Rate Formula Template
Using 2015 Projected and Financial Operating Data for Southwest Power Pool Rates
For Rates Effective January 1, 2015
LINCOLN ELECTRIC SYSTEM

Blue cells are data entry points. However, non-blue cells are not protected so care is needed. All blue cell entries will be forecasts of forward test year amounts. True-up adjustments will be based on the difference between actual and forecast net ATRR for previous test year.

Table of Contents

Worksheet Name	Description
Page 1	Derivation of PTP Rates
Page 2	Derivation of Projected Net ATRR
Page 3	Allocator Calculations
Page 4	Notes & Comments
A	Account 456 Supporting Schedule
B	Account 454 Supporting Schedule
C	True-Up Worksheet
D	True-Up Page 2 - Derivation of True-Up for Net ATRR
F	Schedule - System Scheduling etc
G	Billing Units Divisor
G1	Historic Year Actual Billing Units for Computing Divisor True Up
H	SPP Transmission Cost Allocation Revenue Offsets
I	Upgrade Fixed Charge Rate
J1	Transmission Upgrade Project #1 Calculations
J2	Transmission Upgrade Project #2 Calculations
K	SPP RTO Incentive Adder
L	Transmission Plant Used for Other Purposes (for internal use only)

Decision Variables

Choice: 1 = GP; 0 = NP

Switch for use of General Plant vs Net Plant Allocator for Debt Service: 0

Switch for use of Incentive Plant (column K) in Worksheets J1 and J2 to feed page 1, Line 8, Transmission Revenue Offset

Choice: 1 = No Incentive Plant; 0 = Incentive Plant

1

Forecast Year: 2015

Choice: 1 = Incentive Adder Granted by FERC; 0 Adder not Granted by FERC

ROE Transmission Investment Incentive Adder (basis points): 0

Choice: 1 = RTO Incentive Adder Granted by FERC; 0 RTO Incentive Adder not Granted by FERC

RTO Incentive Adder 1

Rate Formula Template
Using 2015 Projected and Financial Operating Data for Southwest Power Pool Rates
For Rates Effective January 1, 2015

Formula Rate - Cash Flow

LINCOLN ELECTRIC SYSTEM

For the 12 months ending 12/31/2015

Line No.	Acct	(1) Description	(2) Reference/Note	(3) Total	(4) Allocator		(5) (3) x (4) Allocated to Transmission
		A. Zonal Net Annual Transmission Revenue Requirement (ATRR)					
1		**Gross Annual Transmission Revenue Requirement**	Page 2, Line 25, Col 5				$ 25,985,943
		Revenue Credits					
2	456	Less: Revenue from SPP for and Other Short-term Point-to-Point Service	Note A, 'Worksheet A	$ 1,091,069	GTP	0.81935	$ 893,964
3	454	Less: Transmission Related Rents	Note B, 'Worksheet B	$ 241,467	GTP	0.81935	$ 197,845
4		Less: Revenues from service provided by the ISO at a discount	Worksheet B	$ -	GTP	0.81935	$ -
5		**TOTAL TRANSMISSION REVENUE CREDITS**	Sum Lines 2 to 4				$ 1,091,809
		True-Up Adjustment					
6a		Prior Year Actual Net ATRR	Worksheet C	$ 25,932,793			
6b		Prior Year Projected Net ATRR	Worksheet C	$ 26,028,148			
6c		Prior Year ATRR True-Up	Worksheet C				$ (95,355)
6d		Prior Year Divisor True-Up	Note C, Worksheet C				$ (184,310)
6e		Interest on Prior Year True-Up	Worksheet C				$ (14,931)
6f		**Total True-Up Amount**	Sum Lines 6c to 6e				$ (294,595)
7		**ZONAL NET TRANSMISSION REVENUE REQUIREMENT WITH TRUE-UP ADJUSTMENT**	Line 1 - Line 5 + Line 6f				$ 24,599,539
		Transmission Project Revenue Offset Under Schedule 11					
8		Total Schedule 11 Revenue Offset	Worksheets J1 & J2				$ 651,092
9		**ZONAL NET ATRR FOR SPP OPEN ACCESS TRANSMISSION TARIFF - Attachment H**	Line 7 minus Line 8				$ 23,948,447
		B. Point-to-Point Transmission Service Rates					
		DIVISOR (MW)					
10		Projected 12 CP for requirements (RQ) service	Note G1, Worksheet G				600.333 MW
11		Plus 12 CP of firm bundled sales over one year not in line 11	Note G2, Worksheet G				0.000 MW
12		Plus 12 CP of Network Load not in line 11	Note G3, Worksheet G				0.000 MW
13		Less 12 CP of firm P-T-P over one year	Note G4, Worksheet G				0.000 MW
14		Plus Contract Demand of firm P-T-P over one year	Worksheet G				94.000 MW
15		Less Contract Demand from Grandfathered Interzonal transactions over one year	Note G5, Worksheet G				0.000 MW
16		Less 12 CP or Contract Demands from service over one year provided by ISO at a discount	Worksheet G				0.000 MW
17		Total Demand	Sum Lines 10 to 16				694.333 MW
		Rates for Point-to-Point Service					
18		Point-to-Point Firm & Non-Firm ($/MW/Year)	Line 9 / Line 17				$ 34,491.28
19		Point-to-Point Firm & Non-Firm ($/MW/Month)	Line 18 / 12 months				$ 2,874.27
20		Point-to-Point Firm & Non-Firm ($/MW/Week)	Line 18 / 52 weeks				$ 663.29
21		Point-to-Point Firm ($/MW/Day) On Peak	Line 20 / 5 days				$ 132.66
22		Point-to-Point Firm ($/MW/Day) Off Peak	Line 20 / 7 days				$ 94.76
23		Non-firm Point-to-Point ($/MW/Day) On Peak	Line 20 / 5 days				$ 132.66
24		Non-firm Point-to-Point ($/MW/Day) Off Peak	Line 20 / 7 days				$ 94.76
25		Non-firm Point-to-Point ($/MW/Hour) On Peak	Line 23 / 16 hours				$ 8.291
26		Non-firm Point-to-Point ($/MW/Hour) Off Peak	Line 24 / 24 hours				$ 3.948
		FERC Annual Charge ($/MWh)					
27		Short Term	Note D				$ -
28		Long Term					$ -
		C. Scheduling, System Control and Dispatch Service Annual Revenue Requirement					
29		Scheduling, System Control and Dispatch Service Costs	Note F, Worksheet F				$ 803,557
30		**Divisor (MW)**	Line 17				694.33
		Rates for Ancillary Service 1: Scheduling, System Control and Dispatch Service					
31		AS1 ($ / MW-Year)	Line 29 / Line 30				$1,157.31
32		AS1 ($ / MW-Month)	Line 31 / 12				$96.44

Formula Rate - Cash Flow

Rate Formula Template
Using 2015 Projected and Financial Operating Data for Southwest Power Pool Rates
For Rates Effective January 1, 2015
LINCOLN ELECTRIC SYSTEM

For the 12 months ending 12/31/2015

Line No.	Acct	(1) Description	(2) Reference/Note	(3) Total	(4) Allocator	(5) **Allocated to Transmission (3) x (4)**
	Gross Annual Transmission Revenue Requirement (ATRR)					
		Operating & Maintenance (O&M)				
1	560-574	Transmission		$ 16,575,870	TE 0.77963	$ 12,922,992
2	565	Less: Transmission of Electricity by Others	Note W, Worksheet H	$ 7,694,542	1.00000	$ 7,694,542
2a	561	Less: Load Dispatching	Worksheet F	$ 803,557	1.00000	$ 803,557
2b		**TOTAL O&M**		$ 8,077,771		$ 4,424,893
		Administrative & General (A&G)				
3	920-932	A&G		$ 20,240,660	W/S 0.08408	$ 1,701,801
4		Less FERC Annual Fees in Acct 928		$ -	W/S 0.08408	$ -
5	923	Less EPRI & Reg. Comm. Exp. & Non-safety Ad	Note I	$ 619,823	W/S 0.08408	$ 52,114
5a		'Plus Transmission Related Reg. Comm. Exp.	Note I	$ -	TE 0.77963	$ -
6		Common		$ -	CE 0.08408	$ -
7		Transmission Lease Payments		$ -	1.00000	$ -
8		**TOTAL O&M + A&G**	Sum Lines 2b, 3,5a,6,7 minus Lines 4 & 5	$ 27,698,608		$ 6,074,580
		Debt Service				
9	427	Debt Service		$ 47,687,192	NP 0.19969	$ 9,522,751
10	428	Amortization of premium or discount		$ 1,040,507	NP 0.19969	$ 207,781
12		**TOTAL DEBT SERVICE**	Sum Lines 9 & 10	$ 48,727,699		$ 9,730,532
		Taxes Other Than Income Taxes	Note U			
		Labor Related				
13	926	Payroll		$ 2,930,154	W/S 0.08408	$ 246,363
14	185	Highway and vehicle		$ -	W/S 0.08408	$ -
15		Plant Related				
16	505	Property		$ 524,618	GP 0.16000	$ 83,940
17		Gross Receipts		$ -	0.00000	$ -
18		Other		$ -	GP 0.16000	$ -
19	408	Payments in lieu of taxes		$ 12,543,042	GP 0.16000	$ 2,006,923
20		**TOTAL TAXES**	Sum Lines 13 to 19	$ 15,997,814		$ 2,337,226
21		**SUBTOTAL**	Sum Lines 8, 12, & 20			$ 18,142,339
22		**MARGIN REQUIREMENT**	Note M	$ 47,655,628	GP 0.16000	$ 7,625,039
23		**RTO Incentive Adder (Order Nos. 679 & 679-A)**	Note K, Worksheet K	$ 218,565	1.00000	$ 218,565
		Additional Margin on Incentive Plant				
24		**Transmission Upgrade Projects**	Note J, Worksheet J	$ -	1.00000	$ -
25		**GROSS REVENUE REQUIREMENT w/o INCENTIVE PLANT**	Sum Lines 21, 22 & 23			$ 25,985,943
26		**GROSS REVENUE REQUIREMENT w INCENTIVE PLANT**	Sum Lines 24 & 25			$ 25,985,943

Formula Rate - Cash Flow

Rate Formula Template
Using 2015 Projected and Financial Operating Data for Southwest Power Pool Rates
For Rates Effective January 1, 2015
LINCOLN ELECTRIC SYSTEM

For the 12 months ending 12/31/2015

Line No.	(1) Description	(2) Reference/Note	(3) Total		(4) Allocator	(5) Allocated to Transmission (3) x (4)
	SUPPORTING CALCULATIONS AND NOTES					
	GROSS PLANT IN SERVICE					
1	Production	310-316, 320-325, 330-336, 340-346	$ 626,334,911	N/A	0.00000	$ -
2	Transmission	350-359	$ 281,451,092	GTP	0.81935	$ 230,606,008
3	Distribution	360-373	$ 477,213,254	N/A	0.00000	$ -
4	General & Intangible	301-303, 389-399	$ 118,566,247	W/S	0.08408	$ 9,968,855
5	Common		$ -	CE	0.08408	$ -
6	TOTAL GROSS PLANT	Sum Lines 1 to 5	$ 1,503,565,504			$ 240,574,863
7		Line 6 col (5) / Line 6 col (3)			**Gross Plant Allocator (GP) =**	**0.16000**
	ACCUMULATED DEPRECIATION	All plant deprec. Goes into same FERC acct.				
8	Production	108	$ 313,999,828	N/A		$ -
9	Transmission	108	$ 98,438,914	N/A		$ 68,983,270
10	Distribution	108	$ 200,220,869	N/A		$ -
11	General & Intangible	108	$ 54,623,238	N/A		$ -
12	Common	108	$ -	N/A		$ -
13	Sub-Total	Sum Lines 8 to 12	$ 667,282,849			$ 68,983,270
	NET PLANT					
14	Production	Line 1 minus Line 8	$ 312,335,083	N/A	0.00000	$ -
15	Transmission	Line 2 minus Line 9	$ 183,012,178	NTP	0.88313	$ 161,622,738
16	Distribution	Line 3 minus Line 10	$ 276,992,385	N/A	0.00000	$ -
17	General & Intangible	Line 4 minus Line 11	$ 63,943,009	W/S	0.08408	$ 5,376,223
18	Common	Line 5 minus Line 12	$ -	CE	0.08408	$ -
19	Sub-Total	Sum Lines 14 to 18	$ 836,282,655			$ 166,998,961
					Net Plant Allocator (NP) =	**0.19969**
	TRANSMISSION PLANT INCLUDED IN ISO RATES		**Gross Plant**		**Net Plant**	
20	Total transmission plant	Line 2	$ 281,451,092		$ 183,012,178	
21	Less transmission plant excluded from ISO rates	Note L	$ 50,845,084		$ 21,389,440	
22	Less transmission plant included in OATT Ancillary Services	Note O	$ -		$ -	
23	Transmission plant included in ISO rates	Line 20 minus Lines 21 & 22	$ 230,606,008		$ 161,622,738	
24	Percentage of gross transmission plant included in ISO Rates	Col (3) - 'Line 23 / Line 20			**Gross Transmission Plant Allocator (GTP) =**	**0.81935**
25	Percentage of net transmission plant included in ISO Rates	Col (4) - Line 23 / Line 20			**Net Transmission Plant Allocator (NTP) =**	**0.88313**
	TRANSMISSION EXPENSES					
26	Total transmission expenses	Page 2, Line 1, col (3)				$ 16,575,870
27	Less transmission expenses included in OATT Ancillary Services	Note N				$ 803,557
28	Included transmission expenses	Line 26 minus Line 27				$ 15,772,313
29	Percentage of transmission expenses after adjustment	Line 28 / Line 26				0.95152
30	Percentage of transmission plant included in ISO Rates	Line 24. col 5			Gross Transmission Plant Allocator	0.81935
31	Percentage of transmission expenses included in ISO Rates	Line 29 x Line 30			**Transmission Expense Allocator (TE) =**	**0.77963**
	WAGES & SALARIES	Note P				
32	Production		$ 4,309,752		0.00000	$ -
33	Transmission		$ 4,014,433	GTP	0.81935	$ 3,289,212
34	Distribution		$ 10,691,616		0.00000	$ -
35	Other		$ 20,104,995		0.00000	$ -
36	Total	Sum Lines 32 to 35	$ 39,120,796			$ 3,289,212
37		Line 36 - col (5) / col (3)			**Wages & Salaries Allocator (W/S) =**	**0.08408**
	COMMON PLANT	Note Q				
38	Electric	Line 6 col (3)				$ 1,503,565,504
39	Gas					$ -
40	Water					$ -
41	Total	Sum Lines 38 to 40				$ 1,503,565,504
42	% Electric	Line 38 / Line 41				100%
		Line 37 x Line 41			**Common Plant Allocator (CE) =**	**0.08408**
	REVENUE CREDITS					
	ACCOUNT 447 (SALES FOR RESALE)					Load
43	a. Bundled Non-RQ Sales for Resale	Note R				0.00
44	b. Bundled Sales for Resale included in Divisor on page 1					0.00
45	Total	Line 47 minus Line 48				0.00

Rate Formula Template
Using 2015 Projected and Financial Operating Data for Southwest Power Pool Rates
For Rates Effective January 1, 2015
LINCOLN ELECTRIC SYSTEM

For the 12 months ending 12/31/2015

Formula Rate - Cash Flow

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data are to FERC account numbers

Note Letter				
New				
A	The revenues credited on page 1 line 2 include a) amounts received directly from the SPP for Point-to-Point transmission service where the demand is not included in the divisor; b) amounts from customers taking service under grandfathered agreements where the demand is not included in the rate divisor; and c) imputed revenues related to short-term reservations of LES's merchant function. Revenue associated with Federal Regulatory Commission annual charges, gross receipts taxes, ancillary services and facilities excluded from the Transmission Cost of Service are not incuded as revenue credits. Revenue from transmission customers whose coincident peak loads are included in the divisor of the load-ratio share calculation are not included as revenue credits. See Worksheet A for details.			
B	Includes income related only to transmission facilities, such as pole attachments, rentals and special use. See Worksheet B for details.			
C	Calculation of Prior Year Divisor True-Up			
	Historic Year Actual Divisor	Pg C, line 1	698,417	kW
	Projected Year Divisor	Pg C, line 2	703,833	kW
	Difference between Historic & Projected Year Divisors		(5,417)	kW
	Prior Year Projected Annual Cost ($ per kw per year)		$34.03	
	Projected Year Divisor True-Up (Line 3 x Line 4)		-$184,309.50	
D	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any.			
F	System control and load dispatch costs.			
G1	The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of ISO coincident monthly peaks. RQ service is service that the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning).			
G2	Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions), and long-term (duration of at least five years); does not meet definition of RQ service. IF is "firm service" for a term longer than one but less than five years. LU is service from a designated generating unit, of a term no less than five years. LI is service from a designated generating unit for a term between one and five years. Measured at time of ISO coincident monthly peaks.			
G3	LF as defined above at time of ISO coincident monthly peaks.			
G4	LF as defined above at time of ISO coincident monthly peaks.			
G5	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.			
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.			
K	The FERC, in Order Nos. 679 and 679-A, offers a 50-basis point incentive adder for transmission owners joining an RTO as long as the return on equity for the transmission owner is within a zone of reasonableness. In order to be comparable with transmission owners in RTOs (including SPP), LES has included this 50-basis-point incentive adder in its revenue requirements.			
L	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).			
M	The Margin Requirement is the margin the utility uses in calculating rates applicable to its native load sales. The Margin Requirement as a percent of interest expense yields a TIER (times interest earned ratio), and the Margin Requirement as a percent of debt service is the DSR (debt service ratio), either of which may be referred to as a Margin Ratio (MR). Some utilities have MRs required by bond covenants and/or MRs that include expenses additional to interest or debt service (for example, an MR equal to a percentage of the sum of DS+O&M). The ISO will review such party's filings to assure that the MRs are consistent with those applicable to native load or required by bond covenants and utility must provide workpapers showing derivation of margin.			
N	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.			
O	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.			
P	If the utility has more employees assigned to A&G than to the sum of production, transmission, and distribution, set the W&S allocator at page 3, line 37 equal to the gross plant allocator (GP) at page 3, line 7.			
Q	Enter dollar amounts.			
R	Line 45 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.			
U	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.			
V	Additional revenue requirement for facilities receiving incentives. See worksheets I, J, and K			
W	FERC 565 on page 2 includes STEP BPF, STEP HWBW, CWIP, Balanced Portfolio Projects, Balanced Portfolio Transfers, and Priority Projects associated with the Southwest Power Pool. These costs are excluded from the ATRR because they are not funded by transmission rates.			

Return to TOC

Rate Formula Template
Using 2015 Projected and Financial Operating Data for Southwest Power Pool Rates
For Rates Effective January 1, 2015
LINCOLN ELECTRIC SYSTEM

Worksheet A - Revenue Credits, Account 456

Detail of 456 - Transmission Wheeling Fees

Line No.	FERC Account	Description	Transmission	Other	Total
1		Scheduling Fees		-	-
2		Reactive		-	-
3		Regulation		-	-
4		Distribution Line		-	-
5		Distribution Subs		-	-
6		Transformers		-	-
7		Losses		-	-
8		Distribution Wheeling Fees (Direct)		-	-
9		Transmission Revenue for Trans Included in Divisor	$ (868,627)		$ (868,627)
10		Total Transmission Revenue - All Transactions	$ 1,959,696		$ 1,959,696
11	456		$ 1,091,069	-	$ 1,091,069
12		Add: Short-term LES Merchant PTP *			$ -
13		Revenue Credits			$ 1,091,069

* See Worksheet G - Billing Units Divisor (line 40) for details

Return to TOC

Rate Formula Template
Using 2015 Projected and Financial Operating Data for Southwest Power Pool Rates
For Rates Effective January 1, 2015
LINCOLN ELECTRIC SYSTEM

Worksheet B - Revenue Credits - Rents, Account 454

Detail of 454 - Rent

Line No.	FERC Account	Description	Total	Other	Transmission Revenue Credit
1	454.16, 454.17, 454.19	Rent	$ 241,467	$ -	$ 241,467
2	454.12, 454.13	Allocated portion of general rent (1)	$ -	$ -	$ -
3	All Other Sub Accts	Other	$ -	$ -	$ -
4	454	Rent Revenue Credits	$ 241,467	$ -	$ 241,467

Revenues from service provided by the ISO at a discount $ -

(1) Split based on Wages and Salaries. Allocator derived on page 3, line 37

Rate Formula Template
Using 2015 Projected and Financial Operating Data for Southwest Power Pool Rates
For Rates Effective January 1, 2015
LINCOLN ELECTRIC SYSTEM

Worksheet C - True-Up Calculations

Line No.	(1) Description	(2) Reference/Note		(3) Total	
	TRUE-UP CALCULATIONS				
	Calculation of Historic Year Divisor True-Up (1)				
1	Historic Year Actual Divisor	Worksheet G1		698,417	kW
2	Historic Year Projected Dvisor	Worksheet G1		703,833	kW
3	Difference between Historic & Projected Year Divisors	line 1 minus line 2		(5,417)	kW
4	Historic Year Projected Annual Cost		$	34.03	$/kW-year
5	**Projected Year Divisor True-Up**	line 3 x line 4	$	(184,310)	
	Calculation of Historic Year Net ATRR True-Up (2)				
6	Historic Year Actual Net ATRR (i.e., Actual Transmission Cost)	See worksheet D	$	25,932,793	
7	Historic Year Projected Net ATRR	See worksheet D	$	26,028,148	
8	**Prior Year ATRR True-Up**	line 6 minus line 7	$	(95,355)	
9	**Total Net ATRR True-Up**	line 5 + line 8	$	(279,665)	

	Interest on Historic Year True-Up	**APR**	**QPR**
10	If Historic Actual < Projected, Overcollection	3.25%	0.803%
11	If Historic Actual > Projected, Undercollection	0.15%	0.037%

	Quarter		**Levelized True-Up**		**Interest Charge**
12	1	$	(69,916)	$	(4,618)
13	2	$	(69,916)	$	(4,025)
14	3	$	(69,916)	$	(3,436)
15	4	$	(69,916)	$	(2,852)
16	**Total**			**$**	**(14,931)**

Notes
(1) Historic Year Divisor True-Up is computed to account for the difference in volume between projected and actual experience.
(2) Historic Year Actual and Projected Net ATRR accounts for SPP Transmission Project Revenue Offsets

Formula Rate - Cash Flow

Computation of ATRR Adjustment
Page 2 Worksheet
For Rates Effective January 1, 2015
LINCOLN ELECTRIC SYSTEM

Return to TOC

For the 12 Months Ended 12/31/2013

Worksheet D - Net ATRR True-Up Calculations

Line No.	(1) Description	(2) Reference/Note (1)	(3) Projected Total	(4) Actual Total	(5) Delta (4) - (3)	(6) ctual Based on Historic		Projected (7) **Allocated to Transmission (3) x (6)**	Actual (8) **Allocated to Transmission (4) x (6)**
	Gross Annual Transmission Revenue Requirement (ATRR)			**Projected Year Divisor Based on Projected Value for 2013**					
	O&M								
1	Transmission		$ 14,290,478	$ 14,742,898	$ 452,420	TE	0.79199	$ 11,317,895	$ 11,676,206
2	Less Accounts 561 & 565		$ 5,221,887	$ 5,425,787	$ 203,900		1.00000	$ 5,221,887	$ 5,425,787
3	**A&G**		$ 22,659,278	$ 17,469,432	$ (5,189,846)	W/S	0.06145	$ 1,392,340	$ 1,073,441
4	Less FERC Annual Fees		$ -	$ -	$ -	W/S	0.06145	$ -	$ -
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad	Note I	$ 562,198	$ 562,198	$ -	W/S	0.06145	$ 34,545	$ 34,545
5a	Plus Transmission Related Reg. Comm. Exp.	Note I	$ -	$ -	$ -	TE	0.79199	$ -	$ -
6	Common		$ -	$ -	$ -	CE	0.06145	$ -	$ -
7	Transmission Lease Payments		$ -	$ -	$ -		1.00000	$ -	$ -
8	**TOTAL O&M**	Sum lines 1, 3, 5a, 6, 7 less 2, 4, 5	31,165,671	26,224,345	$ (4,941,326)			$ 7,453,802	$ 7,289,314
	DEBT SERVICE								
9	Debt Service		$ 46,810,000	$ 46,963,889	$ 153,889	NP	0.18882	$ 8,838,447	$ 8,867,504
10	Amortization of premium or discount		$ 514,040	$ 714,302	$ 200,262	NP	0.18882	$ 97,059	$ 134,871
11	**TOTAL DEBT SERVICE**	Sum lines 9 & 10	$ 47,324,040	$ 47,678,191				$ 8,935,506	$ 9,002,375
	TAXES OTHER THAN INCOME TAXES	Note K							
	LABOR RELATED								
12	Payroll		$ 2,705,000	$ 2,755,004	$ 50,004	W/S	0.06145	$ 166,214	$ 169,286
13	Highway and vehicle		$ 120	$ -	$ (120)	W/S	0.06145	$ 7	$ -
14	PLANT RELATED				$ -			$ -	$ -
15	Property		$ 722,001	$ 489,942	$ (232,059)	GP	0.15486	$ 111,810	$ 75,873
16	Gross Receipts		$ -	$ -	$ -		0.00000	$ -	$ -
17	Other		$ -	$ -	$ -	GP	0.15486	$ -	$ -
18	Payments in lieu of taxes		$ 12,146,031	$ 12,183,578	$ 37,547	GP	0.15486	$ 1,880,949	$ 1,886,764
19	**TOTAL OTHER TAXES**	Sum lines 12 through 18	15,573,152	15,428,524				$ 2,158,980	$ 2,131,923
21	**SUBTOTAL**	Sum lines 8, 11, 19						$ 18,548,288	$ 18,423,612
22	**MARGIN REQUIREMENT**	Note M	$ 46,810,000	$ 46,999,337	$ 189,337	GP	0.15486	$ 7,249,053	$ 7,278,374
23	**RTO Incentive Adder (Order Nos. 679 & 679-A)**	Note K, Worksheet K	$ 230,807	$ 230,807	$ -		1.00	$ 230,807	$ 230,807
	Additional Margin on Incentive Plant								
25	Transmission Upgrade Projects	Note J, Worksheet J1 + Worksheet J2	$ -	$ -	$ -		1.00	$ -	$ -
26	**GROSS REVENUE REQUIREMENT w/o INCENTIVE PLANT**							$ 26,028,148	$ 25,932,793
27	**GROSS REVENUE REQUIREMENT w INCENTIVE PLANT**							$ 26,028,148	$ 25,932,793
	Transmission Project Revenue Offset Under Schedule 11		**Projected**	**Actual**	**Delta**				
29	Total Schedule 11 Revenue Offset		$ -	$ -	$ -		1.00	$ -	$ -
30	**NET ATRR FOLLOWING TRANSMISSION REVENUE OFFSETS w/o INCENTIVE**	Line 26 minus Line 29						$ 26,028,148	$ 25,932,793
31	**NET ATRR FOLLOWING TRANSMISSION REVENUE OFFSETS w INCENTIVE PL**	Line 27 minus Line 29						$ 26,028,148	$ 25,932,793 *

Note this is the "Available for Debt Service" and Debt Service from the OR, unaudited, page 9.

	Projected	**Actual**	**Delta**
Avail. For D.S.	$ 93,620,000	$ 93,963,226	$ 343,226
minus D.S.	$ 46,810,000	$ 46,963,889	$ 153,889
	$ 46,810,000	$ 46,999,337	$ 189,337

Notes

(1) All references made here are to Worksheets and Notes in the Historical Year Template
(2) True-up value for calendar year 2013 to be applied to 2015 ATRR.

Rate Formula Template

Return to TOC

Using 2015 Projected and Financial Operating Data for Southwest Power Pool Rates

For Rates Effective January 1, 2015

LINCOLN ELECTRIC SYSTEM

For the 12 months ending 12/31/2015

Worksheet F

Scheduling, System Control and Dispatch Service

Line No.	FERC Account	Description		Amount
		Determine Scheduling, System Control & Dispatch Cost		
1	561	Load Dispatching	$	803,557
2	556	System Control & Load D	$	-
3		**Total ATRR for AS#1**	**$**	**803,557**

Transmission Rate Calculation

Using 2015 Projected and Financial Operating Data for Southwest Power Pool Rates

For Rates Effective January 1, 2015

Return to TOC

Worksheet G - Billing Units Divisor

			Projected Network Load				Projected LTPTP Reservations				
Line No.	**Month**	**Hour & Date for Network**	**LES Load**	**Less: Load in other SPP Zones**	**Plus: Network WS Load**	**Total Network Load**	**Contract Demand of firm P-T-P over one year**	**Firm bundled sales over one year**	**Firm P-T-P over one year**	**Contract Demand from Grandfathered Interzonal transactions over one year**	**Contract Demands from service over one year provided by ISO at a discount**
1	Jan		564			564.00	94	0.0	0.0	0.0	0.0
2	Feb		533			533.00	94	0.0	0.0	0.0	0.0
3	Mar		477			477.00	94	0.0	0.0	0.0	0.0
4	Apr		499			499.00	94	0.0	0.0	0.0	0.0
5	May		585			585.00	94	0.0	0.0	0.0	0.0
6	June		738			738.00	94	0.0	0.0	0.0	0.0
7	Jul		768			768.00	94	0.0	0.0	0.0	0.0
8	Aug		755			755.00	94	0.0	0.0	0.0	0.0
9	Sept		672			672.00	94	0.0	0.0	0.0	0.0
10	Oct		549			549.00	94	0.0	0.0	0.0	0.0
11	Nov		503			503.00	94	0.0	0.0	0.0	0.0
12	Dec		561			561.00	94	0.0	0.0	0.0	0.0
13	Total		7,204.00	0.00	0.00	7,204.00	1,128.00	0.00	0.00	0.00	0.00
14	12 CP Average		600.33	0.00	0.00	600.33	94.00	0.00	0.00	0.00	0.00
15	**Total Billing Units**		**600.33**	**0.00**	**0.00**	**600.33**	**94.00**	**0.00**	**0.00**	**0.00**	**0.00**

Projected Wholesale NW Load - MW

		Total WS Load			Total
16	Jan	0.00			0.00
17	Feb	0.00			0.00
18	Mar	0.00			0.00
19	Apr	0.00			0.00
20	May	0.00			0.00
21	June	0.00			0.00
22	July	0.00			0.00
23	Aug	0.00			0.00
24	Sept	0.00			0.00
25	Oct	0.00			0.00
26	Nov	0.00			0.00
27	Dec	0.00			0.00
28	Total MW	0.00	0.00	0.00	0.00

(5) Detail of LES Marketing Transactions. See lines 29 - 41 below

Projected LES Marketing Long-Term Transactions

	OASIS #					Total
29	Jan	0.00				0.00
30	Feb	0.00				0.00
31	Mar	0.00				0.00
32	Apr	0.00				0.00
33	May	0.00				0.00
34	June	0.00				0.00
35	July	0.00				0.00
36	Aug	0.00				0.00
37	Sept	0.00				0.00
38	Oct	0.00				0.00
39	Nov	0.00				0.00
40	Dec	0.00				0.00
41	Total	0.00	0.00	0.00	0.00	0.00

Projected LES Marketing Short-Term Transactions

	Hourly	Daily	Weekly	Monthly
PTP-Firm	0.00	0.00	0.00	0.00
PTP Non-Firm	0.00	0.00	0.00	0.00
PTP-Firm	0.00	0.00	0.00	0.00
PTP Non-Firm	0.00	0.00	0.00	0.00
PTP-Firm	0.00	0.00	0.00	0.00
PTP Non-Firm	0.00	0.00	0.00	0.00
Total All Short-Term Transactions*				0.00

* Sum transferred to Worksheet A, Line 12

Transmission Rate Calculation
Using 2015 Projected and Financial Operating Data for Southwest Power Pool Rates

Return to TOC

Worksheet G1 - Historic Year Actual Billing Units for Computing Divisor True Up

			2013 Actual Network Load				Actual LTPTP Reservations				
Line No.	Month	Hour & Date for Network	LES Load	Less: Load in other SPP Zones	Plus: Network WS Load	Total Network Load	Contract Demand of firm P-T-P over one year	Firm bundled sales over one year	Firm P-T-P over one year	Contract Demand from Grandfathered Interzonal transactions over one year	Contract Demands from service over one year provided by ISO at a discount
1	Jan		535			535	109	-	-	-	-
2	Feb		521			521	109	-	-	-	-
3	Mar		472			472	109	-	-	-	-
4	Apr		454			454	109	-	-	-	-
5	May		575			575	109	-	-	-	-
6	June		682			682	109	-	-	-	-
7	Jul		750			750	109	-	-	-	-
8	Aug		758			758	109	-	-	-	-
9	Sept		725			725	109	-	-	-	-
10	Oct		538			538	109	-	-	-	-
11	Nov		499			499	109	-	-	-	-
12	Dec		564			564	109	-	-	-	-
13	Total		7,073	-	-	7,073	1,308	-	-	-	-
14	**12 CP Average**		**589**	**0**	**0**	**589**	**109**	**0**	**0**	**0**	**0**
15	**Total Billing U**		**589**	**0**	**0**	**589**	**109**	**0**	**0**	**0**	**0**
16		**Total**									**698**

			2013 Projected Network Load				Projected LTPTP Reservations				
Line No.	Month	Hour & Date for Network	LES Load	Less: Load in other SPP Zones	Plus: Network WS Load	Total Network Load	Contract Demand of firm P-T-P over one year	Firm bundled sales over one year	Firm P-T-P over one year	Contract Demand from Grandfathered Interzonal transactions over one year	Contract Demands from service over one year provided by ISO at a discount
1	Jan		573			573	109	-	-	-	-
2	Feb		555			555	109	-	-	-	-
3	Mar		492			492	109	-	-	-	-
4	Apr		485			485	109	-	-	-	-
5	May		576			576	109	-	-	-	-
6	June		716			716	109	-	-	-	-
7	Jul		755			755	109	-	-	-	-
8	Aug		730			730	109	-	-	-	-
9	Sept		636			636	109	-	-	-	-
10	Oct		539			539	109	-	-	-	-
11	Nov		511			511	109	-	-	-	-
12	Dec		570			570	109	-	-	-	-
13	Total		7,138	-	-	7,138	1,308	-	-	-	-
14	**12 CP Average**		**595**	**0**	**0**	**595**	**109**	**0**	**0**	**0**	**0**
15	**Total Billing U**		**595**	**0**	**0**	**595**	**109**	**0**	**0**	**0**	**0**
16		**Total**									**704**

Rate Formula Template

Using 2015 Projected and Financial Operating Data for Southwest Power Pool Rates

For Rates Effective January 1, 2015

LINCOLN ELECTRIC SYSTEM

Worksheet H

Account 565 Transmission by Others

Return to TOC

For the 12 months ending 12/31/2013

Line No.	FERC Account	Description	Notes		(1)
1	**565**	**Account Total**		$	7,694,542
2		Less: Transmission by Others		$	5,057,312
3		Less: SPP Administrative Costs		$	2,637,230
4		Portion of 565 included in transmission rates	Line 1 minus Lines 2&3	$	-

Return to TOC

Rate Formula Template
Using 2015 Projected and Financial Operating Data for Southwest Power Pool Rates
For Rates Effective January 1, 2015
LINCOLN ELECTRIC SYSTEM

Worksheet I - Transmission Upgrade Project Fixed Charge Rate

Calculate Fixed Charge Rate (FCR) for Transmission Upgrade Projects

No.	Description	Notes	Amount
1	LES Forecast Zonal Revenue Requirement (w/o incentive plant)	Page 2, Line 25	$25,985,943
2	Less: Revenue Credits	Page 1, Line 5	$ 1,091,809
3	Less: Depreciation Expense	LES Financial Services	$ 8,435,095
4	Revenue Requirement w/o Depr	Line 1 minus Line 2 & Line 3	$16,459,039
5	Net Plant	Page 3, Line 23, Col 4	$161,622,738
6	Net Rev Req w/o Depreciation	Line 4 above	$16,459,039
7	**Fixed Charge Rate - Upgrade Project**	Line 6 / Line 5	**10.18%**

Return to TOC

Rate Formula Template
Using 2015 Projected and Financial Operating Data for Southwest Power Pool Rates
For Rates Effective January 1, 2015
LINCOLN ELECTRIC SYSTEM

Worksheet J1 - LES Transission Upgrade (TU) Project #1

Facilities receiving incentives accepted by FERC in Docket No.

Line No.					
	Project Description:	Sheldon to Pleasant Hill 115 kV line rebuild			
1	Investment	$5,197,561	Current Year		2015
2	Service Year (yyyy)	2013	Incentive ROE increase (Basis Points)	0	0.00%
3	Service Month (1-12)	1	FCR w/o incentives, less depreciation		10.18%
4	Useful life (Yrs)	30	FCR w/ incentives approved for these facilities, less dep		10.18%
5	CIAC (Yes or No)	No	Annual Depreciation Expense		$173,252

	Investment Year	Year #	Beginning Balance	Depreciation Expense	Ending Balance	TU Rev Req w/o Incentives	TU Rev Req w/ Incentives	Additional ATRR for Incentives on TU Projects
6	2013	1	$5,197,561	$158,814	$5,038,747	$671,941	$671,941	$0
7	2014	2	$5,038,747	$173,252	$4,865,495	$668,735	$668,735	$0
8	2015	3	$4,865,495	$173,252	$4,692,243	$651,092	$651,092	$0
9	2016	4	$4,692,243	$173,252	$4,518,991	$633,449	$633,449	$0
10	2017	5	$4,518,991	$173,252	$4,345,739	$615,805	$615,805	$0
11	2018	6	$4,345,739	$173,252	$4,172,486	$598,162	$598,162	$0
12	2019	7	$4,172,486	$173,252	$3,999,234	$580,519	$580,519	$0
13	2020	8	$3,999,234	$173,252	$3,825,982	$562,875	$562,875	$0
14	2021	9	$3,825,982	$173,252	$3,652,730	$545,232	$545,232	$0
15	2022	10	$3,652,730	$173,252	$3,479,478	$527,589	$527,589	$0
16	2023	11	$3,479,478	$173,252	$3,306,226	$509,945	$509,945	$0
17	2024	12	$3,306,226	$173,252	$3,132,974	$492,302	$492,302	$0
18	2025	13	$3,132,974	$173,252	$2,959,722	$474,659	$474,659	$0
19	2026	14	$2,959,722	$173,252	$2,786,470	$457,015	$457,015	$0
20	2027	15	$2,786,470	$173,252	$2,613,218	$439,372	$439,372	$0
21	2028	16	$2,613,218	$173,252	$2,439,966	$421,729	$421,729	$0
22	2029	17	$2,439,966	$173,252	$2,266,714	$404,085	$404,085	$0
23	2030	18	$2,266,714	$173,252	$2,093,462	$386,442	$386,442	$0
24	2031	19	$2,093,462	$173,252	$1,920,210	$368,799	$368,799	$0
25	2032	20	$1,920,210	$173,252	$1,746,958	$351,156	$351,156	$0
26	2033	21	$1,746,958	$173,252	$1,573,706	$333,512	$333,512	$0
27	2034	22	$1,573,706	$173,252	$1,400,454	$315,869	$315,869	$0
28	2035	23	$1,400,454	$173,252	$1,227,202	$298,226	$298,226	$0
29	2036	24	$1,227,202	$173,252	$1,053,950	$280,582	$280,582	$0
30	2037	25	$1,053,950	$173,252	$880,698	$262,939	$262,939	$0
31	2038	26	$880,698	$173,252	$707,446	$245,296	$245,296	$0
32	2039	27	$707,446	$173,252	$534,194	$227,652	$227,652	$0
33	2040	28	$534,194	$173,252	$360,942	$210,009	$210,009	$0
34	2041	29	$360,942	$173,252	$187,690	$192,366	$192,366	$0
35	2042	30	$187,690	$173,252	$14,438	$174,722	$174,722	$0
36	2043	31	$14,438	$14,438	$0	$14,438	$14,438	$0
37	2044	32	$0	$0	$0	$0	$0	$0
38	2045	33	$0	$0	$0	$0	$0	$0
39	2046	34	$0	$0	$0	$0	$0	$0
40	2047	35	$0	$0	$0	$0	$0	$0
41	2048	36	$0	$0	$0	$0	$0	$0
42	2049	37	$0	$0	$0	$0	$0	$0
43	2050	38	$0	$0	$0	$0	$0	$0
44	2051	39	$0	$0	$0	$0	$0	$0
45	2052	40	$0	$0	$0	$0	$0	$0
46	2053	41	$0	$0	$0	$0	$0	$0
			$80,995,326	$5,197,561	$75,797,765	$12,916,514	$12,916,514	$0

Return to TOC

Rate Formula Template
Using 2015 Projected and Financial Operating Data for Southwest Power Pool Rates
For Rates Effective January 1, 2015
LINCOLN ELECTRIC SYSTEM

Worksheet J2 - LES Transission Upgrade (TU) Project #2

Facilities receiving incentives accepted by FERC in Docket No.

Line No.	**Project Description:**				
1	Investment	$0	Current Year		2015
2	Service Year (yyyy)	2013	Incentive ROE increase (Basis Points)	0	0.00%
3	Service Month (1-12)	1	FCR w/o incentives, less depreciation		10.18%
4	Useful life (Yrs)	30	FCR w/ incentives approved for these facilities, less dep		10.18%
5	CIAC (Yes or No)	No	Annual Depreciation Expense		$0

	Investment Year	Year #	Beginning Balance	Depreciation Expense	Ending Balance	TU Rev Req w/o Incentives	TU Rev Req w/ Incentives	Additional ATRR for Incentives on TU Projects
6	2013	1	$0	$0	$0	$0	$0	$0
7	2014	2	$0	$0	$0	$0	$0	$0
8	2015	3	$0	$0	$0	$0	$0	$0
9	2016	4	$0	$0	$0	$0	$0	$0
10	2017	5	$0	$0	$0	$0	$0	$0
11	2018	6	$0	$0	$0	$0	$0	$0
12	2019	7	$0	$0	$0	$0	$0	$0
13	2020	8	$0	$0	$0	$0	$0	$0
14	2021	9	$0	$0	$0	$0	$0	$0
15	2022	10	$0	$0	$0	$0	$0	$0
16	2023	11	$0	$0	$0	$0	$0	$0
17	2024	12	$0	$0	$0	$0	$0	$0
18	2025	13	$0	$0	$0	$0	$0	$0
19	2026	14	$0	$0	$0	$0	$0	$0
20	2027	15	$0	$0	$0	$0	$0	$0
21	2028	16	$0	$0	$0	$0	$0	$0
22	2029	17	$0	$0	$0	$0	$0	$0
23	2030	18	$0	$0	$0	$0	$0	$0
24	2031	19	$0	$0	$0	$0	$0	$0
25	2032	20	$0	$0	$0	$0	$0	$0
26	2033	21	$0	$0	$0	$0	$0	$0
27	2034	22	$0	$0	$0	$0	$0	$0
28	2035	23	$0	$0	$0	$0	$0	$0
29	2036	24	$0	$0	$0	$0	$0	$0
30	2037	25	$0	$0	$0	$0	$0	$0
31	2038	26	$0	$0	$0	$0	$0	$0
32	2039	27	$0	$0	$0	$0	$0	$0
33	2040	28	$0	$0	$0	$0	$0	$0
34	2041	29	$0	$0	$0	$0	$0	$0
35	2042	30	$0	$0	$0	$0	$0	$0
36	2043	31	$0	$0	$0	$0	$0	$0
37	2044	32	$0	$0	$0	$0	$0	$0
38	2045	33	$0	$0	$0	$0	$0	$0
39	2046	34	$0	$0	$0	$0	$0	$0
40	2047	35	$0	$0	$0	$0	$0	$0
41	2048	36	$0	$0	$0	$0	$0	$0
42	2049	37	$0	$0	$0	$0	$0	$0
43	2050	38	$0	$0	$0	$0	$0	$0
44	2051	39	$0	$0	$0	$0	$0	$0
45	2052	40	$0	$0	$0	$0	$0	$0
46	2053	41	$0	$0	$0	$0	$0	$0
			$0	$0	$0	$0	$0	$0

Return to TOC

Rate Formula Template
Using 2015 Projected and Financial Operating Data for Southwest Power Pool Rates
For Rates Effective January 1, 2015
LINCOLN ELECTRIC SYSTEM

Worksheet K - SPP RTO Incentive Adder

Line No	Description	Amount	Equity %	
	Calculate Premium for Joining an RTO			
	(Plant based on 2015 data)			
1	Transmission Plant	$281,451,092		
2	Allocated Share of General	$9,968,855		
3	Total Plant	$291,419,947		
4	X Equity Ratio	15%		
5	X 50 Basis Point Premium	0.0050		
	Premium $	$218,565		
	Calculate Equity %			
	(Based on 2013 Balance Sheet)			
6	Long-term Debt	$594,822,150	85%	
7	Equity (Cash or Cash Equivalents)	$101,919,281	15%	See Financial Services
8	Total	$696,741,431		

Rate Formula Template
Using 2015 Projected and Financial Operating Data for Southwest Power Pool Rates
For Rates Effective January 1, 2015
LINCOLN ELECTRIC SYSTEM

Return to TOC

Note: This worksheet created for internal use only.
Notes Section of Page 3 Line 21 does not make reference to Worksheet L, only a reference to Note L.

Worksheet L - Transmission Plant Used for Other Purposes

Note: To compute net transmission plant for individual lines (e.g., Walter Scott #4) I computed the ratio of Total Net Plant to Total Gross Plant, and multiplied each Gross plant line by that value.

Line No.	Description	Gross	Net	48.6519% Additional Description
1	**Walter Scott #4**	$ 23,801,198	$ 19,754,358	
2	**LRS**	$ 24,541,219	$ 1,381,745	
3	**LRS - Ault Sub**	$ 535,213	$ 11,016	
4	**Radial Line**	$ 1,967,454	$ 242,321	20th & Pioneer to 29th & Leighton
5		$ -	$ -	14th & Alvo to NW 12th & Arbor Rd. (no longer radial)
6		$ -	$ -	
7		$ -	$ -	
8		$ -	$ -	
5	**Total**	$ 50,845,084	$ 21,389,440	

Note: Various Plant Transmission Lines that are excluded from ISO. See Milt Bayer