WRIGHT &
TALISMAN PC

1200 G Street, N.W.
Suite 600
Washington, D.C. 20005-3802
202.393.1200
Fax 202.393.1240
www.wrightlaw.com

November 19, 2010

The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: *Southwest Power Pool, Inc.*, Docket No. ER11-2071-___
Submission of Errata Filing

Honorable Secretary Bose:

On November 10, 2010, Southwest Power Pool, Inc. ("SPP") submitted in this proceeding ("November 10 Filing") revisions to its Open Access Transmission Tariff ("OATT" or "Tariff") to implement a rate change for Oklahoma Municipal Power Authority ("OMPA"), which is a transmission-owning member of SPP with revenue requirements in the American Electric Power and Oklahoma Gas & Electric ("OG&E") pricing zones under the SPP Tariff. Specifically, the November 10 Filing incorporated into SPP's Tariff the revenue requirements for recently transferred facilities into OMPA's revenue requirement that is collected under the SPP Tariff. The November 10 Filing included exhibits prepared by OMPA to demonstrate the justness and reasonableness of OMPA's rates. SPP requested an effective date of June 1, 2010 for the November 10 Filing.

It has come to SPP's attention that the proposed revisions to Attachments H and T of SPP's Tariff in the November 10 Filing are incorrect. In addition, SPP has been informed that the exhibits prepared by OMPA to support its rates are incomplete. Therefore, SPP includes in this errata filing corrected clean and redline Tariff revisions for Attachments H and T under the Sixth Revised Volume No. 1, as well as corrected retroactive clean and redline Tariff sheets for Attachments H and T under the Fifth Revised Volume No. 1. These revisions replace the revisions to Attachments H and T that were included in the November 10 Filing. SPP also includes as Exhibits Nos. 1 and 2 to this errata filing, respectively, corrected spreadsheets detailing the calculation of the revenue requirement for the new OMPA transmission facilities[1] and the recalculation of

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[1] Specifically, OMPA updated its total plant investment figures. In addition, OMPA updated cost values from OG&E's 2009 FERC Form 1.

rates for Point-To-Point Transmission Service for the OG&E zone. These exhibits replace Exhibits Nos. 3 and 4 of the November 10 Filing.

The remainder of the November 10 Filing is valid, and SPP requests that the Commission accept the November 10 Filing, as amended by this errata filing, with a June 1, 2010 effective date. A copy of this errata filing has been served on all SPP Members and Customers, as well as on all state commissions in SPP's service area. In addition, a copy of this filing has been served on all entities on the service list for this proceeding, and will be posted on the SPP web page (www.spp.org).

Respectfully submitted,

*Matthew K. Segers*
Wendy N. Reed
Matthew K. Segers

**Attorneys for Southwest Power Pool, Inc.**

K:\SPP\1001-1219-258 (OMPA errata rate letter).doc

## CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, DC, this 19th day of November, 2010.

*Matthew K. Segers*
Matthew K. Segers
WRIGHT & TALISMAN, P.C.
1200 G Street, NW, Suite 600
Washington, D.C. 20005
(202) 393-1200
(202) 393-1240 (fax)

Attorney for
Southwest Power Pool, Inc.

# Exhibit No. 1

Using 39-year Service Life - 2.57% Depreciation Rate (Per OG&E Worksheets, F, G and H)

| | | Source | | |
|---|---|---|---|---|
| Gross Plant in Service | 3,066,726 | Investment Analysis Worksheet | | |
| Accumulated Depreciation | 1,645,869 | Investment Analysis Worksheet | | |
| Net Plant in Service | 1,420,858 | Investment Analysis Worksheet | | |
| | | | | |
| ATRR Component | Amount | | Value | Units |
| O&M - Lines | $ 91,558 | OG&E 5-year average 69 kV Lines Expense per mile of 69 kV Line | 3,325 | Lines O&M/Line Miles |
| O&M - Stations | 22,869 | OG&E 5-year average transmission stations expense as % of gross plant investment | 3.01% | Stations O&M/GPIS |
| A&G | 27,279 | OG&E 5-Year Avg. Transm-related A&G as percent of OG&E Transm O&M | 23.8% | A&G/O&M |
| Depreciation | 77,956 | Investment Analysis Worksheet | | |
| Property Taxes (in-lieu) | 20,962 | OG&E property tax as percent of OG&E Net Plant Investment | 1.5% | Tax/NPIS {1} |
| Return | 127,877 | OG&E Rate of Return Applied to Net Plant Investment (Using As-Proposed ROR) | 9.00% | OG&E Settlement ROR {2} |
| Annual Transmission Revenue Requirement | $ 368,501 | | | |
| | | | | |
| Resulting Ratio of ATRR to Gross Plant In Service - % | 12.02% | | | |
| OG&E Gross ATRR (before credits)/ Gross Plant in Service - % | 12.90% | At 9.02 % ROR | | |

{1} per OG&E 2009 Annual True-Up Formula Rate Template = $6,814,562 Property-related Taxes divided by $461,017,226 Net Plant in Service

{2} from OG&E 2009 Annual True-Up Formula Rate Template, "Data" worksheet, Page 4, Line 140, Column (5)

Ponca City Transmission Investment:
Costs based upon present day re-production discounted to date of installatior
Using 2.57% Depreciation Rate

| Line Section | length miles | Poles | Inst Date | Purchase $ | Reproduction Cost New $2009 | Estimated Original Installed Cost | OG&E Depreciatio n Rate - % | Service Years (assume plant added at mid-year) | Accumulated Depreciation to 12-31-2007 | Net Plant In service | Annual Depreciation |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Riggs-NW Tap | 1.25 | | 1975 | | 156,275 | 42,620 | 2.57 | 33.50 | 36,694 | 5,926 | 1,095 |
| NW Tap-NE | 3.09 | | 1974 | | 386,312 | 88,873 | 2.57 | 34.50 | 78,799 | 10,074 | 2,284 |
| NE to Gonterman | 3.14 | | 1973 | | 392,563 | 72,832 | 2.57 | 35.50 | 66,448 | 6,384 | 1,872 |
| Gonterman-Kaw SW | 0.8 | | 1975 | | 100,016 | 27,277 | 2.57 | 33.50 | 23,484 | 3,793 | 701 |
| Kaw SW-Pecan Tap | 0.8 | | 1975 | | 100,016 | 27,277 | 2.57 | 33.50 | 23,484 | 3,793 | 701 |
| Pecan Tap-WW | 1.25 | | 1975 | | 156,275 | 42,620 | 2.57 | 33.50 | 36,694 | 5,926 | 1,095 |
| WW-OMPA East | 0.8 | | 1975 | | 100,016 | 27,277 | 2.57 | 33.50 | 23,484 | 3,793 | 701 |
| OMPA East-Osage | 0.75 | 17 | 1971 | | 111,860 | 18,470 | 2.57 | 37.50 | 17,801 | 670 | 475 |
| OMPA West-Osage | 0.8 | 17 | 1983 | | 111,860 | 49,185 | 2.57 | 25.50 | 32,234 | 16,952 | 1,264 |
| Moran Tap-OMPA West | 3.21 | | 1975 | | 401,314 | 109,449 | 2.57 | 33.50 | 94,230 | 15,219 | 2,813 |
| Moran Tap-Huffy Tap | 1.49 | | 1964 | | 186,280 | 20,736 | 2.57 | 44.50 | 20,736 | - | - |
| Huffy Tap-Riggs | 0.91 | | 1964 | | 113,768 | 12,664 | 2.57 | 44.50 | 12,664 | - | - |
| Kaw SW-Kaw Dam | 9.25 | | 1989 | | | 1,709,138 | 2.57 | 19.50 | 856,535 | 852,603 | 43,925 |
| Kaw SW-Kaw Dam Retired | -0.1 | 3 | 1989 | | | (12,882) | 2.57 | 19.50 | (6,456) | (6,426) | (331) |
| McCord Switch | 0.1 | | 2009 | | | 72,385 | 2.57 | (0.50) | 930 | 71,455 | 1,860 |
| | | | | | | | | | | | |
| Total lines | 27.54 | | | | | 2,307,924 | | | 1,317,762 | 990,162 | 58,455 |
| | | | | | | | | | | | |
| 69 kV SP Post line/795 kcmil | 19 | structures per mile | | | 6,580 | | | | | | |
| | | | | | | | | | | | |
| Riggs Substation - trans | | | 1974 | | 230,000 | 52,913 | 2.57 | 34.50 | 46,915 | 5,998 | 1,360 |
| Kaw Switch sub | | | 1993 | | 705,889 | 705,889 | 2.57 | 15.50 | 281,191 | 424,698 | 18,141 |
| | | | | | | | | | | | |
| Total subs | | | | | | 758,802 | | | 328,106 | 430,696 | 19,501 |
| | | | | | | | | | | | |
| Total investment | | | | | | 3,066,726 | | | 1,645,869 | 1,420,858 | 77,956 |

| | I = | CPI | Discount | | 3.00% |
|---|---|---|---|---|---|
| 0 | 2008 | 213.6 | | 1.000000 | 1.000000 |
| 1 | 2007 | 207.3 | 2.93% | 0.97156 | 0.970874 |
| 2 | 2006 | 201.6 | 2.75% | 0.94556 | 0.942596 |
| 3 | 2005 | 195.3 | 3.12% | 0.916907 | 0.915142 |
| 4 | 2004 | 188.9 | 3.28% | 0.887813 | 0.888487 |
| 5 | 2003 | 184 | 2.59% | 0.865366 | 0.862609 |
| 6 | 2002 | 179.9 | 2.23% | 0.846504 | 0.837484 |
| 7 | 2001 | 177.1 | 1.56% | 0.833531 | 0.813092 |
| 8 | 2000 | 172.2 | 2.77% | 0.811089 | 0.789409 |
| 9 | 1999 | 166.6 | 3.25% | 0.785543 | 0.766417 |
| 10 | 1998 | 163 | 2.16% | 0.768928 | 0.744094 |
| 11 | 1997 | 160.5 | 1.53% | 0.757312 | 0.722421 |
| 12 | 1996 | 156.9 | 2.24% | 0.740699 | 0.701380 |
| 13 | 1995 | 152.4 | 2.87% | 0.720047 | 0.680951 |
| 14 | 1994 | 148.2 | 2.76% | 0.700736 | 0.661118 |
| 15 | 1993 | 144.5 | 2.50% | 0.683667 | 0.641862 |
| 16 | 1992 | 140.3 | 2.91% | 0.664357 | 0.623167 |
| 17 | 1991 | 136.2 | 2.92% | 0.645494 | 0.605016 |
| 18 | 1990 | 130.7 | 4.04% | 0.620439 | 0.587395 |
| 19 | 1989 | 124 | 5.13% | 0.590185 | 0.570286 |
| 20 | 1988 | 118.3 | 4.60% | 0.564248 | 0.553676 |
| 21 | 1987 | 113.6 | 3.97% | 0.542687 | 0.537549 |
| 22 | 1986 | 109.6 | 3.52% | 0.524228 | 0.521893 |
| 23 | 1985 | 107.6 | 1.82% | 0.514833 | 0.506692 |
| 24 | 1984 | 103.9 | 3.44% | 0.497719 | 0.491934 |
| 25 | 1983 | 99.6 | 4.14% | 0.477939 | 0.477606 |
| 26 | 1982 | 96.5 | 3.11% | 0.463512 | 0.463695 |
| 27 | 1981 | 90.9 | 5.80% | 0.438089 | 0.450189 |
| 28 | 1980 | 82.4 | 9.35% | 0.400627 | 0.437077 |
| 29 | 1979 | 72.6 | 11.89% | 0.358044 | 0.424346 |
| 30 | 1978 | 65.2 | 10.19% | 0.324925 | 0.411987 |
| 31 | 1977 | 60.6 | 7.06% | 0.303512 | 0.399987 |
| 32 | 1976 | 56.9 | 6.11% | 0.286047 | 0.388337 |
| 33 | 1975 | 53.8 | 5.45% | 0.271268 | 0.377026 |
| 34 | 1974 | 49.3 | 8.36% | 0.250329 | 0.366045 |
| 35 | 1973 | 44.4 | 9.94% | 0.227698 | 0.355383 |
| 36 | 1972 | 41.8 | 5.86% | 0.215102 | 0.345032 |
| 37 | 1971 | 40.5 | 3.11% | 0.208614 | 0.334983 |
| 38 | 1970 | 38.8 | 4.20% | 0.20021 | 0.325226 |
| 39 | 1969 | 36.7 | 5.41% | 0.18993 | 0.315754 |
| 40 | 1968 | 34.8 | 5.18% | 0.180581 | 0.306557 |
| 41 | 1967 | 33.4 | 4.02% | 0.173598 | 0.297628 |
| 42 | 1966 | 32.4 | 2.99% | 0.168551 | 0.288959 |
| 43 | 1965 | 31.5 | 2.78% | 0.163996 | 0.280543 |
| 44 | 1964 | 31 | 1.59% | 0.161433 | 0.272372 |
| 45 | 1963 | 30.6 | 1.29% | 0.159377 | 0.264439 |
| 46 | 1962 | 30.2 | 1.31% | 0.15732 | 0.256737 |
| 47 | 1961 | 29.9 | 0.99% | 0.155773 | 0.249259 |
| 48 | 1960 | 29.6 | 1.00% | 0.154226 | 0.241999 |
| 49 | 1959 | 29.1 | 1.69% | 0.151664 | 0.234950 |
| 50 | 1958 | 28.9 | 0.69% | 0.150628 | 0.228107 |
| | | | | | |
| | | | 3.89% | | |

| | designation_from | length_dsgnt | length_another | cost_land | cost_other | cost_total | expns_operations | expns_maint | expns_rents | expns_total | GPIS/Mile | Exp/Mile | Exp/GPIS |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2009 | 69 KV | 1467.76 | 80.45 | 4,247,317 | 120,941,887 | 125,189,204 | 4,440,666 | 1,990,807 | - | 6,431,473 | 80,861 | 4,154 | 5.14% |
| 2008 | 69 KV | 1466.26 | 83.97 | 4,049,862 | 107,237,681 | 111,287,593 | 4,158,800 | 2,639,694 | | 6,798,494 | 71,788 | 4,385 | 6.11% |
| 2007 | 69 KV | 1450.82 | 82.5 | 4,031,260 | 99,471,211 | 103,502,471 | 3,954,607 | 1,633,783 | - | 5,588,390 | 67,502 | 3,645 | 5.40% |
| 2006 | 69 KV | 1452.63 | 81.81 | 4,024,341 | 83,651,228 | 87,675,569 | 1,959,953 | 1,095,053 | - | 3,055,006 | 57,138 | 1,991 | 3.48% |
| 2005 | 69 KV | 1463.73 | 81.81 | 3,691,862 | 80,099,347 | 83,791,209 | 2,331,569 | 1,451,297 | - | 3,782,866 | 54,215 | 2,448 | 4.51% |
| 2004 | 69 KV | 1464.62 | 82.49 | 4,005,421 | 78,483,788 | 82,489,209 | 1,362,272 | 1,495,826 | - | 2,858,098 | 53,318 | 1,847 | 3.46% |
| 2003 | 69 KV | 1456.46 | 82.49 | 3,468,069 | 73,909,838 | 77,377,907 | 1,710,343 | 1,229,345 | - | 2,939,688 | 50,280 | 1,910 | 3.80% |
| 5-Year Average (2003-2007) | | | | | | | | | | | 56,491 | 2,368 | 4.13% |
| 5-Year Average (2004-2008) | | | | | | | | | | | 60,792 | 2,863 | 4.59% |
| 5-Year Average (2005-2009) | | | | | | | | | | | 66,301 | 3,325 | 4.93% |

| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|---|---|---|
| 2. TRANSMISSION EXPENSES | | | | | | | |
| Operation | | | | | | | |
| (560) Operation Supervision and Engineering | 4,037,805 | 4,801,285 | 8,919,935 | 2,860,455 | 2,875,787 | 2,746,595 | 3,229,473 |
| (561) Load Dispatching | 821,242 | 11,688 | 139,100 | 36,327 | | | 0 |
| (561.1) Load Dispatch-Reliability | | | 0 | 0 | 527,547 | 844,071 | 1,202,594 |
| (561.2) Load Dispatch-Monitor and Operate Transmission System | | | 0 | 0 | 123,874 | 575,357 | 514,385 |
| (561.3) Load Dispatch-Transmission Service and Scheduling | | | 0 | 108,306 | 4,582,487 | 4,414,355 | 4,612,072 |
| (561.4) Scheduling, System Control and Dispatch Services | | | 0 | 2,684,858 | 3,306,659 | 3,366,840 | 2,817,352 |
| (561.5) Reliability, Planning and Standards Development | | | 0 | 4,123 | 2,075 | 15,897 | 132,166 |
| (561.6) Transmission Service Studies | | | 0 | 0 | | 0 | 17429 |
| (561.7) Generation Interconnection Studies | | | 0 | 0 | | 0 | 7634 |
| (561.8) Reliability, Planning and Standards Development Services | | | 0 | 737,020 | 461,394 | 439,153 | 469,559 |
| (562) Station Expenses | 1,389,513 | 8,336,878 | 6,074,252 | 328,327 | 1,143,867 | 1,168,592 | 1,113,550 |
| (563) Overhead Lines Expenses | 298,772 | 21,900 | 17,987 | 66,688 | 90,014 | 138,902 | 84,599 |
| (564) Underground Lines Expenses | 0 | 0 | 0 | 0 | | 0 | 0 |
| (565) Transmission of Electricity by Others | 221,234 | 506 | 0 | 0 | 187,595 | 709,113 | 1,058,012 |
| (566) Miscellaneous Transmission Expenses | 759,362 | 578,874 | 605,195 | 226,646 | 581,265 | 52,790 | 3,542,760 |
| (567) Rents | 550 | 19 | 60 | 300 | 800 | 1418 | 1647 |
| TOTAL Operation (Enter Total of lines 83 thru 90) | 7,528,478 | 13,751,150 | 15,756,529 | 7,053,050 | 13,883,364 | 14,473,083 | 18,803,232 |
| Maintenance | 0 | 0 | 0 | 0 | | 0 | 0 |
| (568) Maintenance Supervision and Engineering | 496,890 | 844 | 114,043 | 127,055 | 151,927 | 154,305 | 189,370 |
| (569) Maintenance of Structures | 3,507 | 453 | 0 | 0 | | 0 | 0 |
| (569.1) Maintenance of Computer Hardware | | | 0 | 0 | 23,703 | 8,391 | 217,094 |
| (569.2) Maintenance of Computer Software | | | 0 | 0 | 356,363 | 205,605 | 594,056 |
| (569.3) Maintenance of Communication Equipment | | | 0 | 0 | | 0 | 166328 |
| (569.4) Maintenance of Miscellaneous Regional Transmission Plant | | | 0 | 0 | | 0 | 0 |
| (570) Maintenance of Station Equipment | 1,904,427 | 424,480 | 5,186,835 | 7,368,443 | 4,662,168 | 5,207,168 | 3,948,931 |
| (571) Maintenance of Overhead Lines | 3,555,816 | 4,310,156 | 4,118,091 | 3,133,706 | 4,705,385 | 7,666,403 | 5,766,265 |
| (572) Maintenance of Underground Lines | 0 | 0 | 0 | 0 | | 0 | 0 |
| (573) Maintenance of Miscellaneous Transmission Plant | 0 | 0 | 0 | 0 | 22,007 | 0 | 0 |
| TOTAL Maintenance (Enter Total of lines 93 thru 98) | 5,960,640 | 4,735,933 | 9,418,969 | 10,629,204 | 9,921,553 | 13,241,872 | 10,882,044 |
| TOTAL Transmission Expenses (Enter Total of lines 91 and 99) | 13,489,118 | 18,487,083 | 25,175,498 | 17,682,254 | 23,804,917 | 27,714,955 | 29,685,276 |
| Transmission O&M Excluding Account 565 | 13,267,884 | 18,486,577 | 25,175,498 | 17,682,254 | 23,617,322 | 27,005,842 | 28,627,264 |

| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | Include |
|---|---|---|---|---|---|---|---|---|
| 7. ADMINISTRATIVE AND GENERAL EXPENSES | | | | | | | | |
| Operation | | | | | | | | |
| (920) Administrative and General Salaries | 4,059,784 | 6,627,483 | 6,568,501 | 9,470,085 | 13,362,977 | 8,979,732 | 9,980,441 | 1 |
| (921) Office Supplies and Expenses | 3,543,171 | 9,426,437 | 4,315,100 | 2,054,799 | 3,720,639 | 2,188,700 | 696,064 | 1 |
| (Less) (922) Administrative Expenses Transferred-Credit | 275,000 | 530,400 | 574,600 | 194,367 | 307,020 | 330,720 | 300,000 | 1 |
| (923) Outside Services Employed | 1,930,937 | 2,915,369 | 3,725,863 | 2,217,559 | 3,934,775 | 4,321,978 | 4,219,973 | |
| (924) Property Insurance | 5,451,154 | 4,508,418 | 3,043,131 | 2,680,245 | 2,090,861 | 1,803,920 | 1,651,034 | 1 |
| (925) Injuries and Damages | 1,526,791 | 3,073,627 | 4,868,825 | 7,166,110 | 6,109,778 | 6,562,299 | 6,262,522 | 1 |
| (926) Employee Pensions and Benefits | 44,021,936 | 38,717,622 | 39,968,163 | 41,929,023 | 42,387,480 | 40,124,258 | 48,836,999 | 1 |
| (927) Franchise Requirements | 6,426,213 | 6,177,404 | 6,766,118 | 7,053,842 | 3,939,726 | 8,675,145 | 10,230,881 | |
| (928) Regulatory Commission Expenses | 2,454,825 | 4,155,562 | 4,799,592 | 3,694,616 | 3,979,821 | 3,491,791 | 4,522,890 | |
| (929) (Less) Duplicate Charges-Cr. | 6,426,213 | 6,177,404 | 6,766,118 | 7,053,842 | 3,939,726 | 8,675,145 | 10,230,881 | |
| (930.1) General Advertising Expenses | 15,258 | 16,916 | 14,179 | 16,423 | 25,504 | 10,386 | 1,625 | |
| (930.2) Miscellaneous General Expenses | 66,397,140 | 57,797,646 | 46,900,949 | 64,687,551 | 29,820,355 | 36,921,841 | 14,919,172 | |
| (931) Rents | 0 | 0 | 0 | 30 | 83,310 | -131,724 | 0 | |
| TOTAL Operation (Enter Total of lines 151 thru 164) | 129,125,996 | 126,708,680 | 113,629,703 | 133,722,074 | 105,208,480 | 103,942,461 | 90,790,720 | |
| Maintenance | | | | | | 0 | 0 | |
| (935) Maintenance of General Plant | 247,042 | 27,859 | 30,980 | 24,413 | 9,542 | 0 | 0 | 1 |
| TOTAL Admin & General Expenses (Total of lines 165 thru 167) | 129,373,038 | 126,736,539 | 113,660,683 | 133,746,487 | 105,218,022 | 103,942,461 | 90,790,720 | |
| A&G Excluding 923, 927, 928, 929, 930, 931 | 59,124,878 | 62,911,846 | 59,369,300 | 63,519,042 | 67,988,297 | 59,989,629 | 67,727,060 | |
| Ratio A&G Expense to Transmission O&M (excl Acct 565) | | | | | | | | |

| 3. TRANSMISSION PLANT | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 5-Year Average '03-'07 | 5-Year Average '04-'08 | 5-Year Average '05-'09 |
|---|---|---|---|---|---|---|---|---|---|---|
| (350) Land and Land Rights | 25,558,176 | 25,174,684 | 26,757,941 | 27,999,129 | 28,181,017 | 29,442,133 | 29,523,834 | | | |
| (352) Structures and Improvements | 905,719 | 908,383 | 946,431 | 3,402,997 | 3,279,887 | 3,474,235 | 3,767,505 | | | |
| (353) Station Equipment | 159,934,318 | 167,023,303 | 197,589,595 | 214,462,740 | 263,525,599 | 306,207,961 | 338,496,956 | | | |
| (354) Towers and Fixtures | 47,699,147 | 52,394,551 | 54,122,619 | 54,103,769 | 54,375,607 | 55,564,169 | 55,997,346 | | | |
| (355) Poles and Fixtures | 159,507,675 | 161,116,311 | 169,304,422 | 181,996,551 | 200,106,407 | 211,639,272 | 232,218,249 | | | |
| (356) Overhead Conductors and Devices | 143,158,459 | 146,052,335 | 150,902,498 | 160,644,523 | 173,580,323 | 183,314,319 | 200,315,371 | | | |
| (357) Underground Conduit | 0 | 0 | 0 | 0 | | 0 | 0 | | | |
| (358) Underground Conductors and Devices | 110,494 | 110,494 | 110,494 | 110,494 | 110,494 | 110,494 | 110,494 | | | |
| (359) Roads and Trails | 0 | 0 | 0 | 0 | | 0 | 0 | | | |
| (359.1) Asset Retirement Costs for Transmission Plant | 0 | 0 | 0 | 0 | | 18487 | 18487 | | | |
| TOTAL Transmission Plant (Enter Total of lines 48 thru 57) | 536,873,988 | 552,780,061 | 599,734,000 | 642,720,203 | 723,159,334 | 789,771,070 | 860,448,242 | | | |
| Transmission Stations O&M Expense | 3,293,940 | 8,761,358 | 11,261,087 | 7,696,770 | 5,806,035 | 6,375,760 | 5,062,481 | | | |
| Transmission Stations Gross Plant in Service | 159,934,318 | 167,023,303 | 197,589,595 | 214,462,740 | 263,525,599 | 306,207,961 | 338,496,956 | | | |
| Ratio Station O&M to Station Plant in Service | 0.02059558 | 0.052455902 | 0.056992308 | 0.035888612 | 0.022032148 | 0.020821666 | 0.014955765 | 0.037593 | 0.037638 | 0.030138 |

| row_literal | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 5-Year Average '03-'07 | 5-Year Average '04-'08 | 5-Year Average '05-'09 |
|---|---|---|---|---|---|---|---|---|---|---|
| Electric | | | | | | | | | | |
| Operation | | | | | | | | | | |
| Production | 12,756,413 | 17,414,587 | 22,272,583 | 23,832,951 | 24,981,598 | 26,821,862 | 28,791,202 | | | |
| Transmission | 5,315,764 | 6,260,297 | 4,724,655 | 2,633,268 | 2,476,753 | 3,136,707 | 3,741,517 | | | |
| Regional Market | | | | | | 0 | 0 | | | |
| Distribution | 16,852,001 | 16,657,068 | 12,190,975 | 11,895,365 | 7,682,651 | 9,849,495 | 10,347,516 | | | |
| Customer Accounts | 14,713,055 | 12,826,372 | 18,507,097 | 15,767,241 | 14,565,486 | 15,785,173 | 16,712,237 | | | |
| Customer Service and Informational | 5,933,908 | 2,415,043 | 4,590,712 | 4,590,849 | 3,094,445 | 3,032,128 | 2,899,192 | | | |
| Sales | 1,017,437 | 410,652 | 351,896 | 887,383 | 2,249,714 | 3,294,736 | 3,448,623 | | | |
| Administrative and General | 3,602,554 | 6,129,979 | 6,703,847 | 8,696,943 | 15,667,218 | 7,948,633 | 9,906,178 | | | |
| TOTAL Operation (Enter Total of lines 3 thru 10) | 60,191,132 | 62,113,998 | 69,341,765 | 68,304,000 | 70,717,865 | 69,868,734 | 75,846,465 | | | |
| Maintenance | | | | | | 0 | 0 | | | |
| Production | 25,904,372 | 23,428,696 | 20,033,821 | 20,207,192 | 21,101,105 | 20,221,214 | 23,118,350 | | | |
| Transmission | 2,762,281 | 796,107 | 2,011,518 | 4,002,911 | 3,307,927 | 3,658,536 | 3,496,420 | | | |
| Regional Market | | | | | | 0 | 0 | | | |
| Distribution | 10,523,126 | 11,126,795 | 8,771,656 | 14,518,188 | 19,577,622 | 19,079,278 | 24,814,457 | | | |
| Administrative and General | 30 | 12,063 | 16,194 | 8,717 | 993 | 0 | 0 | | | |
| TOTAL Maintenance (Total of lines 13 thru 17) | 39,189,809 | 35,363,661 | 30,833,189 | 38,737,008 | 43,987,647 | 42,959,028 | 51,429,227 | | | |
| Total Operation and Maintenance | | | | | | 0 | 0 | | | |
| Production (Enter Total of lines 3 and 13) | 38,660,785 | 40,843,283 | 42,306,404 | 44,040,143 | 46,082,703 | 47,043,076 | 51,909,552 | | | |
| Transmission (Enter Total of lines 4 and 14) | 8,078,045 | 7,056,404 | 6,736,173 | 6,636,179 | 5,784,680 | 6,795,243 | 7,237,937 | | | |
| Regional Market (Enter Total of Lines 5 and 15) | | | | | | 0 | 0 | | | |
| Distribution (Enter Total of lines 6 and 16) | 27,375,127 | 27,783,863 | 20,962,631 | 26,413,553 | 27,260,273 | 28,928,773 | 35,161,973 | | | |
| Customer Accounts (Transcribe from line 7) | 14,713,055 | 12,826,372 | 18,507,097 | 15,767,241 | 14,565,486 | 15,785,173 | 16,712,237 | | | |
| Customer Service and Informational (Transcribe from line 8) | 5,933,908 | 2,415,043 | 4,590,712 | 4,590,849 | 3,094,445 | 3,032,128 | 2,899,192 | | | |
| Sales (Transcribe from line 9) | 1,017,437 | 410,652 | 351,896 | 887,383 | 2,249,714 | 3,294,736 | 3,448,623 | | | |
| Administrative and General (Enter Total of lines 10 and 17) | 3,602,584 | 6,142,042 | 6,720,041 | 8,705,660 | 15,668,211 | 7,948,633 | 9,906,178 | | | |
| TOTAL Oper. and Maint. (Total of lines 20 thru 27) | 99,380,941 | 97,477,659 | 100,174,954 | 107,041,008 | 114,705,512 | 112,827,762 | 127,275,692 | | | |
| Transmission Labor Ratio (excluding A&G) | 8.43% | 7.73% | 7.21% | 6.75% | 5.84% | 6.48% | 6.17% | 7.19% | 6.80% | 6.49% |
| Allocable A&G | 59,124,878 | 62,911,846 | 59,369,300 | 63,519,042 | 67,988,297 | 59,989,629 | 67,727,060 | | | |
| Transmission-Related A&G | 4,986,653 | 4,860,441 | 4,279,303 | 4,286,594 | 3,971,136 | 3,886,799 | 4,176,589 | | | |
| Transmission O&M (excluding 561, 565) | 12,446,642 | 18,474,889 | 25,036,398 | 14,111,620 | 14,613,286 | 17,350,169 | 18,854,073 | | | |
| A&G % of Transmission O&M | 40.1% | 26.3% | 17.1% | 30.4% | 27.2% | 22.4% | 22.2% | 28.2% | 24.7% | 23.8% |

# Exhibit No. 2

| Line No. | OG&E ATTACHMENT T RATES | Attachment T rates for OG&E as of 1-1-2010 per SPP OATT | Attachment T rates for OMPA as of 6-1-2010 (includes 1-1-2010 rates) | Total Attachment T Rates for OG&E as of 6-1-2010 |
|---|---|---|---|---|
| | | A | B | A+B |
| 1 | OMPA Revenues in the OG&E Zone | | 368,501 | |
| | | | | |
| 2 | 2009 Historic OG&E Zone SPP Average 12-Mo. Peak Demand kW | | 4,899,514.83 | |
| | | | | |
| 3 | Yearly Point-to-Point Rate in $/kW - Year (Line 1 / Line 2) | Rate by Reference | $ 0.0752 | **$ 0.0752** |
| 4 | Monthly Point-to-Point Rate in $/kW - Month (Line 3 / 12) | Rate by Reference | $ 0.0063 | **$ 0.0063** |
| 5 | Weekly Point-to-Point Rate in $/kW - Weekly (Line 3 / 52) | Rate by Reference | $ 0.00145 | **$ 0.0014** |
| 6 | Weekday Point-to-Point Rate in $/kW - Day (Line 5 / 5) | Rate by Reference | $ 0.00029 | **$ 0.0003** |
| 7 | Weekend & Holiday Point-to-Point Rate in $/kW - Day (Line 5 / 7) | Rate by Reference | $ 0.00021 | **$ 0.0002** |
| 8 | Hourly Point-to-Point Rate in $/MW - Hour (Line 7 / 24)*1000 | Rate by Reference | $ 0.0086 | **$ 0.0086** |

**ATTACHMENT H**
**Annual Transmission Revenue Requirement For Network Integration Transmission Service**

**SECTION I: General Requirements**

1. The Zonal Annual Transmission Revenue Requirement within each Zone for purposes of determining the charges under Schedule 9, Network Integration Transmission Service, is specified in Column (3) of Table 1. The Base Plan Zonal Annual Transmission Revenue Requirement used to determine the zonal charges under Schedule 11 is specified in Column (4) of Table 1. The amount of Zonal Annual Transmission Revenue Requirement and Base Plan Zonal Annual Transmission Revenue Requirement that is included in Columns (3) and (4) and reallocated to the Region-wide Annual Transmission Revenue Requirement, in accordance with Attachment J, is specified in Column (5) of Table 1.

Table 1

| (1) Zone | (2) | (3) Zonal ATRR | (4) Base Plan Zonal ATRR | (5) ATRR Reallocated to Balanced Portfolio Region-wide ATRR |
|---|---|---|---|---|
| 1 | American Electric Power –West (Total) | $151,662,031 | $8,500,914 | $0 |
| | American Electric Power (Public Service Company of Oklahoma and Southwestern Electric Power Company) See Section II.3 | $147,162,500 | | |
| | East Texas Electric Cooperative, Inc. | $2,733,879 | | |
| | Tex-La Electric Cooperative of Texas, Inc. | $588,874 | | |
| | Deep East Texas Electric Cooperative, Inc. | $428,131 | | |
| | Oklahoma Municipal Power Authority | $748,647 | | |
| 2 | Reserved for Future Use | | | |
| 3 | City Utilities of Springfield, Missouri | $8,651,509 | ($5,500) | $0 |
| 4 | Empire District Electric Company | $14,075,000 | ($18,001) | $0 |
| 5 | Grand River Dam Authority (Est.) | $24,589,256 | ($92,135) | $0 |
| 6 | Kansas City Power & Light Company | $32,883,232 | $2,594,753 | $0 |
| 7 | Oklahoma Gas & Electric (Total) | $81,413,722 | $1,951,309 | $0 |
| | Oklahoma Gas & Electric | $81,045,221 | | |
| | Oklahoma Municipal Power Authority | $368,501 | | |

| | | | | | |
|---|---|---|---|---|---|
| 2 | Reserved for Future Use | | | | |
| 3 | City Utilities of Springfield, Missouri | $8,651,509 | ($5,500) | | $0 |
| 4 | Empire District Electric Company | $14,075,000 | ($18,001) | | $0 |
| 5 | Grand River Dam Authority (Est.) | $24,589,256 | ($92,135) | | $0 |
| 6 | Kansas City Power & Light Company | $32,883,232 | $2,594,753 | | $0 |
| 7 | Oklahoma Gas & Electric (Total) | $81,413,722 | $1,951,309 | | $0 |
| | Oklahoma Gas & Electric | $81,045,221 | | | |
| | Oklahoma Municipal Power Authority | $368,501 | | | |
| 8 | Midwest Energy, Inc. | $4,197,347 | $131,517 | | $0 |
| 9 | KCP&L Greater Missouri Operations Company | $30,055,990 | $429,141 | | $0 |
| 10 | Southwestern Power Administration | $13,107,700 | $0 | | $0 |
| 11 | Southwestern Public Service | $98,750,173 | $1,264,678 | | $0 |
| 12 | Sunflower Electric Corporation | $14,484,045 | $320,628 | | $0 |
| 13 | Western Farmers Electric Cooperative | $20,719,639 | $429,314 | | $0 |
| 14 | Westar Energy, Inc. (Kansas Gas & Electric and Westar Energy) | $115,503,530 | $11,399,863 | | $0 |
| 15 | Mid-Kansas Electric Cooperative (Total) | $16,212,145 | $305,944 | | $0 |
| 15a | Mid-Kansas Electric Cooperative | $15,142,441 | | | |
| 15b | ITC Great Plains | $1,069,704 | | | |
| 16 | Lincoln Electric System | $14,168,176 | $101,419 | | $0 |
| 17 | Nebraska Public Power District | $46,111,083 | $13,314,707 | | $0 |
| 18 | Omaha Public Power District | $35,176,688 | $1,101,878 | | $0 |
| 19 | Total | | | | $0 |

**OG&E Electric Services**

**Rate Sheet For Point-To-Point Transmission Service**

These Point-to-Point charges shall be calculated using the Existing Zonal Annual Transmission Revenue Requirement ("ATRR") for the OG&E rate zone as specified on Line 7, Column 3, Section 1 of Attachment H of this Tariff, which is the sum of Existing Zonal ATRRs listed in Column 3, Section 1 of Attachment H as being in the OG&E rate zone. As a result of the rate formula set forth in Attachment H, Addendum 2-A ("OG&E Formula Rate") of this Tariff and the OG&E Formula Rate Implementation Protocols set forth in Attachment H, Addendum 2-B of the Tariff, the Existing Zonal ATRR listed on Line 7a, Column 3, Section 1 of Attachment H of this Tariff shall be posted on the SPP website by May 25 of each calendar year and shall be effective on July 1 of such year.

**Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below:

1. Yearly delivery: the Existing Zonal ATRR listed on Line 7, Column 3, Section 1 of Attachment H of this Tariff divided by the 12-CP divisor identified on page 1, line 5 of the OG&E Formula Rate /kW of Reserved Capacity per year plus $0.0752/kW for Oklahoma Municipal Power Authority.
2. Monthly delivery: the yearly charge divided by 12 for the $/kW of Reserved Capacity per month plus $0.0063/kW for Oklahoma Municipal Power Authority.
3. Weekly delivery: the yearly charge divided by 52 for the $/kW Reserved Capacity per week plus $0.0014/kW for Oklahoma Municipal Power Authority.
4. Weekday delivery: the weekly charge divided by 5 for the $/kW of Reserved Capacity per day plus $0.0003/kW for Oklahoma Municipal Power Authority.

5. Weekend and Holiday delivery: the weekly delivery charge divided by 7 for the $/kW of Reserved Capacity per day plus $0.0002/kW for Oklahoma Municipal Power Authority.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

**Non-Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

1. Monthly delivery: the yearly delivery charge for Firm Point-to-Point service specified above divided by 12 for the $/kW of Reserved Capacity per month plus $0.0063/kW for Oklahoma Municipal Power Authority.

2. Weekly delivery: the yearly delivery charge for Firm Point-to-Point service specified above divided by 52 for the $/kW of Reserved Capacity per week plus $0.0014/kW for Oklahoma Municipal Power Authority.

3. Weekday delivery: the weekly delivery charge divided by 5 for the $/kW of Reserved Capacity per day plus $0.0003/kW for Oklahoma Municipal Power Authority.

4. Weekend and Holiday delivery: the weekly delivery charge divided by 7 for the $/kW of Reserved Capacity per day plus $0.0002/kW for Oklahoma Municipal Power Authority.

5. Hourly delivery: the weekend and holiday delivery charge divided by 24 for the $/MW of Reserved Capacity per hour plus $0.0086/kW for Oklahoma Municipal Power Authority.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Weekend and Holiday Delivery rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

**ATTACHMENT H**

**Annual Transmission Revenue Requirement For Network Integration Transmission Service**

**SECTION I: General Requirements**

1. The Zonal Annual Transmission Revenue Requirement within each Zone for purposes of determining the charges under Schedule 9, Network Integration Transmission Service, is specified in Column (3) of Table 1. The Base Plan Zonal Annual Transmission Revenue Requirement used to determine the zonal charges under Schedule 11 is specified in Column (4) of Table 1. The amount of Zonal Annual Transmission Revenue Requirement and Base Plan Zonal Annual Transmission Revenue Requirement that is included in Columns (3) and (4) and reallocated to the Region-wide Annual Transmission Revenue Requirement, in accordance with Attachment J, is specified in Column (5) of Table 1.

Table 1

| (1) Zone | (2) | (3) Zonal ATRR | (4) Base Plan Zonal ATRR | (5) ATRR Reallocated to Balanced Portfolio Region-wide ATRR |
|---|---|---|---|---|
| 1 | American Electric Power –West (Total) | $151,662,031 | $8,500,914 | $0 |
| | American Electric Power (Public Service Company of Oklahoma and Southwestern Electric Power Company) See Section II.3 | $147,162,500 | | |
| | East Texas Electric Cooperative, Inc. | $2,733,879 | | |
| | Tex-La Electric Cooperative of Texas, Inc. | $588,874 | | |
| | Deep East Texas Electric Cooperative, Inc. | $428,131 | | |
| | Oklahoma Municipal Power Authority | $748,647 | | |
| 2 | Reserved for Future Use | | | |
| 3 | City Utilities of Springfield, Missouri | $8,651,509 | ($5,500) | $0 |
| 4 | Empire District Electric Company | $14,075,000 | ($18,001) | $0 |
| 5 | Grand River Dam Authority (Est.) | $24,589,256 | ($92,135) | $0 |
| 6 | Kansas City Power & Light Company | $32,883,232 | $2,594,753 | $0 |

| | | | | |
|---|---|---|---|---|
| 7 | Oklahoma Gas & Electric (Total) | $~~81,151,489~~81,413,722 | $1,951,309 | $0 |
| | Oklahoma Gas & Electric | $81,045,221 | | |
| | Oklahoma Municipal Power Authority | $~~106,268~~368,501 | | |

| | | | | | |
|---|---|---|---|---|---|
| 2 | Reserved for Future Use | | | | |
| 3 | City Utilities of Springfield, Missouri | $8,651,509 | ($5,500) | | $0 |
| 4 | Empire District Electric Company | $14,075,000 | ($18,001) | | $0 |
| 5 | Grand River Dam Authority (Est.) | $24,589,256 | ($92,135) | | $0 |
| 6 | Kansas City Power & Light Company | $32,883,232 | $2,594,753 | | $0 |
| 7 | Oklahoma Gas & Electric (Total) | $~~81,151,489~~81,413,722 | $1,951,309 | | $0 |
| | Oklahoma Gas & Electric | $81,045,221 | | | |
| | Oklahoma Municipal Power Authority | $~~106,268~~368,501 | | | |
| 8 | Midwest Energy, Inc. | $4,197,347 | $131,517 | | $0 |
| 9 | KCP&L Greater Missouri Operations Company | $30,055,990 | $429,141 | | $0 |
| 10 | Southwestern Power Administration | $13,107,700 | $0 | | $0 |
| 11 | Southwestern Public Service | $98,750,173 | $1,264,678 | | $0 |
| 12 | Sunflower Electric Corporation | $14,484,045 | $320,628 | | $0 |
| 13 | Western Farmers Electric Cooperative | $20,719,639 | $429,314 | | $0 |
| 14 | Westar Energy, Inc. (Kansas Gas & Electric and Westar Energy) | $115,503,530 | $11,399,863 | | $0 |
| 15 | Mid-Kansas Electric Cooperative (Total) | $16,212,145 | $305,944 | | $0 |
| 15a | Mid-Kansas Electric Cooperative | $15,142,441 | | | |
| 15b | ITC Great Plains | $1,069,704 | | | |
| 16 | Lincoln Electric System | $14,168,176 | $101,419 | | $0 |
| 17 | Nebraska Public Power District | $46,111,083 | $13,314,707 | | $0 |
| 18 | Omaha Public Power District | $35,176,688 | $1,101,878 | | $0 |
| 19 | Total | | | | $0 |

**OG&E Electric Services**

**Rate Sheet For Point-To-Point Transmission Service**

These Point-to-Point charges shall be calculated using the Existing Zonal Annual Transmission Revenue Requirement ("ATRR") for the OG&E rate zone as specified on Line 7, Column 3, Section 1 of Attachment H of this Tariff, which is the sum of Existing Zonal ATRRs listed in Column 3, Section 1 of Attachment H as being in the OG&E rate zone. As a result of the rate formula set forth in Attachment H, Addendum 2-A ("OG&E Formula Rate") of this Tariff and the OG&E Formula Rate Implementation Protocols set forth in Attachment H, Addendum 2-B of the Tariff, the Existing Zonal ATRR listed on Line 7a, Column 3, Section 1 of Attachment H of this Tariff shall be posted on the SPP website by May 25 of each calendar year and shall be effective on July 1 of such year.

**Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below:

1. Yearly delivery: the Existing Zonal ATRR listed on Line 7, Column 3, Section 1 of Attachment H of this Tariff divided by the 12-CP divisor identified on page 1, line 5 of the OG&E Formula Rate /kW of Reserved Capacity per year plus $0.0752~~.0217~~/kW for Oklahoma Municipal Power Authority.
2. Monthly delivery: the yearly charge divided by 12 for the $/kW of Reserved Capacity per month plus $0.0063~~.0018~~/kW for Oklahoma Municipal Power Authority.
3. Weekly delivery: the yearly charge divided by 52 for the $/kW Reserved Capacity per week plus $0.0014~~.00042~~/kW for Oklahoma Municipal Power Authority.
4. Weekday delivery: the weekly charge divided by 5 for the $/kW of Reserved Capacity per day plus $0.0003~~.00008~~/kW for Oklahoma Municipal Power Authority.

5. Weekend and Holiday delivery: the weekly delivery charge divided by 7 for the $/kW of Reserved Capacity per day plus $0.0002~~.00006~~/kW for Oklahoma Municipal Power Authority.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

**Non-Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

1. Monthly delivery: the yearly delivery charge for Firm Point-to-Point service specified above divided by 12 for the $/kW of Reserved Capacity per month plus $0.0063~~.0018~~/kW for Oklahoma Municipal Power Authority.

2. Weekly delivery: the yearly delivery charge for Firm Point-to-Point service specified above divided by 52 for the $/kW of Reserved Capacity per week plus $0.0014~~.00042~~/kW for Oklahoma Municipal Power Authority.

3. Weekday delivery: the weekly delivery charge divided by 5 for the $/kW of Reserved Capacity per day plus $0.0003~~.00008~~/kW for Oklahoma Municipal Power Authority.

4. Weekend and Holiday delivery: the weekly delivery charge divided by 7 for the $/kW of Reserved Capacity per day plus $0.0002~~.00006~~/kW for Oklahoma Municipal Power Authority.

5. Hourly delivery: the weekend and holiday delivery charge divided by 24 for the $/MW of Reserved Capacity per hour plus $0.0086~~.0025~~/kW for Oklahoma Municipal Power Authority.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Weekend and Holiday Delivery rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

**ATTACHMENT H**
**ANNUAL TRANSMISSION REVENUE REQUIREMENT FOR NETWORK INTEGRATION TRANSMISSION SERVICE**

**SECTION I: General Requirements**

1. The Zonal Annual Transmission Revenue Requirement within each Zone for purposes of determining the charges under Schedule 9, Network Integration Transmission Service, is specified in Column (3) of Table 1. The Base Plan Zonal Annual Transmission Revenue Requirement used to determine the zonal charges under Schedule 11 for Base Plan Upgrades issued a Notification to Construct (NTC) prior to June 19, 2010 is specified in Column (4) of Table 1. The Base Plan Zonal Annual Transmission Revenue Requirement used to determine the zonal charges under Schedule 11 for Base Plan Upgrades issued an NTC on or after June 19, 2010 is specified in Column (5) of Table 1. The amount of Zonal Annual Transmission Revenue Requirement and Base Plan Zonal Annual Transmission Revenue Requirement that is included in Columns (3), (4), and (5) and reallocated to the Region-wide Annual Transmission Revenue Requirement, in accordance with Attachment J, is specified in Column (6) of Table 1.

Table 1

| (1) Zone | (2) | (3) Zonal ATRR | (4) Base Plan Zonal ATRR | (5) Base Plan Zonal ATRR after June 19, 2010 | (6) ATRR Reallocated to Balanced Portfolio Region-wide ATRR |
|---|---|---|---|---|---|
| 1 | American Electric Power –West (Total) | $151,662,031 | $8,500,914 | | $0 |
| | American Electric Power (Public Service Company of Oklahoma and Southwestern Electric Power Company) See Section II.3 | $147,162,500 | | | |
| | East Texas Electric Cooperative, Inc. | $2,733,879 | | | |
| | Tex-La Electric Cooperative of Texas, Inc. | $588,874 | | | |
| | Deep East Texas Electric Cooperative, Inc. | $428,131 | | | |

| | | | | | |
|---|---|---|---|---|---|
| | Oklahoma Municipal Power Authority | $748,647 | | | |
| 2 | Reserved for Future Use | | | | |
| 3 | City Utilities of Springfield, Missouri | $8,651,509 | ($5,500) | | $0 |
| 4 | Empire District Electric Company | $14,075,000 | ($18,001) | | $0 |
| 5 | Grand River Dam Authority (Est.) | $24,589,256 | ($92,135) | | $0 |
| 6 | Kansas City Power & Light Company | $32,883,232 | $2,594,753 | | $0 |
| 7 | Oklahoma Gas & Electric (Total) | $81,413,722 | $1,951,309 | | $0 |
| | Oklahoma Gas & Electric | $81,045,221 | | | |
| | Oklahoma Municipal Power Authority | $368,501 | | | |
| 8 | Midwest Energy, Inc. | $4,197,347 | $131,517 | | $0 |
| 9 | KCP&L Greater Missouri Operations Company | $30,055,990 | $429,141 | | $0 |
| 10 | Southwestern Power Administration | $13,107,700 | $0 | | $0 |
| 11 | Southwestern Public Service | $98,750,173 | $1,264,678 | | $0 |
| 12 | Sunflower Electric Corporation | $14,484,045 | $320,628 | | $0 |
| 13 | Western Farmers Electric Cooperative | $20,719,639 | $429,314 | | $0 |
| 14 | Westar Energy, Inc. (Kansas Gas & Electric and Westar Energy) | $115,503,530 | $11,399,863 | | $0 |
| 15 | Mid-Kansas Electric Cooperative (Total) | $16,212,145 | $305,944 | | $0 |
| 15a | Mid-Kansas Electric Cooperative | $15,142,441 | | | |
| 15b | ITC Great Plains | $1,069,704 | | | |
| 16 | Lincoln Electric System | $14,168,176 | $101,419 | | $0 |
| 17 | Nebraska Public Power District | $46,111,083 | $13,314,707 | | $0 |
| 18 | Omaha Public Power District | $35,176,688 | $1,101,878 | | $0 |
| 19 | Total | | | | $0 |

2. For the purposes of determining the Region-wide Charges under Schedule 11, the Region-wide Annual Transmission Revenue Requirement, as shown in Line 5 of Table 2, shall be the sum of (i) the Base Plan Region-wide Annual Transmission Revenue Requirement, and (ii) the total Balanced Portfolio Region-wide Annual Transmission Revenue Requirements.

Table 2

| | | |
|---|---|---|
| 1 | Base Plan Region-wide ATRR (NTC prior to June 19, 2010) | $20,492,017 |
| 2 | Base Plan Region-wide ATRR (NTC on or after June 19, 2010) | |
| 3 | Total Balanced Portfolio Region-wide ATRR Total, Column (6), Table 1 | $0 |
| 4 | Balanced Portfolio Region Wide ATRR | $1,175,607 |
| 5 | Region-wide ATRR (Line 1 + Line 2 + Line 3 + Line 4) | $21,667,624 |

3. The revenue requirements stated in this Attachment H shall not be changed absent a filing with the Commission, accompanied by all necessary cost support.

4. New or amended revenue requirements in this Attachment H shall not be filed with the Commission by the Transmission Provider unless such revenue requirements have been provided by or for a Transmission Owner. Such revenue requirements shall have been accepted or approved by the applicable regulatory or governing authority except in the event of a simultaneous filing with the Commission by the Transmission Owner and Transmission Provider.

5. If a Transmission Owner has a Commission approved formula rate, the successful completion of its approved annual formula rate update procedures shall constitute regulatory acceptance sufficient to authorize the Transmission Provider to file with the Commission to update that Transmission Owner’s revenue requirements. The Transmission Provider shall follow any special procedures related to updating a Transmission Owner’s revenue requirements as outlined in Section II of this Attachment.

6. The Transmission Provider shall allocate the accepted or approved revenue requirement associated with a Base Plan Upgrade, in accordance with Attachment J to this Tariff, to the Base Plan Region-wide Annual Transmission Revenue Requirement in Table 2 above and to the appropriate Base Plan Zonal Annual Transmission Revenue Requirements in Column (4) or (5) as appropriate of Table 1 above.

**SECTION II: Transmission Owner-Specific Requirements**

**1. Westar Energy, Inc.**

For Westar Energy, Inc., the annual transmission revenue requirement for purposes of the Network Integration Transmission Service, as specified on line 7b and 14, Column 3 of Section 1 of this Attachment H, shall be calculated using the rate formula set forth in

Attachment H Addendum 3 of this Tariff ("Westar Formula Rate"). The results of the formula calculation shall be posted on the Transmission Provider's website and in an accessible location on Westar's OASIS website by October 15 of each calendar year and shall be effective on January 1 of the following year. The Zonal Revenue Requirement to be used for the Westar zone Column (3) of Table 1 of this Attachment H shall be calculated by taking the SPP Zonal Revenue Requirement as identified as Projected Net Revenue Requirements page, line 10; of the Westar Formula Rate; less the sum of the current year's revenue requirement associated with all transmission facilities owned by Westar in other pricing zones when such revenue requirements are included in the revenue requirements specified in the Westar Formula Rate on the Projected Net Revenue Requirements page, line 10; plus the previous calendar year's total firm Point-to-Point transmission revenue allocated to Westar under Attachment L provided such Point-to-Point transmission revenue is deducted from Westar's Annual Transmission Revenue Requirement under Section 34.1 of this Tariff.

The revenue requirements for Base Plan Funded projects owned by Westar shall be the amount contained on the Projected Net Revenue Requirements page, line 9 of the Westar Formula Rate.

The revenue requirements for Balanced Portfolio funded projects owned by Westar shall be the amount contained on the Projected Net Revenue Requirements page, line 9a of the Westar Formula Rate. Following its posting of the updated revenue requirements by October 15 of each calander year as discussed above, the Transmission Provider shall immediately update the various Base Plan and Balanced Portfolio funded costs and allocations contained in the Tariff and file them with the Commission no later than December 15 of each calander year with a requested effective date of January 1.

**2. Southwestern Public Service**

For Southwestern Public Service Company ("SPS"), the Existing Zonal Annual Transmission Revenue Requirement ("ATRR") for Zone 11 in column 3, Section 1 of this Attachment H shall be calculated using: (1) the formula rate as specified in

Attachment O – SPS of the Xcel Energy Operating Companies Joint Open Access Transmission Tariff ("Xcel Energy OATT"), (2) will be equal to the Current Year Revenue Requirement with True Up as specified on line 4, page 1 of Attachment O – SPS of the Xcel Energy OATT, (3) and subject to the Implementation Procedures in Appendix 1 of Attachment O – SPS of the Xcel Energy OATT. The results of the formula calculation shall be posted on the SPP website and in an accessible location on SPS's OASIS website by May 25 of each calendar year and shall be effective on July 1 of such year. The Existing Zonal ATRR for Zone 11, column 3, Table 1 of this Attachment H shall not be subject to adjustment pursuant to section 34.1 for the previous calendar year's total firm Point-to-Point transmission revenue allocated to SPS under Attachment L when determining the monthly zonal Demand Charge for Zone 11.

**3. American Electric Power**

The American Electric Power Annual Transmission Revenue Requirement for purposes of the Network Integrated Transmission Service shall be (i) calculated using the formula rate set forth in Addendum 1 to this Attachment H, (ii) posted on the SPP website by May 25 of each calendar year, and (iii) effective on July 1 of such year.

**4. Nebraska Public Power District: Formula Rate Implementation Protocols and Formula Rate Template**

**Section 1. Annual Updates**

The Formula Rate Template set forth in Addendum 7 and these Formula Rate Implementation Protocols ("Protocols") together comprise the filed rate by Southwest Power Pool ("SPP") for calculating Nebraska Public Power District's ("NPPD") Zonal Annual Transmission Revenue Requirement ("Zonal ATRR") for Transmission Service under the SPP OATT. NPPD must follow the instructions specified in the Formula Rate Template to calculate the rates for NITS, the rates for Schedule 1 Service, the rates for Point-to-Point services over facilities in SPP Zone 17 and the ATRR for Base Plan Upgrades and other network upgrades.

The initial Zonal ATRR and the initial rates will be in effect for a partial year from the effective date of NPPD's transfer of operational control of its transmission facilities to SPP until December 31, 2009. The Formula Rate shall be recalculated each year with the resulting rates to become effective on and after January 1 of each year through December 31 of such year. The resulting rates implemented each January 1 will be subject to review and true-up as further provided in the Protocols.

No later than September 1, 2009 and September 1 of each year thereafter, NPPD, upon initial approval of NPPD's Board of Directors, shall determine its projected Zonal ATRR, and resulting rates for the following calendar year, in accordance with the Protocols and the Formula Rate Template of Addendum 7 of this Attachment H. NPPD will post such determination on its website and will send such determination to SPP for posting on the publicly accessible portion of the SPP website. Contemporaneously, NPPD shall provide notice to its wholesale customers and interested parties of its projected Zonal ATRR and resultant rates, including all inputs in sufficient detail to identify the components of NPPD's Zonal ATRR. Commencing September 1 of each year, such parties may submit written questions and answers will be provided by NPPD within ten (10) business days. NPPD will post on the NPPD website responses to any such inquiries and information regarding frequently asked questions. No later than September 30 of each year, NPPD will hold a meeting with wholesale customers and interested parties to explain the formula rate input projections and provide an opportunity for oral and written comments. Written comments must be submitted no later than October 30. No later than December 15 of each year, NPPD will provide to SPP for posting on the publicly accessible portion of the SPP website and submit to the Commission in an informational filing, NPPD's final Zonal ATRR and resulting rates to become effective January 1 of the following calendar year.

**Section 2. True-Up Adjustments**

On or before June 1, 2010 and on or before June 1 of each year thereafter, NPPD will calculate the True-Up Adjustment with supporting data inputs in sufficient detail to identify the projected and actual cost of each element of NPPD's Zonal ATRR and actual revenues. NPPD will reflect the True-Up Adjustment as a line item in its Zonal ATRR noticed on September 1, 2010 and in the ATRR noticed on September 1 of each year thereafter. The True-up Adjustment will be determined in the following manner:

(1) Actual transmission revenues associated with transactions included in the Divisor of the Formula Rate Template for the previous calendar year will be compared to the Actual Zonal ATRR. The Actual Zonal ATRR shall be calculated in accordance with the Formula Rate Template and actual data for the previous year. For each year, NPPD will complete and make available for review, on its website, actual data as recorded in accordance with FERC's Uniform System of Accounts, including an affidavit of the Chief Financial Officer of NPPD attesting to the accuracy of the cost and revenue data set forth therein. In addition, NPPD shall provide an explanation of any change in accounting policies and practices that NPPD employed during the preceding twelve-month period that affect transmission accounts or the allocation of common costs to transmission. Actual costs incurred during the applicable calendar year will be compared to actual revenues recovered during such period to determine whether there was any under-recovery or over-recovery. The True-up Adjustment and related calculations shall be posted no later than June 1 on NPPD's website and on the publicly accessible portion of the SPP website. Commencing June 1 of each year, any interested party may submit written questions and answers will be provided by NPPD within ten (10) business days. NPPD will post on the NPPD website responses to any such inquiries and information regarding frequently asked questions. Written comments must be submitted no later than July 15 of each year. NPPD will post on the NPPD website the final True-up Adjustment no later than September 1 of each year.

(2) Interest on any over-recovery or under-recovery of the Zonal ATRR shall be based on the interest rate equal to NPPD's actual short-term debt costs, capped at the applicable interest rate set forth in 18 C.F.R. §35.19a of the Commission's regulations. The interest rate equal to NPPD's actual short-term debt costs shall be calculated in accordance with Worksheet K to the Formula Rate Template.

(3) The Zonal ATRR for transmission services for the following year shall be the sum of the projected Zonal ATRR for the following year and a True-up Adjustment for the previous year, including interest as explained above.

**Section 3. NPPD Formula Rate Blank Template**

NPPD's Formula Rate Template to be used for calculating the Zonal ATRR and NITS rates, Schedule 1 rates, Point-to-Point rates, ATRR Base Plan Upgrade and other network upgrades set forth in Attachment H – Addendum 7. The provisions of such Formula Rate Template are not subject to changes except through a filing under Section 205 or 206 of the Federal Power Act.

**5. Omaha Public Power District**

For the Omaha Public Power District (OPPD), the annual transmission revenue requirement for purposes of the Network Integration Transmission Service, Base Plan Upgrades, Scheduling, System Control, and Dispatch Service, and for the determination of Point-to-Point rates shall be calculated using the Formula-based Rate Template set forth in Attachment H - Addendum 8 of this Tariff. The annual transmission revenue requirement and rates calculated pursuant to the formula-based rate template shall be revised annually. The results of such annual calculations shall be posted on OPPD's OASIS website and in a publically accessible location on the Transmission Provider's website by May 15 of each calendar year. Written comments will be accepted until June 15 and the annual revenue requirement and rates shall become effective from August 1 of such year through July 31 of the following year. Initially, the rates calculated pursuant to the formula-based rate template and incorporated into this SPP OATT will be in place through July 31, 2009.

**6. Lincoln Electric System**

For the Lincoln Electric System (LES), the annual transmission revenue requirement for purposes of Network Integration Transmission Service, Base Plan Upgrades, Scheduling, System Control and Dispatch Service, and for the determination of Point-to-Point rates shall be calculated using the Formula Rate Template set forth in Attachment H - Addendum 6 of this Tariff. The annual transmission revenue requirement and rates calculated pursuant to the formula rate template shall be revised annually. The results of such annual calculations shall be posted on LES' OASIS website and in a publicly accessible location on the Transmission Provider's website by May 15 of each calendar year. Written comments will be accepted until June 15 and the annual revenue requirement and rates shall become effective from August 1 of such year through July 31 of the following year. Supporting data for completion of the formula rate template will be available from LES upon request. Initially, the rates calculated pursuant to the formula-based rate template and incorporated into this SPP OATT will be in place through July 31, 2009.

**OG&E Electric Services**

**Rate Sheet for Point-To-Point Transmission Service**

These Point-to-Point charges shall be calculated using the Existing Zonal Annual Transmission Revenue Requirement ("ATRR") for the OG&E rate zone as specified on Line 7, Column 3, Section 1 of Attachment H of this Tariff, which is the sum of Existing Zonal ATRRs listed in Column 3, Section 1 of Attachment H as being in the OG&E rate zone. As a result of the rate formula set forth in Attachment H, Addendum 2-A ("OG&E Formula Rate") of this Tariff and the OG&E Formula Rate Implementation Protocols set forth in Attachment H, Addendum 2-B of the Tariff, the Existing Zonal ATRR listed on Line 7a, Column 3, Section 1 of Attachment H of this Tariff shall be posted on the SPP website by May 25 of each calendar year and shall be effective on July 1 of such year.

**Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below:

1. Yearly delivery: the Existing Zonal ATRR listed on Line 7, Column 3, Section 1 of Attachment H of this Tariff divided by the 12-CP divisor identified on page 1, line 5 of the OG&E Formula Rate /kW of Reserved Capacity per year plus $0.0752/kW for Oklahoma Municipal Power Authority.

2. Monthly delivery: the yearly charge divided by 12 for the $/kW of Reserved Capacity per month plus $0.0063/kW for Oklahoma Municipal Power Authority.

3. Weekly delivery: the yearly charge divided by 52 for the $/kW Reserved Capacity per week plus $0.0014/kW for Oklahoma Municipal Power Authority.

4. Weekday delivery: the weekly charge divided by 5 for the $/kW of Reserved Capacity per day plus $0.0003/kW for Oklahoma Municipal Power Authority.

5. Weekend and Holiday delivery: the weekly delivery charge divided by 7 for the $/kW of Reserved Capacity per day plus $0.0002/kW for Oklahoma Municipal Power Authority.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

**Non-Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

1. Monthly delivery: the yearly delivery charge for Firm Point-to-Point service specified above divided by 12 for the $/kW of Reserved Capacity per month plus $0.0063/kW for Oklahoma Municipal Power Authority.

2. Weekly delivery: the yearly delivery charge for Firm Point-to-Point service specified above divided by 52 for the $/kW of Reserved Capacity per week plus $0.0014/kW for Oklahoma Municipal Power Authority.

3. Weekday delivery: the weekly delivery charge divided by 5 for the $/kW of Reserved Capacity per day plus $0.0003/kW for Oklahoma Municipal Power Authority.

4. Weekend and Holiday delivery: the weekly delivery charge divided by 7 for the $/kW of Reserved Capacity per day plus $0.0002/kW for Oklahoma Municipal Power Authority.

5. Hourly delivery: the weekend and holiday delivery charge divided by 24 for the $/MW of Reserved Capacity per hour plus $0.0086/kW for Oklahoma Municipal Power Authority.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Weekend and Holiday Delivery rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

**ATTACHMENT H**
**ANNUAL TRANSMISSION REVENUE REQUIREMENT FOR NETWORK INTEGRATION TRANSMISSION SERVICE**

**SECTION I: General Requirements**

1. The Zonal Annual Transmission Revenue Requirement within each Zone for purposes of determining the charges under Schedule 9, Network Integration Transmission Service, is specified in Column (3) of Table 1. The Base Plan Zonal Annual Transmission Revenue Requirement used to determine the zonal charges under Schedule 11 for Base Plan Upgrades issued a Notification to Construct (NTC) prior to June 19, 2010 is specified in Column (4) of Table 1. The Base Plan Zonal Annual Transmission Revenue Requirement used to determine the zonal charges under Schedule 11 for Base Plan Upgrades issued an NTC on or after June 19, 2010 is specified in Column (5) of Table 1. The amount of Zonal Annual Transmission Revenue Requirement and Base Plan Zonal Annual Transmission Revenue Requirement that is included in Columns (3), (4), and (5) and reallocated to the Region-wide Annual Transmission Revenue Requirement, in accordance with Attachment J, is specified in Column (6) of Table 1.

Table 1

| (1) Zone | (2) | (3) Zonal ATRR | (4) Base Plan Zonal ATRR | (5) Base Plan Zonal ATRR after June 19, 2010 | (6) ATRR Reallocated to Balanced Portfolio Region-wide ATRR |
|---|---|---|---|---|---|
| 1 | American Electric Power –West (Total) | $151,662,031 | $8,500,914 | | $0 |
| | American Electric Power (Public Service Company of Oklahoma and Southwestern Electric Power Company) See Section II.3 | $147,162,500 | | | |
| | East Texas Electric Cooperative, Inc. | $2,733,879 | | | |
| | Tex-La Electric Cooperative of Texas, Inc. | $588,874 | | | |
| | Deep East Texas Electric Cooperative, Inc. | $428,131 | | | |

| | | | | | |
|---|---|---|---|---|---|
| | Oklahoma Municipal Power Authority | $748,647 | | | |
| 2 | Reserved for Future Use | | | | |
| 3 | City Utilities of Springfield, Missouri | $8,651,509 | ($5,500) | | $0 |
| 4 | Empire District Electric Company | $14,075,000 | ($18,001) | | $0 |
| 5 | Grand River Dam Authority (Est.) | $24,589,256 | ($92,135) | | $0 |
| 6 | Kansas City Power & Light Company | $32,883,232 | $2,594,753 | | $0 |
| 7 | Oklahoma Gas & Electric (Total) | $81,413,722~~$81,151,489~~ | $1,951,309 | | $0 |
| | Oklahoma Gas & Electric | $81,045,221 | | | |
| | Oklahoma Municipal Power Authority | $368,501~~$106,268~~ | | | |
| 8 | Midwest Energy, Inc. | $4,197,347 | $131,517 | | $0 |
| 9 | KCP&L Greater Missouri Operations Company | $30,055,990 | $429,141 | | $0 |
| 10 | Southwestern Power Administration | $13,107,700 | $0 | | $0 |
| 11 | Southwestern Public Service | $98,750,173 | $1,264,678 | | $0 |
| 12 | Sunflower Electric Corporation | $14,484,045 | $320,628 | | $0 |
| 13 | Western Farmers Electric Cooperative | $20,719,639 | $429,314 | | $0 |
| 14 | Westar Energy, Inc. (Kansas Gas & Electric and Westar Energy) | $115,503,530 | $11,399,863 | | $0 |
| 15 | Mid-Kansas Electric Cooperative (Total) | $16,212,145 | $305,944 | | $0 |
| 15a | Mid-Kansas Electric Cooperative | $15,142,441 | | | |
| 15b | ITC Great Plains | $1,069,704 | | | |
| 16 | Lincoln Electric System | $14,168,176 | $101,419 | | $0 |
| 17 | Nebraska Public Power District | $46,111,083 | $13,314,707 | | $0 |
| 18 | Omaha Public Power District | $35,176,688 | $1,101,878 | | $0 |
| 19 | Total | | | | $0 |

2. For the purposes of determining the Region-wide Charges under Schedule 11, the Region-wide Annual Transmission Revenue Requirement, as shown in Line 5 of Table 2, shall be the sum of (i) the Base Plan Region-wide Annual Transmission Revenue Requirement, and (ii) the total Balanced Portfolio Region-wide Annual Transmission Revenue Requirements.

Table 2

| | | |
|---|---|---|
| 1 | Base Plan Region-wide ATRR (NTC prior to June 19, 2010) | $20,492,017 |
| 2 | Base Plan Region-wide ATRR (NTC on or after June 19, 2010) | |
| 3 | Total Balanced Portfolio Region-wide ATRR Total, Column (6), Table 1 | $0 |
| 4 | Balanced Portfolio Region Wide ATRR | $1,175,607 |
| 5 | Region-wide ATRR (Line 1 + Line 2 + Line 3 + Line 4) | $21,667,624 |

3. The revenue requirements stated in this Attachment H shall not be changed absent a filing with the Commission, accompanied by all necessary cost support.

4. New or amended revenue requirements in this Attachment H shall not be filed with the Commission by the Transmission Provider unless such revenue requirements have been provided by or for a Transmission Owner. Such revenue requirements shall have been accepted or approved by the applicable regulatory or governing authority except in the event of a simultaneous filing with the Commission by the Transmission Owner and Transmission Provider.

5. If a Transmission Owner has a Commission approved formula rate, the successful completion of its approved annual formula rate update procedures shall constitute regulatory acceptance sufficient to authorize the Transmission Provider to file with the Commission to update that Transmission Owner's revenue requirements. The Transmission Provider shall follow any special procedures related to updating a Transmission Owner's revenue requirements as outlined in Section II of this Attachment.

6. The Transmission Provider shall allocate the accepted or approved revenue requirement associated with a Base Plan Upgrade, in accordance with Attachment J to this Tariff, to the Base Plan Region-wide Annual Transmission Revenue Requirement in Table 2 above and to the appropriate Base Plan Zonal Annual Transmission Revenue Requirements in Column (4) or (5) as appropriate of Table 1 above.

**SECTION II: Transmission Owner-Specific Requirements**

**1. Westar Energy, Inc.**

For Westar Energy, Inc., the annual transmission revenue requirement for purposes of the Network Integration Transmission Service, as specified on line 7b and 14, Column 3 of

Section 1 of this Attachment H, shall be calculated using the rate formula set forth in Attachment H Addendum 3 of this Tariff ("Westar Formula Rate"). The results of the formula calculation shall be posted on the Transmission Provider's website and in an accessible location on Westar's OASIS website by October 15 of each calendar year and shall be effective on January 1 of the following year. The Zonal Revenue Requirement to be used for the Westar zone Column (3) of Table 1 of this Attachment H shall be calculated by taking the SPP Zonal Revenue Requirement as identified as Projected Net Revenue Requirements page, line 10; of the Westar Formula Rate; less the sum of the current year's revenue requirement associated with all transmission facilities owned by Westar in other pricing zones when such revenue requirements are included in the revenue requirements specified in the Westar Formula Rate on the Projected Net Revenue Requirements page, line 10; plus the previous calendar year's total firm Point-to-Point transmission revenue allocated to Westar under Attachment L provided such Point-to-Point transmission revenue is deducted from Westar's Annual Transmission Revenue Requirement under Section 34.1 of this Tariff.

The revenue requirements for Base Plan Funded projects owned by Westar shall be the amount contained on the Projected Net Revenue Requirements page, line 9 of the Westar Formula Rate.

The revenue requirements for Balanced Portfolio funded projects owned by Westar shall be the amount contained on the Projected Net Revenue Requirements page, line 9a of the Westar Formula Rate. Following its posting of the updated revenue requirements by October 15 of each calander year as discussed above, the Transmission Provider shall immediately update the various Base Plan and Balanced Portfolio funded costs and allocations contained in the Tariff and file them with the Commission no later than December 15 of each calander year with a requested effective date of January 1.

**2. Southwestern Public Service**

For Southwestern Public Service Company ("SPS"), the Existing Zonal Annual Transmission Revenue Requirement ("ATRR") for Zone 11 in column 3, Section 1 of this Attachment H shall be calculated using: (1) the formula rate as specified in Attachment O – SPS of the Xcel Energy Operating Companies Joint Open Access Transmission Tariff ("Xcel Energy OATT"), (2) will be equal to the Current Year Revenue Requirement with True Up as specified on line 4, page 1 of Attachment O – SPS of the Xcel Energy OATT, (3) and subject to the Implementation Procedures in Appendix 1 of Attachment O – SPS of the Xcel Energy OATT. The results of the formula calculation shall be posted on the SPP website and in an accessible location on SPS's OASIS website by May 25 of each calendar year and shall be effective on July 1 of such year. The Existing Zonal ATRR for Zone 11, column 3, Table 1 of this Attachment H shall not be subject to adjustment pursuant to section 34.1 for the previous calendar year's total firm Point-to-Point transmission revenue allocated to SPS under Attachment L when determining the monthly zonal Demand Charge for Zone 11.

**3. American Electric Power**

The American Electric Power Annual Transmission Revenue Requirement for purposes of the Network Integrated Transmission Service shall be (i) calculated using the formula rate set forth in Addendum 1 to this Attachment H, (ii) posted on the SPP website by May 25 of each calendar year, and (iii) effective on July 1 of such year.

**4. Nebraska Public Power District: Formula Rate Implementation Protocols and Formula Rate Template**

**Section 1. Annual Updates**

The Formula Rate Template set forth in Addendum 7 and these Formula Rate Implementation Protocols ("Protocols") together comprise the filed rate by Southwest Power Pool ("SPP") for calculating Nebraska Public Power District's ("NPPD") Zonal Annual Transmission Revenue Requirement ("Zonal ATRR") for Transmission Service under the SPP OATT. NPPD must follow the instructions specified in the Formula Rate Template to calculate the rates for NITS, the rates for Schedule 1 Service, the rates for Point-to-Point services over facilities in SPP Zone 17 and the ATRR for Base Plan Upgrades and other network upgrades.

The initial Zonal ATRR and the initial rates will be in effect for a partial year from the effective date of NPPD's transfer of operational control of its transmission facilities to SPP until December 31, 2009. The Formula Rate shall be recalculated each year with the resulting rates to become effective on and after January 1 of each year through December 31 of such year. The resulting rates implemented each January 1 will be subject to review and true-up as further provided in the Protocols.

No later than September 1, 2009 and September 1 of each year thereafter, NPPD, upon initial approval of NPPD's Board of Directors, shall determine its projected Zonal ATRR, and resulting rates for the following calendar year, in accordance with the Protocols and the Formula Rate Template of Addendum 7 of this Attachment H. NPPD will post such determination on its website and will send such determination to SPP for posting on the publicly accessible portion of the SPP website. Contemporaneously, NPPD shall provide notice to its wholesale customers and interested parties of its projected Zonal ATRR and resultant rates, including all inputs in sufficient detail to identify the components of NPPD's Zonal ATRR. Commencing September 1 of each year, such parties may submit written questions and answers will be provided by NPPD within ten (10) business days. NPPD will post on the NPPD website responses to any such inquiries and information regarding frequently asked questions. No later than September 30 of each year, NPPD will hold a meeting with wholesale customers and interested parties to explain the formula rate input projections and provide an opportunity for oral and written comments. Written comments must be submitted no later than October 30. No later than December 15 of each year, NPPD will provide to SPP for posting on the publicly accessible portion of the SPP website and submit to the Commission in an informational filing, NPPD's final Zonal ATRR and resulting rates to become effective January 1 of the following calendar year.

## Section 2. True-Up Adjustments

On or before June 1, 2010 and on or before June 1 of each year thereafter, NPPD will calculate the True-Up Adjustment with supporting data inputs in sufficient detail to identify the projected and actual cost of each element of NPPD's Zonal ATRR and actual revenues. NPPD will reflect the True-Up Adjustment as a line item in its Zonal ATRR noticed on September 1, 2010 and in the ATRR noticed on September 1 of each year thereafter. The True-up Adjustment will be determined in the following manner:

(1) Actual transmission revenues associated with transactions included in the Divisor of the Formula Rate Template for the previous calendar year will be compared to the Actual Zonal ATRR. The Actual Zonal ATRR shall be calculated in accordance with the Formula Rate Template and actual data for the previous year. For each year, NPPD will complete and make available for review, on its website, actual data as recorded in accordance with FERC's Uniform System of Accounts, including an affidavit of the Chief Financial Officer of NPPD attesting to the accuracy of the cost and revenue data set forth therein. In addition, NPPD shall provide an explanation of any change in accounting policies and practices that NPPD employed during the preceding twelve-month period that affect transmission accounts or the allocation of common costs to transmission. Actual costs incurred during the applicable calendar year will be compared to actual revenues recovered during such period to determine whether there was any under-recovery or over-recovery. The True-up Adjustment and related calculations shall be posted no later than June 1 on NPPD's website and on the publicly accessible portion of the SPP website. Commencing June 1 of each year, any interested party may submit written questions and answers will be provided by NPPD within ten (10) business days. NPPD will post on the NPPD website responses to any such inquiries and information regarding frequently asked questions. Written comments must be submitted no later than July 15 of each year. NPPD will post

on the NPPD website the final True-up Adjustment no later than September 1 of each year.

(2) Interest on any over-recovery or under-recovery of the Zonal ATRR shall be based on the interest rate equal to NPPD’s actual short-term debt costs, capped at the applicable interest rate set forth in 18 C.F.R. §35.19a of the Commission’s regulations. The interest rate equal to NPPD’s actual short-term debt costs shall be calculated in accordance with Worksheet K to the Formula Rate Template.

(3) The Zonal ATRR for transmission services for the following year shall be the sum of the projected Zonal ATRR for the following year and a True-up Adjustment for the previous year, including interest as explained above.

**Section 3. NPPD Formula Rate Blank Template**

NPPD’s Formula Rate Template to be used for calculating the Zonal ATRR and NITS rates, Schedule 1 rates, Point-to-Point rates, ATRR Base Plan Upgrade and other network upgrades set forth in Attachment H – Addendum 7. The provisions of such Formula Rate Template are not subject to changes except through a filing under Section 205 or 206 of the Federal Power Act.

**5. Omaha Public Power District**

For the Omaha Public Power District (OPPD), the annual transmission revenue requirement for purposes of the Network Integration Transmission Service, Base Plan Upgrades, Scheduling, System Control, and Dispatch Service, and for the determination of Point-to-Point rates shall be calculated using the Formula-based Rate Template set forth in Attachment H - Addendum 8 of this Tariff. The annual transmission revenue requirement and rates calculated pursuant to the formula-based rate template shall be revised annually. The results of such annual calculations shall be posted on OPPD’s OASIS website and in a publically accessible location on the Transmission Provider’s website by May 15 of each calendar year. Written comments will be accepted until June

15 and the annual revenue requirement and rates shall become effective from August 1 of such year through July 31 of the following year. Initially, the rates calculated pursuant to the formula-based rate template and incorporated into this SPP OATT will be in place through July 31, 2009.

**6. Lincoln Electric System**

For the Lincoln Electric System (LES), the annual transmission revenue requirement for purposes of Network Integration Transmission Service, Base Plan Upgrades, Scheduling, System Control and Dispatch Service, and for the determination of Point-to-Point rates shall be calculated using the Formula Rate Template set forth in Attachment H - Addendum 6 of this Tariff. The annual transmission revenue requirement and rates calculated pursuant to the formula rate template shall be revised annually. The results of such annual calculations shall be posted on LES' OASIS website and in a publicly accessible location on the Transmission Provider's website by May 15 of each calendar year. Written comments will be accepted until June 15 and the annual revenue requirement and rates shall become effective from August 1 of such year through July 31 of the following year. Supporting data for completion of the formula rate template will be available from LES upon request. Initially, the rates calculated pursuant to the formula-based rate template and incorporated into this SPP OATT will be in place through July 31, 2009.

**OG&E Electric Services**

**Rate Sheet for Point-To-Point Transmission Service**

These Point-to-Point charges shall be calculated using the Existing Zonal Annual Transmission Revenue Requirement (“ATRR”) for the OG&E rate zone as specified on Line 7, Column 3, Section 1 of Attachment H of this Tariff, which is the sum of Existing Zonal ATRRs listed in Column 3, Section 1 of Attachment H as being in the OG&E rate zone. As a result of the rate formula set forth in Attachment H, Addendum 2-A (“OG&E Formula Rate”) of this Tariff and the OG&E Formula Rate Implementation Protocols set forth in Attachment H, Addendum 2-B of the Tariff, the Existing Zonal ATRR listed on Line 7a, Column 3, Section 1 of Attachment H of this Tariff shall be posted on the SPP website by May 25 of each calendar year and shall be effective on July 1 of such year.

**Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below:

1. Yearly delivery: the Existing Zonal ATRR listed on Line 7, Column 3, Section 1 of Attachment H of this Tariff divided by the 12-CP divisor identified on page 1, line 5 of the OG&E Formula Rate /kW of Reserved Capacity per year plus $0.~~0217~~0752/kW for Oklahoma Municipal Power Authority.

2. Monthly delivery: the yearly charge divided by 12 for the $/kW of Reserved Capacity per month plus $0.~~0018~~0063/kW for Oklahoma Municipal Power Authority.

3. Weekly delivery: the yearly charge divided by 52 for the $/kW Reserved Capacity per week plus $0.~~00042~~0014/kW for Oklahoma Municipal Power Authority.

4. Weekday delivery: the weekly charge divided by 5 for the $/kW of Reserved Capacity per day plus $0.~~00008~~0003/kW for Oklahoma Municipal Power Authority.

5. Weekend and Holiday delivery: the weekly delivery charge divided by 7 for the $/kW of Reserved Capacity per day plus $0.~~00006~~0002/kW for Oklahoma Municipal Power Authority.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

**Non-Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

1. Monthly delivery: the yearly delivery charge for Firm Point-to-Point service specified above divided by 12 for the $/kW of Reserved Capacity per month plus $0.0063~~0018~~/kW for Oklahoma Municipal Power Authority.

2. Weekly delivery: the yearly delivery charge for Firm Point-to-Point service specified above divided by 52 for the $/kW of Reserved Capacity per week plus $0.0014~~00042~~/kW for Oklahoma Municipal Power Authority.

3. Weekday delivery: the weekly delivery charge divided by 5 for the $/kW of Reserved Capacity per day plus $0.0003~~00008~~/kW for Oklahoma Municipal Power Authority.

4. Weekend and Holiday delivery: the weekly delivery charge divided by 7 for the $/kW of Reserved Capacity per day plus $0.0002~~00006~~/kW for Oklahoma Municipal Power Authority.

5. Hourly delivery: the weekend and holiday delivery charge divided by 24 for the $/MW of Reserved Capacity per hour plus $0.~~0025~~0086/kW for Oklahoma Municipal Power Authority.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Weekend and Holiday Delivery rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.