

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

IS Transmission and Ancillary Service Rates.....	4-11
IS Load Data.....	12-15
Western’s Transmission Cost Data.....	16-21
Western’s Ancillary Service Cost Data.....	22-51
Basin Electric’s Transmission Cost Data.....	52-62
Basin Electric’s Ancillary Service Cost Data.....	63-69
Heartland’s Transmission Cost Data.....	70-75
Transmission Customer Facility Credits	
Missouri River Energy Services.....	77-82
NWPS.....	83-86

Integrated System Transmission and Ancillary Service Rates

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

Line
No.

1			
2			
3	<u>Annual IS Transmission Costs</u>		<u>Notes</u>
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	<u>Transmission Customer Facility Credits</u>		
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	<u>Annual Revenue Requirement for IS Transmission Service</u>		
17			
18		\$195,756,621	L7 + L13
19			
20	<u>2012 True-up Amount</u>		
21		\$3,542,941	2012 Rate True-up Worksheet
22			
23	<u>2012 Unreserved Use of Transmission Service Penalties</u>		
24			
25		(\$5,590)	2012 Unreserved Use Penalty Worksheet
26			
27	<u>Annual Revenue Requirement for IS Transmission Service after True-up</u>		
28			
29		\$199,293,972	L18 + L21 + L25

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

Line

No.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15

Annual Revenue Requirement for IS Transmission Service

Notes

\$199,293,972

IS Annual Revenue Requirement for
Transmission Service Worksheet, L29

IS Transmission System Total Load

5,496,000 KW IS Transmission System Total Load Estimate

Maximum Firm Point-to-Point Transmission Rate in \$/KW-Mo

\$3.02 / KW-Mo

L5 / L10 / 12 months

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

Line

No.

1
2
3
4
5
6
7
8
9
10

Firm Point-to-Point Transmission Rate in \$/KW-Mo

Notes

\$3.02 / KW-Mo

IS Firm Point-to-Point Rate Design Worksheet, L15

Maximum Non-Firm Point-to-Point Transmission Rate

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	<u>\$0</u>	(2)
C.	Total Reactive Revenue Requirement	\$2,289,895	(A + B)
D.	Over Collection for 2012	<u>(\$800,877)</u>	(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	<u>\$ 474,040,718</u>	(2)
C.	Annual Cost of Generation	<u>\$ 87,735,456</u>	(A x B)
D.	Plant Capacity (kW)	<u>2,372,000</u>	
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	<u>\$ 3,680,505</u>	(E x H)
J.	Annual Charge (\$/kW-Yr)	<u>\$ 2.42</u>	(I /G)
K.	Monthly Charge (\$/kW-mo)	<u>\$ 0.20</u>	(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)**

	(1)	(2)	(3)	(4)	(5)
Line No.	Date	Hour Ending	Network Load	Long-Term Firm Point-to-Point Reservations	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	<u>4,738</u>	<u>426</u>	<u>5,164</u>
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.					Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)				\$ 137,965,146
	REVENUE CREDITS (Note R)	Total		Allocator	
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				<u>14,956,422</u>
9	NET REVENUE REQUIREMENT (line 1 minus line 8)				<u>\$ 123,008,724</u>

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
3	Distribution	Schedule 1A Total	31,898,125	NA	
4	General & Intangible	Bal Sheet - Other Assets - SGL 175002		W/S	1.00000
5	Common		0	CE	0.00000
6	TOTAL GROSS PLANT (sum lines 1-5)		2,297,480,720	GP=	53.936%
ACCUMULATED DEPRECIATION					
7	Production	Schedule 4	560,526,625	NA	
8	Transmission	Schedule 4	582,933,186	TP	1.00000
9	Distribution	Schedule 4	15,182,927	NA	
10	General & Intangible	Bal Sheet - Other Assets - SGL 175902	0	W/S	1.00000
11	Common		0	CE	0.00000
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		1,158,642,738		
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%
ADJUSTMENTS TO RATE BASE (Note B)					
19	Account No. 281 (enter negative)		0		zero
20	Account No. 282 (enter negative)		0	NP	0.57623
21	Account No. 283 (enter negative)		0	NP	0.57623
22	Account No. 190		0	NP	0.57623
23	Account No. 255 (enter negative)		0	NP	0.57623
24	TOTAL ADJUSTMENTS (sum lines 19 - 23)		0		
25	LAND HELD FOR FUTURE USE	(Note C)	0	TP	1.00000
WORKING CAPITAL (Note D)					
26	CWC	calculated	20,738,760		
27	Materials & Supplies (Note C)	Bal Sheet - Other Assets - SGL 151191	0	TE	0.00000
28	Prepayments	Bal Sheet Other Assets	0	GP	0.53936
29	TOTAL WORK NG CAPITAL (sum lines 26 - 28)		20,738,760		
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)	(3)	(4)	(5)
		Results of Operation Reference	Company Total	Allocator	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 Stmt	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
	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)				
21	$T=1 - \{[(1 - \text{SIT}) * (1 - \text{FIT})] / (1 - \text{SIT} * \text{FIT} * p)\} =$		0.00%	NA	
22	$\text{CIT}=(T/1-T) * (1-(\text{WCLTD}/R)) =$		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 [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		52,992,657	NA	29,989,813
29	REV. REQUIREMENT (sum lines 8, 12,20,27,28)		<u>278,869,433</u>		<u>137,965,146</u>

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

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 <u>Letter</u>	To the extent the references to ROOs data are missing, the entity will include a "Notes" section to provide this data.		
A	Combines plant data for both the Upper Great Plains Region and Rocky Mountain Region.		
B	Does not apply to Western. For others, the balances in Accounts 190, 281, 282 and 283, as adjusted by any contra accounts identified as regulatory assets amounts in or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.		
C	Transmission related only.		
D	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported in the Other Assets Section of the Balance Sheet		
E	For O&M Expense, Calculated as Total O&M from Results of Operations less Purchase Power, Transmission Service Provided by Others (FERC 565), O&M Expense Fort Peck Powerhouse, Prior Year Adjustments, A&G Expense from Schedule 11, plus CME and Warehouse Interest from Schedule 5. Depreciation Expense from Results of Operations Schedule 4.		
F	Totals of Results of Operations Schedule 11A Object Classes 1411, 1412, 1415, 1416, 1421, 1422, 1425, 1426, 1431, 1432, 1441, 1442		
G	Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting.		
H	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.		
I	Western is not subject to Federal or State Income Tax.		
	Inputs Required:	FIT =	0.00%
		SIT=	0.00% (State Income Tax Rate or Composite SIT)
		p =	0.00% (percent of federal income tax deductible for state purposes)
J	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Acct No. 561. Western does not include transmission expenses in ancillary service rates.		
K	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until RUS 12 balances are adjusted to reflect application of seven-factor test).		
L	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.		
M	Percentage of Total Plant Allocators are developed separately for the Upper Great Plains Region and Rocky Mountain Region to allocate O&M, A&G, and Depreciation Expenses between Transmission and Generation.		
N	Western does not have Common Plant.		
O	Debt cost rate = long-term interest (line 21) / long term debt (line 22). The Proprietary Capital Cost rate is implicit, a residual calculation after TIER is determined. TIER will be supported in the filing and no change in TIER may be made absent a filing with the ISO and the FERC, if the entity is under FERC's jurisdiction.		
P	Line 29 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the divisor.		
Q	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.		
R	The revenues credited on page 1 lines 2-5 shall include only the amounts received directly reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, facilities not included in this template (e.g., direct assignment facilities 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 (\$)	<u>\$474,040,718</u>	(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	<u>\$2,289,895</u>	(2)
C. Over Collection of Revenue Requirement	<u>\$584,591</u>	(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)	<u>4,973,000</u>	(4)
F. Difference 2012 Rate Load to 2012 Actual Load	<u>(348,000)</u>	(D - E)
G. Over collection of revenue requirement	\$584,591	(C)
H. Over collection due to volume	<u>\$216,286</u>	(F * [A / D] * -1)
I. Net Over Collection	<u>\$800,877</u>	(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	<u>\$0</u>	(2)
C. Total Reactive Revenue Requirement	<u>\$2,874,486</u>	(A + B)
D. 2010 IS Transmission System Total Load (kW-Yr)	4,625,000	(3)
E. Annual Reactive Charge (\$/kW-Yr)	<u>\$0.68</u>	(C / D)
F. Monthly Reactive Charge (\$/kW-Mo)	<u>\$0.06</u>	(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 (\$)	<u>\$172,688,021</u>	(2)
C.	Annual Corps Generation Cost (\$)	<u>\$30,460,440.02</u>	(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	<u>\$0</u>	(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	<u>\$2,154,356</u>	(2)
C. Under Collection of Revenue Requirement	<u>(\$405,756)</u>	(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)	<u>3,229,000</u>	(4)
F. Difference 2012 Rate Load to 2012 Actual Load	<u>(276,000)</u>	(D - E)
G. Under collection of revenue requirement	<u>(\$405,756)</u>	(C)
H. Over collection due to volume	<u>\$163,432</u>	(F * [A / D] * -1)
I. Net Under Collection	<u>(\$242,324)</u>	(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	<u>3.458%</u>	L41
57			
58	Total	<u>18.508%</u>	
59			
60			
61	H. Generation Revenue Requirement		
62			
63	Generation Fixed Charge Rate	18.508%	L58
64			
65	Net Generation Plant Investment	<u>\$676,471,782</u>	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	<u>4.767%</u>	L43
59			
60	Total	<u>22.770%</u>	
61			
62			
63	H. Transmission Revenue Requirement		
64			
65	Transmission Fixed Charge Rate	22.770%	L60
66			
67	Net Transmission Plant Investment	<u>\$593,353,214</u>	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	20,038,251	11,766,373	5,053,994	64,302,887
3						
4	PS-ED Transmission Depreciation	26,211,198	186,356	515,249	0	26,912,803
5						
6	PS-ED Generation Depreciation	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%
10	Generation Plant Factor	0.0144	8/	0.0000	9/	0.6621	10/	0.3235	11/	
11	Weighted Gen. Composite Rate									3.458%

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)	(3)	(4)	(5)	(6)				
	WESTERN UGPR	WESTERN RMR	COE	BOR	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	(2) FY2012 TOTALS		(3) MISCELLANEOUS ADJUSTMENTS		(4) GENERATION ADJUSTMENTS		(5) TRANSMISSION TOTALS		(6) SOURCE/NOTES
		a	TOTALS	b	ADJUSTMENTS	c	GEN ADJ	d	TRANS TOTAL	
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	(2)		(3)	(4)	(5)	(6) SOURCE/NOTES
		FY2012 TOTALS	TOTALS	MISCELLANEOUS ADJUSTMENTS	GENERATION ADJUSTMENTS	TRANSMISSION TOTALS	
		a	b	c	d	e	
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	(2)	(3)	(4)	(5)	(6)
		FY2012 TOTALS TOTALS a	MISCELLANEOUS ADJUSTMENTS ADJUSTMENTS b	GENERATION ADJUSTMENTS GEN ADJ c	TRANSMISSION TOTALS TRANS TOTAL d	SOURCE/NOTES e
124	BISMARCK 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 SUBSTATION	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	(2) FY2012 TOTALS		(3) MISCELLANEOUS ADJUSTMENTS		(4) GENERATION ADJUSTMENTS		(5) TRANSMISSION TOTALS		(6) SOURCE/NOTES
		a	b	c	d	e				
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	OFALLON 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	(2) FY2012 TOTALS		(3) MISCELLANEOUS ADJUSTMENTS	(4) GENERATION ADJUSTMENTS	(5) TRANSMISSION TOTALS	(6) SOURCE/NOTES
		a	TOTALS	b	c	d	
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	
301	WATERTOWN OPER CTR (BFPS)		11,299,013		(4,001,771)	7,297,242	Column 4 shows 35 417% of the Watertown Operations Center that 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	(2)	(3)	(4)	(5)	(6) SOURCE/NOTES
		FY2012 TOTALS a	MISCELLANEOUS ADJUSTMENTS b	GENERATION ADJUSTMENTS c	TRANSMISSION TOTALS d	
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 prorated to generation based on the number of communication channels dedicated to generation
334	BAKER RELAY	27,791		(9,232)	18,559	
335	BANTRY	362,742		(120,503)	242,239	
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	(2)		(3)	(4)	(5)	(6) SOURCE/NOTES
		FY2012 TOTALS	MISCELLANEOUS ADJUSTMENTS	GENERATION ADJUSTMENTS	TRANSMISSION TOTALS		
a		TOTALS	b	c	d	e	
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	ELLEDALE 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	(2) FY2012 TOTALS		(3) MISCELLANEOUS ADJUSTMENTS		(4) GENERATION ADJUSTMENTS		(5) TRANSMISSION TOTALS		(6) SOURCE/NOTES
		a	b	c	d	e				
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	(2)		(3)	(4)	(5)	(6) SOURCE/NOTES
		FY2012 TOTALS a	b	MISCELLANEOUS ADJUSTMENTS c	GENERATION ADJUSTMENTS GEN ADJ d	TRANSMISSION TOTALS TRANS TOTAL e	
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-
525	STEGALL SUBSTATION	8,964,752		(8,662,143)		302,609	Sloan Missouri River Basin Results of Operations, Schedule 1 These
526	STEGALL-WAYSIDE	2,978,205				2,978,205	are RMR facilities utilized by both RMR and UGPR The amount in
527	YELLOWTAIL SWITCHYARD	11,633,005		(8,724,754)		2,908,251	Column 5 will be recovered by UGPR
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
BASIN ELECTRIC POWER COOPERATIVE

Projection for 2014

Line No.		Total Transmission	IS Transmission	West (MBPP) Transmission	Other Transmission
1	GROSS REVENUE REQUIREMENT (page 3, line 28) (MBPP West Excluded - 1-.065997)	\$ 98,265,720	\$ 63,121,627	\$ 8,048,152 \$ (7,516,998)	\$ 27,095,948
 REVENUE CREDITS					
		<u>Total</u>			
		<u>Allocator</u>			
2	Third Party Receipts	\$ (350,472) TP			
3					
4	Third Party Payments	TP			
5					
6	NET REVENUE REQUIREMENT (line 2 + 4) (line 1+ 5)		\$ 104,993	\$ (245,479)	\$ -
7	TOTAL REVENUE REQUIREMENT WITH MBPP EAST		62,876,148	531,154	27,095,948
			\$ 63,407,302		

Revenue Requirement Worksheet
RUS form 12 Data
BASIN ELECTRIC POWER COOPERATIVE

Projection for 2014

Page 2

(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%
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%
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
5	Intangible	12h.A.1 e	78,163,717	DA	0.000%	66,336,542	DA	0.000%
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		
					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%
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%
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
11	Intangible	12h.B.12.f	55,041,001	DA		49,091,509	DA	100.000%
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	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	3,579,949
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	1,093,655
17	Intangible	(line 5 - line 11)	23,122,716	AUTO		17,245,033	AUTO	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%
20	Materials & Supplies Transmission	12h. G, L.4, L.5. C.d.	7,200,000	GP1	100.000%	7,200,000	GP1	Gross Plant
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
BASIN ELECTRIC POWER COOPERATIVE

Projection for 2014

Page 3

Line No.	(1)	(2)	(4)	(5)	(4a)	(6)	(7)	(8)
O&M								
1		Expense Worksheet #3		39,827,984				
2		Transmission less Account 565						
3		Direct Assignment (Note E)	DA	24,740,000	100.000%	24,740,000	DA	100 000%
3		Other	TPW	15,087,984	100.000%	15,087,984	GP2	page 4
4		A&G		64,667,933				
5		Expense Worksheet #3						
5		Less Regulatory Fees (Note F)	NA	200,000	0.000%	-	NA	0.000%
6		Production	NA	2,500,000	0.000%	-	NA	0.000%
7		Transmission (Note G)	DA	990,000		990,000	DA	page 4
8		Headquarters	WS	60,977,933	10.025%	6,113,038	GP2	Gross Plant
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		146,499,970				
11		Transmission	DA	13,802,202	100.000%	13,802,202	DA	100 000%
12		Production	NA	121,439,942	0.000%	-	NA	0.000%
13		General Plant	NA	9,000,000	0.000%	-	NA	0.000%
14		Transmission	DA	2,005,000	100.000%	2,005,000	DA	100 000%
15		Production	NA	6,500,000	0.000%	-	NA	0.000%
16		Hdqtrs General Plant	WS	495,000	10.025%	49,624	GP1	Gross Plant
17		Other Amortization	DA	2,257,826	0.000%	1,917,762	DA	0.000%
18		TOTAL (Sum lines 10,13,17)		\$ 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		2,967,569				
21		Tax Reclassification	NA		0.000%	-	NA	0.000%
22		Gross Receipts (Note I)	DA	2,967,569	100.000%	2,967,569	DA	100 000%
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	WCC	\$ 238,478,570	Rate Base	\$ 30,592,541	WCC	Rate Base
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 #	From Accounting Report	(1)	(2)	(3)	(4)	(5)		(6)	(7)	(8)
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%			
4	Transmission-Allocated		Accounting Records	5,188,854						
5	Distribution				TPW	Trans % excluding MBPP West		Note H		
6	Other Transmission			-						
7	Total Wages and Salaries (sum lines 1-6) (exclude adm)			\$58,613,622						

Note J	Estimated Weighted Cost of Capital		Rate	cost
		Percent		
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

	<u>a</u>	<u>b</u>	<u>c</u>	<u>d</u>	
	Actual	Estimated	Estimated	Transmission	
	2012	Budget Year	Budget Year	Adjusted for 2014	
Line		2013	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
Estimated 2013 Expenses**

Expense Worksheet #3

	(a) 2013 Estimate	(b) 2014 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	<u><u>50,249</u></u>	(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)	<u>35,072,647</u>	<u>106,969,524</u>	<u>275,061,223</u>	<u>103,596,181</u>

	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	<u>2,204,206</u>	<u>2,204,206</u>	<u>876,866</u>	<u>876,866</u>

Gross Plant Intangible	-	-	524,573	524,573
Accum Depr			(182,551)	(182,551)
Net Book	-	-	<u>342,021</u>	<u>342,021</u>

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.
 1 GROSS REVENUE REQUIREMENT (page 3, line 28)

Total
 Production
 \$ 559,381,336

(6)	(7)	(8)	(9)
LO #1	LO #2	AVS #065	AVS #066
\$ 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			
6	NET REVENUE REQUIREMENT		

(line 2 + 4)
 (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)		(7)		(8)		(9)	
						LO #1	LO #2	AVS #065	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	7,976,834
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) Reference	(2) Company Total	(3) Allocator A	(4) %	(5) Total Production	(4a) Allocator B	(6) %	(7) LO #1	(8) LO #2	(8) AVS #065	(9) AVS #066	
												LO #1
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)	Accounting Records	53,116,862	WS	89.816%	47,707,460	GP2	Gross Plant				
9	TOTAL O&M (sum lines 1 and 4)	Expense Worksheet	\$ 316,206,637			\$ 309,624,281			\$ 1,576,424	\$ 3,487,737	\$ 9,925,347	\$ 3,364,712
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	Accounting Records	3,251,777	WS	87.879%	2,857,637	GP1	Gross Plant	79,823	176,604	502,578	170,375
17	Other Amortization	Accounting Records	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												
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	Accounting Records		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 (WS)

Line No.	(1) From Accounting Report	(2)	(3) TOTAL	(4) Allocator	(5) Percent		(6)	(7)	(8)	(9)
							LO #1	LO #2	AVS #065	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%
12a. B.L.39	Equity	1,113,318,613	23.94%	10.85%
		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 form
 - 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

<u>Line No.</u>			<u>Allocated Amount</u>
1	GROSS REVENUE REQUIREMENT (page 3, line 29)		\$ 890,217
	REVENUE CREDITS (Note P)	<u>Total</u>	<u>Allocator</u>
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		<u>13,316</u>
	NET REVENUE REQUIREMENT (line 1 minus line 6)		<u>\$ 876,901</u>

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)	(3)	(4)	(5)	
		Reference	Company Total	Allocator	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 INCOME 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
	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
	INCOME TAXES (Note G)					
21	$T = 1 - \frac{((1 - SIT) * (1 - FIT))}{(1 - SIT * FIT * p)}$		0.00%	NA		
22	$CIT = (T / (1 - T)) * (1 - (WCLTD / R))$ where WCLTD=(page 4, line 27) and R=(page 4, line30) and FIT, SIT & p are as given in footnote G.		0.00%			
23	$1 / (1 - T) =$ (from line 21)		0.0000			
24	Amortized Investment Tax Credit (enter negative)		0			
25	Income Tax Calculation = line 22 * line 28		0	NA		0
26	ITC adjustment (line 23 * line 24)		0	NP	0.10082	0
27	Total Income Taxes (line 25 plus line 26)		0			0
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 24)]		1,541,497	NA		156,605
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		6,704,912			890,217

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.

SUPPORTING CALCULATIONS AND NOTES

TRANSMISSION PLANT INCLUDED IN 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
15	Other	0	0 00	0
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	1.00000	0.07020 = 0.07020
18	Gas	0		
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%	0.0415 =WCLTD
23	Proprietary Capital Schedule A	12,512,835	32%	0.0396
24	Total (sum lines 22, 23)	39,404,948	100%	0.0811 =R

25	Proprietary Capital Cost Rate =	12.38%
26	TER =	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 - Non-Levelized

Revenue Requirement Template
 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.#)

<u>Note Letter</u>										
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: <table border="0" style="margin-left: 20px;"> <tr> <td>FIT =</td> <td style="text-align: right;">0 00%</td> <td>(Federal Income Tax Rate)</td> </tr> <tr> <td>SIT =</td> <td style="text-align: right;">0 00%</td> <td>(State Income Tax Rate or Composite SIT)</td> </tr> <tr> <td>p =</td> <td style="text-align: right;">0 00%</td> <td>(percent of federal income tax deductible for state purposes)</td> </tr> </table>	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)
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 application 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 be 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.			Total	Allocator	Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 31)				\$ 5,685,733
REVENUE CREDITS					
2	Account No. 454	(Note T) (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	(line 1 - 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					
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	\$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
Off-Peak Rate					
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		(5) Transmission (Col 3 times Col 4)
			(3) Company Total	(4) Allocator	
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	(Note G)	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)
1	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
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)					
21	$T=1 - \{(1 - SIT) * (1 - FIT)\} / (1 - SIT * FIT * p) =$		0.00%	NA	
22	$CIT=(T-1-T) * (1-(WCLTD/R)) =$ where WCLTD=(page 4, line 22) and R=(page 4, line 24) and FIT, SIT & p are as given in footnote K.		0.00%		
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 [Rate Base (page 2, line 30 + 30a) * Rate of Return (page 4, line 24)]		16,557,658	NA	7,863,423
28a	RETURN from HCSR [Rate Base (page 2, line 30a) * Rate of Return (page 4, line 30)]		1,282,662	NA	1,282,662
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 (line 29 - line 30 - line 30a)		23,544,200		5,685,733

Formula Rate - Non-Levelized

Rate Formula Template
 Utilizing EIA Form 412 Data
 MRES

For the 12 months ended 12/31/2014

Line No.	SUPPORTING CALCULATIONS AND NOTES				
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)
18	Gas	0		1.00000 *	0.15193 =
19	Water	0			0.15193
20	Total (sum lines 17-19)	405,389,565			CE
ACTUAL CAPITAL STRUCTURE RETURN (ACSR)					
21	Long Term Interest	\$		Cost	
		\$25,479,587		(Note P)	Weighted
22	Long Term Debt (Note GG)	\$	%	5.55%	0.0438 =WCLTD
23	Proprietary Capital (Note GG)	459,100,385	79%	0.1238	0.0260
24	Total (sum lines 22, 23)	123,582,037	21%		0.0698 =R
		582,682,422	100%		
25				Proprietary Capital Cost Rate =	12.38%
26				TIER =	1.26
HYPOTHETICAL CAPITAL STRUCTURE RETURN (HCSR) (NOTE FF)					
				Cost	Weighted
27	Long Term Debt (Cost of Long-term Debt from page 4, line 22)	%		(Note P)	(Note P)
28	Proprietary Capital (Cost of Proprietary Capital from page 4, line 25)	55%		5.55%	0.0305 =WCLTD
29	Total (sum lines 27, 28)	45%		12.38%	0.0557
		100%			0.0862 =R
30	Annual Allocation Factor for Incentive Return (line 29 minus line 24)				1.640%
REVENUE CREDITS					
ACCOUNT 447 (SALES FOR RESALE)					
				Load	
31	a. Bundled Non-RQ Sales for Resale				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. Transmission 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

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

	(1)	(2)	(3)	(4)	(5)
Line No.	Form No. 1 Page, Line, Col.	Company Total	Allocator	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
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
TAXES OTHER THAN INCOME TAXES (Note J)					
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
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
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)
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
38	RETURN	15,480,505	NA		2,183,002
39	[Rate Base * Rate of Return]				
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
6	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)				TP=	1.00000
TRANSMISSION EXPENSES						
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
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
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%
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 the time of the ISO coincident monthly peaks.
- B Labeled LF, LU, IF, IU on pages 310-311 of Form 1 at the time of the ISO coincident monthly peaks.
- C Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
- D Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
- E The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.
- F The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
- G Identified in Form 1 as being only transmission related.
- H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission. 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 currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).
 Inputs Required: FIT = 35.00%
 SIT = 0.00% (State Income Tax Rate or Composite SIT)
 p = 0.00% (percent of federal income tax deductible for state purposes)
- L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.
- M Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
- N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to be 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 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.

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 2012 Rate True-up Calculation

True-up Calculation Worksheet.....	89
IS Transmission Rates – 2012 Actual.....	90-93
IS Transmission Rates – 2012 Estimated.....	94-97
IS 2012 Load Data.....	98-101
Western’s 2012 Revenue Requirement Template – Actual Data.....	102-07
Western’s 2012 Revenue Requirement Template – Estimated Data	108-13
Basin Electric’s 2012 Revenue Requirement Template – Actual Data.....	114-18
Basin Electric’s 2012 Revenue Requirement Template – Estimated Data.....	119-23
Heartland’s 2012 Revenue Requirement Template – Actual Data.....	124-29
Heartland’s 2012 Revenue Requirement Template – Estimated Data.....	130-35
Missouri River Energy Services 2012 Revenue Requirement Template – Actual Data.....	136-41
Missouri River Energy Services 2012 Revenue Requirement Template – Estimated Data.....	142-47
NWPS 2012 Revenue Requirement Template – Actual Data.....	148-51
NWPS 2012 Revenue Requirement Template – Actual Data.....	152-57

IS Revenue Requirement True-up - 2012 Rate

A.	Projected Revenue Requirement	\$ 167,514,234	2012 Revenue Requirement - Estimate
B.	Actual Revenue Requirement	<u>\$ 180,412,085</u>	2012 Revenue Requirement - Actual
C.	Revenue Requirement Over (Under) Collected	\$ (12,897,851)	(A - B)
D.	Estimated Load	4,710,000	2012 Load - Estimate
E.	Actual Load	<u>4,973,000</u>	2012 Load - Actual
F.	Actual Load to Estimated Load Comparison	(263,000)	(D - E)
G.	Over collection due to volume	\$ 9,354,910	(A * (B / D) * -1)
H.	Under Collection of Revenue Requirement	\$ (12,897,851)	C
I.	Over Collection due to Volume	\$ 9,354,910	G
J.	Total Under Collection	<u>\$ (3,542,941)</u>	(C + G)

Integrated System Transmission Rates 2012 Actual

**INTEGRATED SYSTEM
ANNUAL REVENUE REQUIREMENT
FOR TRANSMISSION SERVICE
Effective January 1, 2012 - Actual**

Line

No.

1			
2			
3	<u>Annual IS Transmission Costs</u>		<u>Notes</u>
4	Basin Electric	48,425,769	Basin Electric Revenue Requirement Template
5	Western	123,196,632	Western Revenue Requirement Template
6	Heartland	824,784	Heartland Revenue Requirement Template
7		\$172,447,185	L4 + L5 + L6
8			
9			
10	<u>Transmission Customer Facility Credits</u>		
11		2,776,046	MRES Revenue Requirement Template
12		5,188,854	NWPS Revenue Requirement Template
13		\$7,964,900	L11 + L12
14			
15			
16	<u>Annual Revenue Requirement for IS Transmission Service</u>		
17			
18		\$180,412,085	L7 + L13
19			
20			
21	<u>2012 True-up Amount</u>		
22		\$3,542,941	2012 Rate True-up Worksheet
23			
24	<u>2012 Unreserved Use of Transmission Service Penalties</u>		
25			
26		(\$5,590)	
27			
28			
29			

**INTEGRATED SYSTEM
FIRM POINT-TO-POINT RATE DESIGN
Effective January 1, 2012 - Actual**

Line

No.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15

Annual Revenue Requirement for IS Transmission Service

Notes

\$180,412,085

IS Annual Revenue Requirement for
Transmission Service Worksheet, L18

IS Transmission System Total Load

4,973,000 KW

IS Transmission System Total Load Worksheet, C5L14

Maximum Firm Point-to-Point Transmission Rate in \$/KW-Mo

\$3.02 / KW-Mo

L5 / L10 / 12 months

INTEGRATED SYSTEM
NON-FIRM POINT-TO-POINT RATE DESIGN
Effective January 1, 2012 - Actual

Line

No.

1
2
3
4
5
6
7
8
9
10

Firm Point-to-Point Transmission Rate in \$/KW-Mo

Notes

\$3.02 / KW-Mo

IS Firm Point-to-Point Rate Design Worksheet, L15

Maximum Non-Firm Point-to-Point Transmission Rate

4.14 Mills/KWh

(L5 * 1000) / 730 hours per month

Integrated System Transmission Rates 2012 Estimated

**INTEGRATED SYSTEM
ANNUAL REVENUE REQUIREMENT
FOR TRANSMISSION SERVICE
Effective January 1, 2012**

Line
No.

1			
2			
3	<u>Annual IS Transmission Costs</u>		<u>Notes</u>
4	Basin Electric	\$51,718,527	Basin Electric Revenue Requirement Template
5	Western	\$107,732,241	Western Revenue Requirement Template
6	Heartland	\$888,923	Heartland Revenue Requirement Template
7		\$160,339,691	L4 + L5 + L6
8			
9			
10	<u>Transmission Customer Facility Credits</u>		
11		\$3,902,748	MRES Revenue Requirement Template
12		\$3,271,795	NWPS Revenue Requirement Template
13		\$7,174,543	
14			
15			
16	<u>Annual Revenue Requirement for IS Transmission Service</u>		
17			
18		\$167,514,234	L7 + L13
19			
20	<u>2010 True-up Amount</u>		
21		(\$10,883,748)	2010 Rate True-up Worksheet
22			
23	<u>2010 Unreserved Use of Transmission Service Penalties</u>		
24			
25		(\$6,342)	
26			
27	<u>Annual Revenue Requirement for IS Transmission Service after True-up</u>		
28			
29		\$156,624,144	L18 - L21 - L25

**INTEGRATED SYSTEM
FIRM POINT-TO-POINT RATE DESIGN
Effective January 1, 2012**

Line

No.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15

Annual Revenue Requirement for IS Transmission Service

Notes

\$156,624,144

IS Annual Revenue Requirement for
Transmission Service Worksheet, L29

IS Transmission System Total Load

4,710,000 KW

IS Transmission System Total Load Worksheet, C5L14

Maximum Firm Point-to-Point Transmission Rate in \$/KW-Mo

\$2.77 / KW-Mo

L5 / L10 / 12 months

INTEGRATED SYSTEM
NON-FIRM POINT-TO-POINT RATE DESIGN
Effective January 1, 2012

Line

No.

1
2
3
4
5
6
7
8
9
10

Firm Point-to-Point Transmission Rate in \$/KW-Mo

Notes

\$2.77 / KW-Mo

IS Firm Point-to-Point Rate Design Worksheet, L15

Maximum Non-Firm Point-to-Point Transmission Rate

3.79 Mills/KWh

(L5 * 1000) / 730 hours per month

Integrated System Load Data

2012 IS Transmission System Total Load Estimate
Transmission Rate
(MW)

4,710

2012 IS Transmission System Total Load (MW)

Line No.	(1) Date	(2) Hour Ending	(3) Network Load	(4) Long-Term Firm Point-to-Point Reservations	(5) Total
1	01/19/12	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	<u>4,738</u>	<u>426</u>	<u>5,164</u>
13					
14	12 CP		4,530	443	4,973

2012 Integrated System Network Load

(MW)

Line No.	(1) Date	(2) Hour Ending	(3) Basin Network System Load	(4) Basin Corn Belt	(5) Basin NIMECA	(4) Western Network System Load	(5) Heartland Network System Load	(6) MRES	(7) NWPS	(8) XCEL	(9) NWMT	(10) MDU	(11) MINNKOTA	(12) SMEC	(13) MMPA	(11) Total IS Network Loads
1																
2	01/19/12	800	2,165	0	65	1809	120	361	272	0.810	52	36	5	6	0.000	4,892
3	02/10/12	800	2,043	0	61	1705	115	334	250	0.753	42	24	11	2	0.000	4,588
4	03/01/12	800	2,020	0	52	1422	100	276	226	0.103	41	9	8	3	0.000	4,157
5	04/11/12	800	1,790	0	44	1199	94	252	192	0.559	34	2	11	1	0.662	3,620
6	05/18/12	1600	1,908	0	56	1298	102	271	242	0.094	38	0	6	4	0.000	3,925
7	06/27/12	1700	2,434	0	78	1674	124	355	285	0.513	44	2	6	9	0.693	5,012
8	07/19/12	1800	2,622	0	77	1784	127	400	320	0.801	69	30	10	7	2.132	5,449
9	08/01/12	1700	2,516	0	76	1701	128	379	303	0.720	60	7	6	6	2.566	5,185
10	09/04/12	1700	2,235	0	80	1352	115	317	272	0.621	40	2	10	2	1.476	4,427
11	10/25/12	2000	2,080	0	50	1200	97	233	205	0.076	45	15	10	3	0.000	3,938
12	11/26/12	1900	2,218	0	54	1410	108	318	235	0.709	51	21	10	3	0.000	4,429
13	12/26/12	1900	2,166	0	52	1710	113	332	249	0.802	58	36	10	4	0.000	4,738
14																
15	Average Monthly Peak IS Network Load		2,183	0	63	1,522	112	319	254	0.547	48	15	9	4	0.627	4,530
	2011 Network Load		2,028	0	64	1,578	110	331	263	0.675	48	9	6	4	0	4,442
	Difference		155	0	-1	-56	2	-12	-9	0	0	6	3	0	1	88
	Percent Change		7.10%		-1.59%	-3.68%	1.79%	-3.76%	-3.54%	0.00%	0.00%	40.00%	33.33%	0.00%	159.49%	1.94%

Western's
2012 Actual
Revenue Requirement Template

Revenue Requirement - Non-Levelized

Revenue Requirement Template
 Utilizing Financial Statement Results of Operations

12 Months Ending 9/30/2012

Western Area Power Administration

Line No.		Total	Allocator	Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)			\$ 135,181,417
	REVENUE CREDITS (Note R)			
2	Short-Term Firm Point-to-Point Transmission Service Credit	(39,514)	NA 1.00000	(39,514)
3	Non-Firm Point-to-Point Transmission Service Credit	11,229,129	NA 1.00000	11,229,129
4	Revenue from Existing Transmission Agreements	631,678	NA 1.00000	631,678
5	Scheduling, System Control, and Dispatch Service Credit	84,410	NA 1.00000	84,410
6	Account No. 454 (page 4, line 39)	79,082	TP 1.00000	79,082
7	Account No. 456 (page 34, line 42)	0	TP 1.00000	0
8	TOTAL REVENUE CREDITS			<u>11,984,785</u>
9	NET REVENUE REQUIREMENT (line 1 minus line 8)			<u>\$ 123 196 632</u>

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

12 Months Ending 9/30/2012

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 N SERVICE (Note A)				
1	Production	Schedule 1A Total	971,427,561	NA	
2	Transmission	Schedule 1A Total	1,135,206,587	TP	1,135,206,587
3	Distribution	Schedule 1A Total	30,335,696	NA	
		Bal Sheet - Other Assets			
4	General & Intangible	- SGL 175002		W/S	0
5	Common		0	CE	0
6	TOTAL GROSS PLANT (sum lines 1-5)		2,136,969,844	GP=	53.122%
	ACCUMULATED DEPRECIATION				
7	Production	Schedule 4	539,406,590	NA	
8	Transmission	Schedule 4	541,853,373	TP	541,853,373
9	Distribution	Schedule 4	14,392,053	NA	
		Bal Sheet - Other Assets			
10	General & Intangible	- SGL 175902	0	W/S	0
11	Common		0	CE	0
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		1,095,652,016		541,853,373
	NET PLANT N SERVICE				
13	Production	(line 1 - line 7)	432,020,971		
14	Transmission	(line 2 - line 8)	593,353,214		593,353,214
15	Distribution	(line 3 - line 9)	15,943,643		
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)		1,041,317,828	NP=	56.981%
	ADJUSTMENTS TO RATE BASE (Note B)				
19	Account No. 281 (enter negative)		0		zero
20	Account No. 282 (enter negative)		0	NP	0.56981
21	Account No. 283 (enter negative)		0	NP	0.56981
22	Account No. 190		0	NP	0.56981
23	Account No. 255 (enter negative)		0	NP	0.56981
24	TOTAL ADJUSTMENTS (sum lines 19 - 23)		0		0
25	LAND HELD FOR FUTURE USE	(Note C)	0	TP	1.00000
	WORKING CAPITAL (Note D)				
26	CWC	calculated	22,258,996		0
		Bal Sheet - Other Assets			
27	Materials & Supplies (Note C)	- SGL 151191	0	TE	0.00000
28	Prepayments	Bal Sheet Other Assets	0	GP	0.53122
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		22,258,996		0
30	RATE BASE (sum lines 18, 24, 25, and 29)		1,063,576,824		593,353,214

Western Area Power Administration
Integrated System

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

12 Months Ending 9/30/2012

Western Area Power Administration

Line No.	(1)	(2)	(3)	(4)	(5)
	Results of Operation Reference	Company Total	Allocator	Transmission (Col 3 times Col 4)	
O&M					
1	Transmission (Note E)	Schedule 11			
1a	Western UGP	64,409,359	PTP/UGP 0.95507	61,515,447	
1b	Western RMR	37,768,427	PTP/RMR 0.00930	351,246	
1c	COE	50,686,864	PTP/COE 0.04379	2,219,578	
2	Less Account 565 (Note E)		NA 1.00000	0	
3	A&G (Note F)	Schedule 11			
3a	Western UGP	16,479,304	PTP/UGP 0.95507	15,738,889	
3b	Western RMR	8,728,010	PTP/RMR 0.00930	81,170	
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)	178,071,964		79,906,330	
DEPRECIATION EXPENSE					
9	Transmission (Note E)	Schedule 4			
9a	Western UGP	27,444,269	PTP/UGP 0.95507	26,211,198	
9b	Western RMR	20,038,251	PTP/RMR 0.00930	186,356	
9c	COE	11,766,373	PTP/COE 0.04379	515,249	
10	General	0	W/S 1.00000	0	
11	Common	0	CE 0.00000	0	
12	TOTAL DEPRECIATION (Sum lines 9 - 11)	59,248,893		26,912,803	
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	
PLANT RELATED					
16	Property	0	GP 0.53122	0	
17	Gross Receipts	0	zero	0	
18	Other	0	GP 0.53122	0	
19	Payments in lieu of taxes	0	GP 0.53122	0	
20	TOTAL OTHER TAXES (sum lines 13 - 19)	0		0	
INCOME TAXES (Note I)					
21	$T=1 - \{[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)\}$ =	0.00%	NA		
22	$CIT=(T/1-T) * (1-(WCLTD/R)) =$ where WCLTD=(page 4, line 27) and R=(page 4, line30) and FIT, SIT & p are as given in footnote I. $1 / (1 - T) =$ (from line 21)	0.00%			
23	Amortized Investment Tax Credit (enter negative)	0.0000			
24		0			
25	Income Tax Calculation = line 22 * line 28	0	NA	0	
26	ITC adjustment (line 23 * line 24)	0	NP 0.56981	0	
27	Total Income Taxes (line 25 plus line 26)	0		0	
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]	50,838,972	NA	28,362,284	
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)	288,159,829		135,181,417	

Western Area Power Administration
Integrated System

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

12 Months Ending 9/30/2012

Western Area Power Administration

Line
No.

SUPPORTING CALCULATIONS AND NOTES

TRANSMISSION PLANT INCLUDED IN IS RATES

1	Total transmission plant (page 2, line 2, column 3)		1,135,206,587
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)		1,135,206,587

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)

	\$	TP	Allocation	
12	Production	0	0.00	0
13	Transmission	18,676,720	1.00	18,676,720
14	Distribution	0	0.00	0
15	Other	0	0.00	0
16	Total (sum lines 12-15)	18,676,720		18,676,720 = 1.00000

W&S Allocator
(\$ / Allocation)

PERCENTAGE OF TOTAL PLANT ALLOCATOR PTP (Note M)

	\$			
17	Transmission Plant in Service UGP	1,085,190,759		
18	Total Plant in Service UGP	1,136,236,533		
19	UGP Percentage of Transmission Plant to Total Plant (line 17 divided by line 18)		PTP/UGP =	0.95507
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	43,538,927		
24	Total Plant in Service COE	994,256,410		
25	COE Percentage of Transmission Plant to Total Plant (line 23 divided by line 24)		PTP/COE =	0.04379

COMMON PLANT ALLOCATOR (CE) (Note N)

	\$	% Electric (line 17 / line 20)	Labor Ratio (line 16)	=	CE
26	Electric	0			0.00000
27	Gas	0			
28	Water	0			
29	Total (sum lines 17-19)	0	0.00000 *	1.00000	

RETURN (R)

30	Long Term Interest Schedule 5	\$35,371,577
----	-------------------------------	--------------

	\$	%	Cost (Note O)	Weighted	=WCLTD
31	Long Term Debt	740,200,893	100%	0.0478	0.0478 =R
32	Proprietary Capital	0	0%	0.1238	0.0000
33	Total (sum lines 31-32)	740,200,893	100%		0.0478

Proprietary Capital Cost Rate = 12.38%
T ER = 1.00

REVENUE CREDITS

		Load
36	ACCOUNT 447 (SALES FOR RESALE)	
37	a. Bundled Non-RQ Sales for Resale (Note P)	0
38	b. Bundled Sales for Resale included in Divisor on page 1	0
	Total of (a)-(b)	0

39	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note Q)	79,083
----	--	--------

ACCOUNT 456 (OTHER ELECTRIC REVENUES)

40	a. Transmission charges for all transmission transactions	
41	b. Transmission charges for all transmission transactions included in Divisor on page 1	
42	Total of (a)-(b)	\$0

Western's 2012 Estimated Revenue Requirement Template

Revenue Requirement - Non-Levelized

Revenue Requirement Template
 Utilizing Financial Statement Results of Operations

Est for 12 Months Ending 9/30/2012

Western Area Power Administration

Line No.					Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)				\$ 126,118,760
REVENUE CREDITS (Note R)					
2	Short-Term Firm Point-to-Point Transmission Service Credit	Total	Allocator		7,091,261
3	Non-Firm Point-to-Point Transmission Service Credit	7,091,261	NA 1.00000		9,236,176
4	Revenue from Existing Transmission Agreements	9,236,176	NA 1.00000		1,874,000
5	Scheduling, System Control, and Dispatch Service Credit	1,874,000	NA 1.00000		106,000
6	Account No. 454 (page 3, line 36)	79,082	TP 1.00000		79,082
7	Account No. 456 (page 3, line 39)	0	TP 1.00000		0
8	TOTAL REVENUE CREDITS				18,386,519
9	NET REVENUE REQUIREMENT (line 1 minus line 8)				\$ 107,732,241

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

Est for 12 Months Ending 9/30/2012

Western Area Power Administration

Line No.	(1)	(2) ROOs Reference	(3) Company Total	(4) Allocator	(5) Transmission (Col 3 times Col 4)
RATE BASE:					
GROSS PLANT IN SERVICE (Note A)					
1	Production	Schedule 1A Total	960,298,305	NA	
2	Transmission	Schedule 1A Total	1,126,787,076	TP	1,126,787,076
3	Distribution	Schedule 1A Total	31,991,519	NA	
		Bal Sheet - Other			
4	General & Intangible	Assets - SGL 175002		W/S	1.00000
5	Common		0	CE	0.00000
6	TOTAL GROSS PLANT (sum lines 1-5)		2,119,076,900	GP=	53.173%
ACCUMULATED DEPRECIATION					
7	Production	Schedule 4	544,771,394	NA	
8	Transmission	Schedule 4	539,770,355	TP	1.00000
9	Distribution	Schedule 4	15,241,878	NA	
		Bal Sheet - Other			
10	General & Intangible	Assets - SGL 175902	0	W/S	1.00000
11	Common		0	CE	0.00000
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		1,099,783,627		
NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	415,526,911		
14	Transmission	(line 2- line 8)	587,016,721		587,016,721
15	Distribution	(line 3 - line 9)	16,749,641		
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)		1,019,293,273	NP=	57.591%
ADJUSTMENTS TO RATE BASE (Note B)					
19	Account No. 281 (enter negative)		0		zero
20	Account No. 282 (enter negative)		0	NP	0.57591
21	Account No. 283 (enter negative)		0	NP	0.57591
22	Account No. 190		0	NP	0.57591
23	Account No. 255 (enter negative)		0	NP	0.57591
24	TOTAL ADJUSTMENTS (sum lines 19 - 23)		0		0
25	LAND HELD FOR FUTURE USE (Note C)		0	TP	1.00000
WORKING CAPITAL (Note D)					
26	CWC	calculated	19,682,128		0
		Bal Sheet - Other			
27	Materials & Supplies (Note C)	Assets - SGL 151191	0	TE	0.00000
28	Prepayments	Bal Sheet Other Assets	0	GP	0.53173
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		19,682,128		0
30	RATE BASE (sum lines 18, 24, 25, and 29)		1,038,975,401		587,016,721

Western Area Power Administration
Integrated System

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

Est for 12 Months Ending 9/30/2012

Western Area Power Administration

Line No.	(1)	(2)	(3)	(4)	(5)
		Results of Operation Reference	Company Total	Allocator	Transmission (Col 3 times Col 4)
O&M					
1	Transmission (Note E)	Schedule 11			
1a	Western UGP		53,941,125	PTP/UGP 0.95461	51,492,737
1b	Western RMR		38,546,529	PTP/RMR 0.00925	356,555
1c	COE	COE Financial Stmt	37,352,000	PTP/COE 0.03783	1,413,026
2	Less Account 565 (Note E)			NA 1.00000	0
3	A&G (Note F)	Schedule 11			
3a	Western UGP		18,165,979	PTP/UGP 0.95461	17,341,425
3b	Western RMR		9,451,391	PTP/RMR 0.00925	87,425
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)		157,457,024		70,691,168
DEPRECIATION EXPENSE					
9	Transmission (Note E)	Schedule 4			
9a	Western UGP		27,240,010	PTP/UGP 0.95461	26,003,586
9b	Western RMR		14,220,442	PTP/RMR 0.00925	131,539
9c	COE		10,870,848	PTP/COE 0.03783	411,244
10	General		0	W/S 1.00000	0
11	Common		0	CE 0.00000	0
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		52,331,300		26,546,369
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 0.53173	0
17	Gross Receipts		0	zero	0
18	Other		0	GP 0.53173	0
19	Payments in lieu of taxes		0	GP 0.53173	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		0		0
INCOME TAXES (Note I)					
21	$T=1 - \{[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)\} =$		0.00%	NA	
22	$CIT=(T/(1-T)) * (1-(WCLTD/R)) =$ where WCLTD=(page 4, line 27) and R= (page 4, line 30) and FIT, SIT & p are as given in footnote I.		0.00%		
23	$1 / (1 - T) =$ (from line 21)		0.0000		
24	Amortized Investment Tax Credit (enter negative)		0		
25	Income Tax Calculation = line 22 * line 28		0	NA	0
26	ITC adjustment (line 23 * line 24)		0	NP 0.57591	0
27	Total Income Taxes (line 25 plus line 26)		0		0
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		51,117,590	NA	28,881,223
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		<u>260,905,914</u>		<u>126,118,760</u>

Western Area Power Administration
Integrated System

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

Est for 12 Months Ending 9/30/2012

Western Area Power Administration

Line
No.

SUPPORTING CALCULATIONS AND NOTES

TRANSMISSION PLANT INCLUDED IN IS RATES

1	Total transmission plant (page 2, line 2, column 3)					1,126,787.076
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)					1,126,787.076
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)					0
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)

	\$	TP	Allocation		
12	Production	0	0.00		0
13	Transmission	18,907,420	1.00		18,907,420
14	Distribution	0	0.00		0
15	Other	0	0.00		0
16	Total (sum lines 12-15)	18,907,420			18,907,420 =
					W&S Allocator (\$ / Allocation)
					1.00000

PERCENTAGE OF TOTAL PLANT ALLOCATOR PTP (Note M)

	\$				
17	Transmission Plant in Service UGP	1,083,478,852			
18	Total Plant in Service UGP	1,135,000,426			
19	UGP Percentage of Transmission Plant to Total Plant (line 17 divided by line 18)			PTP/UGP =	0.95461
20	Transmission Plant in Service RMR	6,323,513			
21	Total Plant in Service RMR	683,875,642			
22	RMR Percentage of Transmission Plant to Total Plant (line 20 divided by line 22)			PTP/RMR =	0.00925
23	Transmission Plant in Service COE	36,984,711			
24	Total Plant in Service COE	977,752,962			
25	COE Percentage of Transmission Plant to Total Plant (line 23 divided by line 24)			PTP/COE =	0.03783

COMMON PLANT ALLOCATOR (CE) (Note N)

	\$	% Electric (line 17 / line 20)	Labor Ratio (line 16)	=	CE
26	Electric	0			0.00000
27	Gas	0			
28	Water	0	0.00000 *		1.00000
29	Total (sum lines 17-19)	0			

RETURN (R)

30	Long Term Interest Schedule 5	\$37,434,238
----	-------------------------------	--------------

	HFD Sch's 21RX & 21X Col 8 Lines	\$	%	Cost (Note O)	Weighted	=WCLTD
31	Long Term Debt	23,25,26,29,30	760,936,643	100%	0.0492	0.0492 =R
32	Proprietary Capital			0%	0.1238	0.0000
33	Total (sum lines 22-23)		760,936,643	100%		0.0492
34				Proprietary Capital Cost Rate =	12.38%	
35				TIER =	1.00	

REVENUE CREDITS

		Load
36	ACCOUNT 447 (SALES FOR RESALE)	
	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)	79,082
----	--	--------

40	ACCOUNT 456 (OTHER ELECTRIC REVENUES)	
	a. Transmission charges for all transmission transactions	
41	b. Transmission charges for all transmission transactions included in Divisor on page 1	
42	Total of (a)-(b)	\$0

Western Area Power Administration
Integrated System

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Utilizing Financial Statement Results of Operations

Est for 12 Months Ending 9/30/2012

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:	<table border="0"> <tr> <td>FIT =</td> <td style="background-color: yellow;">0.00%</td> <td></td> </tr> <tr> <td>SIT=</td> <td style="background-color: yellow;">0.00%</td> <td>(State Income Tax Rate or Composite SIT)</td> </tr> <tr> <td>p =</td> <td style="background-color: yellow;">0.00%</td> <td>(percent of federal income tax deductible for state purposes)</td> </tr> </table>	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)
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 be included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.										
M	Percentage of Total Plant Allocators are developed separately for the Upper Great Plains Region and Rocky Mountain Region to allocate O&M, A&G, and Depreciation Expenses between Transmission and Generation.										
N	Western does not have Common Plant.										
O	Debt cost rate = long-term interest (line 21) / long term debt (line 22). The Proprietary Capital Cost rate is implicit, a residual calculation after TIER is determined. TIER will be supported in the filing and no change in TIER may be made absent a filing with the ISO and the FERC, if the entity is under FERC's jurisdiction.										
P	Line 29 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the divisor.										
Q	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.										
R	The revenues credited on page 1 lines 2-5 shall include only the amounts received directly reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Revenue Requirement Template.										

Basin Electric's
2012 Actual
Revenue Requirement Template

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

Average for the twelve months ended 12/31/2012

Line
No.

1 **GROSS REVENUE REQUIREMENT (page 3, line 28)**
 (MBPP West Excluded - 1-.065997)

**Total
Transmission**
\$ 79,641,704

IS Transmission	West (MBPP) Transmission	Other Transmission
\$ 48,209,489	\$ 7,109,714	\$ 24,322,499
	\$ 6,640,494	

REVENUE CREDITS

Total	Allocator
-------	-----------

2	Third Party Receipts	TP	1.00000
3			
4	Third Party Payments	TP	1.00000
5			
6	NET REVENUE REQUIREMENT		

(line 2 + 4)
(line 1+ 5)

\$ (350,472)	\$ -	\$ -
\$ 97,532		
\$ (252,940)	\$ -	\$ -
\$ 47,956,549	\$ 469,220	\$ 24,322,499
\$ 48,425,769		

7 **TOTAL REVENUE REQUIREMENT WITH MBPP EAST**

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

Average for the twelve months ended 12/31/2012

Page 2

(1)	(2) Worksheets	(3)	(4) Allocator A	(5) Total Trans	(4a) Allocator B	(6) IS Transmission	(7) West (MBPP) Transmission	(8) Other Transmission
GROSS PLANT IN SERVICE (Note A)								
1	Production (Note A)	Worksheet 1, L.1. C. d	3,555,800,452	NA	0.000%	-	NA	0.000%
2	Transmission (Note B)	Worksheet 1, L.2. C. d	709,997,514	DA	100.000%	709,997,514	DA	100.000%
3	Distribution		-	NA	0.000%	-	NA	0.000%
4	General	Worksheet 1, L.3. C. d	150,281,946					
4a	Direct Assign - Transmission (Note C)		35,594,161	DA	100.000%	35,594,161	DA	100.000%
4b	Direct Assign - Production		45,757,591	NA	0.000%	-	NA	0.000%
4c	Other		68,930,194	WS	10.184%	7,019,826	GP	Gross Plant
5	Intangible	Worksheet 1, L.4. C. d	78,163,716	DA	100.000%	69,217,960	DA	100.000%
6	TOTAL GROSS PLANT (sum lines 1,2,4,5)	Worksheet 1, L. 5. C. d	\$ 4,494,243,628			\$ 821,829,461		
				GP			GP	Gross Plant
						59.670%	12.878%	27.452%
ACCUMULATED DEPRECIATION								
7	Production	Worksheet 1, L.6. C. d	1,152,022,721	NA	0.000%	-	NA	0.000%
8	Transmission	Worksheet 1, L. 7. C. d	290,490,082	DA	100.000%	290,490,082	DA	100.000%
9	Distribution		-	NA	0.000%	-	NA	0.000%
10	General	Worksheet 1, L. 8. C. d	107,539,122					
10a	Direct Assign - Transmission		23,800,905	DA	100.000%	23,800,905	DA	100.000%
10b	Direct Assign - Production		34,325,071	NA	0.000%	-	NA	0.000%
10c	Other		49,413,146	WS	10.184%	5,032,217	GP	Gross Plant
11	Intangible	Worksheet 1, L. 9. C. d	50,475,156	DA	100.000%	46,690,616	DA	100.000%
12	TOTAL ACCUM. DEPR (sum lines 7,8,10,11)	Worksheet 1, L. 10. C. d	\$ 1,600,527,081			\$ 366,013,821		
						240,254,487	59,763,711	65,995,623
NET PLANT IN SERVICE								
13	Production	(line 1- line 7)	2,403,777,730	AUTO		-	AUTO	
14	Transmission	(line 2- line 8)	419,507,432	AUTO		419,507,432	AUTO	
15	Distribution	(line 3 - line 9)	-	AUTO		-	AUTO	
16	General	(line 4 - line 10)	42,742,824	AUTO		-	AUTO	
16a	Direct Assign	(line 4a - line 10a)	11,793,256	AUTO		11,793,256	AUTO	
16b	Production	(line 4b - line 10b)	11,432,520	AUTO		-	AUTO	
16c	Other	(line 4c - line 10c)	19,517,048	AUTO		1,987,609	AUTO	
17	Intangible	(line 5 - line 11)	27,688,561	AUTO		22,527,344	AUTO	
18	TOTAL NET PLANT (sum lines 13, 14, 16, 17)		\$ 2,893,716,547			\$ 455,815,640		
						244,664,993	38,509,210	172,641,437
WORKING CAPITAL								
19	CWC (Note D)	one eighth of line 9, page 3	10,355,376	DA	100.000%	4,069,515	DA	100.000%
20	Materials & Supplies Transmission	Estimate based on 2010 actual	7,382,624	GP	100.000%	7,382,624	GP	Gross Plant
21	Prepayments (Note D)		-	GP		-	GP	Gross Plant
22	TOTAL WORKING CAPITAL (sum lines 19-21)		\$ 17,738,000			\$ 11,452,139		
						7,170,101	1,359,592	2,922,446
23	Rate Base		\$ 2,911,454,547			\$ 467,267,780		
						251,835,094	39,868,802	175,563,883

A & G Allocation

WAGES AND SALARY ALLOCATOR (W/S)

Line No.	(1) From Accounting Report	(2)	(3) TOTAL	(4) Allocator	(5) Percent	(6) IS Transmission	(7) West (MBPP) Transmission	(8) Other Transmission
1	Production	Accounting Records	51,365,483					
2	Transmission-East	Accounting Records	213,769					
3	Transmission-West	Accounting Records	457,592	WS	10.184%			
4	Transmission-Allocated	Accounting Records	5,152,813					
5	Distribution		-	TPW				
6	Other Transmission		-	Trans % excluding West				
7	Total Wages and Salaries (sum lines 1-6) (exclude adm)		\$57,189,658					

Note J	Weighted Cost of Capital	Percent	Rate	Weighted cost
Wksh#1 LTD	3,537,285,452	76.06%	4.48%	3.41%
Wksh#1 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 transmission includes the transmission maintenance buildings and microwave assigned to transmission.
- 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 \$3,859,923 for member facilities in the IS system and O&M that is charged to specific lines or substations.
- F Line 5 - Regulatory Commission expenses directly related to transmission service, ISO filings, or transmission sitings.
- G A&G costs directly allocated to MBPP - Costs split between MBPP Production and MBPP Transmission based on MBPP gross plant.
Includes OASIS costs for West Side and Common Use System plus legal fees for transmission.
- H West (MBPP) plant investment on page 2, line, column 7 is excluded in the percentage calculations on page 4, GP2 for 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.

Basin Electric's
2012 Estimated
Revenue Requirement Template

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

Projections for 2012

Page 1

Line No.		Total Transmission	IS Transmission	West (MBPP) Transmission	Other Transmission
1	GROSS REVENUE REQUIREMENT (page 3, line 28) (MBPP West Excluded - 1- 065997)	\$ 84,938,398	\$ 51,334,094	\$ 9,392,868 \$ 8,772,967	\$ 24,211,368
REVENUE CREDITS					
		<u>Total</u>			
2	Third Party Receipts				
3					
4	Third Party Payments				
5					
6	NET REVENUE REQUIREMENT (line 1+ 5)				
7	TOTAL REVENUE REQUIREMENT WITH MBPP EAST				

	Total	Allocator
2		TP 1.00000
4		TP 1.00000
5	(line 2 + 4)	
6	(line 1+ 5)	

\$ (333,000)	\$ -	\$ -
\$ 97,532		
\$ (235,468)	\$ -	\$ -
\$ 51,098,626	\$ 619,901	\$ 24,211,368
\$ 51,718,527		

A & G Allocation

WAGES AND SALARY ALLOCATOR (W/S)

Line #	From Accounting Report	(1)	(2)	(3)	(4)	(5)				(6)	(7)	(8)
										IS Transmission	West (MBPP) Transmission	Other Transmission
				TOTAL	Allocator	Percent						
1	Production		Accounting Records	50,196,392						\$223,234	\$457,562	\$194,928,036
2	Transmission-East		Accounting Records	223,234								
3	Transmission-West		Accounting Records	457,562	WS	Trans % of total wages	9.435%	Gross Plant	GP1	59.781%	13.045%	27.173%
4	Transmission-Allocated		Accounting Records	4,548,485								
5	Distribution		Accounting Records	-	TPW	Trans % excluding West			GP2	68.750%	0.000%	31.250%
6	Other Transmission			-								
7	Total Wages and Salaries (sum lines 1-6) (exclude adm)			\$55,425,673								

Transmission Wage and Salary Dollar Split

8	IS transmission Plant (p.2.c.6.L.2)	428,840,769
9	West (MBPP) Transmission Plant (p.2.c.7.L.2)	93,581,195
10	Other transmission Plant (p.2.c.8.L.2)	194,928,036
11		\$717,350,000
12		68.750%
13		31.250%
14		100.000%

Note I	Weighted Cost of Capital	Percent	Rate	Weighted cost
Wksh #1	LTD	3,017,075,000	74.57%	5.00%
Wksh #1	Equity	1,028,845,000	25.43%	10.85%
		4,045,920,000	100.00%	6.49%

- A RUS form 12h plus new investment averaged over 13 months.
- B General Plant directly assigned to transmission includes the transmission maintenance buildings and microwave assigned to transmission.
- C Cash working capital assigned to transmission is one eighth of O&M allocated to transmission on page 3, line 9, column 6-8. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Section B, line 24, in the RUS 12.
- D Includes Lease payments of \$4,140,536.94 for member facilities in the IS system and O&M that is charged to specific lines or substations.
- E Line 5 - Regulatory Commission expenses directly related to transmission service, ISO filings, or transmission sitings.
- F A&G costs directly allocated to MBPP - Costs split between MBPP Production and MBPP Transmission based on MBPP Wages. Includes OASIS costs for West Side and Common Use System plus A&G costs allocated to MBPP Transmission.
- G SD Gross receipts taxes paid in lieu of property with a portion directly assigned to other transmission. Payroll taxes are included in the RUS 500 series of accounts along with the labor costs. ND Trans Line tax is included in O&M, line 2.
- H West (MBPP) plant (93,581,195) is excluded in the percentage calculations on line 12 and 13 as costs for transmission and A&G are directly allocated to MBPP.
- I Equity percent as a percent of total estimated long term debt plus current portion of long term debt plus equity.

Heartland's
2012 Actual
Revenue Requirement Template

Revenue Requirement - Non-Levelized

Revenue Requirement Template
 Annual Transmission Revenue Requirement
 True Up to Actual
 Heartland Consumers Power District

For the 12 months ending 12/31/2012

<u>Line No.</u>			<u>Allocated Amount</u>
1	GROSS REVENUE REQUIREMENT (page 3, line 29)		\$ 837,734
	REVENUE CREDITS (Note P)	<u>Total</u>	
2	Account No. 454 (page 4, line 30)	24,843	
3	Account No. 456.1 (page 4, line 33)	0	
4	Revenue From Existing Transmission Agreements	0	
5	Transmission Service Credits	0	
6	TOTAL REVENUE CREDITS		<u>12,950</u>
	NET REVENUE REQUIREMENT (line 1 minus line 6)		<u>\$ 824,784</u>

	<u>Allocator</u>
TP	0.52127
TP	0.52127
NA	1.00000
NA	1.00000

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Annual Transmission Revenue Requirement

For the 12 months ending 12/31/2012

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	42,255,648	NA	
2	Transmission	Schedule A	14,575,880	TP 0.52127	7,597,969
3	Distribution		0	NA	
4	General & Intangible	Schedule A	6,596,450	W/S 0.06760	445,920
5	Common		0	CE 0.06760	0
6	TOTAL GROSS PLANT (sum lines 1-5)		63,427,978	GP= 12 682%	8,043,889
ACCUMULATED DEPRECIATION					
7	Production	Schedule A	31,413,560	NA	
8	Transmission	Schedule A	11,289,695	TP 0.52127	5,884,979
9	Distribution		0	NA	
10	General & Intangible	Schedule A	2,784,453	W/S 0.06760	188,229
11	Common		0	CE 0.06760	0
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		45,487,708		6,073,208
NET PLANT N SERVICE					
13	Production	(line 1- line 7)	10,842,088		
14	Transmission	(line 2- line 8)	3,286,185		1,712,990
15	Distribution	(line 3 - line 9)	0		
16	General & Intangible	(line 4 - line 10)	3,811,997		257,691
17	Common	(line 5 - line 11)	0		0
18	TOTAL NET PLANT (sum lines 13-17)		17,940,270	NP= 10 985%	1,970,681
ADJUSTMENTS TO RATE BASE (Note A)					
19	Account No. 281 (enter negative)		0	zero	0
20	Account No. 282 (enter negative)		0	NP 0.10985	0
21	Account No. 283 (enter negative)		0	NP 0.10985	0
22	Account No. 190		0	NP 0.10985	0
23	Account No. 255 (enter negative)		0	NP 0.10985	0
24	TOTAL ADJUSTMENTS (sum lines 19 - 23)		0		0
25	LAND HELD FOR FUTURE USE (Note B)		0	TP 0.52127	0
WORKING CAPITAL (Note C)					
26	CWC		496,242		53,442
27	Materials & Supplies (Note B)		0	TE 1.00000	0
28	Prepayments		342,634	GP 0.12682	43,453
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		838,876		96,895
30	RATE BASE (sum lines 18, 24, 25, and 29)		18,779,146		2,067,576

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Annual Transmission Revenue Requirement

For the 12 months ending 12/31/2012

Heartland Consumers Power District

Line No.	(1)	(2)	(3)	(4)	(5)	
		Reference	Company Total	Allocator	Transmission (Col 3 times Col 4)	
O&M						
1	Transmission	Schedule A	223,785	TE	1.00000	223,785
1a	Less LSE Expenses included in Transmission O&M Accounts (Note D)		0		1.00000	0
2	Less Account 565		53,080	NA	1.00000	53,080
3	A&G (Note G)	Schedule A	3,799,231	W/S	0.06760	256,828
4	Less FERC Annual Fees		0	W/S	0.06760	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad(Note E)		0	W/S	0.06760	0
5a	Plus Transmission Related Reg. Comm. Exp. (Note E)		0	TE	1.00000	0
6	Common		0	CE	0.06760	0
7	Transmission Lease Payments		0	NA	1.00000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less 2, 4, 5)		3,969,936			427,533
DEPRECIATION EXPENSE						
9	Transmission		383,100	TP	0.52127	199,699
10	General		161,541	W/S	0.06760	10,920
11	Common		0	CE	0.06760	0
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		544,641			210,619
TAXES OTHER THAN INCOME TAXES (Note F)						
LABOR RELATED						
13	Payroll		94,196	W/S	0.06760	6,368
14	Highway and vehicle		0	W/S	0.06760	0
PLANT RELATED						
16	Property		264,916	GP	0.12682	33,597
17	Gross Receipts		0	NA	zero	0
18	Other		0	GP	0.12682	0
19	Payments in lieu of taxes		0	GP	0.12682	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		359,112			39,965
INCOME TAXES (Note G)						
21	$T = 1 - \frac{((1 - SIT) * (1 - FIT))}{(1 - SIT * FIT * p)}$		0.00%	NA		
22	$CIT = (T / (1 - T)) * (1 - (WCLTD / R))$ where WCLTD=(page 4, line 27) and R=(page 4, line30) and FIT, SIT & p are as given in footnote G.		0.00%			
23	$1 / (1 - T) =$ (from line 21)		0.0000			
24	Amortized Investment Tax Credit (enter negative)		0			
25	Income Tax Calculation = line 22 * line 28		0	NA		0
26	ITC adjustment (line 23 * line 24)		0	NP	0.10985	0
27	Total Income Taxes (line 25 plus line 26)		0			0
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 24)]		1,449,750	NA		159,617
29	REV. REQUIREMENT (sum lines 8, 12,20,27,28)		6,323,439			837,734

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Annual Transmission Revenue Requirement

For the 12 months ending 12/31/2012

Heartland Consumers Power District

Line No.

SUPPORTING CALCULATIONS AND NOTES

TRANSMISSION PLANT INCLUDED IN IS RATES

1	Total transmission plant (page 2, line 2, column 3)		14,575,880
2	Less transmission plant excluded from IS rates (Note H)		6,752,305
3	Less transmission plant included in OATT Ancillary Services (Note I)		225,659
4	Transmission plant included in IS rates (line 1 less lines 2 & 3)		7,597,916
5	Percentage of transmission plant included in IS Rates (line 4 divided by line 1)	TP=	0.52127

TRANSMISSION EXPENSES

6	Total transmission expenses (page 3, line 1, column 3)		223,785
7	Less transmission expenses included in OATT Ancillary Services (Note J)		0
8	Included transmission expenses (line 7 less line 6)		223,785
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	0.52127
11	Percentage of transmission expenses included in IS Rates (Note K)	TE=	1.00000

WAGES & SALARY ALLOCATOR (W&S)

		\$	TP	Allocation	
12	Production	1,169,580	0 00	0	
13	Transmission	174,765	0 52	90,878	
14	Distribution	0	0 00	0	
15	Other	0	0 00	0	
16	Total (sum lines 12-15)	1,344,345		90,878	= 0.06760 = W/S

COMMON PLANT ALLOCATOR (CE) (Note L)

		\$	% Electric (line 17 / line 20)	Labor Ratio (line 16)	CE
17	Electric	63,427,978			
18	Gas	0	1.00000	0.06760	= 0.06760
19	Water	0			
20	Total (sum lines 17-19)	63,427,978			

RETURN (R)

		\$	%	Cost (Note M)	Weighted
21	Long Term Interest	\$2,192,093			
22	Long Term Debt	32,711,945	82%	6.70%	0 0549 =WCLTD
23	Proprietary Capital	7 025 957	18%	12 38%	0 0223
24	Total (sum lines 22, 23)	39,737,902	100%		0 0772 =R

25 Proprietary Capital Cost Rate = 12 38%

26 T ER = 1.15

REVENUE CREDITS

		Load
27	ACCOUNT 447 (SALES FOR RESALE)	
	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

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 application 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 be 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.

Heartland's 2012 Estimated Revenue Requirement Template

Revenue Requirement - Non-Levelized

Revenue Requirement Template
 Annual Transmission Revenue Requirement

For the 12 months ending 12/31/2012

Heartland Consumers Power District

<u>Line No.</u>			<u>Allocated Amount</u>
1	GROSS REVENUE REQUIREMENT (page 3, line 29)		\$ 902,232
	REVENUE CREDITS (Note P)	<u>Total</u>	<u>Allocator</u>
2	Account No. 454 (page 4, line 30)	24,738	TP 0.53801 \$13,309
3	Account No. 456.1 (page 4, line 33)	0	TP 0.53801 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		<u>13,309</u>
	NET REVENUE REQUIREMENT (line 1 minus line 6)		<u>\$ 888,923</u>

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Annual Transmission Revenue Requirement

For the 12 months ending 12/31/2012

Heartland Consumers Power District

Line No.	(1) RATE BASE	(2) Reference	(3) Company Total	(4) Allocator	(5) Transmission (Col 3 times Col 4)
GROSS PLANT IN SERVICE					
1	Production	Schedule A	43,687,899	NA	
2	Transmission	Schedule A	15,104,251	TP 0.53801	8,126,238
3	Distribution		0	NA	
4	General & Intangible	Schedule A	6,598,559	W/S 0.07020	463,219
5	Common		0	CE 0.07020	0
6	TOTAL GROSS PLANT (sum lines 1-5)		65,390,709	GP= 13.136%	8,589,457
ACCUMULATED DEPRECIATION					
7	Production	Schedule A	32,167,045	NA	
8	Transmission	Schedule A	11,321,887	TP 0.53801	6,091,288
9	Distribution		0	NA	
10	General & Intangible	Schedule A	2,823,742	W/S 0.07020	198,227
11	Common		0	CE 0.07020	0
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		46,312,674		6,289,515
NET PLANT N SERVICE					
13	Production	(line 1 - line 7)	11,520,854		
14	Transmission	(line 2 - line 8)	3,782,364		2,034,950
15	Distribution	(line 3 - line 9)	0		
16	General & Intangible	(line 4 - line 10)	3,774,817		264,992
17	Common	(line 5 - line 11)	0		0
18	TOTAL NET PLANT (sum lines 13-17)		19,078,035	NP= 12.055%	2,299,942
ADJUSTMENTS TO RATE BASE (Note A)					
19	Account No. 281 (enter negative)		0	zero	0
20	Account No. 282 (enter negative)		0	NP 0.12055	0
21	Account No. 283 (enter negative)		0	NP 0.12055	0
22	Account No. 190		0	NP 0.12055	0
23	Account No. 255 (enter negative)		0	NP 0.12055	0
24	TOTAL ADJUSTMENTS (sum lines 19 - 23)		0		0
25	LAND HELD FOR FUTURE USE (Note B)		0	TP 0.53801	0
WORKING CAPITAL (Note C)					
26	CWC		474,601		54,417
27	Materials & Supplies (Note B)		0	TE 1.00000	0
28	Prepayments		114,025	GP 0.13136	14,978
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		588,626		69,395
30	RATE BASE (sum lines 18, 24, 25, and 29)		19,666,661		2,369,337

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Annual Transmission Revenue Requirement

For the 12 months ending 12/31/2012

Heartland Consumers Power District

Line No.	(1)	(2)	(3)	(4)	(5)	
		Reference	Company Total	Allocator	Transmission (Col 3 times Col 4)	
O&M						
1	Transmission	Schedule A	242,995	TE	1.00000	242,995
1a	Less LSE Expenses included in Transmission O&M Accounts (Note D)		0		1.00000	0
2	Less Account 565		61,453	NA	1.00000	61,453
3	A&G (Note G)	Schedule A	3,615,268	W/S	0.07020	253,792
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)		3,796,810			435,334
DEPRECIATION EXPENSE						
9	Transmission	Schedule A	402,923	TP	0.53801	216,777
10	General	Schedule A	164,947	W/S	0.07020	11,579
11	Common		0	CE	0.07020	0
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		567,870			228,356
TAXES OTHER THAN INCOME TAXES (Note F)						
LABOR RELATED						
13	Payroll	Schedule A	91,135	W/S	0.07020	6,398
14	Highway and vehicle		0	W/S	0.07020	0
PLANT RELATED						
16	Property	Schedule A	174,573	GP	0.13136	22,932
17	Gross Receipts		0	NA	zero	0
18	Other		0	GP	0.13136	0
19	Payments in lieu of taxes		0	GP	0.13136	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		265,708			29,330
INCOME TAXES (Note G)						
21	$T = 1 - \frac{((1 - SIT) * (1 - FIT))}{(1 - SIT * FIT * p)}$		0.00%	NA		
22	$CIT = (T / (1 - T)) * (1 - (WCLTD / R))$ where WCLTD=(page 4, line 27) and R=(page 4, line 30) and FIT, SIT & p are as given in footnote G.		0.00%			
23	$1 / (1 - T) =$ (from line 21)		0.0000			
24	Amortized Investment Tax Credit (enter negative)		0			
25	Income Tax Calculation = line 22 * line 28		0	NA		0
26	ITC adjustment (line 23 * line 24)		0	NP	0.12055	0
27	Total Income Taxes (line 25 plus line 26)		0			0
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 24)]		1,736,566	NA		209,212
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		6,366,954			902,232

Revenue Requirement - Non-Levelized

Revenue Requirement Template
Annual Transmission Revenue Requirement

For the 12 months ending 12/31/2012

Heartland Consumers Power District

Line
No.

SUPPORTING CALCULATIONS AND NOTES

TRANSMISSION PLANT INCLUDED IN IS RATES

1	Total transmission plant (page 2, line 2, column 3)		15,104,251
2	Less transmission plant excluded from IS rates (Note H)		6,752,305
3	Less transmission plant included in OATT Ancillary Services (Note I)		225,678
4	Transmission plant included in IS rates (line 1 less lines 2 & 3)		8,126,268
5	Percentage of transmission plant included in IS Rates (line 4 divided by line 1)	TP=	0.53801

TRANSMISSION EXPENSES

6	Total transmission expenses (page 3, line 1, column 3)		242,995
7	Less transmission expenses included in OATT Ancillary Services (Note J)		0
8	Included transmission expenses (line 7 less line 6)		242,995
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	0.53801
11	Percentage of transmission expenses included in IS Rates (Note K)	TE=	1.00000

WAGES & SALARY ALLOCATOR (W&S)

	\$	TP	Allocation	
12	Production	1,102,057	0 00	0
13	Transmission	164,675	0 54	88,925
14	Distribution	0	0 00	0
15	Other	0	0 00	0
16	Total (sum lines 12-15)	1,266,732		88,925 = 0.07020 = W/S

COMMON PLANT ALLOCATOR (CE) (Note L)

	\$	% Electric (line 17 / line 20)	Labor Ratio (line 16)	CE
17	Electric	65,390,709	1.00000	0.07020 = 0.07020
18	Gas	0		
19	Water	0		
20	Total (sum lines 17-19)	65,390,709		

RETURN (R)

	\$	%	Cost (Note M)	Weighted
21	Long Term Interest	Schedule A	\$1,614,451	
22	Long Term Debt	Schedule A	26,199,546	57% = 6.16% = 0.0351 = WCLTD
23	Proprietary Capital	Schedule A	19,708,994	43% = 12.38% = 0.0532
24	Total (sum lines 22, 23)		45,908,540	100% = 0.0883 = R

25 Proprietary Capital Cost Rate = 12.38%

26 T ER = 1.43

REVENUE CREDITS

	Account	Load
27	ACCOUNT 447 (SALES FOR RESALE)	
	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) \$24,738

ACCOUNT 456.1 (OTHER ELECTRIC REVENUES)

31	a. Transmission charges for all transmission transactions	\$0
32	b. Transmission charges for all transmission transactions included in Divisor on page 1	\$0
33	Total of (a)-(b)	\$0

Heartland Consumers Power District

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

Note
Letter

- A Does not apply to Heartland. For others, balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
- B Transmission related only.
- C Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 as shown on Schedule I of EIA Form 412.
- D Account Nos. 561.4, 561.8, and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.
- E Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising.
Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings or transmission siting.
- F Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
- G Heartland is not subject to Federal or State Income Tax
Inputs Required: FIT = 0 00% (Federal Income Tax Rate)
 SIT= 0 00% (State Income Tax Rate or Composite SIT)
 p = 0 00% (percent of federal income tax deductible for state purposes)
- H Removes transmission plant determined to be state-jurisdictional by Commission order according to the seven-factor test (until EIA 412 balances are adjusted to reflect application 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 be 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.

Missouri River Energy Services
2012 Actual
Revenue Requirement Template

Formula Rate - Non-Levelized
 Clean Version

Rate Formula Template
 Utilizing EIA Form 412 Data

For the 12 months ended 12/31/2012

MRES

Line No			Total	Allocator	Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 31)				\$ 6,329,442
	REVENUE CREDITS	(Note T)			
2	Account No 454	(page 4, line 34)	1,155,348	TP 1 00000	1,155,348
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)				1,155,348
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	(line 1 - line 6 + Line 6c+ line 6h+ lin			\$ 5,174,094
	DIVISOR				
8	Average of 12 coincident system peaks for requirements (RQ) service			(Note A)	646,731
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)				646,731
16	Annual Cost (\$/kW/Yr)	(line 7 / line 15)	8 000		
17	Network & P-to-P Rate (\$/kW/Mo) (line 11 / 12)		0 667		
			Peak Rate		Off-Peak Rate
18	Point-To-Point Rate (\$/kW/Wk)	(line 16 / 52; line 16 / 52)	0 154		\$0 154
19	Point-To-Point Rate (\$/kW/Day)	(line 16 / 260; line 16 / 365)	0 031	Capped at weekly rate	\$0 022
20	Point-To-Point Rate (\$/MWh)	(line 16 / 4,160; line 16 / 8,760 times 1,000)	1 923	Capped at weekly and daily rates	\$0 913
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 12/31/2012

Line No	(1) RATE BASE:	(2) EIA 412 Reference	(3) MRES 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	279,787,486	NA	
2	Transmission	IV 7 e less Line 2a	59,576,642	TP 1 00000	59,576,642
2a	Transmission for projects with FERC approved incentives (Note EE)		5,584,562	TP 1 00000	5,584,562
3	Distribution	IV 8 e	0	NA	
4	General & Intangible	IV 1e and IV 9 e	23,510,662	W/S 0 15193	3,571,975
5	Common		0	CE 0 15193	0
6	TOTAL GROSS PLANT (sum lines 1-5)		368,459,352	GP= 18 654%	68,733,179
	ACCUMULATED DEPRECIATION (Note AA and Note GG)				
7	Production		175,427,025	NA	
8	Transmission		33,420,456	TP 1 00000	33,420,456
8a	Transmission for projects with FERC approved incentives (Note EE)		63,224	TP 1 00000	63,224
9	Distribution		0	NA	
10	General & Intangible		14,239,893	W/S 0 15193	2,163,467
11	Common		0	CE 0 15193	0
12	TOTAL ACCUM DEPRECIATION (sum lines 7-11)		223,150,598		35,647,147
	NET PLANT IN SERVICE (Note GG)				
13	Production	(line 1- line 7)	104,360,461		
14	Transmission	(line 2- line 8)	26,156,186		26,156,186
14a	Transmission for projects with FERC approved incentives (Line 2a - line 8a) (Note EE)		5,521,338		5,521,338
15	Distribution	(line 3 - line 9)	0		
16	General & Intangible	(line 4 - line 10)	9,270,769		1,408,508
17	Common	(line 5 - line 11)	0		0
18	TOTAL NET PLANT (sum lines 13-17)		145,308,754	NP= 22 769%	33,086,032
18a	CWIP for projects with FERC approved incentives (Note CC and Note GG)		18,711,655	NA 1 00000	18,711,655
	ADJUSTMENTS TO RATE BASE (Note F)				
19	Account No 281 (enter negative)		0	zero	0
20	Account No 282 (enter negative)		0	NP 0 22769	0
21	Account No 283 (enter negative)		0	NP 0 22769	0
22	Account No 190		0	NP 0 22769	0
23	Account No 255 (enter negative)		0	NP 0 22769	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		1,416,365		530,167
27	Materials & Supplies (Note GG)	(Note G)	289,506	TE 0 99089	286,869
28	Prepayments (Note GG)	II 20 b	2,248,540	GP 0 18654	419,443
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		3,954,411		1,236,479
30	RATE BASE earning ACSR (lines 18+24+25+29-14a-23a)		143,741,827		28,801,173
30a	RATE BASE earning HCSR (lines 14a+18a+23a)		24,232,993		24,232,993

Formula Rate - Non-Levelized

Rate Formula Template
 Utilizing EIA Form 412 Data

For the 12 months ended 12/31/2012

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	24,925,642	TE 0 99089	24,698,569
1a	Less LSE Expenses included in Transmission O&M Accounts (Note V)		0	1 00000	0
2	Less Account 565		22,011,523	TE 0 99089	21,810,998
3	A&G	VII 13 d	8,546,500	W/S 0 15193	1,298,470
4	Less FERC Annual Fees		0	W/S 0 15193	0
5	Less EPRI & Reg Comm Exp & Non-safety Ad (Note I)		219,094	W/S 0 15193	33,287
5a	Plus Transmission Related Reg Comm Exp (Note I)		89,394	TE 0 99089	88,580
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)		11,330,919		4,241,334
	DEPRECIATION AND AMORTIZATION EXPENSE (Note AA)				
9	Transmission		873,419	TP 1 00000	873,419
9a	Abandoned Plant Amortization (Note DD)		0	NA 1 00000	0
10	General & Intangible		613,945	W/S 0 15193	93,277
11	Common		0	CE 0 15193	0
12	TOTAL DEPRECIATION (sum lines 9 - 11)		1,487,364		966,696
	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
	PLANT RELATED				
16	Property		1,663,475	GP 0 18654	310,305
17	Gross Receipts		0	NA zero	0
18	Other		0	GP 0 18654	0
19	Payments in lieu of taxes		0	GP 0 18654	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		1,663,475		310,305
	INCOME TAXES (Note K)				
21	$T=1 - \{[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)\} =$		0 00%	NA	
22	$CIT=(T/1-T) * (1-(WCLTD/R)) =$ where WCLTD=(page 4, line 22) and R=(page 4, line 24) and FIT, SIT & p are as given in footnote K		0 00%		
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 22769	0
27	Total Income Taxes (line 25 plus line 26)		0		0
28	RETURN from ACSR [Rate Base (page 2, line 30 + 30a) * Rate of Return (page 4, line 24)]		12,698,896	NA	4,009,383
28a	RETURN from HCSR [Rate Base (page 2, line 30a) * Rate of Return (page 4, line 30)]		261,716	NA	261,716
29	REV REQUIREMENT (sum lines 8, 12, 20, 27, 28 and 28a)		27,442,370		9,789,434
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]		2,981,156		2,981,156
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]		478,836		478,836
31	REVENUE REQUIREMENT TO BE COLLECTED UNDER ATTACHMENT O (line 29 - line 30 - line 30a)		23,982,378		6,329,442

Midwest ISO
 FERC Electric Tariff, Fourth Revised Volume No 1

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

Formula Rate - Non-Levelized

Rate Formula Template
 Utilizing EIA Form 412 Data

For the 12 months ended 12/31/2012

MRES

Line No	SUPPORTING CALCULATIONS AND NOTES				
TRANSMISSION PLANT INCLUDED IN ISO RATES					
1	Total transmission plant (page 2, line 2 and 2a, column 3)				59,576,642
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)				59,576,642
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)				24,925,642
7	Less transmission expenses included in OATT Ancillary Services (Note L)				227,005
8	Included transmission expenses (line 6 less line 7)				24,698,637
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)				0 99089
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 99089
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	368,459,352		(line 17 / line 20)	(line 16)
18	Gas	0		1 00000 *	0 15193 =
19	Water	0			CE
20	Total (sum lines 17-19)	368,459,352			0 15193
ACTUAL CAPITAL STRUCTURE RETURN (ACSR)					
21	Long Term Interest	\$14,730,819			
		\$	%	Cost (Note P)	Weighted
22	Long Term Debt (Note GG)	263,612,308	71%	5 59%	0 0397 =WCLTD
23	Proprietary Capital (Note GG)	106,830,846	29%	0 1238	0 0359
24	Total (sum lines 22, 23)	370,443,154	100%		0 0756 =R
25				Proprietary Capital Cost Rate =	12 38%
26				TIER =	1 35
HYPOTHETICAL CAPITAL STRUCTURE RETURN (HCSR) (NOTE FF)					
				Cost (Note P)	Weighted
27	Long Term Debt 9 (Cost of Long-term Debt from page 4, line 22)	55%		5 59%	0 0307 =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 0864 =R
30	Annual Allocation Factor for Incentive Return (line 29 minus line 24)				1 080%
REVENUE CREDITS					
ACCOUNT 447 (SALES FOR RESALE)					
				Load	
31	a Bundled Non-RQ Sales for Resale				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)				\$1,155,348
ACCOUNT 456 1 (OTHER ELECTRIC REVENUES)					
35	a Transmission charges for all transmission transactions				\$20,803,623
36	b Transmission charges for all transmission transactions included in Divisor on page 1				\$20,803,623
36a	c Transmission charges associated with Schedules 26 and 37 (Note X)				\$0
36b	d Transmission 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

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
- 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
- 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
- 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
- I Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising Line 5a - Regulatory Commission Expenses directly related to
- 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
- 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
 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
- 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
- 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
- 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
- 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
- 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)
- 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
- 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
- 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%
- 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
- 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
- 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%
- GG Calculated using-13 month average balance

Missouri River Energy Services 2012 Estimated Revenue Requirement Template

Formula Rate - Non-Levelized

Rate Formula Template
 Utilizing EIA Form 412 Data

For the 12 months ended 12/31/12 (Estimated)

Missouri River Energy Services

Line No		Total	Allocator	Allocated Amount	
1	GROSS REVENUE REQUIREMENT (page 3, line 31)			\$ 8,949,170	
2	REVENUE CREDITS (Note T)				
2	Account No 454 (page 4, line 30)	135,812	TP 1 00000	135,812	
3	Account No 456 1 (page 4, line 33)	57,906	TP 1 00000	57,906	
4	Revenues from Grandfathered Interzonal Transactions	0	TP 1 00000	0	Line 4 supported by schedules
5	Revenues from service provided by the ISO at a discount	0	TP 1 00000	0	Line 5 supported by schedules
6	TOTAL REVENUE CREDITS (sum lines 2-5)			193,718	
7	NET REVENUE REQUIREMENT (line 1 minus line 6)			\$ 8,755,452	
	DIVISOR				
8	Average of 12 coincident system peaks for requirements (RQ) service		(Note A)	732,481	
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)			732,481	
16	Annual Cost (\$/kW/Yr) (line 7 / line 15)	11 953			
17	Network & P-to-P Rate (\$/kW/Mo) (line 11 / 12)	0 996			
			Peak Rate	Off-Peak Rate	
18	Point-To-Point Rate (\$/kW/Wk) (line 16 / 52; line 16 / 52)		0 230	\$0 230	
19	Point-To-Point Rate (\$/kW/Day) (line 16 / 260; line 16 / 365)		0 046 Capped at weekly rate	\$0 033	
20	Point-To-Point Rate (\$/MWh) (line 16 / 4,160; line 16 / 8,760 times 1,000)		2 873 Capped at weekly and daily rates	\$1 365	
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 12/31/12 (Estimated)

Line No	(1) RATE BASE:	(2) EIA 412 Reference	Missouri River Energy Services		(5) Transmission (Col 3 times Col 4)
			(3) Company Total	(4) Allocator	
GROSS PLANT IN SERVICE					
1	Production	IV 6 e	293,509,353	NA	
2	Transmission	IV 7 e	70,289,426	TP 1 00000	70,289,426
3	Distribution	IV 8 e	0	NA	
4	General & Intangible	IV 9 e	13,511,488	W/S 0 15258	2,061,545
5	Common		0	CE 0 15258	0
6	TOTAL GROSS PLANT (sum lines 1-5)		<u>377,310,267</u>	GP= 19 175%	<u>72,350,971</u>
ACCUMULATED DEPRECIATION					
7	Production		174,226,037	NA	
8	Transmission		33,266,237	TP 1 00000	33,266,237
9	Distribution		0	NA	
10	General & Intangible		6,534,073	W/S 0 15258	996,951
11	Common		0	CE 0 15258	0
12	TOTAL ACCUM DEPRECIATION (sum lines 7-11)		<u>214,026,347</u>		<u>34,263,188</u>
NET PLANT IN SERVICE					
13	Production	(line 1 - line 7)	119,283,316		
14	Transmission	(line 2 - line 8)	37,023,189		37,023,189
15	Distribution	(line 3 - line 9)	0		
16	General & Intangible	(line 4 - line 10)	6,977,415		1,064,595
17	Common	(line 5 - line 11)	0		0
18	TOTAL NET PLANT (sum lines 13-17)		<u>163,283,920</u>	NP= 23 326%	<u>38,087,784</u>
ADJUSTMENTS TO RATE BASE (Note F)					
19	Account No 281 (enter negative)		0	zero	0
20	Account No 282 (enter negative)		0	NP 0 23326	0
21	Account No 283 (enter negative)		0	NP 0 23326	0
22	Account No 190		0	NP 0 23326	0
23	Account No 255 (enter negative)		0	NP 0 23326	0
24	TOTAL ADJUSTMENTS (sum lines 19 - 23)		<u>0</u>		<u>0</u>
25	LAND HELD FOR FUTURE USE	IV 12 e (Note G)	0	TP 1 00000	0
WORKING CAPITAL (Note H)					
26	CWC		1,410,892		621,849
27	Materials & Supplies	(Note G)	286,117	TE 0 98554	281,981
28	Prepayments	II 20 b	2,036,699	GP 0 19175	390,546
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		<u>3,733,708</u>		<u>1,294,376</u>
30	RATE BASE (sum lines 18, 24, 25, and 29)		<u>167,017,628</u>		<u>39,382,160</u>

Formula Rate - Non-Levelized

Rate Formula Template
 Utilizing EIA Form 412 Data

For the 12 months ended 12/31/12 (Estimated)

Line No	(1)	(2) EIA 412 Reference	Missouri River Energy Services		(5) Transmission (Col 3 times Col 4)
			(3) Company Total	(4) Allocator	
O&M					
1	Transmission	VII 8 d	21,306,260	TE 0 98554	20,998,269
1a	Less LSE Expenses included in Transmission O&M Accounts (Note V)		0	1 00000	0
2	Less Account 565		17,690,335	TE 0 98554	17,434,614
3	A&G	VII 13 d	7,838,939	W/S 0 15258	1,196,043
4	Less FERC Annual Fees		0	W/S 0 15258	0
5	Less EPRI & Reg Comm Exp & Non-safety Ad (Note I)		456,672	W/S 0 15258	69,678
5a	Plus Transmission Related Reg Comm Exp (Note I)		288,946	TE 0 98554	284,769
6	Common		0	CE 0 15258	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)		11,287,138		4,974,790
DEPRECIATION EXPENSE					
9	Transmission		738,839	TP 1 00000	738,839
10	General		559,000	W/S 0 15258	85,291
11	Common		0	CE 0 15258	0
12	TOTAL DEPRECIATION (sum lines 9 - 11)		1,297,839		824,130
TAXES OTHER THAN INCOME TAXES (Note J)					
LABOR RELATED					
13	Payroll		0	W/S 0 15258	0
14	Highway and vehicle		0	W/S 0 15258	0
PLANT RELATED					
16	Property		1,326,554	GP 0 19175	254,373
17	Gross Receipts		0	NA zero	0
18	Other		0	GP 0 19175	0
19	Payments in lieu of taxes		0	GP 0 19175	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		1,326,554		254,373
INCOME TAXES (Note K)					
21	$T = 1 - \{[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)\} =$		0 00%	NA	
22	$CIT = (T/1-T) * (1-(WCLTD/R)) =$ where WCLTD=(page 4, line 27) and R= (page 4, line30) and FIT, SIT & p are as given in footnote K		0 00%		
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 23326	0
27	Total Income Taxes (line 25 plus line 26)		0		0
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 24)]		12,281,260	NA	2,895,877
29	REV REQUIREMENT (sum lines 8, 12, 20, 27, 28)		26,192,791		8,949,170
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]		0		0
31	REVENUE REQUIREMENT TO BE COLLECTED UNDER ATTACHMENT O (line 29 - line 30)		26,192,791		8,949,170

Midwest ISO
 FERC Electric Tariff, Fourth Revised Volume No 1

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

Formula Rate - Non-Levelized

Rate Formula Template
 Utilizing EIA Form 412 Data

For the 12 months ended 12/31/12 (Estimated)

Missouri River Energy Services

Line No	SUPPORTING CALCULATIONS AND NOTES				
TRANSMISSION PLANT INCLUDED IN ISO RATES					
1	Total transmission plant (page 2, line 2, column 3)				70,289,426
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)				<u>70,289,426</u>
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)				21,306,260
7	Less transmission expenses included in OATT Ancillary Services (Note L)				<u>307,991</u>
8	Included transmission expenses (line 6 less line 7)				20,998,269
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)				0 98554
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 98554
WAGES & SALARY ALLOCATOR (W&S)					
		\$	TP	Allocation	
12	Production	2,549,769	0 00	0	
13	Transmission	476,908	1 00	476,908	
14	Distribution	0	0 00	0	
15	Other	99,003	0 00	0	
16	Total (sum lines 12-15)	<u>3,125,680</u>		476,908 =	0 15258 = W/S
COMMON PLANT ALLOCATOR (CE) (Note O)					
		\$		% Electric (line 17 / line 20)	Labor Ratio (line 16)
17	Electric	377,310,267			
18	Gas	0		1 00000 *	0 15258 =
19	Water	0			0 15258
20	Total (sum lines 17-19)	<u>377,310,267</u>			CE
RETURN (R)					
		\$			
21	Long Term Interest III 16 b + III 17 b (Note U)	<u>\$15,828,160</u>			
		\$	%	Cost (Note P)	Weighted
22	Long Term Debt II 33 b + II 34 b	277,500,000	75%	5 70%	0 0429 =WCLTD
23	Proprietary Capital II 32 b	91,056,628	25%	12 38%	0 0306
24	Total (sum lines 22, 23)	<u>368,556,628</u>	100%		0 0735 =R
25				Proprietary Capital Cost Rate =	12 38%
26				TIER =	1 29
REVENUE CREDITS					
ACCOUNT 447 (SALES FOR RESALE)					
				Load	
27	a Bundled Non-RQ Sales for Resale (Note Q)				0
28	b Bundled Sales for Resale included in Divisor on page 1				<u>0</u>
29	Total of (a)-(b)				0
30	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)				\$135,812
ACCOUNT 456 1 (OTHER ELECTRIC REVENUES)					
31	a Transmission charges for all transmission transactions				\$16,367,480
32	b Transmission charges for all transmission transactions included in Divisor on page 1				\$16,309,574
32a	c Transmission charges associated with Schedule 26 (Note X)				<u>\$0</u>
33	Total of (a)-(b)-(c)				\$57,906

Line 31 supported
 by notes in Form
 412 or detailed
 Schedule
 Line 32 supported
 by notes in Form
 412 or detailed
 Schedule

NWPS
2012 Actual
Revenue Requirement Template

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

	(1)	(2)	(3)	(4)	(5)
Line No.	Form No. 1 Page, Line, Col.	Company Total	Allocator	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
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
TAXES OTHER THAN INCOME TAXES (Note J)					
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
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
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)
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
RETURN					
38	[Rate Base * Rate of Return]	15,480,505	NA		2,183,002
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
6	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)				TP=	1.00000
TRANSMISSION EXPENSES						
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
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
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%
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 the time of the ISO coincident monthly peaks.
- B Labeled LF, LU, IF, IU on pages 310-311 of Form 1 at the time of the ISO coincident monthly peaks.
- C Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
- D Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
- E The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.
- F The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
- G Identified in Form 1 as being only transmission related.
- H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission .
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 currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).
Inputs Required: FIT = 35.00%
SIT = 0.00% (State Income Tax Rate or Composite SIT)
p = 0.00% (percent of federal income tax deductible for state purposes)
- L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.
- M Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
- N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to be 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 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.

NWPS
2012 Estimated
Revenue Requirement Template

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

Line No.			Total	Allocator	Allocated Amount
1	GROSS REVENUE REQUIREMENT	(page 3, line 29)			\$ 3,473,780
	REVENUE CREDITS	(Note T)			
2	Account No. 454	(page 4, line 34)	169,771	TP 0.83220	141,283
3	Account No. 456	(page 4, line 37)	72,942	TP 0.83220	60,702
4	Revenues from Grandfathered Interzonal Transactions		0	TP 0.83220	0
5	Revenues from service provided by the ISO at a discount		0	TP 0.83220	0
6	TOTAL REVENUE CREDITS (sum lines 2-5)				<u>201,985</u>
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)			<u>\$ 3,271,795</u>
	DIVISOR				
8	Average of 12 coincident system peaks for requirements (RQ) service			(Note A)	243,862
9	Plus 12 CP of firm bundled sales over one year not in line 8			(Note B)	14,000
10	Plus 12 CP of Network Load not in line 8			(Note C)	0
11	Less 12 CP of firm P-T-P over one year (enter negative)			(Note D)	0
12	Plus Contract Demand of firm P-T-P over one year				0
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)				0
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)				<u>0</u>
15	Divisor (sum lines 8-14)				257,862
16	Annual Cost (\$/kW/Yr)	(line 7 / line 15)	12.688		
17	Network & P-to-P Rate (\$/kW/Mo)	(line 16 / 12)	1.057		
			Peak Rate		Off-Peak Rate
18	Point-To-Point Rate (\$/kW/Wk)	(line 16 / 52; line 16 / 52)	0.244		\$0.244
19	Point-To-Point Rate (\$/kW/Day)	(line 18 / 5; line 18 / 7)	0.049	Capped at weekly rate	\$0.035
20	Point-To-Point Rate (\$/MWh)	(line 19 / 16; line 19 / 24 times 1,000)	3.050	Capped at weekly and daily rates	\$1.452
21	FERC Annual Charge(\$/MWh)	(Note E)	\$0.000	Short Term	\$0.000 Short Term
22			\$0.000	Long Term	\$0.000 Long Term

Line No.	(1) RATE BASE:	Utilizing FERC Form 1 Data With 7-Factor Changes -EXCLUDES EXT. joint Plant Transmission Facilities					
		(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)	
GROSS PLANT IN SERVICE							
1	Production	206.42.g	160,809,843	NA			
2	Transmission	206.53.g	37,068,925	TP	0.83220	30,848,681	6,220,244
3	Distribution	206.69.g	231,358,884	NA			
4	General & Intangible	206.5.g & 83.g	10,588,800	W/S	0.08071	854,614	
5	Common	356.1	21,084,142	CE	0.05060	1,066,893	
6	TOTAL GROSS PLANT (sum lines 1-5)		<u>460,910,594</u>	GP=	7.110%	<u>32,770,188</u>	
ACCUMULATED DEPRECIATION							
7	Production	219.18-22.c	106,195,863	NA			Accumulated Depreciation of Joint Plant
8	Transmission	219.23.c	23,416,063	VEst.	75.176%	17,603,154	Transmission Facilities, see Assets file
9	Distribution	219.24.c	89,702,256	NA			-5,812,909
10	General & Intangible	219.25.c	2,431,212	W/S	0.08071	196,221	
11	Common	356.1	5,257,460	CE	0.05060	266,036	
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		<u>227,002,853</u>			<u>18,065,412</u>	
NET PLANT IN SERVICE							
13	Production	(line 1- line 7)	54,613,980				
14	Transmission	(line 2- line 8)	13,652,862			13,245,527	
15	Distribution	(line 3 - line 9)	141,656,628				
16	General & Intangible	(line 4 - line 10)	8,157,588			658,392	
17	Common	(line 5 - line 11)	15,826,683			800,857	
18	TOTAL NET PLANT (sum lines 13-17)		<u>233,907,741</u>	NP=	6.287%	<u>14,704,776</u>	
ADJUSTMENTS TO RATE BASE (Note F)							
19	Account No. 281 (enter negative)	273.8.k	0	NA	zero	0	
20	Account No. 282 (enter negative)	275.2.k	-46,240,385	NP	0.06287	-2,906,935	
21	Account No. 283 (enter negative)	277.9.k	-2,197,034	NP	0.06287	-138,118	
22	Account No. 190	234.8.c	9,119,761	NP	0.06287	573,320	
23	Account No. 255 (enter negative)	267.8.h	-1,793,779	NP	0.06287	-112,767	
24	TOTAL ADJUSTMENTS (sum lines 19- 23)		<u>-41,111,437</u>			<u>-2,584,500</u>	
25	LAND HELD FOR FUTURE USE	214.x.d (Note G)	0	VEst.	0.75176	0	
WORKING CAPITAL (Note H)							
26	CWC	calculated	820,434			110,946	
27	Materials & Supplies (Note G)	227.6.c & .15.c	0		1.00000	0	Excluded transmission maintained and supplied by others
28	Prepayments (Account 165)	111.46.d	0	GP	0.07110	0	
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		<u>820,434</u>			<u>110,946</u>	
30	RATE BASE (sum lines 18, 24, 25, & 29)		<u>193,616,738</u>			<u>12,231,223</u>	

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

(1)	(2)	(3)	(4)	(5)		
Line No.	Form No. 1 Page, Line, Col.	Company Total	Allocator	Transmission (Col 3 times Col 4)		
O&M						
1	Transmission 321.100.b	6,633,001	TE	0.83220	6,513,752	Reduce non-565 by TE Ratio
2	Less Account 565 321.88.b	5,922,347		1.00000	5,922,347	
3	A&G 323.168.b	5,852,820	W/S	0.05060	296,163	
4	Less FERC Annual Fees	0	W/S	0.05060	0	
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)	0	W/S	0.05060	0	
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)	0	TE	0.83220	0	
6	Common 356.1	0	CE	0.05060	0	
7	Transmission Lease Payments	0		1.00000	0	
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)	<u>6,563,474</u>			<u>887,568</u>	
DEPRECIATION EXPENSE						
9	Transmission 336.7.b	1,212,154	VRB00	0.75176	1,011,240	Excluded 200,914
10	General 336.9.b	669,608	W/S	0.05060	33,883	
11	Common 336.10.b	1,345,290	CE	0.05060	68,074	
12	TOTAL DEPRECIATION (Sum lines 9 - 11)	<u>3,227,051</u>			<u>1,113,197</u>	
TAXES OTHER THAN INCOME TAXES (Note J)						
LABOR RELATED						
13	Payroll 262.i	763,562	W/S	0.05060	38,638	
14	Highway and vehicle 262.i	54,207	W/S	0.05060	2,743	
PLANT RELATED						
16	Property 262.i	3,149,405	GP	0.07110	223,919	
17	Gross Receipts 262.i	146,268	NA	zero	0	
18	Other 262.i	243,562	GP	0.07110	17,317	
19	Payments in lieu of taxes	0	GP	0.07110	0	
20	TOTAL OTHER TAXES (sum lines 13 - 19)	<u>4,357,003</u>			<u>282,616</u>	
INCOME TAXES (Note K)						
21	$T=1 - \frac{((1 - SIT) * (1 - FIT))}{(1 - SIT * FIT * p)}$	35.00%				
22	$CIT=(T/1-T) * (1-(WCLTD/R))$ where WCLTD=(page 4, line 27) and R=(page 4, line30) and FIT, SIT & p are as given in footnote K.	34.17%				
23	$1 / (1 - T) =$ (from line 21)	1.5385				
24	Amortized Investment Tax Credit (266.8f) (enter negative)	-1,996,006				
25	Income Tax Calculation = line 22 * line 28	5,577,651	NA		352,353	
26	ITC adjustment (line 23 * line 24)	-3,070,778	NP	0.06287	-193,047	
27	Total Income Taxes (line 25 plus line 26)	<u>2,506,874</u>			<u>159,307</u>	
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]	16,321,891	NA		1,031,092	
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)	<u><u>32,976,294</u></u>			<u><u>3,473,780</u></u>	

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

SUPPORTING CALCULATIONS AND NOTES

Line No.	TRANSMISSION PLANT INCLUDED IN ISO RATES								
1	Total transmission plant (page 2, line 2, column 3)				37,068,925				Transmission Plant Grandfathered with
2	Less transmission plant excluded from ISO rates (Note M)				6,220,244				Joint Plants from VRB00t
3	Less transmission plant included in OATT Ancillary Services (Note N)				0				6,220,244
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)				<u>30,848,681</u>				
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)			TP=		0.83220			
TRANSMISSION EXPENSES									
6	Total transmission expenses (page 3, line 1, column 3)				6,633,001				
7	Less transmission expenses included in OATT Ancillary Services (Note L)				0				
8	Included transmission expenses (line 6 less line 7)				<u>6,633,001</u>				
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)					1.00000			
10	Percentage of transmission plant included in ISO Rates (line 5)			TP		0.83220			
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)			TE=		0.83220			
WAGES & SALARY ALLOCATOR (W&S)									
		Form 1 Reference	\$	TP	Allocation				
12	Production	354.18.b	1,662,518	0.00	0				
13	Transmission	354.19.b	3,069,905	0.83	2,554,768				
14	Distribution	354.20.b	25,995,224	0.00	0				
15	Other	354.21,22,23.b	<u>7,308,971</u>	0.00	0				
16	Total (sum lines 12-15)		38,036,618		2,554,768	=	0.06717	= WS	Wages & salaries by others
							0.08071	= Wsact	for excluded facilities
									MEC, OTP, MDU
COMMON PLANT ALLOCATOR (CE) (Note O)									
			\$	% Electric	W&S Allocator				
17	Electric	200.3.c	439,875,046	(line 17 / line 20)	(line 16)				CE
18	Gas	200.3.d	143,991,901	0.75338	0.06717	=			0.05060
19	Water	200.3.e	0						
20	Total (sum lines 17 - 19)		583,866,947						
RETURN (R)									
21	Long Term Interest (117, sum of 56c through 60c)				\$				\$0
22	Preferred Dividends (118.29c) (positive number)				\$				-
Development of Common Stock:									
23	Proprietary Capital (112.14d)								0
24	Less Preferred Stock (line 28)								0
25	Less Account 216.1 (112.12d) (enter negative)								0
26	Common Stock (sum lines 23-25)								0
			\$	%	Cost (Note P)		Weighted		
27	Long Term Debt (112, sum of 16d through 19d)		905,205,000	0.5246	0.0000	0.0587	0.0000	0.0308	=WCLTD
28	Preferred Stock (112.3d)		0	0.0000	0.0000	0.0000	0.0000	0.0000	
29	Common Stock (line 26)		820,347,000	0.4754	0.0000	0.1125	0.0000	0.0535	
30	Total (sum lines 27-29)		1,725,552,000		0.0000	0.0000	0.0000	0.0843	=R
REVENUE CREDITS									
	ACCOUNT 447 (SALES FOR RESALE) (310-311) (Note Q)								Load
31	a. Bundled Non-RQ Sales for Resale (311.x.h)								220,080
32	b. Bundled Sales for Resale included in Divisor on page 1								<u>220,080</u>
33	Total of (a)-(b)								0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)								\$169,771
	ACCOUNT 456 (OTHER ELECTRIC REVENUES) (330.x.n)								
35	a. Transmission charges for all transmission transactions								\$233,946
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1								<u>\$161,004</u>
37	Total of (a)-(b)								\$72,942

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

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

Note
Letter

- A Peak as would be reported on page 401, column d of Form 1 at the time of the ISO coincident monthly peaks.
- B Labeled LF, LU, IF, IU on pages 310-311 of Form 1 at the time of the ISO coincident monthly peaks.
- C Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
- D Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
- E The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.
- F The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
- G Identified in Form 1 as being only transmission related.
- H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 100-111 line 46 in the Form 1.
- I Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
- J Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
- K The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).
- | | | |
|------------------|-------|---|
| Inputs Required: | FIT = | 35 00% |
| | SIT = | 0 00% (State Income Tax Rate or Composite SIT) |
| | p = | 0 00% (percent of federal income tax deductible for state purposes) |
- L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.
- M Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
- N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to be included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
- O Enter dollar amounts
- P Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
- Q Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the divisor.
- R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
- S Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.
- T The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.