps Generation Fixed Charge Rate	17.639%	L58
64			
65	Net Corps Generation Plant Investment	$421,137,377	L6
66			
67	Western Annual Corps Generation Revenue Requirement	$74,284,422	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	$64,086,271	O&M Expenses Worksheet, C6L17
5	Transmission of Electricity by Others	$0	
6	Total O&M Expense for Transmission	$64,086,271	L4 + L5
7			
8	Net Transmission Plant Investment	$593,353,214	Net Plant Investment Worksheet, C6L11
9			
10	O&M as % of Net Transmission Plant Investment	10.801%	L6/L8
11			
12			
13	**B. A&G Expense for Transmission**		
14			
15	Transmission A&G Expense	$15,820,059	A&G Expenses Worksheet, C6L16
16			
17	Net Transmission Plant Investment	$593,353,214	L8
18			
19	A&G as % of Net Transmission Plant Investment	2.666%	L15/L17
20			
21			
22	**C. Depreciation Expense for Transmission**		
23			
24	Transmission Depreciation Expense	$26,912,803	Depreciation Expense Worksheet, C6L4
25			
26	Net Transmission Plant Investment	$593,353,214	L8
27			
28	Depreciation as a % of Net Transmission Plant Investment	4.536%	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	4.767%	Cost of Capital Worksheet, C6L9
44			
45			
46	**G. Transmission Fixed Charge Rate**		
47			
48	Operation and Maintenance Expense	10.801%	L10
49			
50	A&G Expense	2.666%	L19
51			
52	Depreciation Expense	4.536%	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	4.767%	L43
59			
60	Total	22.770%	
61			
62			
63	**H. Transmission Revenue Requirement**		
64			
65	Transmission Fixed Charge Rate	22.770%	L60
66			
67	Net Transmission Plant Investment	$593,353,214	L8
68			
69	Annual Western-UGPR Transmission Cost	$135,106,527	L65 * L67
70			
71			
72			
73			

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

Line No.	(1)	(2) WESTERN UGPR 1/	(3) WESTERN RMR 2/	(4) COE 3/	(5) BOR 4/	(6) Total
1						
2	**Total Electric Operating Expense**	156,295,708	71,311,291			227,606,999
3						
4	**Less:**					
5	**Other Power Supply Expenses**	76,291,284	25,148,641			101,439,925
6	**A&G Expenses**	16,479,304	8,728,010			25,207,314
7	**Sunflower Payment**					0
8	**Prior Year Adjustments**	5,456	0			5,456
9						
10	**Plus:**					
11	**Moveable Property Interest**	796,145	260,428			1,056,573
12	**Warehouse Stores Interest**	93,550	73,359			166,909
13						
14	**COE/BOR Total**			50,686,864	35,068,344	85,755,208
15	**PS Total O&M**	64,409,359	37,768,427	50,686,864	35,068,344	187,932,994
16						
17	**PS-ED Transmission O&M 5/**	61,515,447	351,246	2,219,578	0	64,086,271
18						
19	**PS-ED Generation O&M 6/**	1,174,183	0	48,467,286	35,068,344	84,709,813

1/ All Western UGPR O&M Expenses are from the FY 2012 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 2012 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 2012 Corps of Engineers Financial Statements.

4/ Total BOR O&M Expenses are from the FY 2012 Historical Financial Data in Support of the Power Repayment Study for the Pick-Sloan Missouri Basin Program, Schedule 14.

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

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

A&G Expenses
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	2,999,453	1,886,341	0	0	4,885,794
3	1412	1,915,491	2,283,060	0	0	4,198,551
4	1415	1,631	15,738	0	0	17,369
5	1416	14,049	7,966	0	0	22,015
6	1421	1,177,317	733,796	0	0	1,911,113
7	1422	1,696,897	2,145	0	0	1,699,042
8	1425	815	7,869	0	0	8,684
9	1426	(8,216)	(40)	0	0	(8,256)
10	1431	0	0	0	0	0
11	1432	0	0	0	0	0
12	1441	5,110,677	2,983,427	0	0	8,094,104
13	1442	3,571,190	807,708	0	0	4,378,898
14	**PS Total A&G**	16,479,304	8,728,010	0	0	25,207,314
15						
16	**PS-ED Transmission A&G 4/**	15,738,889	81,170	0	0	15,820,059
17						
18	**PS-ED Generation A&G 5/**	300,418	0	0	0	300,418

1/ Western UGPR A&G Expenses are from the FY 2012 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 2012 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
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	27,444,269	1/	20,038,251	2/	11,766,373	3/	5,053,994	4/	64,302,887
3										
4	PS-ED Transmission Depreciation 5/	26,211,198		186,356		515,249		0		26,912,803
5										
6	PS-ED Generation Depreciation 6/	500,309		0		11,251,124		5,053,994		16,805,427

1/ FY 2012 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 4.

2/ FY 2012 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 4.

3/ FY 2012 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.

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

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

Line No.	(1)	(2) WESTERN UGPR		(3) WESTERN RMR		(4) COE		(5) BOR		(6) Total	
1											
2	**Long Term Debt:**										
3	FY 2012 Balances	746,913,965	1/	422,864,409	1/	523,250,361	1/	134,099,748	1/	1,827,128,483	
4											
5	**Interest Expenses:**										
6	FY 2012 Interest	36,010,087	13/	25,669,588	13/	16,914,738	2/	5,174,903	2/	83,769,316	
7	Average Interest Rate	4.821%	L6/L3	6.070%	L6/L3	3.233%	L6/L3	3.859%	L6/L3		
8	Transmission Plant Factor	0.9559	3/	0.0057	4/	0.0384	5/	0.0000	6/		
9	Weighted Trans. Composite Rate									4.767%	7/
10	Generation Plant Factor	0.0144	8/	0.0000	9/	0.6621	10/	0.3235	11/		
11	Weighted Gen. Composite Rate									3.458%	12/

1/ FY 2012 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedules 21X and 21RX.
2/ FY 2012 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
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	1,136,236,533	1/	696,161,474	2/	994,256,410	3/	464,588,741	12/	3,291,243,158
3	PS-ED Transmission Plant-in-Service	1,085,190,759	4/	6,476,901	5/	43,538,927	6/	0		1,135,206,587
4	PS-ED Generation Plant-in-Service	20,710,078	7/	0		950,717,483	L2-L3	464,588,741	L2-L3	1,436,016,302
5	Generation Plant to Total Plant	0.01823	L4/L2	0.00000	L4/L2	0.95621	L4/L2	1.00000	L4/L2	
6	Transmission Plant to Total Plant	0.95507	L3/L2	0.00930	L3/L2	0.04379	L3/L2	0.00000	L3/L2	
7										
8	PS Accumulated Depreciation	539,028,209	8/	300,148,307	9/	553,832,428	10/	220,137,930	11/	1,613,146,874
9	PS-ED Trans. Accumulated Depreciation	514,809,672	L6*L8	2,791,379	L6*L8	24,252,322	L6*L8	0	L6*L8	541,853,373
10	PS-ED Gen. Accumulated Depreciation	9,826,484	L5*L8	0	L5*L8	529,580,106	L8-L9	220,137,930	L5*L8	759,544,520
11	PS-ED Net Transmission Plant	570,381,087	L3-L9	3,685,522	L3-L9	19,286,605	L3-L9	0	L3-L9	593,353,214
12	PS-ED Net Generation Plant	10,883,594	L4-L10	0	L4-L10	421,137,377	L4-L10	244,450,811	L4-L10	676,471,782

1/ Transmission Plant-in-Service Worksheet, C2L514.
2/ FY 2012 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 1.
3/ FY 2012 Corps of Engineers Financial Statements, Electric and Power Multi-Purpose Plant in Service.
4/ Transmission Plant-in-Service Worksheet, C5L519.
5/ Transmission Plant-in-Service Worksheet, C5L528.
6/ Transmission Plant-in-Service Worksheet, C5L532.
7/ Transmission Plant-in-Service Worksheet, C4L519.
8/ FY 2012 UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 4.
9/ FY 2012 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 4.
10/ FY 2012 Corps of Engineers Financial Statements, Statement of Assets and Liabilities.
11/ FY 2012 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 15.
12/ FY 2012 Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 17.

Line No.	(1) DESCRIPTION	a	(2) FY2012 TOTALS TOTALS	b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS	c	(4) GENERATION ADJUSTMENTS GEN ADJ	d	(5) TRANSMISSION TOTALS TRANS TOTAL	e	(6) SOURCE/NOTES
1	**Transmission Lines**										
2	AURORA- BROOKINGS 115-KV T/L		133,158						133,158		
3	AURORA-FLANDREAU 115-KV T/L		96,623						96,623		
4	BAKER-HETTINGER		459,778						459,778		
5	BEULAH-GARRISON		351,685						351,685		
6	BISMARCK-GLENHAM		5,000,750						5,000,750		
7	BISMARCK-JAMESTOWN NO 1		5,473,497						5,473,497		
8	BISMARCK-JAMESTOWN NO 2		3,096,816						3,096,816		
9	BISMARCK-MEDORA		7,523,391						7,523,391		
10	BROOKINGS-SIOUX FALLS		1,954,466						1,954,466		
11	BROOKINGS-WATERTOWN NO 1		1,718,240						1,718,240		
12	BROOKINGS-WATERTOWN NO 2		3,318,558						3,318,558		
13	BROOKINGS-WHITE 115/230KV		2,952,237						2,952,237		
14	CARRINGTON-JAMESTOWN		1,259,668						1,259,668		
15	CHARLIE CREEK - WATFORD CITY		12,440,184						12,440,184		
16	CHARLIE CREEK-BELFIELD		14,513,308						14,513,308		
17	CONRAD-SHELBY #2		5,804,318						5,804,318		
18	CRESTON-MARYVILLE		1,366,481						1,366,481		
19	DAWSON COUNTY - MILES CITY		2,605,678						2,605,678		
20	DAWSON-GLENDIVE		553,800						553,800		
21	DAWSON-MEDORA		2,862,712						2,862,712		
22	DAWSON-MEDORA		5,088						5,088		
23	DAWSON-O'FALLON CREEK		918,676						918,676		
24	DAWSON-WILLISTON		1,258,900						1,258,900		
25	DENISON-CRESTON		17,452,346						17,452,346		
26	DEVILS LAKE-CARRINGTON		7,359,165						7,359,165		
27	DEVILS LAKE-LAKOTA		1,872,142						1,872,142		
28	EDGELEY-FORMAN		375,316						375,316		
29	EDGELEY-GROTON		771,572						771,572		
30	ELK CREEK-NEWELL-MAURINE 115-kV T/L		60,704						60,704		
31	FARGO-GRAND FORKS		2,369,098						2,369,098		
32	FARGO-MORRIS		6,914,811						6,914,811		
33	FORMAN-SUMMIT (BISMARCK)		922,098						922,098		
34	FORMAN-SUMMIT (HURON)		3,440,115						3,440,115		
35	FORT PECK-DAWSON #1		481,450						481,450		
36	FORT PECK-DAWSON #2		7,919,832						7,919,832		
37	FORT PECK-HAVRE		28,806,330						28,806,330		
38	FORT PECK-WHATELY		157,876						157,876		
39	FORT PECK-WILLISTON		10,096,097						10,096,097		
40	FORT PECK-WOLF POINT #2		7,554,492						7,554,492		
41	FORT RANDALL-FORT THOMPSON 1&2		7,326,839						7,326,839		
42	FORT RANDALL-GAVIN'S POINT		1,990,424						1,990,424		
43	FORT RANDALL-GREGORY		777,327						777,327		
44	FORT RANDALL-MT VERNON		967,828						967,828		
45	FORT RANDALL-O'NEILL		679,540						679,540		
46	FORT RANDALL-SIOUX CITY 1&2		8,505,957						8,505,957		
47	FORT THOMPSON-GRAND ISLAND		16,397,505						16,397,505		
48	FORT THOMPSON-HURON 230-KV 1&2		5,033,030						5,033,030		
49	FORT THOMPSON-SIOUX FALLS 1&2		10,035,508						10,035,508		
50	GARRISON-BISMARCK 230KV 1&2		5,176,778						5,176,778		
51	GARRISON-JAMESTOWN		4,306,775						4,306,775		
52	GARRISON-MALLARD		1,266,645						1,266,645		
53	GARRISON-WM J NEAL		1,540,944						1,540,944		
54	GAVINS POINT-BELDEN		455,727						455,727		
55	GAVINS POINT-SIOUX FALLS		2,360,380						2,360,380		
56	GRANITE FALLS- MORRIS		3,279,089						3,279,089		
57	GRANITE FALLS-MINNESOTA VALLEY		156,778						156,778		
58	GREAT FALLS-CONRAD		12,747,013						12,747,013		
59	GREGORY-MISSION		2,010,227						2,010,227		
60	GROTON-HURON		1,212,199						1,212,199		

Line No.	(1) DESCRIPTION	a	(2) FY2012 TOTALS TOTALS	b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS	c	(4) GENERATION ADJUSTMENTS GEN ADJ	d	(5) TRANSMISSION TOTALS TRANS TOTAL	e	(6) SOURCE/NOTES
61	GROTON-SUMMIT		3,176,751						3,176,751		
62	HAVRE-RAINBOW		8,685,923						8,685,923		
63	HAVRE-SHELBY#2		5,561,905						5,561,905		
64	HESKETT-DEVAUL		434,209						434,209		
65	HETTINGER-NEW UNDERWOOD		10,753,121						10,753,121		
66	HURON-MT VERNON		617,623						617,623		
67	HURON-WATERTOWN 230KV 1&3		5,792,955						5,792,955		
68	JAMESTOWN-EDGELEY		324,360						324,360		
69	JAMESTOWN-FARGO NO 1		4,941,649						4,941,649		
70	JAMESTOWN-FARGO NO 2		3,155,850						3,155,850		
71	JAMESTOWN-GRAND FORKS		19,691,614						19,691,614		
72	JAMESTOWN-VALLEY CITY		1,055,414						1,055,414		
73	LEEDS-DEVILS LAKE		8,826,671						8,826,671		
74	LEEDS-ROLLA		2,037,660						2,037,660		
75	MALLARD-RUGBY		1,282,436						1,282,436		
76	MARTIN-MISSION		1,816,904						1,816,904		
77	MARTIN-PHILIP		1,790,108						1,790,108		
78	MAURINE-RAPID CITY		5,265,666						5,265,666		
79	MILES CITY-BAKER (BEPS)		8,205,790						8,205,790		
80	MILES CITY-BAKER (BEFP)		2,363,548						2,363,548		
81	MILES CITY-CUSTER		3,750,704						3,750,704		
82	NEW UNDERWOOD-PHILIP		2,272,040						2,272,040		
83	NEW UNDERWOOD-RAPID CITY NO 1		1,132,486						1,132,486		
84	NEW UNDERWOOD-RAPID CITY NO 2		309,991						309,991		
85	NEW UNDERWOOD-STEGALL (HURON)		2,672,947						2,672,947		
86	OAHE-FORT THOMPSON 230KV 1&2		3,149,034						3,149,034		
87	OAHE-FORT THOMPSON 230KV 3&4		5,119,119						5,119,119		
88	OAHE-GLENHAM		5,768,280						5,768,280		
89	OAHE-MAURINE		1,967,901						1,967,901		
90	OAHE-NEW UNDERWOOD		6,683,770						6,683,770		
91	OAHE-PIERRE		388,816						388,816		
92	O'FALLON CREEK-MILES CITY		2,488,318						2,488,318		
93	PIERRE-PHILIP		1,187,034						1,187,034		
94	RAPID CITY-ELK CREEK 115-kV T/L		52,064						52,064		
95	RUGBY-LEEDS		2,235,655						2,235,655		
96	SHELBY-SHELBY#2		576,090						576,090		
97	SIOUX CITY-DENISON		1,661,311						1,661,311		
98	SIOUX CITY-SPENCER		1,938,353						1,938,353		
99	SIOUX FALLS- SIOUX CITY		3,217,192						3,217,192		
100	SIOUX FALLS-VIRGIL FODNESS 230KV T-LINE		277,897						277,897		
101	SUMMIT-WATERTOWN		6,743,203						6,743,203		
102	TIBER TAP-TIBER		1,084,858						1,084,858		
103	UTICA JCT-SIOUX FALLS		3,485,236						3,485,236		
104	VALLEY CITY-FORMAN		1,527,895						1,527,895		
105	VERONA GREAT FALLS 161-kV LINE		4,552,744						4,552,744		
106	VIRGIL FODNESS-UTICA JUNCTION-FT RANDALL/RASM		312,931 04						312,931		
107	WATERTOWN-GRANITE FALLS 1&2		5,955,119						5,955,119		
108	WATERTOWN-SIOUX CITY		26,679,769						26,679,769		
109	WATFORD CITY-BEULAH		992,709						992,709		
110	WILLISTON-WATFORD CITY		17,608,556						17,608,556		
111	WM J NEAL-RUGBY		4,629,316						4,629,316		
112	YELLOWTAIL-CUSTER		2,265,163						2,265,163		
113	**Subtotal**		476,914,624		0		0		476,914,624		
114											
115	**Substations**										
116	APPELDORN SUBSTATION		7,581,692						7,581,692		
117	ARMOUR SUBSTATION		1,988,118		(82,000)				1,906,118		
118	ASH SUBSTATION		63,325						63,325		
119	AURORA SUBSTATION		2,899,881						2,899,881		
120	BELDEN SUBSTATION		164,986						164,986		
121	BELFIELD SUBSTATION		9,945,668						9,945,668		
122	BERESFORD SUBSTATION		3,671,464		(624,149)				3,047,315		17% of the costs of this facility have been allocated to distribution
123	BISBEE SUBSTATION		272,529		(136,265)				136,264		50% of the costs of this facility have been allocated to distribution

Line No.	(1) DESCRIPTION	a	(2) FY2012 TOTALS TOTALS	b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS	c	(4) GENERATION ADJUSTMENTS GEN ADJ	d	(5) TRANSMISSION TOTALS TRANS TOTAL	e	(6) SOURCE/NOTES
124	BISMARK SUBSTATION		8,038,393						8,038,393		
125	BISON		12,472						12,472		
126	BOLE SUB (BEFP)		92,092						92,092		
127	BOLE SUB (BEPS)		3,111,717						3,111,717		
128	BONESTEEL SUBSTATION		3,443,566		(1,721,783)				1,721,783		50% of the costs of this facility have been allocated to distribution
129	BROOKINGS SUBSTATION		4,422,924						4,422,924		
130	CARPENTER SUBSTATION		2,463,312						2,463,312		
131	CARRINGTON SUBSTATION		3,744,809		(486,825)				3,257,984		13% of the costs of this facility have been allocated to distribution
132	CIRCLE SUBSTATION		1,632,040						1,632,040		
133	CONRAD SUB		311,656						311,656		
134	CONRAD SUB (BEPS)		5,008,913						5,008,913		
135	CRESTON SUBSTATION		4,941,437		(55,000)				4,886,437		
136	CROSSOVER SUB (BEFP)		313,924						313,924		
137	CROSSOVER SUB		10,785,373						10,785,373		
138	CULBERTSON EAST SWITCHING STATION		2,390,851						2,390,851		
139	CUSTER SUBSTATION (BEFP)		3,189,684						3,189,684		
140	CUSTER SUBSTATION		1,401,908						1,401,908		
141	CUSTER TRAIL SUBSTATION		1,475,222		(737,611)				737,611		50% of the costs of this facility have been allocated to distribution
142	DAWSON COUNTY SUBSTATION		10,702,674		(856,214)				9,846,460		8% of the costs of this facility have been allocated to distribution
143	DENISON SUBSTATION		15,865,912						15,865,912		
144	DEVAUL SUBSTATION		882,271		(529,362)				352,909		60% of the costs of this facility have been allocated to distribution
145	DEVILS LAKE SUBSTATION		2,649,649		(291,461)				2,358,188		11% of the costs of this facility have been allocated to distribution
146	EAGLE BUTTE SUBSTATION		1,179,875						1,179,875		
147	EDGELEY SUBSTATION		3,490,702		(488,698)				3,002,004		14% of the costs of this facility have been allocated to distribution
148	ELK CREEK SUBSTATION		2,086,660						2,086,660		
149	ELLENDALE SUBSTATION		579						579		
150	ELLIOTT SWITCHING STATION		3,121,488						3,121,488		
151	ENDERLIN TAP STATION		749,768						749,768		
152	EXIRA SWITCHING STATION		5,500,776						5,500,776		
153	FAIRVIEW WEST SWITCHING STATION		4,296,873						4,296,873		
154	FAITH SUBSTATION		1,212,383		(606,191)				606,192		50% of the costs of this facility have been allocated to distribution
155	FARGO SUBSTATION		20,411,627		(47,000)				20,364,627		
156	FLANDREAU SUBSTATION		4,254,673		(723,294)				3,531,379		17% of the costs of this facility have been allocated to distribution
157	FORMAN SUBSTATION		6,160,581		(800,875)				5,359,706		13% of the costs of this facility have been allocated to distribution
158	FORT RANDALL		253,710						253,710		
159	FORT THOMPSON #2		10,761,312						10,761,312		
160	FORT THOMPSON SUBSTATION		15,464,906		(354,000)				15,110,906		
161	GLENDIVE SUBSTATION		1,725,310						1,725,310		
162	GRAND FORKS SUBSTATION		9,371,746						9,371,746		
163	GRAND ISLAND SUBSTATION		12,050,347						12,050,347		
164	GRANITE FALLS SUBSTATION		19,391,434		(57,000)				19,334,434		
165	GREAT FALLS SUB (BEFP)		122,533						122,533		
166	GREAT FALLS SUB		456,557						456,557		
167	GREGORY SUBSTATION		1,538,606		(307,721)				1,230,885		20% of the costs of this facility have been allocated to distribution
168	GROTON SUBSTATION		5,105,701						5,105,701		
169	HAVRE SUBSTATION		6,786,727		(1,153,744)				5,632,983		17% of the costs of this facility have been allocated to distribution
170	HILKEN SUSTATION		3,874,407						3,874,407		
171	HURON SUBSTATION		10,858,215						10,858,215		
172	JAMESTOWN SUBSTATION		18,469,966		(1,846,997)				16,622,969		10% of the costs of this facility have been allocated to distribution
173	KILLDEER SUBSTATION		6,501,113						6,501,113		
174	LAKOTA SUBSTATION		2,855,212		(942,220)				1,912,992		33% of the costs of this facility have been allocated to distribution
175	LEEDS SUBSTATION		1,463,330		(204,866)				1,258,464		14% of the costs of this facility have been allocated to distribution
176	LETCHER SUBSTATION		10,998,129						10,998,129		
177	MARTIN SUBSTATION		1,827,365						1,827,365		
178	MAURINE SUBSTATION		7,920,648						7,920,648		
179	MIDLAND SUBSTATION		836,212						836,212		
180	MILES CITY SUB #2		4,280,430						4,280,430		
181	MILES CITY #2 (BEFP)		1,783,805						1,783,805		
182	MILES CITY SUB #3		1,669,005						1,669,005		
183	MILES CITY SUB #3 (BEFP)		226,697						226,697		
184	MILES CITY SUBSTATION (BEFP)		160,336						160,336		
185	MILES CITY SUBSTATION		714,993						714,993		
186	MISSION SUBSTATION		3,473,710						3,473,710		

Line No.	(1) DESCRIPTION a	(2) FY2012 TOTALS TOTALS b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS c	(4) GENERATION ADJUSTMENTS GEN ADJ d	(5) TRANSMISSION TOTALS TRANS TOTAL e	(6) SOURCE/NOTES
187	MORRIS SUBSTATION	7,229,447			7,229,447	
188	MT VERNON SUBSTATION	2,030,824			2,030,824	
189	NELSON SUBSTATION	1,944,817			1,944,817	
190	NEW UNDERWOOD SUBSTATION	9,578,256	(1,053,608)		8,524,648	11% of the costs of this facility have been allocated to distribution
191	NEWELL SUBSTATION	1,152,964			1,152,964	
192	Non-Facility	263,535			263,535	
193	O'FALLON CREEK SUBSTATION	3,264,302	(1,632,151)		1,632,151	50% of the costs of this facility have been allocated to distribution
194	PHILIP SUBSTATION	1,767,095			1,767,095	
195	PIERRE SUBSTATION	4,282,907	(2,141,453)		2,141,454	50% of the costs of this facility have been allocated to distribution
196	RAINBOW SUBSTATION	723,556			723,556	
197	RAPID CITY SUBSTATION	4,787,093			4,787,093	
198	RICHLAND SUBSTATION	1,574,590	(1,259,672)		314,918	80% of the costs of this facility have been allocated to distribution
199	ROLLA SUBSTATION	623,513	(155,878)		467,635	25% of the costs of this facility have been allocated to distribution
200	RUDYARD SUBSTATION	2,552,955	(434,002)		2,118,953	17% of the costs of this facility have been allocated to distribution
201	RUGBY SUBSTATION	5,931,909	(830,467)		5,101,442	14% of the costs of this facility have been allocated to distribution
202	SAVAGE SUB	74,403			74,403	
203	SHELBY SUBSTATION	1,084,272			1,084,272	
204	SHELBY SUBSTATION #2 (BEFP)	286,340			286,340	
205	SHELBY SUBSTATION #2 (BEPS)	4,134,102			4,134,102	
206	SIOUX CITY #2	10,558,920			10,558,920	
207	SIOUX CITY SUBSTATION	16,756,924	(57,000)		16,699,924	
208	SIOUX FALLS SUBSTATION	7,393,883			7,393,883	
209	SPENCER	3,240,715			3,240,715	
210	SULLY BUTTES	74,428			74,428	
211	SUMMIT SUBSTATION	2,703,704			2,703,704	
212	TYNDALL SUBSTATION	922,316			922,316	
213	UTICA JCT	12,863,876			12,863,876	
214	VALLEY CITY SUBSTATION	3,850,456			3,850,456	
215	VERONA	25,210			25,210	
216	VIRGIL FODNESS SUBSTATION	3,206,763			3,206,763	
217	WALL SUBSTATION	1,495,170	(747,585)		747,585	50% of the costs of this facility have been allocated to distribution
218	WARD SUBSTATION	3,456,032			3,456,032	
219	WASHBURN SUBSTATION	2,064,740			2,064,740	
220	WATERTOWN #2	2,900,981			2,900,981	
221	WATERTOWN STATIC VAR SYSTEM	11,751,835			11,751,835	
222	WATERTOWN SUBSTATION	14,223,794			14,223,794	
223	WATFORD CITY SUB	1,638,667	(30,000)		1,608,667	
224	WESSINGTON SPRINGS SUBSTATION	5,141,440			5,141,440	
225	WHATELY (NORTHERN)	40,860			40,860	
226	WHATELY SUBSTATION	109,910	(54,955)		54,955	50% of the costs of this facility have been allocated to distribution
227	WHITE 345/115 SUB	10,936,510			10,936,510	
228	WICKSVILLE SUBSTATION	687,329	(343,664)		343,665	50% of the costs of this facility have been allocated to distribution
229	WILLISTON 2 SUBSTATION	5,931,177			5,931,177	
230	WILLISTON SUBSTATION	8,080,145			8,080,145	
231	WINNER SUBSTATION	3,219,465	(1,609,733)		1,609,732	50% of the costs of this facility have been allocated to distribution
232	WOLF POINT SUBSTATION	7,147,204	(2,144,161)		5,003,043	30% of the costs of this facility have been allocated to distribution
233	WOONSOCKET SUBSTATION	2,303,185			2,303,185	
234	YANKTON SUBSTATION	53,583			53,583	
235	**Subtotal**	522,943,010	(25,547,605)	0	497,395,405	
236						
237	**Line Taps & Related Equipment**					
238	ANITA	6,259			6,259	
239	ASSINNIBOINE	35,005			35,005	
240	BAKER (BEFP)	230,277			230,277	
241	BAKER	50,352			50,352	
242	CANYON FERRY (BEFP)	15,145			15,145	
243	CANYON FERRY	30,065			30,065	
244	CHARLIE CREEK	1,166,042			1,166,042	
245	COTTON	1,399			1,399	
246	DENBIGH TAP	848,872			848,872	
247	DICKINSON	23,704			23,704	
248	E J MANNING	49,112			49,112	
249	EAGLE	91,230			91,230	

Line No.	(1) DESCRIPTION	a	(2) FY2012 TOTALS TOTALS	b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS	c	(4) GENERATION ADJUSTMENTS GEN ADJ	d	(5) TRANSMISSION TOTALS TRANS TOTAL	e	(6) SOURCE/NOTES
250	FORSYTH		32,070						32,070		
251	FORSYTH		273,368						273,368		
252	HARLEM		174,745						174,745		
253	HARLEM (BEFP)		191,690						191,690		
254	HETTINGER		10,832						10,832		
255	HIGHWOOD		22,896						22,896		
256	MALLARD		29,969						29,969		
257	MALTA		340,848						340,848		
258	NASHUA SUB		72,368						72,368		
259	O'NEILL SUB (NPP)		180,660						180,660		
260	PENN TAP		890,607						890,607		
261	PLEASANT LAKE TAP		992,415						992,415		
262	POPLAR (MDU)		3,758						3,758		
263	SHIRLEY TAP		22,102						22,102		
264	STANLEY		49,735						49,735		
265	TERRY TAP		78,497						78,497		
266	TERRY TAP		345,850		(172,925)				172,925		50% of the costs of this facility have been allocated to distribution
267	TIBER TAP		166,306		(83,153)				83,153		50% of the costs of this facility have been allocated to distribution
268	VETAL TAP		232,375						232,375		
269	V T HANLON		5,553						5,553		
270	WM J NEAL		156,417						156,417		
271	YANKTON JCT		28,526						28,526		
272	ZENITH		2,047						2,047		
273	**Subtotal**		6,851,097		(256,078)		0		6,595,019		
274											
275	**O&M Service & Maintenance Centers**										
276	ARMOUR O&M SER CEN		3,488,667						3,488,667		
277	BISMARCK O&M SER CEN		9,482,956						9,482,956		
278	DAWSON SER CEN		22,545						22,545		
279	DEVILS LAKE O&M SER CEN		3,852,064						3,852,064		
280	FARGO LINE MAINTENANCE FACILITY		2,040,287						2,040,287		
281	FARGO O&M SER CEN		794,673						794,673		
282	FORT PECK SER CEN		5,626,463						5,626,463		
283	FORT THOMPSON O&M S C		315,000						315,000		
284	HAVRE SERVICE CENTER		249,377						249,377		
285	HURON O&M SER CEN		2,512,836						2,512,836		
286	JAMESTOWN O&M SER CEN		3,841,398						3,841,398		
287	MILES CITY MTCE FAC		21,817						21,817		
288	MILES CITY MTCE FAC		1,003,437						1,003,437		
289	NEW UNDERWOOD SER CEN		96,884						96,884		
290	PHILIP O&M SER CENT		1,690,034						1,690,034		
291	PIERRE O&M SER CEN		1,051,383						1,051,383		
292	RAPID CITY GARAGE & STOR		2,064,165						2,064,165		
293	SIOUX CITY O&M SER CEN		3,007,882						3,007,882		
294	SIOUX FALLS O&M SER CEN		239,920						239,920		
295	WATERTOWN MAINT CEN		934,402						934,402		
296	**Subtotal**		42,336,191		0		0		42,336,191		
297											
298	**Operation Centers**										
299	WATERTOWN ALTERNATE OPERATIONS CENTER		6,128,823				(2,170,645)		3,958,178		
300	WATERTOWN OPERATIONS CENT		876,775				(310,527)		566,248		Column 4 shows 35 417% of the Watertown Operations Center that
301	WATERTOWN OPER CTR (BFPS)		11,299,013				(4,001,771)		7,297,242		was prorated to generation based on FTE associated with generation
302	**Subtotal**		18,304,610		0		(6,482,943)		11,821,667		
303											
304	**Mobile Equipment**										
305	MOB 115KV SWITCH TRAILER		12,328						12,328		
306	MOB 115KV SWITCH TRAILER		57,413						57,413		
307	MOB TRANSF 111KV 15MVA		213,000						213,000		
308	MOB TRANSF 115KV 10MVA		76,258						76,258		
309	MOB TRANSF 115KV 10MVA		142,235						142,235		
310	MOB TRANSF 115KV 25MVA		556,464						556,464		
311	MOB TRANSF 115KV 40MVA		499,220						499,220		
312	MOB TRANSF 230KV 1-33MVA		170,278						170,278		

Line No.	(1) DESCRIPTION	a	(2) FY2012 TOTALS TOTALS	b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS	c	(4) GENERATION ADJUSTMENTS GEN ADJ	d	(5) TRANSMISSION TOTALS TRANS TOTAL	e	(6) SOURCE/NOTES
313	MOBILE BY PASS KIT (BISMARCK)		35,071						35,071		
314	MOBILE BY PASS KIT (HURON)		163,695						163,695		
315	MOBILE CAPACITOR BANK		19,075						19,075		
316	MOBILE SUB 110KV		127,144						127,144		
317	MOBILE SUB 115KV 20MVA		404,166						404,166		
318	MOBILE SUB 41 8 KV		192,498						192,498		
319	MOBILE SUB 69KV		71,118						71,118		
320	MOB SH REACTOR		179,328						179,328		
321	**Subtotal**		2,919,291		0		0		2,919,291		
322											
323	**Transmission-Related Generation Facilities**										
324	BIG BEND-FORT THOMPSON (LOW VOLTAGE)		81,944				(81,944)		0		
325	CANYON FERRY-EAST HELENA "A"		141,044				(141,044)		0		
326	CANYON FERRY-EAST HELENA "B"		141,044				(141,044)		0		
327	FORT PECK POWERPLANT (COE)		72,991				(72,991)		0		
328	FORT THOMPSON-BIG BEND NO 1		922,164				(922,164)		0		
329	FORT THOMPSON-BIG BEND NO 2		690,735				(690,735)		0		
330	**Subtotal**		2,049,922		0		(2,049,922)		0		
331											
332	**Communication Facilities**										
333	ATLANTIC COMMUNICATION SITE		17,199				(5,714)		11,485		Column 4 shows 33 22% of the Communication Facilities that were
334	BAKER RELAY		27,791				(9,232)		18,559		prorated to generation based on the number of communication
335	BANTRY		362,742				(120,503)		242,239		channels dedicated to generation
336	BARRETT		244,695				(81,288)		163,407		
337	BATTLE MT MICROWAVE		324,151				(107,683)		216,468		
338	BELLE PRAIRIE		16,111				(5,352)		10,759		
339	BELLE PRAIRIE		577,323				(191,787)		385,536		
340	BENEDICT		36,772				(12,216)		24,556		
341	BEULAH		10,679				(3,547)		7,132		
342	BIG BEND		113,362				(37,659)		75,703		
343	BIJOU REPEATER		585,814				(194,608)		391,206		
344	BISMARCK REPEATER		248,435				(82,530)		165,905		
345	BISON REPEATER		227,955				(75,727)		152,228		
346	BOLE NORTH REPEATER		149,228				(49,573)		99,655		
347	BRINSMADE		237,551				(78,915)		158,636		
348	BRISTOL		11,441				(3,801)		7,640		
349	BRUNSVILLE REPEATER		92,595				(30,760)		61,835		
350	BUFFALO		255,051				(84,728)		170,323		
351	CAHOON		194,709				(64,682)		130,027		
352	CARRINGTON REPEATER		726,855				(241,461)		485,394		
353	CHARTER OAK REPEATER		12,546				(4,168)		8,378		
354	CHARTER OAK REPEATER		3,121				(1,037)		2,084		
355	CHINOOK (BEFP)		284,048				(94,361)		189,687		
356	CHINOOK REPEATER		15,293				(5,080)		10,213		
357	CLARK MW REPEATER		632,695				(210,181)		422,514		
358	CLEVELAND REPEATER, N D		263,617				(87,574)		176,043		
359	COLEMAN REPEATER		105,281				(34,974)		70,307		
360	COLOME REPEATER		293,101				(97,368)		195,733		
361	CONRAD BUTTE REPEATER		371,283				(123,340)		247,943		
362	CONRAD BUTTE REPEATER		84,384				(28,032)		56,352		
363	CRESTON REPEATER		11,107				(3,690)		7,417		
364	CROW LAKE REPEATER		311,803				(103,581)		208,222		
365	CROWN BUTTE		52,565				(17,462)		35,103		
366	CULBERTSON RADIO RELAY SITE		1,926				(640)		1,286		
367	CUSTER LOOKOUT		80,620				(26,782)		53,838		
368	DALTON (WES)		198,021				(65,782)		132,239		
369	DEVILS LAKE REPEATER		465,879				(154,765)		311,114		
370	DODSON REPEATER		288,483				(95,834)		192,649		
371	DOGDEN BUTTE		281,286				(93,443)		187,843		
372	DRISCOLL		196,774				(65,368)		131,406		
373	DUPREE REPEATER		1,821				(605)		1,216		
374	DUTTON REPEATER (BEPS)		18,530				(6,156)		12,374		
375	DUTTON REPEATER (BEFP)		370,609				(123,116)		247,493		

Line No.	(1) DESCRIPTION	a	(2) FY2012 TOTALS TOTALS	b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS	c	(4) GENERATION ADJUSTMENTS GEN ADJ	d	(5) TRANSMISSION TOTALS TRANS TOTAL	e	(6) SOURCE/NOTES
376	EAST RAINY BUTTE		147,041				(48,847)		98,194		
377	ECKELSON		231,893				(77,035)		154,858		
378	ELKTON		165,481				(54,973)		110,508		
379	ELLENDALE REPEATER		644,579				(214,129)		430,450		
380	ELLSWORTH AIR BASE		204,548				(67,951)		136,597		
381	ERHARD		301,774				(100,249)		201,525		
382	EXIRA REPEATER		2,527				(839)		1,688		
383	F L BLAIR		76,407				(25,383)		51,024		
384	FAIRPOINT REPEATER		339,030				(112,626)		226,404		
385	FALLON REPEATER		263,375				(87,493)		175,882		
386	FERGUS FALLS COMMUNICATIONS SITE		485,567				(161,305)		324,262		
387	FLOWING WELLS		68,763				(22,843)		45,920		
388	FORBES COMMUNICATION SITE		45,316				(15,054)		30,262		
389	FORT PECK RELAY (WES)		250,960				(83,369)		167,591		
390	FORT PECK COMMUNICATIONS BUILDING		380,212				(126,306)		253,906		
391	FORT PECK REPEATER		109,069				(36,233)		72,836		
392	FORT THOMPSON REPEATER		99,223				(32,962)		66,261		
393	FORT THOMPSON REPEATER (EAST RIVER)		301,614				(100,196)		201,418		
394	FOX CREEK MICROWAVE		590,764				(196,252)		394,512		
395	FRYBURG SUB & MICROWAVE		61,204				(20,332)		40,872		
396	GARRISON		267,755				(88,948)		178,807		
397	GARY REPEATER		80,799				(26,841)		53,958		
398	GAVIN'S POINT		148,752				(49,416)		99,336		
399	GAVINS POINT REPEATER		425,943				(141,498)		284,445		
400	GETTYSBURG REPEATER		354,286				(117,694)		236,592		
401	GLENHAM		293,701				(97,567)		196,134		
402	GRAND FORKS MINNKOTA (MPC)		23,847				(7,922)		15,925		
403	HAILSTONE BUTTE		74,835				(24,860)		49,975		
404	HALLOWAY REPEATER		109,706				(36,444)		73,262		
405	HATHAWAY		17,314				(5,752)		11,562		
406	HATHAWAY		191,777				(63,708)		128,069		
407	HERMOSA MICROWAVE		302,701				(100,557)		202,144		
408	HIGHLAND REPEATER		177,964				(59,119)		118,845		
409	HIGHMORE REPEATER		145,723				(48,409)		97,314		
410	HINSDALE		201,837				(67,050)		134,787		
411	HINSDALE REPEATER		91,648				(30,445)		61,203		
412	HOPEWELL REPEATER		231,172				(76,795)		154,377		
413	HUNTER MICROWAVE		210,227				(69,837)		140,390		
414	HURON DISTRICT OFFICE		747,055				(248,172)		498,883		
415	HYSHAM		250,143				(83,098)		167,045		
416	JAMESTOWN REPEATER		46,981				(15,607)		31,374		
417	JONES CREEK		251,034				(83,393)		167,641		
418	KELLY CREEK (BEFP)		76,048				(25,263)		50,785		
419	KELLY CREEK		211,835				(70,371)		141,464		
420	KILLDEER REPEATER		380,028				(126,245)		253,783		
421	KNEE HILL MW		381,086				(126,597)		254,489		
422	KNEE HILL MW		119,303				(39,632)		79,671		
423	LAC QUI PARLE		766,404				(254,599)		511,805		
424	LAKE ANDES REPEATER		657,431				(218,398)		439,033		
425	LEFOR		48,470				(16,102)		32,368		
426	LINDSAY RIDGE		235,489				(78,229)		157,260		
427	LINTON COMMUNICATIONS SITE		339,867				(112,904)		226,963		
428	LITTLE MISSOURI SUBSTATION		54,516				(18,110)		36,406		
429	LODGEPOLE REPEATER		186,559				(61,975)		124,584		
430	MALTA REPEATER		1,023,986				(340,168)		683,818		
431	MANDAN MICROWAVE SITE		69,988				(23,250)		46,738		
432	MAPLE RIVER		172,792				(57,402)		115,390		
433	MARTIN REPEATER		300,728				(99,902)		200,826		
434	MAYVILLE		196,624				(65,318)		131,306		
435	MIDLAND REPEATER		516,515				(171,586)		344,929		
436	MILES CITY SUB (BEFP)		305,418				(101,460)		203,958		
437	MOE REPEATER		129,266				(42,942)		86,324		
438	MOORHEAD		251,422				(83,523)		167,899		

Line No.	(1) DESCRIPTION	a	(2) FY2012 TOTALS TOTALS	b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS	c	(4) GENERATION ADJUSTMENTS GEN ADJ	d	(5) TRANSMISSION TOTALS TRANS TOTAL	e	(6) SOURCE/NOTES
439	MORRIS REPEATER & MICROWAVE		128,242				(42,602)		85,640		
440	NEWCASTLE REPEATER		216,330				(71,865)		144,465		
441	OAHE		564,580				(187,554)		377,026		
442	O'KREEK REPEATER		367,630				(122,127)		245,503		
443	ORCHARD REPEATER		43,642				(14,498)		29,144		
444	OTO MICROWAVE		16,445				(5,463)		10,982		
445	OTTUMWA ROAD REPEATER SITE		7,685				(2,553)		5,132		
446	PAGE N D		1,646				(547)		1,099		
447	PAHOJA SUB		107,003				(35,546)		71,457		
448	PEAK		83,844				(27,853)		55,991		
449	PHILIP JCT REPEATER		457,145				(151,863)		305,282		
450	PINE RIDGE		15,766				(5,237)		10,529		
451	PINE RIDGE		273,894				(90,987)		182,907		
452	PRIMGHAR REPEATER		11,990				(3,983)		8,007		
453	PUKWANNA REPEATER		258,360				(85,827)		172,533		
454	RAPID CITY REPEATER		347,279				(115,366)		231,913		
455	RICHARDSON COULEE		161,748				(53,733)		108,015		
456	RICHARDSON COULEE REPEATER		175,397				(58,267)		117,130		
457	RICHLAND MW REPEATER (BEPS)		491,870				(163,399)		328,471		
458	ROCKY RIDGE REPEATER		226,934				(75,387)		151,547		
459	ROLLAG		172,922				(57,445)		115,477		
460	RUGBY REPEATER		276,659				(91,906)		184,753		
461	RUTLAND		388,869				(129,182)		259,687		
462	SACO		1,237				(411)		826		
463	SENTINEL BUTTE		87,667				(29,123)		58,544		
464	SHEEP COULEE REPEATER		475,744				(158,042)		317,702		
465	SIOUX CITY REPEATER		546,252				(181,465)		364,787		
466	SIOUX FALLS REPEATER		330,718				(109,864)		220,854		
467	SIOUX PASS		1,366				(454)		912		
468	SNAKE BUTTE REPEATER		670,911				(222,877)		448,034		
469	SPALDING REPEATER		38,651				(12,840)		25,811		
470	SPIRIT MOUND		226,293				(75,174)		151,119		
471	STRASBERG		17,870				(5,936)		11,934		
472	SUMMIT REPEATER		50,053				(16,628)		33,425		
473	TAPPEN COMMUNICATIONS SITE		291,767				(96,925)		194,842		
474	TAPPEN REPEATER		272,393				(90,489)		181,904		
475	TENNANT COMMUNICATIONS SITE		8,781 54				(2,917)		5,865		
476	TORONTO REPEATER		106,096				(35,245)		70,851		
477	TRIPP REPEATER		114,817				(38,142)		76,675		
478	TURKEY RIDGE REPEATER		638,584				(212,138)		426,446		
479	TYLER REPEATER		463,186				(153,870)		309,316		
480	VICTOR (EREC)		35,530				(11,803)		23,727		
481	VIDA		14,357				(4,770)		9,587		
482	VIDA		323,156				(107,352)		215,804		
483	WALL REPEATER		472,343				(156,912)		315,431		
484	WATERTOWN REPEATER		713,148				(236,908)		476,240		
485	WAYSIDE		17,781				(5,907)		11,874		
486	WESSINGTON SPGS REPEATER		624,746				(207,541)		417,205		
487	WESTFIELD		19,003				(6,313)		12,690		
488	WHITE SWAN		116,529				(38,711)		77,818		
489	WHITLOCK (BCPS)		165,594				(55,010)		110,584		
490	WOLBACH REPEATER		28,280				(9,395)		18,885		
491	YELLOWTAIL SWITCHYARD (BEPS)		343,984				(114,271)		229,713		
492	**Subtotal**		36,656,294		0		(12,177,213)		24,479,081		
493											
494	**Miles City Converter Station**										
495	MILES CITY CONVERTER STATION - BEPS		20,377,448						20,377,448		
496	MILES CITY CONVERTER STATION - BEFP		2,352,031						2,352,031		
497	**Subtotal**		22,729,480		0		0		22,729,480		
498											
499	**Distribution Facilities**										
500	BUFORD TRENTON TAP - BUFORD TRENTON P P		650,001		(650,001)				0		
501	BUFORD TRENTON PUMP SUB		184,827		(184,827)				0		These facilities have been determined to be used solely for distribution

Line No.	(1) DESCRIPTION	a	(2) FY2012 TOTALS TOTALS	b	(3) MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS	c	(4) GENERATION ADJUSTMENTS GEN ADJ	d	(5) TRANSMISSION TOTALS TRANS TOTAL	e	(6) SOURCE/NOTES
502	FALLON PUMPING PLANT SUBS		223,594		(223,594)				0		and are therefore not recovered in the transmission rate
503	FALLON RELIFT PUMPING PLA		171,257		(171,257)				0		
504	FALLON-GLENDIVE PUMP #4		25,506		(25,506)				0		
505	FORT PECK-WOLF POINT		190,500		(190,500)				0		
506	FRAZER PUMP SUB		253,597		(253,597)				0		
507	GARRISON-SNAKE CREEK		569,241		(569,241)				0		
508	GLENDIVE P P #1 SUB		425,706		(425,706)				0		
509	INTAKE SUBSTATION		108,040		(108,040)				0		
510	INTAKE-INTAKE PUMP		6,494		(6,494)				0		
511	SAVAGE PUMPING PLANT SUBS		102,283		(102,283)				0		
512	SHIRLEY PUMP SUBSTATION		127,053		(127,053)				0		
513	SNAKE CREEK PUMP SUBSTATI		662,435		(662,435)				0		
514	TERRY PUMPING PLANT SWITC		474,404		(474,404)				0		
515	TIBER DAM SUBSTATION		318,568		(318,568)				0		
516	WIOTA SUBSTATION		38,507		(38,507)				0		
517	**Subtotal Distribution Facilities**		4,532,014		(4,532,013)		0		1		
518											
519	**Subtotal Upper Great Plains Region Facilities**		1,136,236,533		(30,335,696)		(20,710,078)		1,085,190,759		
520											
521											
522											
523	**Rocky Mountain Region Facilities**										
524	NEW UNDERWOOD-STEGALL		287,835						287,835		Column 2 includes plant-in-service from FY 2011 RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 1 These are RMR facilities utilized by both RMR and UGPR The amount in Column 5 will be recovered by UGPR
525	STEGALL SUBSTATION		8,964,752		(8,662,143)				302,609		
526	STEGALL-WAYSIDE		2,978,205						2,978,205		
527	YELLOWTAIL SWITCHYARD		11,633,005		(8,724,754)				2,908,251		
528			23,863,798		(17,386,897)		0		6,476,901		
529											
530	**Corps of Engineers Facilities**										
531	CORPS SWITCHYARD FACILITIES		55,589,535				(12,050,608)		43,538,927		
532			55,589,535		0		(12,050,608)		43,538,927		
533											
534	**TOTAL FACILITIES**		1,215,689,866		(47,722,593)		(32,760,686)		1,135,206,587		

Basin Electric's Transmission Cost Data

Revenue Requirement Worksheet
RUS Form 12 Data **Projection for 2014**
BASIN ELECTRIC POWER COOPERATIVE

Line No.			Total		Allocator	Total Transmission	IS Transmission	West (MBPP) Transmission	Other Transmission
1	**GROSS REVENUE REQUIREMENT (page 3, line 28)**					**$ 98,265,720**	**$ 63,121,627**	**$ 8,048,152**	**$ 27,095,948**
	(MBPP West Excluded - 1-.065997)							$ (7,516,998)	
	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)					**62,876,148**	**531,154**	**27,095,948**
7	**TOTAL REVENUE REQUIREMENT WITH MBPP EAST**						**$ 63,407,302**		

	(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	**4,656,172,637**	NA	0.000%		NA	0.000%	-	-	-
2	Transmission (Note B)	12h.A.11.e & 12h.A 23 e	**768,049,447**	DA	100.000%	768,049,447	DA	100.000%	456,993,507	91,586,910	219,469,030
3	Distribution	12h.A.16.e	-	NA	0.000%		NA	0.000%			
4	General	12h.A.18.e	**177,760,782**								
4a	Direct Assign - Transmission (Note C)		34,022,925	DA	100.000%	34,022,925	DA	100.000%	23,912,678	3,147,763	6,962,484
4b	Direct Assign - Production		41,860,630	NA	0.000%		NA	0.000%			
4c	Other		101,877,227	WS	10.025%	10,213,192	WS	Gross Plant	6,076,951	1,217,923	2,918,420
5	Intangible	12h.A.1 e	**78,163,717**	DA	0.000%	66 336 542	DA	0.000%	32 355 705	2 617 629	31 363 208
6	**TOTAL GROSS PLANT (sum lines 1,2,4,5)**	12h.A.18.e & 12h.A 24 e	**$ 5,680,146,583**			**$ 878,622,106**			**$ 519,338,841**	**$ 98,570,225**	**$ 260,713,142**
							GP1	Gross Plant	59.501%	11.925%	28.575%
	ACCUMULATED DEPRECIATION										
7	Production	12h.B.1-4.f	**1,365,211,899**	NA	0.000%		NA	0.000%	-		
8	Transmission	12h.B 5.f & 12h.B.15.f	**317,024,250**	DA	100.000%	317,024,250	DA	100.000%	209,089,536	56,466,805	51,467,909
9	Distribution	12h.B 6.f	**-**	NA	0.000%		NA	0.000%			-
10	General	12h.B.7.f	**129,070,814**								-
10a	Direct Assign - Transmission		27,345,356	DA	100.000%	27,345,356	DA	100.000%	20,721,856	3,240,965	3,382,535
10b	Direct Assign - Production		38,025,928	NA	0.000%		NA	0.000%			
10c	Other		63,699,530	WS	10.025%	6,385,878	GP1	Gross Plant	3,799,661	761,516	1,824,765
11	Intangible	12h.B.12.f	**55,041,001**	DA		49,091,509	DA	100.000%	24,893,678	2,148,495	22,049,335
12	**TOTAL ACCUM. DEPR (sum lines 7,8,10,11)**	12h.B.18.f less 12h B.14.f	**$ 1,866,347,964**			**$ 399,846,993**			**$ 258,504,731**	**$ 62,617,781**	**$ 78,724,544**
	NET PLANT IN SERVICE										
13	Production	(line 1- line 7)	**3,290,960,738**	AUTO		-	AUTO		-	-	-
14	Transmission	(line 2- line 8)	**451,025,197**	AUTO		451,025,197	AUTO		247,903,971	35,120,105	168,001,121
15	Distribution	(line 3 - line 9)	**-**	AUTO		-	AUTO		-	-	-
16	General	(line 4 - line 10)	**48,689,968**	AUTO		-	AUTO		-	-	-
16a	Direct Assign	(line 4a - line 10a)	6,677,569	AUTO		6,677,569	AUTO		3,190,822	(93,202)	3,579,949
16b	Production	(line 4b - line 10b)	3,834,702	AUTO		-	AUTO		-	-	-
16c	Other	(line 4c - line 10c)	38,177,697	AUTO		3,827,314	AUTO		2,277,290	456,407	1,093,655
17	Intangible	(line 5 - line 11)	**23,122,716**	AUTO		17,245,033	AUTO		7,462,027	469,134	9,313,873
18	**TOTAL NET PLANT (sum lines 13, 14, 16, 17)**		**$ 3,813,798,619**			**$ 478,775,113**			**$ 260,834,110**	**$ 35,952,444**	**$ 181,988,598**
	WORKING CAPITAL										
19	CWC (Note D)	one eighth of line 9, page 3	13,061,990	DA	100.000%	5,866,378	DA	100.000%	4,289,765	539,504	1,037,109
20	Materials & Supplies Transmission	12h. G, L.4. L.5. C.d.	7,200,000	GP1	100.000%	7,200,000	GP1	Gross Plant	4,284,072	858,600	2,057,400
21	Prepayments (Note D)	12a.B.25	-	GP1	10.025%	-	GP1	Gross Plant			
22	**TOTAL WORKING CAPITAL (sum lines 19-21)**		**$ 20,261,990**			**$ 13,066,378**			**$ 8,573,837**	**$ 1,398,104**	**$ 3,094,509**
23	**Rate Base**		**$ 3,834,060,609**			**$ 491,841,491**			**$ 269,407,947**	**$ 37,350,548**	**$ 185,083,107**

Revenue Requirement Worksheet
RUS form 12 Data — **Projection for 2014**
BASIN ELECTRIC POWER COOPERATIVE

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	**39,827,984**								
2	Direct Assignment (Note E)	Accounting Records	24,740,000	DA	100.000%	24,740,000	DA	100 000%	19,800,000	3,560,000	1,380,000
3	Other	Accounting Records	15,087,984	TPW	100.000%	15,087,984	GP2	page 4	10,192,838	-	4,895,146
4	A&G	Expense Worksheet #3	**64,667,933**			-					
5	Less Regulatory Fees (Note F)	Accounting Records	200,000	NA	0.000%	-	NA	0.000%			
6	Production	Accounting Records	2,500,000	NA	0.000%	-	NA	0.000%			
7	Transmission (Note G)	Accounting Records	990,000	DA		990,000	DA	page 4	195,557	756,031	38,412
8	Headquarters		60,977,933	WS	10.025%	6,113,038	GP2	Gross Plant	4,129,724	-	1,983,314
9	**TOTAL O&M (sum lines 1 and 4)**		**$ 104,495,917**			**$ 46,931,022**			**$ 34,318,119**	**$ 4,316,031**	**$ 8,296,872**
	DEPRECIATION & AMORTIZATION EXPENSE										
10	Depreciation and Amortization Expense	Accounting Records	**146,499,970**								
11	Transmission	Accounting Records	13,802,202	DA	100.000%	13,802,202	DA	100 000%	7,349,285	1,181,261	5,271,656
12	Production	Accounting Records	121,439,942	NA	0.000%		NA	0.000%			
13	General Plant	Accounting Records	**9,000,000**	NA	0.000%		NA	0.000%			
14	Transmission	Accounting Records	2,005,000	DA	100.000%	2,005,000	DA	100 000%	981,149	156,341	867,510
15	Production	Accounting Records	6,500,000	NA	0.000%		NA	0.000%			
16	Hdqtrs General Plant		495,000	WS	10.025%	49,624	GP1	Gross Plant	29,527	5,918	14,180
17	Other Amortization		**2,257,826**	DA	0.000%	1,917,762	DA	0.000%	934,373	65,397	917,992
18	**TOTAL (Sum lines 10,13,17)**	Expense Worksheet, L 20. C.b	**$ 146,499,970**			**$ 17,774,588**			**$ 9,294,334**	**$ 1,408,917**	**$ 7,071,338**
	TAXES OTHER THAN INCOME TAXES										
19	PLANT RELATED										
20	Property total	2012 12a A.21 (less income tax)	**2,967,569**								
21	Tax Reclassification	Accounting Records		NA	0.000%	-	NA	0.000%			
22	Gross Receipts (Note I)	2012 RUS Form 12	2,967,569	DA	100.000%	**2,967,569**	DA	100 000%	2,752,000	-	215,569
23	Production			NA	0.000%		NA	0.000%			
24	**TOTAL OTHER TAXES**		**$ 2,967,569**			**$ 2,967,569**			**$ 2,752,000**	**$ -**	**$ 215,569**
25	**TOTAL OPERATING EXPENSES (Sum 9+18+24)**		**$ 253,963,456**			**$ 67,673,179**			**$ 46,364,453**	**$ 5,724,948**	**$ 15,583,779**
26	**Return**		**$ 238,478,570**	WCC	Rate Base	**$ 30,592,541**	WCC	Rate Base	**$ 16,757,174**	**$ 2,323,204**	**$ 11,512,169**
27	**REV. REQUIREMENT (sum lines 25+26)**		**$ 492,442,026**			**$ 98,265,720**			**$ 63,121,627**	**$ 8,048,152**	**$ 27,095,948**

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	52,737,585								
2	Transmission-East	Accounting Records	245,111								
3	Transmission-West	Accounting Records	442,072	**WS**	Trans % of total wages	10.025%		GP1	59.5010%	11.9250%	28 5750%
4	Transmission-Allocated	Accounting Records	5,188,854								
5	Distribution			**TPW**	Trans % excluding MBPP West		Note H	GP2	67.556%	0.000%	32.444%
6	Other Transmission		-								
7	Total Wages and Salaries (sum lines 1-6) (exclude adm)		**$58,613,622**								

Note J		**Estimated Weighted Cost of Capital**			
			Percent	**Rate**	**cost**
Estimated wksht #1	LTD	3,286,072,939	72.56%	4.47%	3 24%
Estimated wksht #1	Equity	1,242,698,580	27.44%	10.85%	2 98%
		4,528,771,519	100.00%		6 22%

Notes

A RUS form 12h plus new investment averaged over 13 months.
B Transmission capital lease for $40,000,000 is excluded from transmission plant investment.
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.
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 $14,000,000 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 gross plant investment.
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 2012	b Estimated Budget Year 2013	c Estimated Budget Year 2014	d Transmission Adjusted for 2014 Average Balance
	GROSS PLANT IN SERVICE				
1	Production	3,746,098,376	4,534,200,000	4,778,145,273	4,656,172,637
2	Transmission	731,236,325	740,800,000	875,298,893	808,049,447
3	General	154,416,977	165,416,977	190,104,587	177,760,782
4	Intangible	78,281,111	78,046,322	78,281,111	78,163,717
5	**TOTAL GROSS PLANT**	**4,710,032,789**	**5,518,463,299**	**5,921,829,864**	**5,720,146,582**
	ACCUMULATED DEPRECIATION				
6	Production	1,188,060,720	1,323,782,708	1,406,641,090	1,365,211,899
7	Transmission	297,026,574	310,343,940	331,704,559	321,024,250
8	General	110,809,095	126,900,000	131,241,627	129,070,814
9	Intangible	51,610,444	53,855,519	56,226,482	55,041,001
10	**TOTAL ACCUM. DEPR**	**1,647,506,832**	**1,814,882,167**	**1,925,813,758**	**1,870,347,963**
	NET PLANT IN SERVICE				
11	Production	2,558,037,656	3,210,417,292	3,371,504,183	3,290,960,738
12	Transmission	434,209,751	430,456,060	543,594,334	487,025,197
13	General	43,607,882	38,516,977	58,862,960	48,689,969
14	Intangible	26,670,667	24,190,803	22,054,629	23,122,716
15	**TOTAL NET PLANT**	**3,062,525,957**	**3,703,581,132**	**3,996,016,106**	**3,849,798,619**

		2014 Estimate
Long-term Liabilities		
Long-term debt, net of current portion	$	3,036,283,412
Obligations under capital lease	$	38,747,384
Total Long-term Liabilities	**$**	**3,075,030,796**
Current Liabilities		
Current portion of long-term debt	$	210,657,892
Current portion of capital lease obligations	$	384,251
Total Current Portion of Long-term Liabilities		**211,042,143**
Total LTD		**3,286,072,939**
Equity		**1,242,698,580**

Basin Electric Power Cooperative							IS Facilities - Worksheet #2							
Integrated System Facilities (IS)														
			Actual 2012				Updated Estimated 2013				Estimated 2014			
						2012				2013				2014
			12/31/12	12/31/12	12/31/12	Depreciation	12/31/13	12/31/13	12/31/13	Depreciation	12/31/14	12/31/14	12/31/14	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			274 028 039	137 891 817.27	136 136 221.73	4 047 027	274 028 039	141 938 844	132 089 195	4 047 027	274 028 039	143 962 358	130 065 681	4 047 027
IS Substations			134,469,423	64,360,297.00	54,976,729.75	2,142,158	134,469,423	66,502,455	58,706,476	2,142,158	134,469,423	67,573,534	66,895,889	2,142,158
IS Trans Mntnce Bldgs			21,091,117	14,411,511.19	6,679,605.98	882,191	21,091,117	15,293,702	3,623,754	882,191	21,091,117	15,734,798	5,356,319	882,191
Microwave			8,508,892	6,939,630.43	1,862,067.35	162,994	8,508,892	7,102,624	1,735,997	162,994	8,508,892	7,184,121	1,324,771	162,994
Intangible			32,355,705	23,024,941.29	9,330,763.61	934,373	32,355,705	23,959,315	8,647,666	934,373	32,355,705	24,426,501	7,929,204	934,373
Accum Depr Adjustment				(6 327 719)				(6 327 719)				(6 327 719)		
Total			**470,453,176**	**240,300,478**	**230,152,698**	**8,168,743**	**470,453,176**	**248,469,221**	**221,983,955**	**8,168,743**	**470,453,176**	**252,553,592**	**217,899,584**	**8,168,743**
Watford City 230/115 kV Transformer	06/01/12	740,986	740,986	239,867	501,120	8,568	740,986	248,435	492,551	8,568	740,986	264,241	476,745	31,612
C Creek Sub & 345/230 kV Transformer	"04/01/12	7,377,266	7,377,266	152,283	7,224,983	152,283	7,377,266	304,566	7,072,700	152,283	7,377,266	380,708	6,996,559	152,283
230/115 Transformer, Caps, etc. Philip	06/01/12	2,370,484	2,370,484	369,186	2,001,298	42,620	2,370,484	411,806	191,750	42,620	2,370,484	433,116	1,937,368	42,620
Switches - Witten	08/01/12	30,800	30,888	-	30,888	-	200,000	5,500	191,750	5,500	200,000	8,250	191,750	5,500
Blaisdell 230/115 Sub	05/01/12	11 919 978	11 919 978	218 715	11 701 263	218 715	11 919 978	437 430	11 482 548	218 715	11 919 978	601 330	11 318 648	327 799
Lonesome Creek - clutch	04/30/13	2,000,000					1,384,615	11,458	1,366,282	22,917	2,000,000	50,417	1,949,583	55,000
Pioneer Station Clutch	04/30/13	2,000,000					1,384,615	11,458	1,366,282	22,917	2,000,000	50,417	1,949,583	55,000
115 KV Line Blaisdell to Berthold	06/30/13	4,800,000					2,584,615	33,000	2,551,615	66,000	4,800,000	132,000	4,668,000	132,000
Williston 230/115 KV Transformer # 2	06/30/13	2,400,000					1,292,308	16,500	1,275,808	33,000	2,400,000	66,000	2,334,000	33,000
Charlie Creek Spare 345 kV transformer	08/01/13	3,000,000					1,384,615	17,188	1,367,428	34,375	3,000,000	75,625	2,924,375	82,500
Rapid City 230/115 KV Transformer	01/01/14	6 500 000									6 000 000	89 375	5 910 625	178 750
			22,439,602	**980,051**	**21,459,552**	**422,186**	**30,639,483**	**1,497,341**	**27,358,714**	**572,520**	**42,808,714**	**2,151,478**	**40,657,237**	**1,096,064**
			492,892,778	**241,280,528**	**251,612,250**	**8,590,929**	**501,092,659**	**249,966,562**	**249,342,669**	**8,741,263**	**513,261,890**	**254,705,070**	**258,556,820**	**9,264,807**
						2012				2013				2014
West (MBPP)			12/31/12	12/31/12	12/31/12	Depreciation	12/31/13	12/31/13	12/31/13	Depreciation	12/31/14	12/31/14	12/31/14	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	43,510,237	27,239,338	910,642	70,749,575	44,420,879	26,784,017	910,642	70,749,575	44,876,200	25,873,375	910,642
West (MBPP) Substations			19,732,903	12,302,151	7,430,752	263,725	19,778,012	12,565,876	7,322,172	263,725	19,778,012	12,697,738	7,080,274	263,725
West (MBPP) Trans Mntnce Bldgs			2 614 354	1 935 687	678 667	79 885	2 362 545	2 015 572	367 473	79 885	2 362 545	2 055 515	307 030	79 885
West (MBPP) Microwave			1,671,059	1,327,067	343,992	83,350	1,844,541	1,410,417	329,813	83,350	1,844,541	1,452,092	392,449	83,350
Intangible			2,617,629	1,952,304	665,325	65,397	2,617,629	2,017,701	567,229	65,397	2,617,629	2,050,400	567,229	65,397
Accum Depr Adjustment			-	(1,275,679)		-	-	(1,275,679)			-	(1,275,679)		
Total			**97,385,520**	**59,751,767**	**37,633,753**	**1,402,999**	**97,352,302**	**61,154,766**	**36,197,536**	**1,402,999**	**97,352,302**	**61,856,265**	**35,496,037**	**1,402,999**
Miscellaneous Add/replace			-	-	-	-	-	-	-	-	-	-	-	-
GRAND TOTAL MBPP			**97,385,520**	**59,751,767**	**37,633,753**	**1,402,999**	**97,352,302**	**61,154,766**	**36,197,536**	**1,402,999**	**97,352,302**	**61,856,265**	**35,496,037**	**1,402,999**

Basin Electric Power Cooperative
Estimated 2013 Expenses

		Expense Worksheet #3	
		(a)	(b)
		2013	2014
		Estimate	Estimated
	Expenses - Operations:		
1	Production - Excluding Fuel	115,136,131	121,514,368
2	Production - Fuel	263,128,686	264,157,641
3	Production - Rents	40,540,858	40,775,246
4	Other Power Supply	314,164,287	363,589,146
5	**Sub-Total Operations Exp.**	**732,969,962**	**790,036,401**
6			
7	Transmission Operations	24,330,702	34,991,020
8	Trans of Electricity by others	38,142,100	36,331,952
9	Subtotal - Transmission	**62,472,802**	**71,322,972**
10			
11	Administration	57,845,091	64,667,933
12	**Total Operations Expense**	**795,442,764**	**926,027,306**
13			
14	**Expenses - Maintenance:**		
15	Production	128,506,184	143,487,050
16	Transmission	5,098,721	4,836,964
17	General Plant	0	
18	**Total Maintenance Expense**	**133,604,905**	**148,324,014**
19			
20	Depreciation & Amortization	137,592,503	146,499,970
21	Taxes	2,957,826	2,967,569
22	Interest & Other Deductions	153,853,440	148,795,893
		294,403,769	**298,263,432**
	Total Cost of Electric Service	**1,223,451,438**	**1,372,614,752**

Basin Electric Power Cooperative

December 31, 2012

cpx	Type	Description	BookBasisAmount	AccumDepr LTD	NetBookAmount	Depr YTD
012	L	230kv LO#1 DC Line to Washburn	1,485,282	1,450,404	34,878	-
021	L	345 kv line Stanton to SD Border	9,297,594	8,267,736	1,029,858	26,842
022	L	345 kv line - SD to Ft Thompson	9,134,431	7,899,366	1,235,066	25,089
023	L	345 kv line Stanton to SD Border	11,511,850	10,115,156	1,396,693	31,822
024	L	345 kv line SD to Watertown	10,164,504	8,732,378	1,432,126	32,443
025	L	230 kv line LOS#1 to Logan	5,181,912	3,895,142	1,286,771	31,078
026	L	230 kv line-230/115/69-sub (16)	289,132	252,635	36,497	1,259
031	L	115 kv line Logan to Kenmare	3,115,809	2,253,236	862,574	15,614
032	L	115 kv line Logan to Mallard	632,973	442,784	190,189	3,052
034	L	230 kv line Philip Tap-Philip Sub	853,709	772,454	81,255	2,419
127	L	345 kv N line #1 dbl circ	12,390,821	5,486,522	6,904,299	217,946
128	L	345 kv S line #2 dbl circ	11,215,381	5,868,908	5,346,473	161,916
129	L	500 kv AVS switchyd to SD bdr	57,926,565	30,975,904	26,950,661	852,932
130	L	500 kv SD bdr to Broadland sub	53,098,066	28,278,350	24,819,716	778,666
134	L	345 kv dbl circ line	942,053	661,537	280,516	10,018
141	L	230 kv line Broadland to Huron	1,068,625	599,164	469,461	16,505
150	L	230 kv line Estavan to Sask bdr	15,071,877	10,755,277	4,316,600	119,132
152	L	345 kv line AVS to Charlie Creek	11,657,031	6,426,488	5,230,544	156,831
181	L	230 KV Line - Rhame to Belfield	28,337,329	2,056,379	26,280,950	752,729
185	L	230 kv line MC-Bowman-NU	9,716,689	8,297,074	1,419,615	283,688
234	L	115Kv Line-Char Ck-Sqw Gab Sub	1,218,283	137,684	1,080,599	33,507
235	L	115Kv Line-Sqw Gap-ND/MT Bordr	375,853	41,665	334,188	10,416
236	L	115Kv Line-ND/MT Brd-Richld Sb	281,424	31,628	249,796	7,746
296	L	230 kv line - Williston to Tioga	24,588,853	1,345,757	23,243,096	674,567
311	L	115 kv tie line to Groton sub	136,010	95,940	40,071	1,431
361	L	69KV Line Cornbelt	41,112	10,553	30,559	1,200
411	L	230 KV Line RC to New Underwood	6,010,877	1,327,687	4,683,191	142,952
		Subtotal Lines	**285,744,047**	**146,477,805**	**139,266,241**	**4,391,801**

013	S	**230KV LO Washburn Substation**	71,594	70,298	1,296	-
016	S	**230/115/69KV LO Substation**	1,234,995	1,150,924	84,071	2,800
036	S	**345KV FT Thompson Substation**	2,374,699	2,077,027	297,672	10,631
039	S	**230/115KV Storla, SD Substation**	2,207,566	1,861,688	345,878	12,087
040	S	**230/115KV Philip, SD Substation**	3,233,349	503,572	2,729,777	58,133
042	S	**230KV Philip,SD Tap Substation**	214,957	196,640	18,318	613
046	S	**Martin, SD USBR Sub Capacitor Installed**	1,148,649	182,395	966,253	27,735
047	S	**Armour, SD USBR Sub Capacitor Installed**	137,379	125,631	11,748	420
058	S	**115KV Williston, ND Substation**	643,259	485,817	157,441	5,623
060	S	**230/115KV Dickinson, ND Substation**	1,204,038	1,096,318	107,720	3,650
061	S	**115KV Spirit Mound Switchyard**	1,570,210	1,234,829	335,382	18,632
063	S	**Static VAR Suppt-Victory Hill Sub-Sctbluff**	1,647,967	1,578,420	69,547	52,163
126	S	**500KV Broadland SD, Substation**	12,470,254	6,982,073	5,488,180	194,672
142	S	**230KV USBR Huron Substation Addition**	1,683,941	929,949	753,992	26,928
145	S	**Manning,ND Sub Capacitor Installed**	186,623	157,982	28,640	1,591
153	S	**345/115KV Charlie Creek Substation**	5,342,496	3,839,609	1,502,887	52,055
179	S	**Little Missouri Tap 115 kv Capacitor Bank**	1,244,509	108,466	1,136,042	34,253
182	S	**230 kv Belfield Substation**	526,115	460,672	65,443	2,196
183	S	**230 kv Rhame Substation**	6,014,030	489,947	5,524,083	160,911
194	S	**Bowman Sub -230 KV breakers**	1,393,433	379,462	1,013,971	36,213
195	S	**Hettinger Capacitors**	827,735	206,734	621,001	22,789
196	S	**Baker Capacitors**	827,735	206,734	621,001	22,789
211	S	**Charlie Creek Addition**	7,377,266	152,283	7,224,983	152,283
278	S	**230 kV Sully Butte Sub (Shunt)**	1,435,657	72,943	1,362,714	39,787
279	S	**230 kV Glenham Sub (Shunt)**	2,784,671	101,776	2,682,895	76,381
295	S	**230/115kV Blaisdell Substation**	12,120,173	218,715	11,901,458	218,715
297	S	**230 kv Neset (Tioga) Substation (T3)**	10,309,585	911,021	9,398,564	302,235
299	S	**230Kv Willistn Sub Transformer**	2,736,411	81,590	2,654,821	75,314
310	S	**345/115KV Groton Substation Addition**	5,046,112	3,322,143	1,723,969	59,259
314	S	**Groton 115kv Capacitor Banks**	2,284,014	230,457	2,053,557	73,341
325	S	**230 mw Miles City DC Tie**	18,989,386	14,257,941	4,731,445	525,716
327	S	**Witten**	30,888	-	30,888	-
328	S	**Watford**	740,986	239,867	501,120	8,568
329	S	**Mission**	1,794,141	49,837	1,744,304	49,837
362	S	**69KV Substation - Cornbelt**	1,557,920	402,343	1,155,578	45,765
408	S	**RC Tie East Interconnect**	1,060,552	271,002	789,550	29,153
470	S	**Groton Clutch**	1,115,796	225,645	890,151	33,086
550	S	**115 kV Ordway Substation**	2,244,767	151,183	2,093,584	62,032
711	S	**230KV LO #1 Switchyard and AVS Addition**	5,226,218	4,134,038	1,092,180	27,030
720	S	**345/230KV LO#2 Switchyard and AVS Add**	22,320,778	10,548,084	11,772,694	201,997
734	S	**Tioga substation - Capacitor bank**	387,866	207,277	180,589	6,450
735	S	**345/230KV Watertown Substation**	2,871,896	2,623,059	248,837	8,887
737	S	**230/115KV Logan Substation & Sask Addition**	4,115,005	3,169,070	945,935	30,453
767	S	**345KV AVS Switchyard & Charlie Creek Add't**	24,793,104	14,083,840	10,709,264	380,769
		Subtotal Substation	**177,548,722**	**79,779,300**	**97,769,421**	**3,153,943**

070	TSM	**Mandan Transmission Maint Bldg**	8,929,440	5,717,473	3,211,967	352,917
071	TSM	**Gettysburg Trans Maint Bldg**	2,081,183	1,095,676	985,507	62,271
072	TSM	**Groton Trans Maint Bldg**	2,238,314	1,781,343	456,971	169,888
109	TSM	**Logan Trans Maint Bldg**	1,709,852	1,265,017	444,835	91,762
119	TSM	**Broadland Trans Maint Bldg**	1,428,073	1,097,272	330,801	50,791
120	TSM	**AVS Plantsite Trans Maint Bldg**	4,367,353	3,427,413	939,941	127,246
570	TSM	**Williston TSM**	336,902	27,317	309,585	27,317
		Subtotal TSM	**21,091,117**	**14,411,511**	**6,679,606**	**882,191**
043	M	**Microwave - North Dakota**	10,619,076	8,218,846	2,400,230	233,752
044	M	**Microwave -South Dakota**	4,935,686	4,252,167	683,520	80,684
136	M	**Microwave - SD AVS**	897,056	846,339	50,717	10,858
137	M	**Microwave - AVS**	2,175,315	1,501,203	674,112	66,664
139	M	**Microwave - ND Sask**	1,340,022	1,291,237	48,784	8,924
155	M	**Microwave - ND CC**	1,061,358	1,014,093	47,265	4,074
308	M	**Microwave - SD Groton**	143,259	143,259	-	605
		Subtotal Microwave	**21,171,772**	**17,267,144**	**3,904,628**	**405,560**
		Microwave Adjustment	(12,662,879)	(10,327,514)	(2,335,366)	(242,566)
		Total Microwave	**8,508,892**	**6,939,630**	**1,569,262**	**162,994**
		Accumulated Depreciation Adjustment		(6,327,719)		
		TOTAL IS TRANSMISSION	**492,892,778**	**241,280,528**	**251,612,250**	**8,590,930**

Basin Electric's Ancillary Services Cost Data

Basin Electric Power Cooperative
IS Ancillary Services
Regulation and Frequency Response - Estimate 2014

Summary

A	Total LOS and AVS Net Plant Investment	527,545,762	(ancillary worksheet 1)
B	Facilities with AGC (LOS 1 & AVS)	418,372,032	(Ancillary worksheet 1 less LOS 2)
C	B/A	79.305%	
D	AGC Facilities	35,140	
E	AGC Facilities Percentage (D/B)	0.0084%	
F	Generation Revenue Requirement	179,881,505	(Generation revenue require LO#1 and AVS)
G	Plant Allocated to AGC	15,109	(E x F)
H	Regulation Revenue Requirement	**50,249**	(D + G)

Basin Electric Power Cooperative
Generation Plant
December 31, 2012

	LO #1	**LO #2**	**AVS #065**	**AVS #066**
Gross Plant - Production	104,641,174	231,511,902	658,832,958	223,345,691
Accum Depr - Production	(70,576,467)	(126,338,151)	(387,432,559)	(121,469,969)
Accum Depr - Adjustment	1,007,940	1,795,773	3,660,824	1,720,459
Net Book (RUS 310-349)	35,072,647	106,969,524	275,061,223	103,596,181

	LO #1	**LO #2**	**AVS #065**	**AVS #066**
Gross General Plant	7,057,230	7,057,230	6,165,403	6,165,403
G/P Gross Microwave Alloc	1,811,480	1,811,480	1,811,480	1,811,480
Accum Depr	(4,404,066)	(4,404,066)	(4,937,167)	(4,937,167)
Microwave Accum Depr	(1,494,745)	(1,494,745)	(1,494,745)	(1,494,745)
Accum Depr Adjust	(765,693)	(765,693)	(668,105)	(668,105)
Net Book - General Plant	2,204,206	2,204,206	876,866	876,866
Gross Plant Intangible	-	-	524,573	524,573
Accum Depr			(182,551)	(182,551)
Net Book	-	-	342,021	342,021
Total Net Plant	**37,276,853**	**109,173,730**	**276,280,110**	**104,815,068**

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

For the twelve months ended 12/31/2012

Line No.		Total Production	(6) LO #1	(7) LO #2	(8) AVS #065	(9) AVS #066
1	**GROSS REVENUE REQUIREMENT (page 3, line 28)**	**$ 559,381,336**	**$ 26,760,056**	**$ 68,477,825**	**$ 69,978,151**	**$ 83,143,298**
			39.76%			

	REVENUE CREDITS		Total	Allocator	
2	Third Party Receipts			TP	1.00000
3					
4	Third Party Payments			TP	1.00000
5		(line 2 + 4)			
6	**NET REVENUE REQUIREMENT**	(line 1+ 5)			

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

For the twelve months ended 12/31/2012

	(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
	GROSS PLANT IN SERVICE											
1	Production (Note A)	12h.A.6.e	**3,746,098,376**	DA	100.000%	3,746,098,376	NA	100.000%	104,641,174	231,511,902	658,832,958	223,345,691
2	Transmission (Note B)	12h.A.11.e & 12h.A.23.e	**731,236,325**	DA	N/A	-	DA	N/A	-	-	-	-
3	Distribution	12h.A.e.16	-	NA	0.000%	-	NA	0.000%	-	-	-	-
4	General	12h.A.17.e	**154,416,977**			-			-	-	-	-
4a	Direct Assign - Transmission	12h.A.17.e	34,894,715	DA	N/A	-	DA	N/A	-	-	-	-
4b	Direct Assign - Production (Note C)	12h.A.17.e	49,654,552	NA	100.000%	49,654,552	NA	100.000%	8,868,710	8,868,710	7,976,883	7,976,883
4c	Other	12h.A.17.e	69,867,710	WS	89.816%	62,752,407	WS	Gross Plant	1,752,887	3,878,149	11,036,377	3,741,354
5	Intangible	12h.A.1.e	**78,281,111**	DA	100.000%	1,049,145	DA	100.000%	-	-	524,573	524,573
6	**TOTAL GROSS PLANT (sum lines 1,2,4,5)**	12h.A.18.e & 12h.A.23.e	**$ 4,710,032,789**			**$ 3,859,554,480**			**$ 115,262,771**	**$ 244,258,761**	**$ 678,370,790**	**$ 235,588,500**
							GP1	Gross Plant	2.793%	6.180%	17.587%	5.962%
	ACCUMULATED DEPRECIATION											
7	Production	12h.B.1-4.f	**1,188,060,720**	DA	100.000%	1,188,060,720	NA	0.000%	69,568,527	124,542,378	383,771,735	119,749,510
8	Transmission	12h.B.5.f & 12h.B.15.f	**297,026,574**	N/A	100.000%	-	DA	100.000%	-	-	-	-
9	Distribution	12h.B.6.f	**-**	NA	0.000%	-	NA	0.000%	-	-	-	-
10	General	12h.B.7.f	**110,809,095**			-			-	-	-	-
10a	Direct Assign - Transmission		24,515,791	N/A	0.000%	-	DA	0.000%	-	-	-	-
10b	Direct Assign - Production		35,917,181	DA	100.000%	35,917,181	DA	100.000%	6,664,504	6,664,504	7,100,016	7,100,016
10c	Other		50,376,122	WS	89.816%	45,245,836	GP1	Gross Plant	1,263,869	2,796,229	7,957,465	2,697,597
11	Intangible	12h.B.12.f	**51,610,444**	DA	100.000%	365,102	DA	100.000%	-	-	182,551	182,551
12	**TOTAL ACCUM. DEPR (sum lines 7,8,10,11)**	12h.B.18.f	**$ 1,647,506,832**			**$ 1,269,588,839**			**$ 77,496,900**	**$ 134,003,111**	**$ 399,011,768**	**$ 129,729,674**
	NET PLANT IN SERVICE											
13	Production	(line 1- line 7)	**2,558,037,656**	AUTO		2,558,037,656	AUTO		35,072,647	106,969,524	275,061,223	103,596,181
14	Transmission	(line 2- line 8)	**434,209,751**	AUTO		-	AUTO		-	-	-	-
15	Distribution	(line 3 - line 9)	**-**	AUTO		-	AUTO		-	-	-	-
16	General	(line 4 - line 10)	**43,607,882**	AUTO		-	AUTO		-	-	-	-
16a	Direct Assign	(line 4a - line 10a)	10,378,924	AUTO		-	AUTO		2,204,206	2,204,206	876,866	876,866
16b	Production	(line 4b - line 10b)	13,737,371	AUTO		13,737,371	AUTO		-	-	-	-
16c	Other	(line 4c - line 10c)	19,491,587	AUTO		17,506,571	AUTO		489,018	1,081,920	3,078,912	1,043,757
17	Intangible	(line 5 - line 11)	**26,670,667**	AUTO		684,043	AUTO		-	-	342,021	342,021
18	**TOTAL NET PLANT (sum lines 13, 14, 16, 17)**		**$ 3,062,525,957**			**$ 2,589,965,641**			**$ 37,765,871**	**$ 110,255,650**	**$ 279,359,022**	**$ 105,858,826**
	WORKING CAPITAL											
19	CWC (Note D)	one eighth of line 9, page 3	39,525,830	DA	100.000%	38,703,035	DA	100.000%	2,721,567	7,063,431	5,045,457	8,940,380
20	Materials & Supplies Production	12h, Section G, L.3. C.d.	48,155,419	DA	100.000%	48,155,419	GP1	Gross Plant	1,345,143	2,976,044	8,469,179	2,871,069
21	Prepayments (Note D)	12a.Section B. L.25		GP1	0.000%	-	GP1	Gross Plant				
22	**TOTAL WORKING CAPITAL (sum lines 19 21)**		**$ 87,681,249**			**$ 86,858,454**			**$ 4,066,710**	**$ 10,039,474**	**$ 13,514,635**	**$ 11,811,448**
23	**Rate Base**		$3,150,207,205			$ 2,676,824,095			$ 41,832,581	$ 120,295,125	$ 292,873,658	$ 117,670,274

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

For the twelve months ended 12/31/2012

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
	O&M											
1	Production Plant	RUS 12a, L5 & L16	**259,493,088**	DA	100.000%	259,493,088	DA	100.000%	20,196,110	53,019,709	30,438,306	68,158,324
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.	**56,713,549**			-						
5	Less Regulatory Fees (Note E)	Accounting Records	155,664	NA	0.000%	-	NA	0.000%				
6	Production (Note F)	Accounting Records	2,423,734	DA	100.000%	2,423,734	NA	0.000%				
7	Transmission	Accounting Records	1,017,289	DA/TPW	0.000%		DA /TPW	page 4	-	-	-	-
8	Headquarters (Note G)		53,116,862	WS	89.816%	47,707,460	GP2	Gross Plant	1,576,424	3,487,737	9,925,347	3,364,712
9	**TOTAL O&M (sum lines 1 and 4)**	Expense Worksheet	**$ 316,206,637**			**$ 309,624,281**			**$ 21,772,534**	**$ 56,507,446**	**$ 40,363,653**	**$ 71,523,037**
	DEPRECIATION & AMORTIZATION EXPENSE											
10	Depreciation and Amortization Expense	Accounting Records	**106,188,066**									
11	Transmission	Accounting Records	12,804,877	NA	0.000%	-	NA	0.000%				
12	Production	Accounting Records	82,259,352	DA	100.000%	82,259,352	DA	100.000%	1,605,084	3,781,331	10,956,111	3,810,918
13	General Plant	Accounting Records	**8,853,261**	NA	0.000%	-	NA	0.000%				
14	Transmission	Accounting Records	1,692,075	NA	0.000%	-	NA	0.000%				
15	Production	Accounting Records	3,909,409	DA	100.000%	3,909,409	DA	100.000%	791,552	791,552	550,458	550,458
16	Other General Plant		3,251,777	WS	87.879%	2,857,637	GP1	Gross Plant	79,823	176,604	502,578	170,375
17	Other Amortization		**2,270,577**	DA	100.000%	50,359	DA	100.000%			25,180	25,180
18	**TOTAL (Sum lines 10,13,17)**	Expense Worksheet, L.20. C.a	**$ 106,188,066**			**$ 89,076,757**			**$ 2,476,459**	**$ 4,749,487**	**$ 12,034,326**	**$ 4,556,931**
	TAXES OTHER THAN INCOME TAXES											
19	PLANT RELATED											
20	Property total	2010 12a.A.21 (less income tax)	**2,278,696**									
21	Tax Reclassification	Accounting Records		NA	0.000%	-	NA	0.000%				
22	Gross Receipts (Note G)	2010 RUS Form 12	2,288,217	NA	0.000%	**-**	DA	100.000%	-	-	-	-
23	Production			NA	0.000%		NA	0.000%				
24	**TOTAL OTHER TAXES**		**$ 2,288,217**			**$ -**			**$ -**	**$ -**	**$ -**	**$ -**
25	**TOTAL OPERATING EXPENSES (Sum 9+18+24)**		**$ 424,682,920**			**$ 398,701,038**			**$ 24,248,994**	**$ 61,256,933**	**$ 52,397,979**	**$ 76,079,967**
26	**Return**		**$ 189,095,814**	WCC	Rate Base	**$ 160,680,298**	WCC	Rate Base	**$ 2,511,062**	**$ 7,220,892**	**$ 17,580,171**	**$ 7,063,331**
27	**REV. REQUIREMENT (sum lines 25+26)**		**$ 613,778,735**			**$ 559,381,336**			**$ 26,760,056**	**$ 68,477,825**	**$ 69,978,151**	**$ 83,143,298**

A & G Allocation

WAGES AND SALARY ALLOCATOR (W/S)

Line No.	(1) From Accounting Report	(2)	(3) TOTAL	(4) Allocator		(5) Percent		(6) LO #1	(7) LO #2	(8) AVS #065	(9) AVS #066
1	Production	Accounting Records	51,365,483								
2	Transmission-East	Accounting Records	213,769								
3	Transmission-West	Accounting Records	457,592	**WS**		89.816%					
4	Transmission-Allocated	Accounting Records	5,152,813	GP2	% excludes MBPP West		GP2	3.304%	7.311%	20.805%	7.053%
5	Distribution		-								
6	Other Transmission		-								
7	Total Wages and Salaries (sum lines 1-6) (exclude adm)		**$57,189,658**								

Note H	**Weighted Cost of Capital**		**Percent**	**Rate**	**Weighted cost**
12a. B.L.46 & L. 52	LTD	3,537,285,452	76 06%	4.48%	3.41%
12a. B.L.39	Equity	1,113,318,613	23 94%	10.85%	2.60%
		4,650,604,065	100 00%		6.00%

Note
A Line 1, page 2 excludes $1,055,780 and is included in line 2, page 2. Line 2 also includes $2,825,409 transmission acquisition adjustment.
Accumulated Depreciation for 214,908 associated with the $1,055,780 is excluded in line 7 and added to line 8
B Transmission lease for $40,270,827 is excluded from transmission plant investment.
C General Plant directly assigned to production includes common facilities and microwave assigned to production.
D Cash working capital assigned to transmission is one eighth of O&M allocated to transmission on page 3 , line 9, column 6-7
Prepayments are the electric related prepayments booked to Account No. 165 and reported on Section B, line 24, on the RUS 12 forr
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 gross plant.
Includes OASIS costs for West Side and Common Use System plus legal fees for transmission.
G 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.
H 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

For the 12 months ending 12/31/2014

Heartland Consumers Power District

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQU REMENT (page 3, line 29)					$ 890,217
	REVENUE CREDITS	(Note P)				
2	Account No. 454	(page 4, line 30)	24,843	TP	0.53599	$13,316
3	Account No. 456.1	(page 4, line 33)	0	TP	0.53599	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					13,316
	NET REVENUE REQUIREMENT	(line 1 minus line 6)				$ 876,901

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Annual Transmission Revenue Requirement

For the 12 months ending 12/31/2014

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		44,214,611	NA		
2	Transmission	Schedule A		15,038,480	TP	0.53599	8,060,475
3	Distribution			0	NA		
4	General & Intangible	Schedule A		6,668,990	W/S	0.07020	468,163
5	Common			0	CE	0.07020	0
6	TOTAL GROSS PLANT (sum lines 1-5)			65,922,081	GP=	12 937%	8,528,638
	ACCUMULATED DEPRECIATION						
7	Production	Schedule A		32,547,276	NA		
8	Transmission	Schedule A		12,087,768	TP	0.53599	6,478,923
9	Distribution			0	NA		
10	General & Intangible	Schedule A		3,148,767	W/S	0.07020	221,043
11	Common			0	CE	0.07020	0
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)			47,783,811			6,699,966
	NET PLANT N SERVICE						
13	Production	(line 1- line 7)		11,667,335			
14	Transmission	(line 2- line 8)		2,950,712			1,581,552
15	Distribution	(line 3 - line 9)		0			
16	General & Intangible	(line 4 - line 10)		3,520,223			247,120
17	Common	(line 5 - line 11)		0			0
18	TOTAL NET PLANT (sum lines 13-17)			18,138,270	NP=	10 082%	1,828,672
	ADJUSTMENTS TO RATE BASE (Note A)						
19	Account No. 281 (enter negative)			0		zero	0
20	Account No. 282 (enter negative)			0	NP	0.10082	0
21	Account No. 283 (enter negative)			0	NP	0.10082	0
22	Account No. 190			0	NP	0.10082	0
23	Account No. 255 (enter negative)			0	NP	0.10082	0
24	TOTAL ADJUSTMENTS (sum lines 19 - 23)			0			0
25	LAND HELD FOR FUTURE USE (Note B)			0	TP	0.53599	0
	WORKING CAPITAL (Note C)						
26	CWC			526,463			58,006
27	Materials & Supplies (Note B)			0	TE	1.00000	0
28	Prepayments	Schedule A		342,634	GP	0.12937	44,327
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)			869,097			102,333
30	RATE BASE (sum lines 18, 24, 25, and 29)			19 007 367			1 931 005

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Annual Transmission Revenue Requirement

For the 12 months ending 12/31/2014

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	237,414	TE	1.00000	237,414
1a	Less LSE Expenses included in Transmission O&M Accounts (Note D)		0		1.00000	0
2	Less Account 565	Schedule A	56,313	NA	1.00000	56,313
3	A&G (Note G)	Schedule A	4,030,604	W/S	0.07020	282,948
4	Less FERC Annual Fees		0	W/S	0.07020	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad(Note E)		0	W/S	0.07020	0
5a	Plus Transmission Related Reg. Comm. Exp. (Note E)		0	TE	1.00000	0
6	Common		0	CE	0.07020	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)		4,211,705			464,049
	DEPRECIATION EXPENSE					
9	Transmission	Schedule A	399,587	TP	0.53599	214,175
10	General	Schedule A	171,141	W/S	0.07020	12,014
11	Common		0	CE	0.07020	0
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		570,728			226,189
	TAXES OTHER THAN NCOME TAXES (Note F)					
	LABOR RELATED					
13	Payroll	Schedule A	99,933	W/S	0.07020	7,015
14	Highway and vehicle		0	W/S	0.07020	0
15	PLANT RELATED					
16	Property	Schedule A	281,049	GP	0.12937	36,359
17	Gross Receipts		0	NA	zero	0
18	Other		0	GP	0.12937	0
19	Payments in lieu of taxes		0	GP	0.12937	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		380,982			43,374
	NCOME 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	0.10082	0
27	Total Income Taxes	(line 25 plus line 26)	0			0
28	RETURN		1,541,497	NA		156,605
	[Rate Base (page 2, line 30) * Rate of Return (page 4, line 24)]					
29	REV. REQU REMENT (sum lines 8, 12,20,27,28)		6,704,912			890,217

Revenue Requirement Template
Annual Transmission Revenue Requirement

Revenue Requirement - Non-Levelized

For the 12 months ending 12/31/2014

Heartland Consumers Power District

SUPPORTING CALCULATIONS AND NOTES

Line No.			$					
	TRANSMISSION PLANT NCLUDED N IS RATES							
1	Total transmission plant (page 2, line 2, column 3)						15,038,480	
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)						8,060,516	
5	Percentage of transmission plant included in IS Rates (line 4 divided by line 1)					TP=	0.53599	
	TRANSMISSION EXPENSES							
6	Total transmission expenses (page 3, line 1, column 3)						237,414	
7	Less transmission expenses included in OATT Ancillary Services (Note J)						0	
8	Included transmission expenses (line 7 less line 6)						237,414	
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	0.53599	
11	Percentage of transmission expenses included in IS Rates (Note K)					TE=	1.00000	
	WAGES & SALARY ALLOCATOR (W&S)							
			$	TP	Allocation			
12	Production		1,240,807	0 00	0			
13	Transmission		185,408	0 54	100,120			
14	Distribution		0	0 00	0		W&S Allocator	
15	Other		0	0 00	0		($ / Allocation)	
16	Total (sum lines 12-15)		1,426,215		100,120	=	0.07020	= W/S
	COMMON PLANT ALLOCATOR (CE) (Note L)							
			$		% Electric (line 17 / line 20)		Labor Ratio (line 16)	CE
17	Electric	Schedule A	65,922,081					
18	Gas		0		1.00000	*	0.07020 =	0.07020
19	Water		0					
20	Total (sum lines 17-19)		65,922,081					
	RETURN (R)		$					
21	Long Term Interest	Schedule A	$1,644,280					
			$	%	Cost (Note M)		Weighted	
22	Long Term Debt	Schedule A	26,892,113	68%	6.11%		0 0415	=WCLTD
23	Proprietary Capital	Schedule A	12 512 835	32%	12 38%		0 0396	
24	Total (sum lines 22, 23)		39,404,948	100%			0 0811	=R
25					Proprietary Capital Cost Rate =		12 38%	
26					T ER =		1.33	
	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)						$24,843	
	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 Template
Revenue Requirement - Non-Levelized | Annual Transmission Revenue Requirement | For the 12 months ending 12/31/2014

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 T ER is determined. TIER will be supported in the filing and no change in T ER 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

Formula Rate - Non-Levelized
Clean Version

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/2014

MRES

Line No.						Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 31)					$ 5,685,733
	REVENUE CREDITS	(Note T)	Total	Allocator		
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)				$ 5 550 577
	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 ($/kW/Yr)	(line 7 / line 15)	8.233			
17	Network & P-to-P Rate ($/kW/Mo) (line 11 / 12)		0.686			
			Peak Rate			Off-Peak Rate
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	0.158			$0.158
19	Point-To-Point Rate ($/kW/Day)	(line 16 / 260; line 16 / 365)	0.032	Capped at weekly rate		$0.023
20	Point-To-Point Rate ($/MWh)	(line 16 / 4,160; line 16 / 8,760 times 1,000)	1.979	Capped at weekly and daily rates		$0.940
21	FERC Annual Charge ($/MWh)	(Note E)	$0.000	Short Term		$0.000 Short Term
22			$0.000	Long Term		$0.000 Long Term

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/2014

Line No.	(1) RATE BASE:	(2) EIA 412 Reference	MRES (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	295,228,274	NA		
2	Transmission	IV.7.e less Line 2a	66,413,815	TP	1.00000	66,413,815
2a	Transmission for projects with FERC approved incentives (Note EE)		19,344,335	TP	1.00000	19,344,335
3	Distribution	IV.8.e	0	NA		
4	General & Intangible	IV.1e and IV.9.e	24,403,142	W/S	0.15193	3,707,569
5	Common		0	CE	0.15193	0
6	TOTAL GROSS PLANT (sum lines 1-5)		405,389,566	GP=	22.069%	89,465,719
	ACCUMULATED DEPRECIATION (Note AA and Note GG)					
7	Production		180,858,845	NA		
8	Transmission		34,739,854	TP	1.00000	34,739,854
8a	Transmission for projects with FERC approved incentives (Note EE)		412,912	TP	1.00000	412,912
9	Distribution		0	NA		
10	General & Intangible		15,470,311	W/S	0.15193	2,350,404
11	Common		0	CE	0.15193	0
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		231,481,922			37,503,170
	NET PLANT IN SERVICE (Note GG)					
13	Production	(line 1- line 7)	114,369,429			
14	Transmission	(line 2- line 8)	31,673,961			31,673,961
14a	Transmission for projects with FERC approved incentives (Line 2a - line 8a) (Note EE)		18,931,423			18,931,423
15	Distribution	(line 3 - line 9)	0			
16	General & Intangible	(line 4 - line 10)	8,932,831			1,357,165
17	Common	(line 5 - line 11)	0			0
18	TOTAL NET PLANT (sum lines 13-17)		173,907,644	NP=	29.879%	51,962,549
18a	CWIP for projects with FERC approved incentives (Note CC and Note GG)		59,279,672	NA	1.00000	59,279,672
	ADJUSTMENTS TO RATE BASE (Note F)					
19	Account No. 281 (enter negative)		0		zero	0
20	Account No. 282 (enter negative)		0	NP	0.29879	0
21	Account No. 283 (enter negative)		0	NP	0.29879	0
22	Account No. 190		0	NP	0.29879	0
23	Account No. 255 (enter negative)		0	NP	0.29879	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		1,519,613			634,406
27	Materials & Supplies (Note GG)	(Note G)	294,598	TE	0.98851	291,213
28	Prepayments (Note GG)	II.20.b	2,214,197	GP	0.22069	488,651
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		4,028,408			1,414,270
30	RATE BASE earning ACSR (lines 18+24+25+29-14a-23a)		159 004 629			34 445 396
30a	RATE BASE earning HCSR (lines 14a+18a+23a)		78 211 095			78 211 095

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/2014

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		30,146,861	TE	0.98851	29,800,474
1a	Less LSE Expenses included in Transmission O&M Accounts (Note V)			0		1.00000	0
2	Less Account 565			26,387,993	TE	0.98851	26,084,795
3	A&G	VII.13.d		8,733,034	W/S	0.15193	1,326,810
4	Less FERC Annual Fees			0	W/S	0.15193	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)			435,000	W/S	0.15193	66,090
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)			100,000	TE	0.98851	98,851
6	Common			0	CE	0.15193	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)			12,156,902			5,075,250
	DEPRECIATION AND AMORTIZATION EXPENSE (Note AA)						
9	Transmission			1,379,544	TP	1.00000	1,379,544
9a	Abandoned Plant Amortization (Note DD)			0	NA	1.00000	0
10	General & Intangible			695,660	W/S	0.15193	105,692
11	Common			0	CE	0.15193	0
12	TOTAL DEPRECIATION (sum lines 9 - 11)			2,075,204			1,485,236
	TAXES OTHER THAN INCOME TAXES (Note J)						
	LABOR RELATED						
13	Payroll			0	W/S	0.15193	0
14	Highway and vehicle			0	W/S	0.15193	0
15	PLANT RELATED						
16	Property			1,915,300	GP	0.22069	422,688
17	Gross Receipts			0	NA	zero	0
18	Other			0	GP	0.22069	0
19	Payments in lieu of taxes			0	GP	0.22069	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)			1,915,300			422,688
	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	0.29879	0
27	Total Income Taxes	(line 25 plus line 26)		0			0
28	RETURN from ACSR			16,557,658	NA		7,863,423
	[Rate Base (page 2, line 30 + 30a) * Rate of Return (page 4, line 24)]						
28a	RETURN from HCSR			1,282,662	NA		1,282,662
	[Rate Base (page 2, line 30a) * Rate of Return (page 4, line 30)]						
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28 and 28a)			33,987,726			16,129,259
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]			7,608,800			7,608,800
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]			2,834,726			2,834,726
31	REVENUE REQUIREMENT TO BE COLLECTED UNDER ATTACHMENT O			23,544,200			5,685,733
	(line 29 - line 30 - line 30a)						

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing EIA Form 412 Data

For the 12 months ended 12/31/2014

MRES

SUPPORTING CALCULATIONS AND NOTES

Line No.								
	TRANSMISSION PLANT INCLUDED IN ISO RATES							
1	Total transmission plant (page 2, line 2 and 2a, column 3)						66,413,815	
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)						66,413,815	
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)						30,146,861	
7	Less transmission expenses included in OATT Ancillary Services (Note L)						346,409	
8	Included transmission expenses (line 6 less line 7)						29,800,452	
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)						0.98851	
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=	0.98851	
	WAGES & SALARY ALLOCATOR (W&S)		$	TP	Allocation			
12	Production		2,313,512	0.00	0			
13	Transmission		442,160	1.00	442,160			
14	Distribution		0	0.00	0		W&S Allocator	
15	Other		154,621	0.00	0		($ / Allocation)	
16	Total (sum lines 12-15)		2,910,293		442,160	=	0.15193 = W/S	
	COMMON PLANT ALLOCATOR (CE) (Note O)		$		% Electric		Labor Ratio	
17	Electric		405,389,565		(line 17 / line 20)		(line 16)	CE
18	Gas		0		1.00000	*	0.15193 =	0.15193
19	Water		0					
20	Total (sum lines 17-19)		405,389,565					
	ACTUAL CAPITAL STRUCTURE RETURN (ACSR)		$					
21	Long Term Interest	III.16.b + III.17.b (Note U)	$25,479,587					
			$	%	Cost (Note P)		Weighted	
22	Long Term Debt (Note GG)	II 37.b	459,100,385	79%	5.55%		0.0438 =WCLTD	
23	Proprietary Capital (Note GG)	II.32.b	123 582 037	21%	0.1238		0.0260	
24	Total (sum lines 22, 23)		582,682,422	100%			0.0698 =R	
25					Proprietary Capital Cost Rate =		12.38%	
26					TIER =		1.26	
	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%	5.55%		0.0305 =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%			0.0862 =R	
30	Annual Allocation Factor for Incentive Return (line 29 minus line 24)						1.640%	
	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						$25,964,969	
36	b. Transmission charges for all transmission transactions included in Divisor on page 1						$25,964,969	
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	

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing EIA Form 412 Data
MRES

For the 12 months ended 12/31/2014

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.

NWPS
Facility Credits

Line No.						Allocated Amount
1	GROSS REVENUE REQUIREMENT					$ 5,598,663
2						
3						
4	REVENUE CREDITS	(Note T)	Total	Allocator		
5	Account No. 454		259,850	TP	100%	259,850
6	Account No. 456		1,225,943	GP=	12.2%	149,959
7	TOTAL REVENUE CREDITS					409,809
8						
9						
10	NET REVENUE REQUIREMENT					$ 5,188,854
11						
12						
13	(1)	(2)	(3)	(4)		(5)
14		**Form No. 1**				**Transmission**
15		**Page, Line, Col.**	**Company Total**	**Allocator**		(Col 3 times Col 4)
16	**RATE BASE:**					
17						
18	SD GROSS PLANT IN SERVICE					
19	Produc ion	206.42 g	167,101,900			
20	Transmission	206.53 g	53,011,772	TP	100.0%	53,011,772
21	Distribution	206.69 g	188,807,480			
22	General & Intangible	206.5 g & 83.g	12,898,841	W/S	5.3%	683,262
23	Common	356.1	25,521,260	CE	4.0%	1,024,437
24	TOTAL GROSS PLANT		447,341,253	GP=	12.2%	54,719,470
25						
26	ACCUMULATED DEPRECIATION					
27	Produc ion	219.18-22.c	112,605,521			
28	Transmission	219.23.c	21,947,091	TP	100.0%	21,947,091
29	Distribution	219.24.c	73,184,406			
30	General & Intangible	219.25.c	3,555,172	W/S	5.3%	188,320
31	Common	356.1	7,040,001	CE	4.0%	282,589
32	TOTAL ACCUMULATED DEPRECIATION		218,332,191			22,418,001
33						
34	NET PLANT IN SERVICE					
35	Produc ion		54,496,379			
36	Transmission		31,064,681			31,064,681
37	Distribution		115,623,074			
38	General & Intangible		9,343,669			494,941
39	Common		18,481,260			741,847
40	TOTAL NET PLANT		229,009,062	NP=	14.10%	32,301,469
41						
42	ADJUSTMENTS TO RATE BASE	(Note F)				
43	Account No. 281 (enter negative)	273.8 k	0	NP	14.10%	-
44	Account No. 282 (enter negative)	275.2 k	(44,679,654)	NP	14.10%	(6,302,015)
45	Account No. 283 (enter negative)	277.9 k	-	NP	14.10%	-
46	Account No. 190	234.8.c	-	NP	14.10%	-
47	Account No. 255 (enter negative)	267.8 h	(1,196,810)	NP	14.10%	(168,809)
48	TOTAL ADJUSTMENTS		(45,876,464)			(6,470,823)
49						
50	LAND HELD FOR FUTURE USE	214.x.d (Note G)	0	TP	100%	0
51						
52	WORKING CAPITAL (Note H)					
53	CWC	calculated	939,994		O&M/8	126,566
54	Materials & Supplies (Note G)	Transmission	0	GP	12.23%	0
55	Prepayments (Account 165)	111.46 d	0	GP	12.23%	0
56	TOTAL WORKING CAPITAL		939,994			126,566
57						
58	RATE BASE		184,072,592			25,957,212

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 - only 115KV portion	321.100.b	3,295,020	TE	100%	3,295,020
2	Less Account 565 - only 115KV pc	321.88 b	2,646,472		100%	2,646,472
3	A&G	323.168.b	6,988,157	W/S	5.3%	370,168
4	Less FERC Annual Fees		0	W/S	5%	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		116,757	W/S	5%	6,185
6	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	100%	0
7	Common	356.1	0	CE	4%	0
8	Transmission Lease Payments		0		100%	0
9	TOTAL O&M		7,519,949			1,012,532
10						
11	DEPRECIATION EXPENSE					
12	Transmission - only 115KV assets	336.7 b	1,415,150	TP	100%	1,415,150
13	General	336.9 b	845,387	W/S	5.3%	44,781
14	Common	336.10 b	1,637,359	CE	4.0%	65,724
15	TOTAL DEPRECIATION		3,897,896			1,525,655
16						
17	TAXES OTHER THAN INCOME TAXES (Note J)					
18	LABOR RELATED					
19	Payroll	262.i	771,425	W/S	5.3%	40,863
20	Highway and vehicle	262.i	50,449	W/S	5.3%	2,672
21	PLANT RELATED					
22	Property	262.i	4,062,553	GP	12.2%	496,938
23	Gross Receipts	262.i (excluded)	152,058			0
24	Other	262.i	34,462	GP	12.2%	4,215
25	Payments in lieu of taxes		0	GP	12.2%	0
26	TOTAL OTHER TAXES		5,070,947			544,689
27						
28	INCOME TAXES	(Note K)				
29	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		35.00%			
30	CIT=(T/1-T) * (1-(WCLTD/R)) =		37.20%			
31	1 / (1 - T) = (from line 21)		1 5385			
32	Amortized Investment Tax Credit (266.8f)		(1,196,810)	GP	12.2%	(146,396)
33						
34	Income Tax Calculation		5,758,640	GP	12.2%	704,406
35	ITC adjustment		(1,841,246)	GP	12.2%	(225,224)
36	Total Income Taxes		3,917,394			332,786
37						
38	RETURN		15,480,505	NA		2,183,002
39	[Rate Base * Rate of Return]					
40						
41	REV. REQUIREMENT		35,886,691			5,598,663

SUPPORTING CALCULATIONS AND NOTES

Line No.	TRANSMISSION PLANT INCLUDED IN ISO RATES								
1	Total transmission plant						123,741,589		
2	Less transmission plant excluded from ISO rates (Note M)						70,729,817		
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)				42.8%		53,011,772		
5									
6	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)					TP=	1.00000		
7									
8	TRANSMISSION EXPENSES								
9									
10	Total transmission expenses						3,295,020		
11	Less transmission expenses included in OATT Ancillary Services (Note L)						0		
12	Included transmission expenses						3,295,020		
13									
14	Percentage of transmission expenses after adjustment						1.00000		
15	Percentage of transmission plant included in ISO Rates					TP	1.00000		
16	Percentage of transmission expenses included in ISO Rates					TE=	1.00000		
17									
18	WAGES & SALARY ALLOCATOR (W&S)								
19		Form 1 Reference	$	TP	Allocation				
20	SD Electric Production	354.18 b	449,000	0 00	0				
21	SD Electric Transmission	354.19 b	423,007	1 00	423,007				
22	SD Electric Distribution	354.20 b	2,024,311	0 00	0		W&S Allocator		
23	SD Electric Other	354.21,22,23.b	5,089,350	0 00	0		($ / Allocation)		
24	Total		7,985,668		423,007	WS =	5.3%		
25									
26	COMMON PLANT ALLOCATOR (CE) (Note O)								
27			**$**		% Electric		W&S Allocator		
28	Electric	200.3.c	492,604,252		(line 28 / line 31)		(line 24)		CE
29	Gas	200.3 d	157,452,886		75.8%	*	5.3%	=	4.0%
30	Water	200.3 e	0						
31	Total		650,057,137						

Line No.			$	%	Cost (Note P)	Weighted	
	RETURN (R)						
1	Long Term Debt (112, sum of 16d through 19d)		1,055,187,000	48.39%	5.4%	2.60%	=WCLTD
2	Preferred Stock (112.3d)		0	0.00%	0.0%	0.0%	
3	Common Stock (line 26)		934,032,000	51.61%	11.25%	5.81%	
4	Total (sum lines 27-29)		1,989,219,000			8.41%	=R
5							
6	REVENUE CREDITS						
7						Load	
8	ACCOUNT 447 (SALES FOR RESALE)	(310-311)		(Note Q)		2,959,317	
9							
10	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY)	(Note R)				$259,850	
11							
12	ACCOUNT 456 (OTHER ELECTRIC REVENUES)	(330.x.n)				$1,225,943	

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

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

B Labeled LF, LU, IF, IU on pages 310-311 of Form 1at the time of he 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 .
Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 100-111 line 46 in the Form 1.

I 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 curren ly 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 u ilize amortiza ion 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 Amor ized 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 deduc ible 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 (un il 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, genera ion 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 ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.

Q 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.

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

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.