Exhibit No. AEP - 100

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

American Electric Power Service Corporation	)	Docket No. ER07-_____-000
on behalf of:	)	
Public Service Company of Oklahoma	)	
Southwestern Electric Power Company	)	

DIRECT TESTIMONY OF

DENNIS W. BETHEL

ON BEHALF OF THE AEP COMPANIES,

PUBLIC SERVICE COMPANY OF OKLAHOMA

AND

SOUTHWESTERN ELECTRIC POWER COMPANY

June 22, 2007

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I. Introduction and Qualifications

Q. BY WHOM ARE YOU EMPLOYED, AND IN WHAT CAPACITY?

A. My name is Dennis W. Bethel, and I am employed by American Electric Power Service Corporation ("AEPSC" or "AEP"), as Managing Director – Regulated tariffs. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. WHAT EXPERIENCE DO YOU HAVE IN ELECTRIC UTILITY SERVICE MATTERS RELEVANT TO THIS PROCEEDING?

A. In 1973, I earned a Bachelor of Science Degree in Electrical Engineering from the University of Evansville. I began my career with AEP, at Indiana Michigan Power Company (I&M), that same year. During my career with AEP I have held positions in the customer service and rate departments at I&M, and the Rate Research and Design, System Transactions, Transmission Operations, and Regulatory Services Departments of AEPSC. In the I&M rate department I was responsible for wholesale contract development and administration, cost of service and rate studies, fuel clause filings and other regulatory analyses. From 1980 to 1988 I performed and supervised cost of service and rate design studies and testified in a number of retail rate cases on those topics as a rate analyst at AEPSC. In 1988 I transferred to Systems Transactions Department, and in 1991 was promoted to Manager – Interconnection Agreements. During this time I helped to develop and support AEP's first Open Access Transmission Tariff ("OATT") and rates filed in Docket No. ER93-540-000. In 1997 I moved to the Transmission Operations Department as Manager – Transmission Contracts and Regulatory Support. In June

2000, the merger of AEP and Central and South West Corporation was approved, and I was named Director – Transmission and Interconnection Services in the AEPSC Regulatory Services Department. In that position I was responsible for the development and implementation of transmission, interconnection and related agreements, tariffs and policies on behalf of the AEP companies in the three regions where we provide service, Southwest Power Pool ("SPP"), PJM and Electric Reliability Council of Texas ("ERCOT"). I assumed my present position in July 2005. As Managing Director-Regulated tariffs, I direct a staff that is responsible for cost of service studies, rate design, service agreements and tariffs for retail and regulated wholesale services throughout the eleven-state AEP service area. I frequently represent the AEP Companies in Regional Transmission Organization ("RTO") forums, particularly relating to the transmission tariffs, rate design, and related committee matters.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY UTILITY REGULATORY COMMISSIONS?

A. Yes. I have previously submitted testimony or affidavits on transmission and related services before the Federal Energy Regulatory Commission ("Commission"). Significant cases include Dockets ER93-540, ER98-2786, EL01-73, EL02-111, ER03-242, ER03-765, EL05-6, EL05-74, EL05-121, and ER05-751. I have also testified on various electric cost-of-service and rate design issues before the utility regulatory commissions of Michigan, Kentucky, Ohio, Tennessee, Virginia, and West Virginia. I am registered as a Professional Engineer in the States of Indiana and Ohio.

II. **Overview of Rate Filing**

Q. WHAT IS THE PURPOSE OF THIS RATE FILING?

A. AEP's submissions in this docket seek to establish an up-to-date revenue requirement for transmission services over the facilities of the AEP Companies, Public Service Company of Oklahoma ("PSO") and Southwestern Electric Power Company ("SWEPCO"), under the SPP OATT, and to establish a formula rate for the annual updating of the transmission revenue requirement.

Q. WHAT IS THE PRESENTLY EFFECTIVE REVENUE REQUIREMENT FOR TRANSMISSION SERVICE PROVIDED BY AEP IN SPP, AND WHEN WAS IT ESTABLISHED?

A. Presently, the annual transmission revenue requirement ("ATRR") reflected in AEP's rates for Network Integration Transmission Service ("NITS") under the SPP OATT is $88,681,579. The present ATRR was established pursuant to a settlement in Docket No. ER98-2786. In that case, filed concurrently with the merger proposal of AEP and Central and South West Corporation, I sponsored cost of service and rate proposals based on costs as of December 31, 1996. As such, it has been ten years since the revenue requirement for AEP transmission service in SPP was last updated.

Q. WHAT TRANSMISSION SERVICE REVENUE REQUIREMENT DOES THE FORMULA RATE SUPPORT TO REPLACE THE PRESENTLY AUTHORIZED AMOUNT?

A. The formula rate proposed in this filing supports a combined NITS revenue requirement for the AEP Companies of $140,261,459. That revised revenue requirement, which is based on the projected costs as of December 31, 2007, represents a 58% increase compared to the present NITS revenue requirement. The formula rate also produces a calculation of the NITS revenue requirements for the AEP Companies as of December 31, 2006. Those historic test-year amounts total $129,336,984 or 46% more than the presently authorized amount. Under the formula rate implementation we propose, the filed rate going forward will be the formula rate template and the accompanying protocols for implementation of the formula rate, pursuant to which annual updates will be calculated.

Q. PLEASE IDENTIFY THE MOST SIGNIFICANT ISSUES IN THIS CASE, AND THE WITNESSES WHO ADDRESS THEM?

A. The major issues and the AEP witnesses who address them are as follows:

- The protocols governing annual formula updates and the stakeholder review process – Dennis W. Bethel;
- The rate formula template, and the recovery of costs associated with current-year estimated plant additions, subject to subsequent true-up – Dennis W. Bethel;
- The initial calculation of the revenue requirements for PSO and SWEPCO under the formula rate template – Robert L. Pennybaker;
- The estimated 2007 AEP Companies' transmission plant-in-service additions – Bernard M. Pasternack; and
- The recommended return on equity (ROE) for AEP of 11.9% that includes a 50 basis point incentive for RTO participation – William E. Avera.

Q. WHAT EXHIBITS ARE YOU SPONSORING IN THIS PROCEEDING?

A. I am sponsoring the following Exhibits:

AEP-100	Prepared Direct Testimony
AEP-101	Black-lined Versions of SPP Open Access Transmission Tariff *pro forma* Tariff Sheets for, (1) SCHEDULE 1 – Scheduling, System Control and Dispatch Service, (2) ADDENDUM 1 to SCHEDULE 1, Revenue Requirements for the Allocation of Through And Out Transaction Revenue, (3) ATTACHMENT H, Annual Transmission Revenue Requirement For Network Integration Transmission Service, (4) ADDENDUM 1 to ATTACHMENT H, Monthly Demand Charge Calculation for Zone 1 Network Integration Transmission Service, and (5) ATTACHMENT T, Rate Sheets for Point-To-Point Transmission Service; and
AEP-102	Clean Versions of SPP Open Access Transmission Tariff *pro forma* Tariff Sheets for, (1) SCHEDULE 1 – Scheduling, System Control and Dispatch Service, (2) ADDENDUM 1 to SCHEDULE 1, Revenue Requirements for the Allocation of Through And Out Transaction Revenue, (3) ATTACHMENT H, Annual Transmission Revenue Requirement For Network Integration Transmission Service, (4) ADDENDUM 1 to ATTACHMENT H, Monthly Demand Charge Calculation for Zone 1 Network Integration Transmission Service, and (5) ATTACHMENT T, Rate Sheets for Point-To-Point Transmission Service.

III. Formula Rate

Q. WHY IS AEP PROPOSING A FORMULA RATE FOR ITS SPP TRANSMISSION REVENUE REQUIREMENT?

A. The AEP Companies have made and expect to make further significant annual additions to transmission plant for an extended period. In such a case, a formula rate is the most efficient way to keep rates current with the cost of transmission service. PSO and

SWEPCO have placed their transmission facilities under the functional control of the SPP RTO, and they have committed to construct transmission facilities in their SPP service areas (collectively the "AEP Zone") that are approved as part of the SPP transmission expansion planning ("STEP") process. As more fully discussed by AEP Witness Bernard M. Pasternack, SPP has established a regional transmission planning process that, together with AEP initiated transmission improvements and capital replacements, is expected to cause a significant increase in the AEP Companies' transmission construction over at least the next decade. Mr. Pasternack discusses how the transmission planning process works in SPP, the substantial cost of transmission improvements that the AEP Companies have made since the last rate case, and the improvements that the AEP Companies expect to place in service in 2007. Looking ahead, Mr. Pasternack discusses the even larger cost of transmission improvements that are anticipated under SPP transmission expansion plans, including the SPP Base Plan Upgrade ("BPU") projects. The BPU cost allocation process in SPP makes the adoption of a formula rate a near necessity. A working group of the SPP Regional State Committee, the Cost Allocation Working Group ("CAWG"), led the effort in SPP to develop a regional sharing method that allocates 33% of the cost of BPU projects to all SPP zones through a region-wide rate, and assigns the remainder of the costs to those zones that SPP identifies as benefiting more directly from the upgrades. A formula rate is the most efficient way for a transmission owner to contemporaneously determine the revenue requirements of BPU projects, in harmony with the zonal revenue requirement for NITS. At the same time, a formula rate will provide customers assurance of a consistent and transparent rate setting process that will minimize administrative and litigation-related costs.

The Commission has encouraged utilities to adopt formula rates for transmission service in Orders 679 and 679A, as well as in cases involving Baltimore Gas and Electric Company, PHI Companies, Idaho Power, Duquesne Light Company, and the Southwest Power Pool, Inc. In its Order on Proposed Tariff Revisions, issued April 22, 2005 in Southwest Power Pool Docket No. ER05-652, *et al,* the Commission said, in response to comments filed by AEP, "we agree that entities making investments pursuant to the [RTO's] plan should be able to recover their costs in a timely manner. We encourage utilities to consider adopting formula rates to facilitate such recovery." [1]

Q. WOULD YOU PLEASE BRIEFLY DESCRIBE THE FORMULA RATE AND HOW IT WILL BE IMPLEMENTED?

A. The formula rate proposed in this case relies on the FERC Form-1 reports of PSO and SWEPCO, and specified additional historic test year data, to determine the transmission cost of service or annual transmission revenue requirement ("ATRR") each year as of the end of the prior calendar year. The formula develops rate base in traditional fashion including electric transmission plant at original cost, reduced for the accumulated reserve for depreciation and amortization ("ARDA"), an allocated share of general and intangible plant and related ARDA, plant held for future use, and with adjustments for deferred federal income taxes, and allowances for working capital.

The expense portion of the cost of service is also built up from the Form-1 cost

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[1] 111 FERC ¶ 61,118 at P 32 (2005)

data in straight-forward fashion, capturing transmission operation and maintenance (“O&M”) expenses, an allocated portion of administrative and general (“A&G”) expenses, test year depreciation and amortization expense, taxes other than income taxes, and state and federal income taxes synchronized to the allowed net income by way of a formula.

The capital structure, the cost of interest on long-term debt and of dividends on preferred stock are, like rate base, valued at test-year end. The formula recognizes that it is possible for significant changes to occur in the capital structure over the course of a year. To ensure that a representative capital structure and cost rates for debt and preferred stock are reflected in the cost of service, the formula provides for synchronizing adjustments should a significant change during the year in the debt or preferred stock shares issued cause the average cost of debt interest or preferred stock dividends to fall outside the range of cost rates on issues outstanding. While we recognize that other more automatic approaches to dealing with potential year-end capital structure/cost issues in a formulaic cost of service might be acceptable, the proposed capital structure and cost calculation method will produce accurate results in a manner consistent with the review process set out in the formula implementation protocols.

Finally, the proposed cost rate for common equity, or “ROE”, is determined by AEP Witness William E. Avera using the standard Commission discounted cash flow method for a proxy group of transmission-owning electric utilities that operate in the SPP RTO and other market areas contiguous with the areas where AEP operating subsidiaries provide service and interact with other market participants. Dr. Avera recommends that the Commission approve the mid-point of his range of reasonable returns on equity, 11.4% for the proxy group, plus 50 basis points, in recognition of AEP's RTO participation, for a total ROE of 11.9%. AEP is a recognized leader in transmission, having many pioneering achievements to its credit, including the research, design and construction of the only 765 kV network in the United States. AEP operates in three RTOs, and aspires to continue and expand its leadership role in building transmission to deliver electricity throughout broad regions of America with the kind of efficiency and reliability that our 765 kV network has brought to the eastern United States. I urge the Commission to approve Dr. Avera's recommendations, as a strong ROE will be essential in raising the capital and encouraging the ingenuity that will be required to meet America's goals for transmission expansion in the years ahead.

Q. YOU MENTIONED THAT THE FORMULA RATE INCORPORATES CURRENT YEAR PLANT ADDITIONS IN THE RATE BASE. PLEASE DESCRIBE HOW THAT IS ACCOMPLISHED.

A. The transmission plant-in-service as of December 31 of each historic year will be established in the formula from the Form-1 reports. Each year as the time to update the formula rate approaches, the AEP Companies will review the status of transmission projects planned and under construction to determine, based on planned and actual progress and costs, the projects that are likely to be in-service by the end of that year, and the likely cost of construction. AEP Witness Bernard M. Pasternack supports the development of those projections for 2007, and discusses the process by which the estimates are developed. The capital construction tracking system employed by the AEP

Companies permits the cost of plant additions to be estimated for each month. That data is used in the formula rate to calculate estimated depreciation expense for the new plant over the portion of the current year that the plant additions completed each month are in-service. The formula develops the historic, Form-1-based, transmission cost of service ("TCOS"), and replicates those historic costs in another section of the spreadsheet where the projected plant addition adjustments are added. It is in that second TCOS, actually presented first in the template page sequence, that the adjustments for projected transmission plant additions are made. The result is that each update of the formula rate will produce a historic (prior year) and a projected (current year) TCOS. Since adjustments are made only for plant-in-service and depreciation, the projected costs are not likely to exceed the actual costs for the new plant, but, in any case, the projected costs will be trued-up to actual costs in the next formula rate update.

Q. WHAT EFFECTIVE DATE DOES AEP PROPOSE FOR THE INITIAL RATES UNDER THE RATE FORMULA?

A. AEP proposes an effective date of September 1, 2007 for the initial ATRR and rates calculated pursuant to the formula proposed in this case. A nominal suspension is warranted in this case for several reasons. First, the formula rate uses established methods to determine and allocate cost components and thereby to minimize controversy as to the level of costs. Second, implementation and review of formula updates are governed by a set of protocols that are structured to provide customers ample review and challenge opportunities. Finally, customers are protected from over collections by the formula's true up mechanism that will refund any excess collections, and collect any shortfalls, including the time value of money.

Q. PLEASE EXPLAIN HOW THE FORMULA RATE'S TRUE-UP MECHANISM WILL WORK.

A. Each May beginning in 2008, AEP will re-compute the formula using data contained in the prior calendar year's Form-1 and other data required by the cost support schedules contained in the formula. Whereas the ATRR collected under the formula rate between updates, from July through June of the next year ("Rate Year"), includes estimated plant-in-service additions through the mid-point of the Rate Year, the subsequent update ATRR calculation will determine the actual costs as of that mid-point date. The difference between the "estimated" ATRR collected during the prior Rate Year and the "actual" ATRR for that Rate Year calculated in the update represents the over or under collection to be "trued up". One twelfth of the true-up amount, whether a shortfall or excess in prior Rate Year collections, will be collected or refunded with interest during each month of the following Rate Year. Thus, in the second and subsequent Rate Years, the amounts collected each month from NITS customers will represent the estimated ATRR for the current Rate Year and the true-up adjustment for the prior Rate Year.

Q. HOW DOES AEP PROPOSE TO COMPUTE THE INTEREST ON TRUE-UP AMOUNTS?

A. AEP proposes to use the quarterly FERC refund interest rate applicable at the beginning of each quarter of the Rate Year to compute the interest on the true-up amount. Table 1, using hypothetical quarterly true-up amounts and interest rates, illustrates the true-up calculation.

Table 1 – Example True Up Calculation With Interest

Rate Year X by Quarter	Excess Collection	Cumulative and Avg.	Refund Interest Rate	Interest to next July	Refund Amount
1	$25,000	$25,000	8.25%	$2,063	$27,063
2	$25,000	$50,000	8.25%	$1,547	$53,609
3	$25,000	$75,000	8.25%	$1,031	$79,641
4	$25,000	$100,000	8.25%	$516	$105,156
Year	$100,000	$62,500	8.25%	$5,156	$105,156

Monthly True Up Amount During Rate Year X+1 at 8.25% APR **($9,160)**
(calculated using Payment function for 12 months at 8.25% APR)

True Up Amount to be Collected or (Refunded) in Rate Year X+1 **($109,914)**
(12-month Total True-up to collect or (refund) $105,156 with 8.25% APR)

Q. DO ANY OTHER SPP TRANSMISSION OWNERS USE A FORMULA RATE TO CALCULATE THEIR TRANSMISSION REVENUE REQUIREMENT ON AN ANNUAL BASIS?

A. Yes. Westar has a formula rate for transmission service in SPP that was the result of a settlement in Docket No. ER05-925. The Westar formula rate relies completely on historic costs, primarily from the FERC Form-1, and does not involve cost true-up.

Q. IS THERE AN ACTIVE EFFORT BY SPP STAKEHOLDERS TO DEVELOP A STANDARD FORMULA RATE FOR SPP TRANSMISSION OWNERS?

A. Yes, the Formula Rates Task Force ("FRTF") has been working on that for several years. Its goal was to develop generic formulas and protocols for investor owned, cooperative, municipal and governmental authority transmission owners. The FRTF made significant progress, in terms of issue exploration, but the group recently reported to the Regional Tariff Working Group ("RTWG") that consensus could not be reached. On May 24, 2007, the RTWG approved the FRTF's proposal to change its goals of developing a generic protocol and formula rate for the SPP. Instead, the FRTF will now attempt to develop processes, procedures and/or criteria that will apply to all SPP transmission owners implementing a formula rate, and an "illustrative" formula rate template reflecting a Cap Ex/True-Up revenue requirement structure and the adjustments needed to accommodate the SPP cost allocation process.

Q. WHY ISN'T AEP WAITING FOR THE FRTF TO FINISH ITS WORK BEFORE FILING A FORMULA RATE?

A. AEP has waited for the FRTF to complete its work. Had it not been for the prospect that the SPP FRTF might reach agreement on a generic formula rate, AEP would in all likelihood have filed this case much sooner, as the AEP zone ATRR, based on 1996 costs, has become significantly stale. The significant increase proposed in this case is not large because of any peculiarity of the formula we have proposed; rather, the increase supported by the filing in this case results from the AEP Companies having built a lot of new transmission plant since their transmission revenue requirements were last determined. While AEP supports the FRTF's continuing efforts, the AEP Companies simply decided that it was not prudent to wait any longer to update their rates. Further, this filing is consistent with the new goals of the FRTF to develop a formula rate template reflecting a Cap Ex/True-Up revenue requirement structure and the adjustments needed to accommodate the SPP cost allocation process.

Q. HOW DOES THE FORMULA COMPUTE THE REVENUE REQUIREMENT FOR SPECIFIC TRANSMISSION PROJECTS?

A. Worksheets F and G provide the mechanism to calculate the revenue requirement for SPP Base Plan Upgrades and other network upgrades that are allocated regionally or on a benefit basis. Those Worksheets have been set up to compute an annual revenue requirement over the depreciable life of each transmission project. The depreciable life used to calculate the revenue requirements for PSO and SWEPCO Base Plan Upgrades, 50 years and 36 years, respectively, reflect the present average transmission depreciation rates for the two companies. The Worksheets also accommodate the option to calculate the revenue requirement for transmission projects with the standard ROE award, and an incentive ROE, should the Commission approve incentive rate treatment. For purely illustrative purposes, the Tulsa Area EHV project has been included in Worksheet F of the PSO and SWEPCO formula rate calculations sponsored by AEP Witness Robert L. Pennybaker, and the revenue requirements computed with an ROE of 11.9% and with an incentive ROE of 13.5%. A complete discussion of the data sources and workings of the formula rate templates, filled in with PSO and SWEPCO data, is presented by Mr. Pennybaker.

IV. Formula Rate Implementation Protocols

Q. WILL AEP'S CUSTOMERS AND OTHER INTERESTED PARTIES HAVE AN OPPORTUNITY TO REVIEW AND CHALLENGE THE ANNUAL RATE RESTATEMENTS UNDER THE PROPOSED FORMULA?

A. Yes. The proposed protocols are detailed in Exhibit AEP-101, on pages 7 through 10. That exhibit, drafted as *pro forma* SPP OATT Addendum 1 to Attachment H, affords affected parties a multi-part opportunity to investigate and challenge annual formal rate updates. The protocols provide approximately nine months for review and resolution of issues after the publication date of each year's update. During that period, AEP's transmission customers, the affected state regulatory Commissions, and other interested parties will receive the annual update by May 25th, be invited to participate in a Customer Meeting to be held by June 25th, and have 75 days after the Customer Meeting to serve information requests on AEP. AEP is obligated to make a good faith effort to respond to information requests within 15 business days. After the review period, affected parties may notify AEP of the need to resolve any issues. If the parties have not been able to resolve any such issues within 60 days after the review period, the party bringing the challenge may, within the next 3 months, lodge a formal challenge as to any unresolved issues involving the annual update with the Commission. This time line allows ample time for review of the updates, and resolution of issues before the next update.

Q. WHO WILL HAVE THE BURDEN OF PROOF IN A CHALLENGE TO AN ANNUAL UPDATE UNDER THE FORMULA RATE, THE CUSTOMER OR THE AEP COMPANIES?

A. The AEP Companies will have the burden of proof as to the appropriateness of formula rate implementation for challenges brought under the terms of the proposed protocols; however; the protocols do not apply to proposals by any party to change the formula rate itself. In that regard, the protocols do not limit or enhance the right of an affected customer to file a complaint requesting changes in the formula under Section 206 of the Federal Power Act ("FPA"), nor abridge AEP's right to file to change the formula under Section 205 of the FPA.

V. SPP Open Access Transmission Tariff Sheets

Q. PLEASE BRIEFLY DESCRIBE THE SPP TARIFF CHANGES PROPOSED BY AEP TO IMPLEMENT THE PROPOSED FORMULA RATE.

A. Exhibit AEP-101 shows the SPP Tariff sheet changes that AEP proposes. I have labeled each Tariff sheet "*pro forma*" to indicate that, if the changes we propose are approved by the Commission, the revised Tariff sheets will be issued by SPP. Further, SPP will file annual changes in those sheets that contain revenue requirement and/or rate values that will change each year as the AEP Companies update their costs of service using the Formula Rate.

Q. PLEASE DESCRIBE THE CHANGES PROPOSED FOR SPP TARIFF SCHEDULE 1 AND ADDENDUM 1 TO SCHEDULE 1.

A SPP Tariff Schedule 1 – Scheduling, System Control and Dispatch Service, contains, in section 1, the rates that SPP uses to collect charges for that ancillary service on through and out point-to-point ("PTP") transmission service transactions. We have made no change in those rates, but SPP adjusts those rates when the Schedule 1 revenue requirement of an SPP control area operator changes. Since the AEP Companies operate the control area corresponding to SPP Zone 1, and they are supporting a new revenue requirement for Schedule 1, we expect that SPP will adjust the rates in section 1 of Schedule 1 when the Commission approves a new revenue requirement for the AEP Companies in this case, and each year when that revenue requirement is updated by action of the Formula Rate.

Sections 2 and 3 of Schedule 1 direct customers to the location of zonal rates for

Scheduling service for PTP and NITS respectively. Presently the AEP Companies' rates for that service are in the AEP OATT; however, in this case the AEP Companies propose hereafter to place those rates in the SPP Tariff. Accordingly, we propose additions to both section 2 and section 3 of Schedule 1 to point customers to Addendum 1 to SPP Schedule 1, where we have added the AEP Companies' revised revenue requirement for Schedule 1 service, and the rates for that ancillary service for PTP and NITS in Zone 1.

Q. PLEASE DESCRIBE THE CHANGES PROPOSED FOR SPP TARIFF ATTACHMENT H AND ADDENDUM 1 TO ATTACHMENT H.

A SPP Tariff Attachment H (Sheet No. 161) displays, in tabular format, the Existing Zonal ATRR and Base Plan ATRR for each SPP transmission owner by Zone. The AEP Companies propose to eliminate the identification of AEP Texas North Company as a transmission owner, since ownership of the AEP Texas North transmission facilities located in SPP was transferred to SWEPCO in February 2007. The transmission cost of service studies supported for SWEPCO by AEP Witness Robert L. Pennybaker include adjustments to recognize this change of ownership. We also insert in the Existing Zonal ATRR column a note directing customers to "See Section 7 below". The statement added in Section 7 (Sheet No. 161A) notes that the AEP Companies' ATRR for network service will be calculated using the formula rate contained in Addendum 1 to Attachment H, will be posted on the SPP website each year by May 25, and will be effective on July 1st of each year.

Addendum 1 to Attachment H, Monthly Demand Charge Calculation for Zone 1 Network Integration Transmission Service, presently contains statements describing the

"Charges for Compensation to AEP" and for compensation to the other transmission owners in Zone 1. The changes proposed to Addendum 1 to Attachment H simplify the calculation of Charges for Compensation to AEP by making the monthly charge for each NITS customer equal to one-twelfth of the Existing Zonal ATRR times the customer's monthly Network Load divided by the total Network Load for Zone 1. This method differs from the present monthly charge calculation that uses a stated rate that is updated each year for the prior-year load. The proposed ATRR collection method results in one-twelfth of the ATRR being collected each month, whereas the present method charges the same rate each month, but collects revenues that vary with the network load. The proposed method may be described as a monthly load ratio sharing of the Existing Zonal ATRR among Zone 1 NITS customers. AEP Witness Robert L. Pennybaker discusses the customer impacts resulting from the change in ATRR collection method.

The AEP Formula Rate Implementation Protocols and Blank Formula Rate Template are also inserted in Addendum 1 to Attachment H as *pro forma* Original Sheet Nos. 161C.1 through 161C.4, and *pro forma* Original Sheet Nos. 161D.1 through 161D.14, respectively.

Q. PLEASE DESCRIBE THE SPP TARIFF CHANGES PROPOSED FOR ATTACHMENT T.

A. SPP Tariff Attachment T, Rate Sheet for PTP Transmission Service, includes rates for firm and non-firm PTP transmission service into, within and exiting SPP from each Zone. Sheet Nos. 218, 219, 219A and 220 contain the rates for Zone 1, presently defined as the "American Electric Power – West" zone. We propose to change the name of the zone to

"Zone 1", recognizing that the rates are no longer designed to collect only AEP costs. The rates for monthly, weekly, daily and hourly service until recently were based solely on the AEP Companies' revenue requirements, but have been adjusted recently by SPP to include charges associated with the transmission costs of other transmission owner's in Zone 1. The revised rates included in *pro forma* Third Revised Sheet No. 218 include the rates calculated by Witness Pennybaker in his Exhibit AEP-201, and the additional charges reflected in the presently effective Sheet No. 218 for the other transmission owners in Zone 1. Provisions on Sheet Nos. 219, 219A and 220 that describe a now obsolete discounting methodology have been deleted. The discount described in those pages was implemented in the AEP OATT at the time of the merger of AEP and Central and South West Corporation to limit charges for use of AEP transmission such that a customer that paid the rate for AEP service in one of the AEP Zones (East Zone, West Zone-SPP or West Zone-ERCOT) would not be charged more than the rate for either the East or West Zone. Now that PSO, SWEPCO and the other AEP Companies in the east and in ERCOT have transferred functional control of their transmission facilities to RTOs, and the PTP service rates are now "RTO rates" rather than "AEP rates", the limits on transmission service charges are inapposite.

Q. IS AEP PROPOSING A REVISION OF ITS REVENUE REQUIREMENT OR RATES FOR REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE?

A. No. In 2006 the SPP Board of Directors approved a filing by SPP to change the method by which SPP compensates generators in SPP for providing Reactive Supply and Voltage

Control from Generation Sources Service. The new rate, resulting from the SPP stakeholder process, pays all generators the same rate for reactive power supplied by the generator in response to a request from SPP or the control area operator in coordination with SPP, to the extent such generator is required to operate its generator outside of a power factor range of 95% leading to 95% lagging. The method is very similar to that used in ERCOT. Because the new rate is uniform for all SPP generators, the AEP Companies' cost to provide reactive power capability is not an issue. The Commission accepted the new uniform reactive power supply rate filed by SPP effective March 1, 2007.

Q. IS AEP PROPOSING CHANGES IN THE RATES FOR ANY OF THE OTHER ANCILLARY SERVICES SUPPLIED BY AEP GENERATORS?

A. No. The AEP Companies are not proposing changes in their rates for any of the generation-based ancillary services at this time.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

American Electric Power Service Corporation on behalf of: Public Service Company of Oklahoma Southwestern Electric Power Company	Docket No ER07-___-000

AFFIDAVIT OF WITNESS

I, the undersigned, being duly sworn, depose and say, under penalty of perjury, that the Prepared Direct Testimony of Dennis W. Bethel is the testimony of the undersigned, and that the exhibits sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

Dennis W Bethel

Dennis W. Bethel

Subscribed and sworn to before me this
19th day of June, 2007.

My Commission expires: 05/11/11

Ellen A McQuinn

Notary Public

SCHEDULE 1

Scheduling, System Control And Dispatch Service

Scheduling, System Control and Dispatch Service is required to schedule the movement of power through, out of, within or into a Control Area. Charges for such service shall be as follows:

1) For Customers taking Firm or Non-Firm Point-To-Point Transmission Service, for through and out transactions, the Schedule 1 charge shall be the product of the capacity reserved, expressed in MW and the appropriate rate as follows:

On-Peak:

Monthly Rate $ 59.2979 per MW-Month

Weekly Rate $13.6841 per MW-Week (The Monthly Rate times 12, divided by 52)

Daily Rate $2.7368 per MW-Day (The Monthly Rate times 12, divided by 260)

Hourly Rate $0.1711 per MW-Hour (The Monthly Rate times 12, divided by 4160)

Off Peak:

Daily Rate/MW $1.9495 per MW-Day (The Monthly Rate times 12, divided by 365)

Hourly Rate/MW $0.1711 per MW-Hour (The Monthly Rate times 12, divided by 8760)

On-Peak and Off-Peak Periods

Off-Peak days shall be Saturdays and Sundays and all NERC holidays. All other days shall be On-Peak. All hours during Off-Peak days shall be Off-Peak. On-Peak hours during On-Peak days shall be all hours from HE 0700 through HE 2200 Central Prevailing Time. All other hours during On-Peak days shall be Off-Peak.

2) For Customers taking Firm or Non-Firm Point-To-Point Transmission Service, for transactions into and within the Transmission System, the Schedule 1 charge shall be the charge computed pursuant to the approved rate schedule of the Zone that is the Point of Delivery. See Addendum 1 to this Schedule 1 for Zone 1 charges.

3) For Customers taking Network Integration Transmission Service, the Schedule 1 charge shall be the charge computed pursuant to the approved rate schedule of the Zone in which the load is located. See Addendum 1 to this Schedule 1 for Zone 1 charges.

ADDENDUM 1 TO SCHEDULE 1
Revenue Requirements for the Allocation of Through And Out Transaction Revenue

Revenue associated with the provision of Schedule 1 service for Customers taking Firm or Non-Firm Point-To-Point Transmission Service for through and out transactions, shall be allocated to Transmission Owners in proportion to the respective scheduling revenue requirement of each such Transmission Owner associated with the provision of this service. Such scheduling revenue requirements are:

Transmission Owner	CURRENTLY EFFECTIVE Revenue Requirement
AEP	$3,257,073~~2,911,599~~
Aquila - MPS	$1,620,559
Aquila - WPK	$594,828
Empire	$260,944
GRDA	$686,880
KCPL	$0
Midwest	$190,804
OG+E	$4,759,216
SPA	$1,622,827
Springfield	$0
SPS	$1,674,015
Westar	$3,209,760
WFEC	$1,824,120
Total	$19,355,553

Zone 1 charges for Scheduling, System Control and Dispatch Service:

(a) Network Integration Transmission Service: $34.55 per MW of Network Load per month.
(b) Point-to-Point Transmission Service per MW reserved per:

Month	Week	Day	Hour
$34.55	$7.97	$1.14	$0.05

ATTACHMENT H

Annual Transmission Revenue Requirement For Network Integration Transmission Service

1. The Existing 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. The Base Plan Zonal Annual Transmission Revenue Requirement within each Zone for the purposes of determining the zonal charges under Schedule 11, Base Plan Charges, is specified in column 4.

(1) Zone	(2)	(3) Existing Zonal ATRR	(4) Base Plan Zonal ATRR
~~1~~	~~American Electric Power – West~~	~~$ 92,432,463~~	~~$0~~
1	American Electric Power (Public Service Company of Oklahoma, and Southwestern Electric Power Company, collectively "AEP" ~~and SPP portion of Texas North Company~~)	~~88,681,579~~ See Section 7 below	$~~0~~
1	East Texas Electric Cooperative, Inc.	$2,733,879	$0
1	Tex-La Electric Cooperative of Texas, Inc.	$588,874	$0
1	Deep East Texas Electric Cooperative, Inc.	$428,131	$0
2	Cleco Corporation	$ 29,328,000	$0
3	City Utilities of Springfield, Missouri	$ 8,651,509	$0
4	Empire District Electric Company	$ 14,075,000	$0
5	Grand River Dam Authority (Est.)	$ 24,589,256	$0
6	Kansas City Power & Light Company	$ 35,461,776	$0
7	Oklahoma Gas & Electric Company	$ 65,065,032	$0
8	Midwest Energy, Inc.	$ 4,197,347	$0
9	Aquila Networks-MPS/L&P	$ 20,759,283	$0
9a	Aquila Networks-MPS	$14,059,183	$0
9b	Aquila Networks-L&P	$6,700,100	$0
10	Southwestern Power Administration	$9,155,900	$0
11	Southwestern Public Service	$65,500,000	$0
12	Sunflower Electric Corporation	$ 14,484,045	$0
13	Western Farmers Electric Cooperative	$ 20,719,639	$0
14	Westar Energy, Inc. (Kansas Gas & Electric and Westar Energy)	See section 5 below	$0
15	Aquila Networks-WPK	$ 5,947,002	$0

2. The Base Plan Region-wide Annual Transmission Revenue Requirement for the purposes of determining the region-wide charges under Schedule 11 shall initially be $0.
3. The amounts in (1) and (2) shall be effective until amended by the Transmission Owner or modified by the Commission or other applicable regulatory authority.
4. The revenue requirements stated in Attachment H shall not be changed absent a filing with the Commission.
5. The Annual Transmission Revenue Requirement for purposes of the Network Integration Transmission Service shall be calculated using the rate formula set forth in Attachment H-1 of the Westar Open Access Transmission Tariff (Westar formula rate). The results of the formula calculation shall be posted on the SPP website and in an accessible location on Westar's OASIS website by May 15 of each calendar year and shall be effective on June 1 of such year. The Annual Transmission Revenue Requirement will be as identified on page 1, line 7 of the Westar formula rate, 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.
6. Pursuant to the Offer of Settlement approved by the Federal Energy Regulatory Commission in Xcel Energy Services Inc., 115 FERC ¶ 61,011, the Annual Transmission Reveune Requirement for the Southwestern Public Service Company (SPS) rate zone (Zone 11) stated on Sheet 161 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.
7. The AEP Annual Transmission Revenue Requirement for purposes of the Network Integration 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.

ADDENDUM 1 TO ATTACHMENT H
MONTHLY DEMAND CHARGE CALCULATION FOR ZONE 1
NETWORK INTEGRATION TRANSMISSION SERVICE

This Addendum to Attachment H sets forth the monthly Demand Charge for Zone 1 for Network Customers taking Network Integration Transmission Service under Schedule 9 to this Tariff.

Charges for Compensation to AEP

~~Unless a different rate is approved by the Commission, t~~The monthly Demand Charge to Network Customers for compensation to AEP shall be determined by multiplying one twelfth (1/12) of the Existing Zonal ATRR for AEP, specified in Attachment H, by the Network Customer's monthly Network Load, determined in accordance with the provisions of Section 34.2, expressed in MW, divided by the total monthly Network Load for Zone 1. The total monthly Network Load shall be adjusted as necessary to incorporate the load of Network Integration Transmission Service Customers, and any zonal load served under grandfathered network and long-term firm point-to-point service agreements.~~times the rate per MW-month determined by dividing the Existing Zonal Annual Transmission Revenue Requirement of AEP, specified in Attachment H, by the sum of the twelve (12) coincident peak loads during the year 2000.~~

~~Until a different rate has been approved by the Commission, such rate for each succeeding calendar year, to be effective on and after January 1, of such succeeding year, will be calculated by dividing AEP's Existing Zonal Annual Transmission Revenue Requirement, specified in Attachment H, by the sum of the twelve (12) coincident peak loads during the preceding calendar year. The rate for 2001, pursuant to the above, is $1,013.18 per MW-month.~~

Charges for Compensation to East Texas Electric Cooperative, Inc., Tex-La Electric Cooperative of Texas, Inc. and Deep East Texas Electric Cooperative, Inc.

In addition to the charges specified for compensation to AEP above, the Transmission Provider shall calculate a monthly Demand Charge associated with the revenue requirements of East Texas Electric Cooperative, Inc., Tex-La Electric Cooperative of Texas, Inc. and Deep East Texas Electric Cooperative, Inc. which shall be applicable to all customers located in Zone 1 taking Network Service under this tariff, including any Transmission Owner within Zone 1 taking service under Section 39. The monthly charge to each customer for compensation to East Texas Electric Cooperative, Inc., Tex-La Electric Cooperative of Texas, Inc. and Deep East Texas Electric Cooperative, Inc. shall be the product of the customer's load ratio share and one twelfth (1/12) of such Transmission Owner's Existing Zonal Annual Transmission Revenue Requirement.

AEP Formula Rate Implementation Protocols

I. Annual Update

1. The rate formula template ("Formula") and these protocols together comprise the filed rate of Public Service Company of Oklahoma and Southwestern Electric Power Company (collectively, "AEP") for transmission service under the SPP OATT. AEP must follow the instructions specified in the Formula to calculate its Annual Transmission Revenue Requirements ("ATRR") and the rates for its Network Integration Transmission Service and Point-to-Point transmission service ("Formula Rate").

2. The Formula Rate shall initially be effective for service on and after the date specified by the Federal Energy Regulatory Commission ("FERC") in an order accepting the Formula Rate, and in subsequent years on and after July 1 of each calendar year through June 30 of the subsequent calendar year ("Rate Year"), subject to review, challenge and refunds or surcharges with interest, to the extent provided herein.

3. On or before May 25 of each calendar year, AEP shall:

    (a) recalculate the ATRR and the Formula Rate for the new Rate Year in accordance with the Formula Rate ("Annual Update");

    (b) provide such Annual Update and supporting information in read-only format to SPP, for posting on the SPP website, such information to include a populated Formula showing the calculation of such Annual Update and documentation supporting such calculation as provided in Section I.4 below (the date of such posting to be the "Posting Date");

    (c) disclose any changes in AEP accounting policies, practices or procedures that impact the Formula or calculations under the Formula that have occurred since the initial filing of the Formula or posting of the most recent Annual Update, as applicable; and

    (d) notify its transmission customers and affected regulatory commissions of the Annual Update posting, and provide, upon request, fully functioning spreadsheet files supporting the Annual Update.

4. The Annual Update for the Rate Year shall:

    (a) be based upon AEP's FERC Forms No. 1 for the most recent calendar year, and, to the extent specified in the Formula, upon the books and records of AEP consistent with the FERC accounting policies and practices ("Prior Year ATRR");

(b) include adjustments reflecting the additional transmission plant in service, and related depreciation, and income taxes that are reasonably projected to be recorded upon the books and records of AEP consistent with the Formula and FERC accounting policies and practices, so as to estimate the ATRR as of the current calendar year end ("Projected ATRR");

(c) as and to the extent specified in the Formula, provide sufficiently detailed supporting documentation for data (and all adjustments thereto or allocations thereof) that are used to develop the Formula Rate and are not otherwise available directly from the FERC Form No. 1;

(d) beginning in the second year, compare the latest Prior Year ATRR with the Projected ATRR calculated in the prior year's Annual Update, thereby to determine the amount needed to be surcharged or refunded to customers in the new Rate Year to true up collections for the soon to end Rate Year, including interest at the applicable FERC refund interest rates; and

(d) be subject to review only in accordance with the procedures set forth in these Formula Rate Review Protocols ("Protocol").

5. A change to the Formula inputs related to revised return on equity financing ("ROE") or depreciation rates may not be made absent an appropriate filing with the FERC pursuant to Federal Power Act Section 205 or Section 206. Additionally, an annual increase in Post-Employment Benefits Other than Pensions ("PBOP") expenses that results in an increase in the Projected ATRR equivalent to $0.05 per kW per month for Network Integration Transmission Service, as compared to the immediately preceding ATRR Annual Update, may not be included in an Annual Update without such a filing.

6. If AEP files any corrections to its FERC Forms No. 1 during a Rate Year that would affect the Formula Rate for that Rate Year, such corrections and any resulting refunds or surcharges shall be reflected in the true up adjustment made part of the Annual Update for the next effective Rate Year.

II. Review Procedures for Annual Update

1. Each Annual Update shall be subject to the following review procedures ("Annual Review Procedures"):

(a) Each year, after the Posting Date and before June 25, AEP will convene a meeting ("Customer Meeting") to afford interested parties (e.g., Transmission Customers and affected state and federal regulatory authorities) an opportunity to discuss and become better informed regarding the Annual Update;

(b) Interested parties will have seventy-five (75) days after the Customer Meeting to serve reasonable information requests on AEP for information and workpapers supporting an Annual Update. Such information requests shall be limited to that which is necessary to determine if AEP has properly calculated the Annual Update under review (including any corrections pursuant to Section I.6). Further, such information requests shall not include requests for information related to Annual Updates from prior years except (i) to determine whether a prior year's approach on a given matter was the same or different from the current year's approach, or (ii) in connection with corrections pursuant to Section I.6.

(c) AEP shall make a good faith effort to respond to information requests pertaining to an Annual Update within fifteen (15) business days of receipt of such requests. Information requests received after 4 p.m. CPT shall be considered received the next business day.

(d) To the extent AEP and any interested party(ies) are unable to resolve disputes related to information requests submitted in accordance with these Annual Review Procedures, AEP or any interested party may petition the FERC to appoint an Administrative Law Judge as a discovery master. The discovery master shall have the power to issue binding orders to resolve discovery disputes and compel the production of discovery, as appropriate, in accordance with the Annual Review Procedures and consistent with the FERC's discovery rules.

(e) Any interested party shall have until the later of ninety (90) days after the Customer Meeting or fifteen (15) days after AEP's last response to reasonable information requests submitted pursuant to Section II.1(b) above, to review the calculation of the Annual Update ("Review Period") and to notify AEP in writing of any specific challenges to the Annual Update ("Issues"). Challenges to the Formula itself shall not be considered "Issues" for purposes of these Annual Review Procedures.

III. Resolution of Challenges

For each Annual Update:

1. If AEP and any interested party(ies) have not resolved all Issues identified pursuant to Section II.1(e) above within sixty (60) days after the Review Period for a given Annual Update, the interested party(ies) may file a complaint challenging the Annual Update, with regard to such Issue(s), in a proceeding at the FERC ("Formal Challenge").

(a) A party may file a Formal Challenge for a limited period of up to three (3) months after the sixty-day resolution period has ended. A party may not, thereafter, file a Formal Challenge as to the disputed Issue(s) for the then effective Rate Year. Failure to pursue an Issue or lodge a Formal Challenge regarding an Issue(s) as to a given Annual Update shall not bar pursuit of such Issue or the lodging of a Formal Challenge as to such Issue(s) as relates to a subsequent Annual Update review.

(b) All information produced pursuant to these Protocols may be included in any Formal Challenge.

2. In any proceeding ordered by the FERC in response to a Formal Challenge, AEP will bear the burden of proving that it has properly calculated the challenged Annual Update pursuant to the Formula. Challenges to the Formula itself shall not be considered "Formal Challenges" for purposes of these Annual Review Procedures, and shall be subject to the Commission's Rules and Regulations applicable to filings pursuant to 18 C.F.R. § 385.206.

3. Each Annual Update shall become final and shall no longer be subject to challenge on the later to occur of: (i) passage of the time specified in III.1(a) above for a Formal Challenge, if no such Formal Challenge has been filed and the FERC has not itself initiated a proceeding to consider the Annual Update; or (ii) the issuance of a final FERC order in response to a Formal Challenge or a proceeding initiated by the FERC to consider the Annual Update.

4. Any refunds or surcharges resulting from a Formal Challenge shall be calculated, with interest, from the effective date of the challenged Annual Update, and shall be reflected in the Annual Update for the next effective Rate Year.

Attachment H & T Support
Page 1 of 1

AEP Transmission Formula Rate Template
For rates effective July 1, ______

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SPP Zone 1 AEP Revenue Requirements

Line No.			AEP Annual Revenue Requirement	PSO Annual Revenue Requirement	SWEPCO Annual Revenue Requirement
	A. Network Service				
1	REVENUE REQUIREMENT (w/o incentives)	(TCOS Line 1)			
2	LESS: REVENUE CREDITS	(TCOS Line 5)			
3	CURRENT YEAR ZONE 1 AEP NETWORK SERVICE REVENUE REQUIREMENT	(TCOS Line 6)			
4	LESS: REVENUE REQUIREMENTS INCLUDED IN LINE 1 FOR:				
5	BASE PLAN UPGRADES (W/O INCENTIVES)	(TCOS Line 7)			
6	REQUESTED UPGRADES (W/O INCENTIVES)	(Worksheet F)			
7	ECONOMIC UPGRADES (W/O INCENTIVES)	(Worksheet F)			
8	SUBTOTAL				
9	EXISTING ZONAL ATRR (W/O INCENTIVES)	(Line 3- Line 8)			
10	INCENTIVE REVENUE REQUIREMENT FOR ZONAL PROJECTS	(TCOS ln 16)			
11	EXISTING ZONAL ATRR (W/ INCENTIVES)	(Line 9 + Line 10)			
12	HISTORICAL YEAR (2006) ACTUAL ATRR				
13	PROJECTED (2006) ATRR FROM PRIOR YEAR	Input from Prior Year			
14	PRIOR YEAR TRUE-UP	(Line 12 - Line 13)			
15	INTEREST ON PRIOR YEAR TRUE UP				
16	**EXISTING ZONAL ATRR FOR SPP OATT ATTACHMENT H, SEC. 1, COL. 3**	(Ln 11 + Ln 14 + Ln 15)			
	B. Point-to-Point Service				
17	2007 Projected AEP West Zone SPP Average 12-Mo. Peak Demand	(Load WS, ln 11)		MW	
18	Annual Point-to-Point Rate in $/MW - Year	(Line 16 / Line 17)			
19	Monthly Point-to-Point Rate in $/MW - Month	(Line 18 / 12)			
20	Weekly Point-to-Point Rate in $/MW - Weekly	(Line 19 / 52)			
21	Daily On-Peak Point-to-Point Rate in $/MW - Day	(Line 20 / 260)			
22	Daily Off-Peak Point-to-Point Rate in $/MW - Day	(Line 21 / 365)			
23	Hourly On-Peak Point-to-Point Rate in $/MW - Hour	(Line 22 / 4160)			
24	Hourly Off-Peak Point-to-Point Rate in $/MW - Hour	(Line 23 / 8760)			
	C. SPP Regional Service				
25	BASE PLAN UPGRADE ATRR W/O INCENTIVES	(Line 8)			
26	ADDITIONAL ATRR FOR FERC-APPROVED INCENTIVES ON BPU	(Worksheet G)			
27	**BASE PLAN UPGRADE ATRR FOR SPP COLLECTION UNDER SCHEDULE 11**				

AEP Transmission Formula Rate Template
For rates effective July 1, ______

SPP SCHEDULE 1 AEP Revenue Requirements

Line No.			AEP Annual Revenue Requirement	PSO Annual Revenue Requirement	SWEPCO Annual Revenue Requirement
A.	**Schedule 1 ARR**				
1	Total Load Dispatch & Scheduling (Account 561) (TCOS Line 76)				
2	Less: Load Disptach - Scheduling, System Control and Dispatch Services (321.88.b)				
3	Less: Load Disptach - Reliability, Planning & Standards Development Services (321.92.6)				
4	Total 561 Internally Developed Costs	(Line 1 - Line 2 - Line 3)			
5	Less: PTP Service Credit				
6	EXISTING ZONAL ARR	(Line 4 - Line 5)			
7	HISTORICAL YEAR (2006) ACTUAL ARR				
8	PROJECTED (2006) ARR FROM PRIOR YEAR				
9	PRIOR YEAR TRUE-UP				
10	INTEREST ON PRIOR YEAR TRUE UP				
11	Net Schedule 1 Revenue Requirement for Zone				
B.	**Schedule 1 Rate Calculations**				
12	2007 Projected AEP West Zone SPP Average 12-Mo. Peak Demand	(LOAD WS, Line 11)	MW		
13	Annual Point-to-Point Rate in $/MW - Year	(Line 11 / Line 12)			
14	Monthly Point-to-Point Rate (ln 13 / 12) $/MW - Month	(Line 13 / 12)			
15	Weekly Point-to-Point Rate (ln 13 / 52) $/MW - Weekly	(Line 13 / 52)			
16	Daily Off-Peak Point-to-Point Rate (ln 13 / 365) $/MW - Day	(Line 13 / 365)			
17	Hourly Off-Peak Point-to-Point Rate (ln 13 / 8760) $/MW - Hour	(Line 13 / 8760)			

AEP Companies: PSO and SWEPCO
Network Load for January Through December, ______
Based on West Zone-SPP Monthly Transmission System Firm Peak Demands (1) for the Twelve Months Ended December 31, ______

Projected Combined Load Worksheet

Line No.	SPP Load Responsibility	Month Peak Day Peak Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	12 Month Average MW
							*projected	*projected	*projected	*projected	*projected	*projected	*projected	*projected	
1	**PSO**														
2	**SWEPCO**														
3	**TNCN**														
4	**OMPA**														
5	**NTEC**														
6	**ETEC**														
7	**TEXLA**														
8	**Greenbelt**														
9	**Lighthouse**														
10	**Coffeyville, KS (OATT Firm PTP) (2)**														
11	**Zone 1 - System Firm Peak Demands**														

Historical Combined Load Worksheet

Line No.	SPP Load Responsibility	Month Peak Day Peak Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	12 Month Average MW
12	**PSO**														
13	**SWEPCO**														
14	**TNCN**														
15	**OMPA**														
16	**NTEC**														
17	**ETEC**														
18	**TEXLA**														
19	**Greenbelt**														
20	**Lighthouse**														
21	**Coffeyville, KS (OATT Firm PTP) (2)**														
22	**Zone 1 - System Firm Peak Demands**														
	Supporting Data														
23	**PSO:** PSO Native Load														
24	KAMO														
25	WFEC														
26	**PSO Load Responsibility**														
27	**SWEPCO:** SWEPCO Native Load														
28	Less: NTEC														
29	Less: ETEC														
30	Less: TEXLA														
31	AECC														
32	LaGen (Formerly Cajun)														
33	Lafayette														
34	Dolet Hills Aux. Load (not self-generate														
35	**SWEPCO Load Responsibility**														
36	**TNC** TNC North Native Load														
37	**TNC North Load Responsibility**														
38	Coffeyville Actual Load (2)														

Notes:
(1) MW, at the time of the AEP-SPP Native Peak. At the generator. Transmission losses added to metered values which include appropriate dist.& xfmr loss
(2) Net load from East and West Coffeyville ties, not included in AEP Control Area

Issued by: L. Patrick Bourne, Director
Transmission and Regulatory Policy

Issued on:

Effective:

AEP Transmission Formula Rate Template
Utilizing FERC Form 1 Cost Data for ______
Plus Capital Additions for ______

TCOS
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Company: ________________________________

Line No.			Total	Allocator	Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(ln 128)			
2	REVENUE CREDITS	(Note A)			
3	Transmission Credits	(Worksheet A)		DA	
4	Assoc. Business Development	(Worksheet A)		DA	
5	Total Revenue Credits				
6	REVENUE REQUIREMENT (w/o incentives) For All AEP Facilities	(ln 1 less ln 5)			
7	Revenue Requirement for SPP Base Plan Upgrades (w/o incentives)	(Worksheet G)		DA	
8	REVENUE REQUIREMENT EXCLUDING BASE PLAN UPGRADE ATRR	(ln 6 less ln 7)			
9	NET PLANT CARRYING CHARGE (w/o incentives)	(Note B)			
10	Annual Rate	(ln 6 / ln 42 x 100)			
11	Monthly Rate	(ln 10 / 12)			
12	NET PLANT CARRYING CHARGE, W/O DEPRECIATION (w/o incentives) (Note B)				
13	Annual Rate	((ln 6 - ln 98) / ln 42 x 100)			
14	NET PLANT CARRYING CHARGE, W/O DEPRECIATION, INCOME TAXES AND RETURN (Note B)				
15	Annual Rate	((ln 6 - ln 98 - ln 122 - ln 123) / ln 42 x 100)			
16	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note C) (Worksheet F)			NA	
17	**PROJECTED YE 2007 TRANSMISSION REVENUE REQUIREMENT**	**(ln 8 + ln 16)**			

AEP Transmission Formula Rate Template
Utilizing FERC Form 1 Cost Data for ______
Plus Capital Additions for ______

TCOS
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Company: ______________________________

Line No.	(1) RATE BASE CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator		(5) Total Transmission
	GROSS PLANT IN SERVICE					
18	Production	205.46.g		NA		
19	Transmission	207.58.g		DA		
20	Plus: Transmission Plant-in-Service Additions (Worksheet H)			DA		
21	Plus: Additional Trans Plant on Transferred Assets (Worksheet H)			DA		
22	Distribution	207.75.g		NA		
23	General Plant	207.99.g (Note K)		W/S		
24	Intangible Plant	205.5.g		W/S		
25	Common	356		CE		
26	TOTAL GROSS PLANT	(sum lns 18 to 25)		**GP(p)=**		
				GTD(p)=		
27	ACCUMULATED DEPRECIATION AND AMORTIZATION					
28	Production	219.20-24.c		NA		
29	Transmission	219.25.c		**TP1=**		
30	Plus: Transmission Plant-in-Service Additions (Worksheet H)			DA		
31	Plus: Additional Projected Deprec on Transferred Assets (Worksheet H)			DA		
32	Plus: Additional Transmission Depreciation for 2007 (ln 98)			TP1		
33	Plus: Additional General & Intangible Depreciation for 2007 (ln 100 + ln 101)			W/S		
34	Plus: Additional Accum Deprec on Transferred Assets (Worksheet H)			DA		
35	Distribution	219.26.c		NA		
36	General Plant	219.28.c (Note K)		W/S		
37	Intangible Plant	219		W/S		
38	Common	356		CE		
39	TOTAL ACCUMULATED DEPRECIATION	(sum lns 28 to 38)				
40	NET PLANT IN SERVICE					
41	Production	(ln 18 - ln 28)				
42	Transmission	(ln 19 - ln 29)				
43	Plus: Transmission Plant-in-Service Additions	(ln 20 - ln 30)				
44	Plus: Additional Trans Plant on Transferred Assets	(ln 21 - ln 31)				
45	Plus: Additional Transmission Depreciation for 2007	(-ln 32)				
46	Plus: Additional General & Intangible Depreciation for 2007	(-ln 33)				
47	Plus: Additional Accum Deprec on Transferred Assets (Worksheet H)	(-ln 34)				
48	Distribution	(ln 22 - ln 35)				
49	General Plant	(ln 23 - ln 36)				
50	Intangible Plant	(ln 24 - ln 37)				
51	Common	(ln 25 - ln 38)				
52	TOTAL NET PLANT IN SERVICE	(sum lns 41 to 51)		**NP(p)=**		
53	ADJUSTMENTS TO RATE BASE	(Note D)				
54	Account No. 281 (enter negative)	273.8.k (Worksheet C)		DA		
55	Account No. 282 (enter negative)	275.2.k (Worksheet C)		DA		
56	Account No. 283 (enter negative)	277.9.k (Worksheet C)		DA		
57	Account No. 190	234.8.c (Worksheet C)		DA		
58	Account No. 255 (enter negative)	267.8.h (Worksheet C)		DA		
59	Account 107 for Approved Multi-Year Projects	216.43.b (Worksheet K)		DA		
60	Other Additions/Deductions	(Note E)		DA		
61	TOTAL ADJUSTMENTS	(sum lns 54 to 60)				
62	PLANT HELD FOR FUTURE USE	214.x.d (Note F)		DA		
63	WORKING CAPITAL	(Note G)				
64	Cash Working Capital	(1/8 * ln 96)				
65	Transmission Materials & Supplies	227.8.c		TP		
66	A&G Materials & Supplies	227.11.c		W/S		
67	Undistributed Stores Expense (Acct 163)	227.16.c		GP(h)		
68	Prepayments (Account 165) - Labor Allocated	111.57.c (Worksheet I)		W/S		
69	Prepayments (Account 165) - Direct Allocated	111.57.c (Worksheet I)		DA		
70	Prepayments (Account 165) - Gross Plant	111.57.c (Worksheet I)		GP(h)		
71	TOTAL WORKING CAPITAL	(sum lns 64 to 70)				
72	IPP CONTRIBUTIONS FOR CONSTRUCTION	#REF!		DA		
73	RATE BASE (sum lns 52, 61, 62, 71, 72)					

AEP Transmission Formula Rate Template
Utilizing FERC Form 1 Cost Data for ______
Plus Capital Additions for ______

TCOS
Page 3 of 10
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Company: ______________________________

Line No.	(1) EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator	(5) Total Transmission
	OPERATION & MAINTENANCE EXPENSE				
74	Transmission	321.112.b		TP	
75	Less: expenses 100% assigned to TO billed customers (Worksheet E, ln 14)			DA	
76	Less: Total Account 561 (Load Dispatch - Sch 1) (Note I)	321.84-92.b		TP	
77	Less: Account 565	321.96.b (Note J)		TP	
78	Plus: Acct 565 native load, zonal or pool	(Note J)		DA	
79	Transmission Subtotal (lns 74-75-76-77+78)				
80	Administrative and General	323.197.b (Note K)			
81	Less: Acc. 928, Reg. Com. Exp.	323.189.b			
82	Acct. 930.1, Gen. Advert. Exp.	323.191.b			
83	Acc. 924, Property Insurance	323.185.b			
84	Acc. 930.2, Misc. Gen. Exp.	323.192.b			
85	Acc. 935, Maint. of Gen. Plant	323.196.b		W/S	
86	Balance of A & G	(ln 80 - sum ln 81 to ln 85)		W/S	
87	Plus: Acct. 924, Property Insurance	(ln 83)		NP(h)	
88	Acct. 928 - Transmission Specific	(Note L) (Worksheet D)		TP	
89	Acct. 928 - Transmission Allocated	(Note L) (Worksheet D)		GP(h)	
90	Acct 930.1 - Only safety related ads.	(Note L) (Worksheet D)		W/S	
91	Acct 930.2 - Misc Gen. Exp. - Trans	(Worksheet D)		TP	
92	Acct 930.2 - Misc Gen. Exp. - Allocated	(Worksheet D)		W/S	
93	A & G Subtotal	(sum lns 84 to 90)			
94	Common	356		CE	
95	Transmission Lease Payments			DA	
96	TOTAL O & M EXPENSE	(ln 79 + ln 93 + ln 94 + ln 95)			
97	DEPRECIATION AND AMORTIZATION EXPENSE				
98	Transmission	336.7.f		TP	
99	Plus: Transmission Plant-in-Service Additions (Worksheet H)			DA	
100	General	336.10.f		W/S	
101	Intangible	336.1.f		W/S	
102	Common	336.11.f		CE	
103	TOTAL DEPRECIATION AND AMORTIZATIN	(sum lns 98 to 102)			
104	TAXES OTHER THAN INCOME	(Note M)			
105	Labor Related				
106	Payroll	262.x-263.x.i		W/S	
107	Plant Related				
108	Property	262.x-263.x.i		NP(h)	
109	Gross Receipts/Sales & Use	262.x-263.x.i		NA	
110	Other	262.x-263.x.i		GP(h)	
111	Payments in lieu of taxes			GP(h)	
112	TOTAL OTHER TAXES	114.14.c			
113	INCOME TAXES	(Note N)			
114	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =				
115	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =				
116	where WCLTD=(ln 158) and WACC = (ln 161)				
117	and FIT, SIT & p are as given in Note N.				
118	GRCF=1 / (1 - T) = (from ln 114)				
119	Amortized Investment Tax Credit (enter negative)				
120	Income Tax Calculation	(ln 115 * ln 123)			
121	ITC adjustment	(ln 118 * ln 119)		NP(h)	
122	TOTAL INCOME TAXES	(sum lns 120 to 121)			
123	RETURN ON RATE BASE (Rate Base*WACC)	(ln 73 * ln 161)			
124	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note H) (Worksheet B, ln 16)			DA	
125	REVENUE REQUIREMENT BEFORE TEXAS GROSS MARGIN TAX				
126	(sum lns 96, 103, 112, 122, 123, 124)				
127	TEXAS GROSS MARGIN TAX (NOTE O) (Worksheet J)			DA	
128	REVENUE REQUIREMENT INCLUDING GROSS MARGIN TAX				

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Utilizing FERC Form 1 Cost Data for ______
Plus Capital Additions for ______

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Company: ______________________________

SUPPORTING CALCULATIONS

ln No.							
	TRANSMISSION PLANT INCLUDED IN SPP TARIFF						
129	Total transmission plant	(ln 19 + ln 20 + ln 21)					
130	Less transmission plant excluded from SPP Tariff (Note P)						
131	Less transmission plant included in OATT Ancillary Services (Note Q)		(Worksheet L)				
132	Transmission plant included in SPP Tariff	(ln 129 - ln 130 - ln 131)					
133	Percent of transmission plant in SPP Tariff	(ln 132 / ln 129)				TP=	
134	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	Payroll Billed from AEP Service Corp.			
135	Production	354.20,22.b			NA		
136	Transmission	354.21.b			TP		
137	Distribution	354.23.b			NA		
138	Other (Excludes A&E	354.24,25,26.b			NA		
139	Total	(sum lns 135 to 138)					
140	Transmission related amount					W/S=	
141	COMMON PLANT ALLOCATOR (CE)						
142	Electric	200.3.c			DA		
143	Gas	200.3.d			NA		
144	Other	200.3. e, f, g			NA		
145	Total	(sum lns 142 to 144)					
146	Electric related amount						
147	W/S Allocator					W/S	
148	Transmission related amount	(ln 146 * ln 147)				**CE=**	
149	WEIGHTED AVERAGE COST OF CAPITAL (WACC)						$
150		Long Term Interest (117, sum of 62c - 66c)					
151		Preferred Dividends (118.29.c) (positive number)					
152	Development of Common Stock:						
153		Proprietary Capital (112.16.c)					
154		Less Preferred Stock (ln 159)					
155		Less Account 219.1 (112.15.c)					
156		Common Stock (ln 153 - ln 154 - ln 155)					
157			$	%	Cost (Note S)		Weighted
158	Long Term Debt (112, sum of 18.c - 21.c)						
159	Preferred Stock (112.3.c)						
160	Common Stock (ln 156)						
161	Total (sum lns 158 to 160)					**WACC=**	

AEP Transmission Formula Rate Template
Utilizing FERC Form 1 Cost Data for ______
Plus Capital Additions for ______

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Company: ______________________________

Letter	Notes
	General Notes: a) References to data from FERC Form 1 are indicated as: page#.line#.col.# b) If transmission owner ("TO") functionalizes its costs to transmission on its books, those costs are shown above and on any supporting workpapers rather than using the allocations above.
A	The revenue credits shall include a) amounts received directly from the SPP for PTP transmission services, b) direct assignment charges for transmission facilities, the cost of which has been included in the TCOS, and c) amounts from customers taking service under grandfathered agreements, where the demand is not included in the rate divisor. Revenues associated with FERC annual charges, gross receipts taxes, ancillary services or facilities excluded from the TCOS are not included 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	The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for facilities and any upgrades.
C	This additional revenue requirement is determined using a net plant carrying charge (fixed carrying charge or FCR) approach. Worksheet F shows the calculation of the additional incentive revenue requirement for each project receiving incentive rate treatment, as accepted by FERC. These individual additional revenue requirements shall be summed, for the projected year, and included here.
D	Reflects the transmission related portion of balances in Accounts 281, 282, 283, 190, 255 and, if applicable, 107. The balance of Account 255 is reduced by prior flow throughs and completely excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note M. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. Transmission allocations are shown on Worksheet C.
E	Include Account 182.3, Other Regulatory Assets, related to Transmission Service under this Tariff, if any. Also include any unamortized balances related to pre-commercial operation costs when recovery of abandonment costs are granted.
F	Identified as being transmission related or functionally booked to transmission.
G	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission on line 96.
H	Consistent with Paragraph 657 of Order 2003-A, the amount on line 72 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 124.
I	Removes the expense booked to transmission accounts included in the development of OATT ancillary services rates, including all of Account No. 561.
J	Removes cost of transmission service provided by others to the extent such service is not incurred to provide the SPP service at issue.
K	General Plant and Administrative & General expenses may be functionalized based on allocators other then the W/S allocator. Full documentation must be provided.
L	Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. Worksheet D allocates these expense items. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS.
M	Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts tax and taxes related to income are excluded.
N	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (ln 119) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0. Inputs Required: FIT = 0.00% SIT= 0.00% (State Income Tax Rate or Composite SIT. Worksheet J)) p = 0.00% (percent of federal income tax deductible for state purposes)
O	Effective January 1, 2007, Texas instituted a gross margin tax. This tax is calculated on the Texas allocated revenue of the Company, reduced by 30% to derive a "Gross Margin" for the Company. The tax rate of one percent is assessed on the resulting amount. The jurisdictional allocator is based on transmission demand allocators.
P	Removes plant excluded from the OATT because it does not meet the SPP's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.
Q	Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
R	Includes functional wages & salaries incurred by parent company service corporation for support of the operating company.
S	Long Term Debt cost rate = long-term interest (ln 150) / long term debt (ln 158). Preferred Stock cost rate = preferred dividends (ln 151) / preferred outstanding (ln 159).

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Utilizing FERC Form 1 Cost Data for ______
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Company: ______________________________

Line No.			Total	Allocator	Transmission Amount
162	REVENUE REQUIREMENT (w/o incentives)	(ln 286)			
163	REVENUE CREDITS	(Note A)			
164	Transmission Credits	(Worksheet A)		DA	
165	Assoc. Business Development	(Worksheet A)		DA	
166	Total Revenue Credits				
167	REVENUE REQUIREMENT (w/o incentives) For All AEP Facilities	(ln 162 less ln 166)			
168	Revenue Requirement for SPP Base Plan Upgrades (w/o incentives)	(Worksheet G)		DA	
169	REVENUE REQUIREMENT EXCLUDING BASE PLAN UPGRADE ATRR	(ln 167 less ln 168)			
170	NET PLANT CARRYING CHARGE (w/o incentives) (Note B)				
171	Annual Rate	(ln 167 / ln 203 x 100)			
172	Monthly Rate	(ln 171 / 12)			
173	NET PLANT CARRYING CHARGE, W/O DEPRECIATION (w/o incentives) (Note B)				
174	Annual Rate	((ln 167 - ln 259) / ln 203 x 100)			
175	NET PLANT CARRYING CHARGE, W/O DEPRECIATION, INCOME TAXES AND RETURN (Note B)				
176	Annual Rate	((ln 167 - ln 259 - ln 283 - ln 284) / ln 203 x 100)			
177	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note C) (Worksheet F)			NA	
178	**HISTORICAL YE 2006 TRANSMISSION REVENUE REQUIREMENT**	**(ln 169 + ln 177)**			

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Utilizing FERC Form 1 Cost Data for ______
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Company: ________________________________

Line No.	(1) RATE BASE CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator	(5) Total Transmission
	GROSS PLANT IN SERVICE				
179	Production	205.46.g		NA	
180	Transmission	207.58.g		DA	
181	Plus: Transmission Plant-in-Service Additions (Worksheet H)		N/A	DA	N/A
182	Plus: Additional Trans Plant on Transferred Assets (Worksheet H)		N/A	DA	N/A
183	Distribution	207.75.g		NA	
184	General Plant	207.99.g (Note K)		W/S	
185	Intangible Plant	205.5.g		W/S	
186	Common	356		CE	
187	TOTAL GROSS PLANT	(sum lns 179 to 186)		GP(h)=	
				GTD=	
188	ACCUMULATED DEPRECIATION AND AMORTIZATION				
189	Production	219.20-24.c		NA	
190	Transmission	219.25.c		TP1=	
191	Plus: Transmission Plant-in-Service Additions (Worksheet H)		N/A	DA	N/A
192	Plus: Additional Projected Deprec on Transferred Assets (Worksheet H)		N/A	DA	N/A
193	Plus: Additional Transmission Depreciation for 2007 (ln 259)		N/A	TP1	N/A
194	Plus: Additional General & Intangible Depreciation for 2007 (ln 261 + ln 262)		N/A	W/S	N/A
195	Plus: Additional Accum Deprec on Transferred Assets (Worksheet H)		N/A	DA	N/A
196	Distribution	219.26.c		NA	
197	General Plant	219.28.c (Note K)		W/S	
198	Intangible Plant	219		W/S	
199	Common	356		CE	
200	TOTAL ACCUMULATED DEPRECIATION	(sum lns 189 to 199)			
201	NET PLANT IN SERVICE				
202	Production	(ln 179 - ln 189)			
203	Transmission	(ln 180 - ln 190)			
204	Plus: Transmission Plant-in-Service Additions	(ln 181 - ln 191)	N/A		N/A
205	Plus: Additional Trans Plant on Transferred Assets	(ln 182 - ln 192)	N/A		N/A
206	Plus: Additional Transmission Depreciation for 2007	(-ln 193)	N/A		N/A
207	Plus: Additional General & Intangible Depreciation for 2007	(-ln 194)	N/A		N/A
208	Plus: Additional Accum Deprec on Transferred Assets (Worksheet H)	(-ln 195)	N/A		N/A
209	Distribution	(ln 183 - ln 196)			
210	General Plant	(ln 184 - ln 197)			
211	Intangible Plant	(ln 185 - ln 198)			
212	Common	(ln 186 - ln 199)			
213	TOTAL NET PLANT IN SERVICE	(sum lns 202 to 212)		NP(h)=	
214	ADJUSTMENTS TO RATE BASE	(Note D)			
215	Account No. 281 (enter negative)	273.8.k (Worksheet C)		DA	
216	Account No. 282 (enter negative)	275.2.k (Worksheet C)		DA	
217	Account No. 283 (enter negative)	277.9.k (Worksheet C)		DA	
218	Account No. 190	234.8.c (Worksheet C)		DA	
219	Account No. 255 (enter negative)	267.8.h (Worksheet C)		DA	
220	Account 107 for Approved Multi-Year Projects	216.43.b (Worksheet K)		DA	
221	Other Additions/Deductions	(Note E)		DA	
222	TOTAL ADJUSTMENTS	(sum lns 215 to 221)			
223	PLANT HELD FOR FUTURE USE	214.x.d (Note F)		DA	
224	WORKING CAPITAL	(Note G)			
225	Cash Working Capital	(1/8 * ln 257)			
226	Transmission Materials & Supplies	227.8.c		TP	
227	A&G Materials & Supplies	227.11.c		W/S	
228	Undistributed Stores Expense (Acct 163)	227.16.c		GP(h)	
229	Prepayments (Account 165) - Labor Allocated	111.57.c (Worksheet I)		W/S	
230	Prepayments (Account 165) - Direct Allocated	111.57.c (Worksheet I)		DA	
231	Prepayments (Account 165) - Gross Plant	111.57.c (Worksheet I)		GP(h)	
232	TOTAL WORKING CAPITAL	(sum lns 225 to 231)			
233	IPP CONTRIBUTIONS FOR CONSTRUCTION	#REF!		DA	
234	RATE BASE (sum lns 213, 222, 223, 232, 233)				

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Utilizing FERC Form 1 Cost Data for ______
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Company: ________________________________

Line No.	(1) EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator	(5) Total Transmission
	OPERATION & MAINTENANCE EXPENSE				
235	Transmission	321.112.b		TP	
236	Less: expenses 100% assigned to TO billed customers (Worksheet E, ln 14)			DA	
237	Less: Total Account 561 (Load Dispatch - Sch 1) (Note I)	321.84-92.b		TP	
238	Less: Account 565	321.96.b (Note J)		TP	
239	Plus: Acct 565 native load, zonal or pool	(Note J)		DA	
240	Transmission Subtotal (lns 235-236-237-238+239)				
241	Administrative and General	323.197.b (Note K)			
242	Less: Acc. 928, Reg. Com. Exp.	323.189.b			
243	Acct. 930.1, Gen. Advert. Exp.	323.191.b			
244	Acc. 924, Property Insurance	323.185.b			
245	Acc. 930.2, Misc. Gen. Exp.	323.192.b			
246	Acc. 935, Maint. of Gen. Plant	323.196.b		W/S	
247	Balance of A & G	(ln 241 - sum ln 242 to ln 246)		W/S	
248	Plus: Acct. 924, Property Insurance	(ln 244)		NP(h)	
249	Acct. 928 - Transmission Specific	(Note L) (Worksheet D)		TP	
250	Acct. 928 - Transmission Allocated	(Note L) (Worksheet D)		GP(h)	
251	Acct 930.1 - Only safety related ads	(Note L) (Worksheet D)		W/S	
252	Acct 930.2 - Misc Gen. Exp. - Trans	(Worksheet D)		TP	
253	Acct 930.2 - Misc Gen. Exp. - Allocated	(Worksheet D)		W/S	
254	A & G Subtotal	(sum lns 246 to 253)			
255	Common	356		CE	
256	Transmission Lease Payments			DA	
257	TOTAL O & M EXPENSE	(ln 240 + ln 254 + ln 255 + ln 256)			
258	DEPRECIATION AND AMORTIZATION EXPENSE				
259	Transmission	336.7.f		TP	
260	Plus: Transmission Plant-in-Service Additions (Worksheet H)		N/A	DA	N/A
261	General	336.10.f		W/S	
262	Intangible	336.1.f		W/S	
263	Common	336.11.f		CE	
264	TOTAL DEPRECIATION AND AMORTIZATION	(sum lns 259 to 263)			
265	TAXES OTHER THAN INCOME	(Note M)			
266	Labor Related				
267	Payroll	262.x-263.x.i		W/S	
268	Plant Related				
269	Property	262.x-263.x.i		NP(h)	
270	Gross Receipts/Sales & Use	262.x-263.x.i		NA	
271	Other	262.x-263.x.i		GP(h)	
272	Payments in lieu of taxes			GP(h)	
273	TOTAL OTHER TAXES	114.14.c			
274	INCOME TAXES	(Note N)			
275	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =				
276	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =				
277	where WCLTD=(ln 319) and WACC = (ln 322)				
278	and FIT, SIT & p are as given in Note N.				
279	GRCF=1 / (1 - T) = (from ln 275)				
280	Amortized Investment Tax Credit (enter negative)				
281	Income Tax Calculation	(ln 276 * ln 284)			
282	ITC adjustment	(ln 279 * ln 280)		NP(h)	
283	TOTAL INCOME TAXES	(sum lns 281 to 282)			
284	RETURN ON RATE BASE (Rate Base*WACC)	(ln 234 * ln 322)			
285	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note H) (Worksheet B, ln 16)			DA	
286	REVENUE REQUIREMENT BEFORE TEXAS GROSS MARGIN TAX				
287	(sum lns 257, 264, 273, 283, 284, 285)				
288	TEXAS GROSS MARGIN TAX (NOTE O) (Worksheet J)			DA	
289	REVENUE REQUIREMENT INCLUDING GROSS MARGIN TAX				

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Company: ________________________________

SUPPORTING CALCULATIONS

ln No.							
	TRANSMISSION PLANT INCLUDED IN SPP TARIFF						
290	Total transmission plant	(ln 180)					
291	Less transmission plant excluded from SPP Tariff (Note P)						
292	Less transmission plant included in OATT Ancillary Services (Note Q)		(Worksheet L)				
293	Transmission plant included in SPP Tariff	(ln 290 - ln 291 - ln 292)					
294	Percent of transmission plant in SPP Tariff	(ln 293 / ln 290)				**TP=**	
				Payroll Billed from AEP			
295	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	Service Corp.			
296	Production	354.20,22.b			NA		
297	Transmission	354.21.b			TP		
298	Distribution	354.23.b			NA		
299	Other (Excludes A&E	354.24,25,26.b			NA		
300	Total	(sum lns 296 to 299)					
301	Transmission related amount					**W/S=**	
302	COMMON PLANT ALLOCATOR (CE)						
303	Electric	200.3.c			DA		
304	Gas	200.3.d			NA		
305	Other	200.3. e, f, g			NA		
306	Total	(sum lns 303 to 305)					
307	Electric related amount						
308	W/S Allocator					W/S	
309	Transmission related amount	(ln 307 * ln 308)				**CE=**	
310	WEIGHTED AVERAGE COST OF CAPITAL (WACC)						$
311		Long Term Interest (117, sum of 62c - 66c)					
312		Preferred Dividends (118.29.c) (positive number)					
313	Development of Common Stock						
314		Proprietary Capital (112.16.c)					
315		Less Preferred Stock (ln 320)					
316		Less Account 219.1 (112.15.c)					
317		Common Stock (ln 314 - ln 315 - ln 316)					
318			$	%		Cost (Note S)	Weighted
319	Long Term Debt (112, sum of 18.c - 21.c)						
320	Preferred Stock (112.3.c)						
321	Common Stock (ln 317)						
322	Total (sum lns 319 to 321)					**WACC=**	

AEP Transmission Formula Rate Template
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Letter	Notes
	General Notes: a) References to data from FERC Form 1 are indicated as: page#.line#.col.# b) If transmission owner ("TO") functionalizes its costs to transmission on its books, those costs are shown above and on any supporting workpapers rather than using the allocations above
A	The revenue credits shall include a) amounts received directly from the SPP for PTP transmission services, b) direct assignment charges for transmission facilities the cost of which has been included in the TCOS, and c) amounts from customers taking service under grandfathered agreements, where the demand is not included in the rate divisor. Revenues associated with FERC annual charges, gross receipts taxes, ancillary services or facilities excluded from the TCOS are not included 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	The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for facilities and any upgrades.
C	This additional revenue requirement is determined using a net plant carrying charge (fixed carrying charge or FCR) approach. Worksheet F shows the calculation of the additional incentive revenue requirement for each project receiving incentive rate treatment, as accepted by FERC. These individual additional revenue requirements shall be summed, for the projected year, and included here.
D	Reflects the transmission related portion of balances in Accounts 281, 282, 283, 190, 255 and, if applicable, 107. The balance of Account 255 is reduced by prior flow throughs and completely excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note M. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. Transmission allocations are shown on Worksheet C.
E	Include Account 182.3, Other Regulatory Assets, related to Transmission Service under this Tariff, if any. Also include any unamortized balances related to pre-commercial operation costs when recovery of abandonment costs are granted.
F	Identified as being transmission related or functionally booked to transmission.
G	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission on line 257.
H	Consistent with Paragraph 657 of Order 2003-A, the amount on line 233 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 285.
I	Removes the expense booked to transmission accounts included in the development of OATT ancillary services rates, including all of Account No. 561.
J	Removes cost of transmission service provided by others to the extent such service is not incurred to provide the SPP service at issue.
K	General Plant and Administrative & General expenses may be functionalized based on allocators other then the W/S allocator. Full documentation must be provided.
L	Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. Worksheet D allocates these expense items. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS.
M	Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts tax and taxes related to income are excluded.
N	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (ln 280) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.

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

Letter	Notes
O	Effective January 1, 2007, Texas instituted a gross margin tax. This tax is calculated on the Texas allocated revenue of the Company, reduced by 30% to derive a "Gross Margin" for the Company. The tax rate of one percent is assessed on the resulting amount. The jurisdictional allocator is based on transmission demand allocators.
P	Removes plant excluded from the OATT because it does not meet the SPP's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT
Q	Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
R	Includes functional wages & salaries incurred by parent company service corporation for support of the operating company.
S	Long Term Debt cost rate = long-term interest (ln 311) / long term debt (ln 319). Preferred Stock cost rate = preferred dividends (ln 312) / preferred outstanding (ln 320).

Worksheet List:

- **A** **Revenue Credits**
- **B** **IPP - System Upgrade Credit**
- **C** **ADIT & ITC Details**
- **D** **A&G Expense Detail**
- **E** **Transmission Expense Adjustments**
- **F** **ATRR Calculation for Non-Base Plan Projects**
- **G** **ATRR Calculation for SPP Base Plan Upgrades**
- **H** **Transmission Plant-in-Service Additions**
- **I** **Non-Tax Balance Sheet Adjustments**
- **J** **Tax**
- **K** **CWIP Balances on Multi-Year Projects**
- **L** **GSU Net Book Values**

ATTACHMENT T

Rate Sheets For Point-To-Point Transmission Service

~~American Electric Power – West~~Zone 1

Rate Sheet For Point-to-Point Transmission Service

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. Monthly delivery: $1528.30~~1090.33~~/MW of Reserved Capacity per month.
2. Weekly delivery: $ 352.66~~250.92~~/MW of Reserved Capacity per week.
3. Daily delivery:
   On-Peak: $ 70.54~~50.19~~/MW of Reserved Capacity per day.
   Off-Peak: $ 50.25~~35.85~~/MW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in Section 2 above times the highest amount in megawatts of Reserved Capacity in any day during such week. For the purpose of the rate specified in Section 3 above, the Off-Peak Period shall be Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day and the On-Peak Period shall be all days that are not in the Off-Peak Period.

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: $1528.30~~1090.33~~/MW of Reserved Capacity per month.
2. Weekly delivery: $ 352.66~~250.92~~/MW of Reserved Capacity per week.
3. Daily delivery:
   On-Peak: $ 70.54~~50.19~~/MW of Reserved Capacity per day.
   Off-Peak $ 50.25~~35.85~~/MW of Reserved Capacity per day.
4. Hourly delivery:
   On-Peak: $ 4.41~~3.14~~/MW of Reserved Capacity per hour.
   Off-Peak $ 2.10~~1.50~~/MW of Reserved Capacity per hour.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in Section 3 above times the highest amount in megawatts 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 megawatts of Reserved Capacity in any hour during such week.

For the purpose of the rate specified in Section 3 above, the Off-Peak Period shall be Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day and the On-Peak Period shall be all days that are not in the Off-Peak Period.

For the purpose of the rate specified in Section 4 above, On-Peak is all hours between HE 0700 and HE 2200, inclusive, Central Time Zone, excluding Sundays and holidays. Holidays shall be as defined by NERC, currently New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. Off-Peak is all hours not designated as On-Peak.

~~Discounts for Certain Through and Out Service Transactions Via American Electric Power (Public Service Company of Oklahoma, Southwestern Electric Power Company, and SPP portion of Texas North Company) Pricing Zone:~~

~~For the purpose of this Section, the following definitions shall apply:~~

~~CPL:~~ ~~Central Power and Light Company.~~

~~AEP:~~ ~~American Electric Power, Inc. including its operating company affiliates located in the SPP region (Public Service Company of Oklahoma, Southwestern Electric Power Company , and the SPP portion of Texas North Company).~~

~~AEP Operating Companies' Tariff:~~ ~~The open access transmission service tariff on file with the Commission under which the AEP Operating Companies offer, among other services, ERCOT Regional Transmission Service.~~

~~ERCOT:~~ ~~The Electric Reliability Council of Texas.~~

:

~~ERCOT Power Supplier:~~ ~~An electric utility that sells electricity for resale into ERCOT and takes transmission service under Part IV of the AEP Operating Companies' Tariff for such sales~~.

RESERVED

~~**Load Serving Entity:**~~ ~~Any electric utility operating in ERCOT that serves Native Load Customers within ERCOT.~~

~~**Native Load Customer:**~~ ~~The wholesale and retail power customers of CPL and WTU on whose behalf CPL and WTU, by statute, franchise, regulatory requirement, or contract, have undertaken an obligation to construct and operate the CPL and WTU systems to meet the reliable electric needs of such customers or the wholesale and retail power customers of a Load Serving Entity, by statute, franchise, regulatory requirement, or contract has undertaken an obligation to plan, construct and operate the Load Serving Entity's system to meet the reliable electric needs of such customers. Native Load Customers do not include load served outside of ERCOT.~~

~~**Planned Resource:**~~ ~~Any generation resource owned, controlled, or purchased by an ERCOT Power Supplier or Load Serving Entity and designated as a Planned Resource for the purpose of serving load located in ERCOT.~~

RESERVED

~~**Unplanned Resource:**~~ ~~Any generation resource owned or purchased by an ERCOT Power Supplier or Load Serving Entity, used to serve loads within ERCOT and not designated as a Planned Resource.~~

~~**WTU:**~~ ~~West Texas Utilities Company.~~

~~**Discount Provision:**~~

~~A Load Serving Entity that takes ERCOT Regional Transmission Service under Part IV of the AEP Operating Companies' Tariff and also takes transmission service under Part II of this Tariff to import into ERCOT Planned Resources or Unplanned Resources to serve its Native Load Customers in ERCOT shall have its zonal rates under Schedules 7 and 8 reduced by 45.27% in instances when AEP is the applicable pricing zone under the SPP Tariff. This discount applies only to charges under Schedules 7 and 8 of the SPP Tariff.~~

SCHEDULE 1

Scheduling, System Control And Dispatch Service

Scheduling, System Control and Dispatch Service is required to schedule the movement of power through, out of, within or into a Control Area. Charges for such service shall be as follows:

1) For Customers taking Firm or Non-Firm Point-To-Point Transmission Service, for through and out transactions, the Schedule 1 charge shall be the product of the capacity reserved, expressed in MW and the appropriate rate as follows:

   On-Peak:

   Monthly Rate $ 59.2979 per MW-Month
   Weekly Rate $13.6841 per MW-Week (The Monthly Rate times 12, divided by 52)
   Daily Rate $2.7368 per MW-Day (The Monthly Rate times 12, divided by 260)
   Hourly Rate $0.1711 per MW-Hour (The Monthly Rate times 12, divided by 4160)

   Off Peak:

   Daily Rate/MW $1.9495 per MW-Day (The Monthly Rate times 12, divided by 365)
   Hourly Rate/MW $0.1711 per MW-Hour (The Monthly Rate times 12, divided by 8760)

   On-Peak and Off-Peak Periods

   Off-Peak days shall be Saturdays and Sundays and all NERC holidays. All other days shall be On-Peak. All hours during Off-Peak days shall be Off-Peak. On-Peak hours during On-Peak days shall be all hours from HE 0700 through HE 2200 Central Prevailing Time. All other hours during On-Peak days shall be Off-Peak.

2) For Customers taking Firm or Non-Firm Point-To-Point Transmission Service, for transactions into and within the Transmission System, the Schedule 1 charge shall be the charge computed pursuant to the approved rate schedule of the Zone that is the Point of Delivery. See Addendum 1 to this Schedule 1 for Zone 1 charges.

3) For Customers taking Network Integration Transmission Service, the Schedule 1 charge shall be the charge computed pursuant to the approved rate schedule of the Zone in which the load is located. See Addendum 1 to this Schedule 1 for Zone 1 charges.

ADDENDUM 1 TO SCHEDULE 1
Revenue Requirements for the Allocation of Through And Out Transaction Revenue

Revenue associated with the provision of Schedule 1 service for Customers taking Firm or Non-Firm Point-To-Point Transmission Service for through and out transactions, shall be allocated to Transmission Owners in proportion to the respective scheduling revenue requirement of each such Transmission Owner associated with the provision of this service. Such scheduling revenue requirements are:

Transmission Owner	**CURRENTLY EFFECTIVE** Revenue Requirement
AEP	$3,257,073
Aquila - MPS	$1,620,559
Aquila - WPK	$594,828
Empire	$260,944
GRDA	$686,880
KCPL	$0
Midwest	$190,804
OG+E	$4,759,216
SPA	$1,622,827
Springfield	$0
SPS	$1,674,015
Westar	$3,209,760
WFEC	$1,824,120
Total	$19,355,553

Zone 1 charges for Scheduling, System Control and Dispatch Service:

(a) Network Integration Transmission Service: $34.55 per MW of Network Load per month.
(b) Point-to-Point Transmission Service per MW reserved per:

Month	Week	Day	Hour
$34.55	$7.97	$1.14	$0.05

ATTACHMENT H

Annual Transmission Revenue Requirement For Network Integration Transmission Service

1. The Existing 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. The Base Plan Zonal Annual Transmission Revenue Requirement within each Zone for the purposes of determining the zonal charges under Schedule 11, Base Plan Charges, is specified in column 4.

(1) Zone	(2)	(3) Existing Zonal ATRR	(4) Base Plan Zonal ATRR
1	American Electric Power (Public Service Company of Oklahoma, and Southwestern Electric Power Company, collectively “AEP”)	See Section 7 below	$
1	East Texas Electric Cooperative, Inc.	$2,733,879	$0
1	Tex-La Electric Cooperative of Texas, Inc.	$588,874	$0
1	Deep East Texas Electric Cooperative, Inc.	$428,131	$0
2	Cleco Corporation	$ 29,328,000	$0
3	City Utilities of Springfield, Missouri	$ 8,651,509	$0
4	Empire District Electric Company	$ 14,075,000	$0
5	Grand River Dam Authority (Est.)	$ 24,589,256	$0
6	Kansas City Power & Light Company	$ 35,461,776	$0
7	Oklahoma Gas & Electric Company	$ 65,065,032	$0
8	Midwest Energy, Inc.	$ 4,197,347	$0
9	Aquila Networks-MPS/L&P	$ 20,759,283	$0
9a	Aquila Networks-MPS	$14,059,183	$0
9b	Aquila Networks-L&P	$6,700,100	$0
10	Southwestern Power Administration	$9,155,900	$0
11	Southwestern Public Service	$65,500,000	$0
12	Sunflower Electric Corporation	$ 14,484,045	$0
13	Western Farmers Electric Cooperative	$ 20,719,639	$0
14	Westar Energy, Inc. (Kansas Gas & Electric and Westar Energy)	See section 5 below	$0
15	Aquila Networks-WPK	$ 5,947,002	$0

2. The Base Plan Region-wide Annual Transmission Revenue Requirement for the purposes of determining the region-wide charges under Schedule 11 shall initially be $0.
3. The amounts in (1) and (2) shall be effective until amended by the Transmission Owner or modified by the Commission or other applicable regulatory authority.
4. The revenue requirements stated in Attachment H shall not be changed absent a filing with the Commission.
5. The Annual Transmission Revenue Requirement for purposes of the Network Integration Transmission Service shall be calculated using the rate formula set forth in Attachment H-1 of the Westar Open Access Transmission Tariff (Westar formula rate). The results of the formula calculation shall be posted on the SPP website and in an accessible location on Westar's OASIS website by May 15 of each calendar year and shall be effective on June 1 of such year. The Annual Transmission Revenue Requirement will be as identified on page 1, line 7 of the Westar formula rate, 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.
6. Pursuant to the Offer of Settlement approved by the Federal Energy Regulatory Commission in Xcel Energy Services Inc., 115 FERC ¶ 61,011, the Annual Transmission Reveune Requirement for the Southwestern Public Service Company (SPS) rate zone (Zone 11) stated on Sheet 161 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.
7. The AEP Annual Transmission Revenue Requirement for purposes of the Network Integration 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.

ADDENDUM 1 TO ATTACHMENT H
MONTHLY DEMAND CHARGE CALCULATION FOR ZONE 1
NETWORK INTEGRATION TRANSMISSION SERVICE

This Addendum to Attachment H sets forth the monthly Demand Charge for Zone 1 for Network Customers taking Network Integration Transmission Service under Schedule 9 to this Tariff.

Charges for Compensation to AEP

The monthly Demand Charge to Network Customers for compensation to AEP shall be determined by multiplying one twelfth (1/12) of the Existing Zonal ATRR for AEP, specified in Attachment H, by the Network Customer's monthly Network Load, determined in accordance with the provisions of Section 34.2, expressed in MW, divided by the total monthly Network Load for Zone 1. The total monthly Network Load shall be adjusted as necessary to incorporate the load of Network Integration Transmission Service Customers, and any zonal load served under grandfathered network and long-term firm point-to-point service agreements.

Charges for Compensation to East Texas Electric Cooperative, Inc., Tex-La Electric Cooperative of Texas, Inc. and Deep East Texas Electric Cooperative, Inc.

In addition to the charges specified for compensation to AEP above, the Transmission Provider shall calculate a monthly Demand Charge associated with the revenue requirements of East Texas Electric Cooperative, Inc., Tex-La Electric Cooperative of Texas, Inc. and Deep East Texas Electric Cooperative, Inc. which shall be applicable to all customers located in Zone 1 taking Network Service under this tariff, including any Transmission Owner within Zone 1 taking service under Section 39. The monthly charge to each customer for compensation to East Texas Electric Cooperative, Inc., Tex-La Electric Cooperative of Texas, Inc. and Deep East Texas Electric Cooperative, Inc. shall be the product of the customer's load ratio share and one twelfth (1/12) of such Transmission Owner's Existing Zonal Annual Transmission Revenue Requirement.

AEP Formula Rate Implementation Protocols

I. Annual Update

1. The rate formula template ("Formula") and these protocols together comprise the filed rate of Public Service Company of Oklahoma and Southwestern Electric Power Company (collectively, "AEP") for transmission service under the SPP OATT. AEP must follow the instructions specified in the Formula to calculate its Annual Transmission Revenue Requirements ("ATRR") and the rates for its Network Integration Transmission Service and Point-to-Point transmission service ("Formula Rate").

2. The Formula Rate shall initially be effective for service on and after the date specified by the Federal Energy Regulatory Commission ("FERC") in an order accepting the Formula Rate, and in subsequent years on and after July 1 of each calendar year through June 30 of the subsequent calendar year ("Rate Year"), subject to review, challenge and refunds or surcharges with interest, to the extent provided herein.

3. On or before May 25 of each calendar year, AEP shall:

   (a) recalculate the ATRR and the Formula Rate for the new Rate Year in accordance with the Formula Rate ("Annual Update");

   (b) provide such Annual Update and supporting information in read-only format to SPP, for posting on the SPP website, such information to include a populated Formula showing the calculation of such Annual Update and documentation supporting such calculation as provided in Section I.4 below (the date of such posting to be the "Posting Date");

   (c) disclose any changes in AEP accounting policies, practices or procedures that impact the Formula or calculations under the Formula that have occurred since the initial filing of the Formula or posting of the most recent Annual Update, as applicable; and

   (d) notify its transmission customers and affected regulatory commissions of the Annual Update posting, and provide, upon request, fully functioning spreadsheet files supporting the Annual Update.

4. The Annual Update for the Rate Year shall:

   (a) be based upon AEP's FERC Forms No. 1 for the most recent calendar year, and, to the extent specified in the Formula, upon the books and records of AEP consistent with the FERC accounting policies and practices ("Prior Year ATRR");

   (b) include adjustments reflecting the additional transmission plant in service, and related depreciation, and income taxes that are reasonably projected to be recorded upon the books and records of AEP consistent with the Formula and FERC accounting policies and practices, so as to estimate the ATRR as of the current calendar year end ("Projected ATRR");

(c) as and to the extent specified in the Formula, provide sufficiently detailed supporting documentation for data (and all adjustments thereto or allocations thereof) that are used to develop the Formula Rate and are not otherwise available directly from the FERC Form No. 1;

(d) beginning in the second year, compare the latest Prior Year ATRR with the Projected ATRR calculated in the prior year's Annual Update, thereby to determine the amount needed to be surcharged or refunded to customers in the new Rate Year to true up collections for the soon to end Rate Year, including interest at the applicable FERC refund interest rates; and

(d) be subject to review only in accordance with the procedures set forth in these Formula Rate Review Protocols ("Protocol").

5. A change to the Formula inputs related to revised return on equity financing ("ROE") or depreciation rates may not be made absent an appropriate filing with the FERC pursuant to Federal Power Act Section 205 or Section 206. Additionally, an annual increase in Post-Employment Benefits Other than Pensions ("PBOP") expenses that results in an increase in the Projected ATRR equivalent to $0.05 per kW per month for Network Integration Transmission Service, as compared to the immediately preceding ATRR Annual Update, may not be included in an Annual Update without such a filing.

6. If AEP files any corrections to its FERC Forms No. 1 during a Rate Year that would affect the Formula Rate for that Rate Year, such corrections and any resulting refunds or surcharges shall be reflected in the true up adjustment made part of the Annual Update for the next effective Rate Year.

II. Review Procedures for Annual Update

1. Each Annual Update shall be subject to the following review procedures ("Annual Review Procedures"):

(a) Each year, after the Posting Date and before June 25, AEP will convene a meeting ("Customer Meeting") to afford interested parties (e.g., Transmission Customers and affected state and federal regulatory authorities) an opportunity to discuss and become better informed regarding the Annual Update;

(b) Interested parties will have seventy-five (75) days after the Customer Meeting to serve reasonable information requests on AEP for information and workpapers supporting an Annual Update. Such information requests shall be limited to that which is necessary to determine if AEP has properly calculated the Annual Update under review (including any corrections pursuant to Section I.6). Further, such information requests shall not include requests for information related to Annual Updates from prior years except (i) to determine whether a prior year's approach on a given matter was the same or different from the current year's approach, or (ii) in connection with corrections pursuant to Section I.6.

(c) AEP shall make a good faith effort to respond to information requests pertaining to an Annual Update within fifteen (15) business days of receipt of such requests. Information requests received after 4 p.m. CPT shall be considered received the next business day.

(d) To the extent AEP and any interested party(ies) are unable to resolve disputes related to information requests submitted in accordance with these Annual Review Procedures, AEP or any interested party may petition the FERC to appoint an Administrative Law Judge as a discovery master. The discovery master shall have the power to issue binding orders to resolve discovery disputes and compel the production of discovery, as appropriate, in accordance with the Annual Review Procedures and consistent with the FERC's discovery rules.

(e) Any interested party shall have until the later of ninety (90) days after the Customer Meeting or fifteen (15) days after AEP's last response to reasonable information requests submitted pursuant to Section II.1(b) above, to review the calculation of the Annual Update ("Review Period") and to notify AEP in writing of any specific challenges to the Annual Update ("Issues"). Challenges to the Formula itself shall not be considered "Issues" for purposes of these Annual Review Procedures.

III. Resolution of Challenges

For each Annual Update:

1. If AEP and any interested party(ies) have not resolved all Issues identified pursuant to Section II.1(e) above within sixty (60) days after the Review Period for a given Annual Update, the interested party(ies) may file a complaint challenging the Annual Update, with regard to such Issue(s), in a proceeding at the FERC ("Formal Challenge").

(a) A party may file a Formal Challenge for a limited period of up to three (3) months after the sixty-day resolution period has ended. A party may not, thereafter, file a Formal Challenge as to the disputed Issue(s) for the then effective Rate Year. Failure to pursue an Issue or lodge a Formal Challenge regarding an Issue(s) as to a given Annual Update shall not bar pursuit of such Issue or the lodging of a Formal Challenge as to such Issue(s) as relates to a subsequent Annual Update review.

(b) All information produced pursuant to these Protocols may be included in any Formal Challenge.

2. In any proceeding ordered by the FERC in response to a Formal Challenge, AEP will bear the burden of proving that it has properly calculated the challenged Annual Update pursuant to the Formula. Challenges to the Formula itself shall not be considered "Formal Challenges" for purposes of these Annual Review Procedures, and shall be subject to the Commission's Rules and Regulations applicable to filings pursuant to 18 C.F.R. § 385.206.

3. Each Annual Update shall become final and shall no longer be subject to challenge on the later to occur of: (i) passage of the time specified in III.1(a) above for a Formal Challenge, if no such Formal Challenge has been filed and the FERC has not itself initiated a proceeding to consider the Annual Update; or (ii) the issuance of a final FERC order in response to a Formal Challenge or a proceeding initiated by the FERC to consider the Annual Update.

4. Any refunds or surcharges resulting from a Formal Challenge shall be calculated, with interest, from the effective date of the challenged Annual Update, and shall be reflected in the Annual Update for the next effective Rate Year.

AEP Transmission Formula Rate Template
For rates effective July 1, ______

..

SPP Zone 1 AEP Revenue Requirements

Line No.			AEP Annual Revenue Requirement	PSO Annual Revenue Requirement	SWEPCO Annual Revenue Requirement
A.	**Network Service**				
1	REVENUE REQUIREMENT (w/o incentives)	(TCOS Line 1)			
2	LESS: REVENUE CREDITS	(TCOS Line 5)			
3	CURRENT YEAR ZONE 1 AEP NETWORK SERVICE REVENUE REQUIREMENT	(TCOS Line 6)			
4	LESS: REVENUE REQUIREMENTS INCLUDED IN LINE 1 FOR:				
5	BASE PLAN UPGRADES (W/O INCENTIVES)	(TCOS Line 7)			
6	REQUESTED UPGRADES (W/O INCENTIVES)	(Worksheet F)			
7	ECONOMIC UPGRADES (W/O INCENTIVES)	(Worksheet F)			
8	SUBTOTAL				
9	EXISTING ZONAL ATRR (W/O INCENTIVES)	(Line 3- Line 8)			
10	INCENTIVE REVENUE REQUIREMENT FOR ZONAL PROJECTS	(TCOS ln 16)			
11	EXISTING ZONAL ATRR (W/ INCENTIVES)	(Line 9 + Line 10)			
12	HISTORICAL YEAR (2006) ACTUAL ATRR				
13	PROJECTED (2006) ATRR FROM PRIOR YEAR	Input from Prior Year			
14	PRIOR YEAR TRUE-UP	(Line 12 - Line 13)			
15	INTEREST ON PRIOR YEAR TRUE UP				
16	**EXISTING ZONAL ATRR FOR SPP OATT ATTACHMENT H, SEC. 1, COL. 3**	(Ln 11 + Ln 14 + Ln 15)			
B.	**Point-to-Point Service**				
17	2007 Projected AEP West Zone SPP Average 12-Mo. Peak Demand	(Load WS, ln 11)		MW	
18	Annual Point-to-Point Rate in $/MW - Year	(Line 16 / Line 17)			
19	Monthly Point-to-Point Rate in $/MW - Month	(Line 18 / 12)			
20	Weekly Point-to-Point Rate in $/MW - Weekly	(Line 19 / 52)			
21	Daily On-Peak Point-to-Point Rate in $/MW - Day	(Line 20 / 260)			
22	Daily Off-Peak Point-to-Point Rate in $/MW - Day	(Line 21 / 365)			
23	Hourly On-Peak Point-to-Point Rate in $/MW - Hour	(Line 22 / 4160)			
24	Hourly Off-Peak Point-to-Point Rate in $/MW - Hour	(Line 23 / 8760)			
C.	**SPP Regional Service**				
25	BASE PLAN UPGRADE ATRR W/O INCENTIVES	(Line 8)			
26	ADDITIONAL ATRR FOR FERC-APPROVED INCENTIVES ON BPU	(Worksheet G)			
27	**BASE PLAN UPGRADE ATRR FOR SPP COLLECTION UNDER SCHEDULE 11**				

AEP Transmission Formula Rate Template
For rates effective July 1, ______

SPP SCHEDULE 1 AEP Revenue Requirements

Line No.			AEP Annual Revenue Requirement	PSO Annual Revenue Requirement	SWEPCO Annual Revenue Requirement
A.	**Schedule 1 ARR**				
1	Total Load Dispatch & Scheduling (Account 561) (TCOS Line 76)				
2	Less: Load Disptach - Scheduling, System Control and Dispatch Services (321.88.b)				
3	Less: Load Disptach - Reliability, Planning & Standards Development Services (321.92.6)				
4	Total 561 Internally Developed Costs	(Line 1 - Line 2 - Line 3)			
5	Less: PTP Service Credit				
6	EXISTING ZONAL ARR	(Line 4 - Line 5)			
7	HISTORICAL YEAR (2006) ACTUAL ARR				
8	PROJECTED (2006) ARR FROM PRIOR YEAR				
9	PRIOR YEAR TRUE-UP				
10	INTEREST ON PRIOR YEAR TRUE UP				
11	Net Schedule 1 Revenue Requirement for Zone				
B.	**Schedule 1 Rate Calculations**				
12	2007 Projected AEP West Zone SPP Average 12-Mo. Peak Demand	(LOAD WS, Line 11)		MW	
13	Annual Point-to-Point Rate in \$/MW - Year	(Line 11 / Line 12)			
14	Monthly Point-to-Point Rate (ln 13 / 12) \$/MW - Month	(Line 13 / 12)			
15	Weekly Point-to-Point Rate (ln 13 / 52) \$/MW - Weekly	(Line 13 / 52)			
16	Daily Off-Peak Point-to-Point Rate (ln 13 / 365) \$/MW - Day	(Line 13 / 365)			
17	Hourly Off-Peak Point-to-Point Rate (ln 13 / 8760) \$/MW - Hour	(Line 13 / 8760)			

AEP Companies: PSO and SWEPCO
Network Load for January Through December, ______
Based on West Zone-SPP Monthly Transmission System Firm Peak Demands [1] for the Twelve Months Ended December 31, ______

Projected Combined Load Worksheet

Line No.	SPP Load Responsibility	Month / Peak Day / Peak Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	12 Month Average MW
							*projected	*projected	*projected	*projected	*projected	*projected	*projected	*projected	
1	PSO														
2	SWEPCO														
3	TNCN														
4	OMPA														
5	NTEC														
6	ETEC														
7	TEXLA														
8	Greenbelt														
9	Lighthouse														
10	Coffeyville, KS (OATT Firm PTP) [2]														
11	Zone 1 - System Firm Peak Demands														

Historical Combined Load Worksheet

Line No.	SPP Load Responsibility	Month / Peak Day / Peak Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	12 Month Average MW
12	PSO														
13	SWEPCO														
14	TNCN														
15	OMPA														
16	NTEC														
17	ETEC														
18	TEXLA														
19	Greenbelt														
20	Lighthouse														
21	Coffeyville, KS (OATT Firm PTP) [2]														
22	Zone 1 - System Firm Peak Demands														
	Supporting Data														
23	**PSO:** PSO Native Load														
24	KAMO														
25	WFEC														
26	**PSO Load Responsibility**														
27	**SWEPCO:** SWEPCO Native Load														
28	Less: NTEC														
29	Less: ETEC														
30	Less: TEXLA														
31	AECC														
32	LaGen (Formerly Cajun)														
33	Lafayette														
34	Dolet Hills Aux. Load (not self-generate														
35	**SWEPCO Load Responsibility**														
36	**TNC** TNC North Native Load														
37	**TNC North Load Responsibility**														
38	Coffeyville Actual Load [2]														

Notes:
(1) MW, at the time of the AEP-SPP Native Peak. At the generator. Transmission losses added to metered values which include appropriate dist.& xfmr loss
(2) Net load from East and West Coffeyville ties, not included in AEP Control Area

AEP Transmission Formula Rate Template
Utilizing FERC Form 1 Cost Data for ______
Plus Capital Additions for ______

TCOS
Page 1 of 10
PROJECTED

Company: ______________________________

Line No.			Total	Allocator	Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(ln 128)			
2	REVENUE CREDITS	(Note A)			
3	Transmission Credits	(Worksheet A)		DA	
4	Assoc. Business Development	(Worksheet A)		DA	
5	Total Revenue Credits				
6	REVENUE REQUIREMENT (w/o incentives) For All AEP Facilities	(ln 1 less ln 5)			
7	Revenue Requirement for SPP Base Plan Upgrades (w/o incentives)	(Worksheet G)		DA	
8	REVENUE REQUIREMENT EXCLUDING BASE PLAN UPGRADE ATRR	(ln 6 less ln 7)			
9	NET PLANT CARRYING CHARGE (w/o incentives)	(Note B)			
10	Annual Rate	(ln 6 / ln 42 x 100)			
11	Monthly Rate	(ln 10 / 12)			
12	NET PLANT CARRYING CHARGE, W/O DEPRECIATION (w/o incentives) (Note B)				
13	Annual Rate	((ln 6 - ln 98) / ln 42 x 100)			
14	NET PLANT CARRYING CHARGE, W/O DEPRECIATION, INCOME TAXES AND RETURN (Note B)				
15	Annual Rate	((ln 6 - ln 98 - ln 122 - ln 123) / ln 42 x 100)			
16	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note C)	(Worksheet F)		NA	
17	**PROJECTED YE 2007 TRANSMISSION REVENUE REQUIREMENT**	**(ln 8 + ln 16)**			

AEP Transmission Formula Rate Template
Utilizing FERC Form 1 Cost Data for ______
Plus Capital Additions for ______

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Company: ______________________________

Line No.	(1) RATE BASE CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator		(5) Total Transmission
	GROSS PLANT IN SERVICE					
18	Production	205.46.g		NA		
19	Transmission	207.58.g		DA		
20	Plus: Transmission Plant-in-Service Additions (Worksheet H)			DA		
21	Plus: Additional Trans Plant on Transferred Assets (Worksheet H)			DA		
22	Distribution	207.75.g		NA		
23	General Plant	207.99.g (Note K)		W/S		
24	Intangible Plant	205.5.g		W/S		
25	Common	356		CE		
26	TOTAL GROSS PLANT	(sum lns 18 to 25)		GP(p)=		
				GTD(p)=		
27	ACCUMULATED DEPRECIATION AND AMORTIZATION					
28	Production	219.20-24.c		NA		
29	Transmission	219.25.c		TP1=		
30	Plus: Transmission Plant-in-Service Additions (Worksheet H)			DA		
31	Plus: Additional Projected Deprec on Transferred Assets (Worksheet H)			DA		
32	Plus: Additional Transmission Depreciation for 2007 (ln 98)			TP1		
33	Plus: Additional General & Intangible Depreciation for 2007 (ln 100 + ln 101)			W/S		
34	Plus: Additional Accum Deprec on Transferred Assets (Worksheet H)			DA		
35	Distribution	219.26.c		NA		
36	General Plant	219.28.c (Note K)		W/S		
37	Intangible Plant	219		W/S		
38	Common	356		CE		
39	TOTAL ACCUMULATED DEPRECIATION	(sum lns 28 to 38)				
40	NET PLANT IN SERVICE					
41	Production	(ln 18 - ln 28)				
42	Transmission	(ln 19 - ln 29)				
43	Plus: Transmission Plant-in-Service Additions	(ln 20 - ln 30)				
44	Plus: Additional Trans Plant on Transferred Assets	(ln 21 - ln 31)				
45	Plus: Additional Transmission Depreciation for 2007	(-ln 32)				
46	Plus: Additional General & Intangible Depreciation for 2007	(-ln 33)				
47	Plus: Additional Accum Deprec on Transferred Assets (Worksheet H)	(-ln 34)				
48	Distribution	(ln 22 - ln 35)				
49	General Plant	(ln 23 - ln 36)				
50	Intangible Plant	(ln 24 - ln 37)				
51	Common	(ln 25 - ln 38)				
52	TOTAL NET PLANT IN SERVICE	(sum lns 41 to 51)		NP(p)=		
53	ADJUSTMENTS TO RATE BASE	(Note D)				
54	Account No. 281 (enter negative)	273.8.k (Worksheet C)		DA		
55	Account No. 282 (enter negative)	275.2.k (Worksheet C)		DA		
56	Account No. 283 (enter negative)	277.9.k (Worksheet C)		DA		
57	Account No. 190	234.8.c (Worksheet C)		DA		
58	Account No. 255 (enter negative)	267.8.h (Worksheet C)		DA		
59	Account 107 for Approved Multi-Year Projects	216.43.b (Worksheet K)		DA		
60	Other Additions/Deductions	(Note E)		DA		
61	TOTAL ADJUSTMENTS	(sum lns 54 to 60)				
62	PLANT HELD FOR FUTURE USE	214.x.d (Note F)		DA		
63	WORKING CAPITAL	(Note G)				
64	Cash Working Capital	(1/8 * ln 96)				
65	Transmission Materials & Supplies	227.8.c		TP		
66	A&G Materials & Supplies	227.11.c		W/S		
67	Undistributed Stores Expense (Acct 163)	227.16.c		GP(h)		
68	Prepayments (Account 165) - Labor Allocated	111.57.c (Worksheet I)		W/S		
69	Prepayments (Account 165) - Direct Allocated	111.57.c (Worksheet I)		DA		
70	Prepayments (Account 165) - Gross Plant	111.57.c (Worksheet I)		GP(h)		
71	TOTAL WORKING CAPITAL	(sum lns 64 to 70)				
72	IPP CONTRIBUTIONS FOR CONSTRUCTION	#REF!		DA		
73	RATE BASE (sum lns 52, 61, 62, 71, 72)					

AEP Transmission Formula Rate Template
Utilizing FERC Form 1 Cost Data for ______
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Company: ______________________________

Line No.	(1) EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator	(5) Total Transmission
	OPERATION & MAINTENANCE EXPENSE				
74	Transmission	321.112.b		TP	
75	Less: expenses 100% assigned to TO billed customers (Worksheet E, ln 14)			DA	
76	Less: Total Account 561 (Load Dispatch - Sch 1) (Note I)	321.84-92.b		TP	
77	Less: Account 565	321.96.b (Note J)		TP	
78	Plus: Acct 565 native load, zonal or pool	(Note J)		DA	
79	Transmission Subtotal (lns 74-75-76-77+78)				
80	Administrative and General	323.197.b (Note K)			
81	Less: Acc. 928, Reg. Com. Exp.	323.189.b			
82	Acct. 930.1, Gen. Advert. Exp.	323.191.b			
83	Acc. 924, Property Insurance	323.185.b			
84	Acc. 930.2, Misc. Gen. Exp.	323.192.b			
85	Acc. 935, Maint. of Gen. Plant	323.196.b		W/S	
86	Balance of A & G	(ln 80 - sum ln 81 to ln 85)		W/S	
87	Plus: Acct. 924, Property Insurance	(ln 83)		NP(h)	
88	Acct. 928 - Transmission Specific	(Note L) (Worksheet D)		TP	
89	Acct. 928 - Transmission Allocated	(Note L) (Worksheet D)		GP(h)	
90	Acct 930.1 - Only safety related ads.	(Note L) (Worksheet D)		W/S	
91	Acct 930.2 - Misc Gen. Exp. - Trans	(Worksheet D)		TP	
92	Acct 930.2 - Misc Gen. Exp. - Allocated	(Worksheet D)		W/S	
93	A & G Subtotal	(sum lns 84 to 90)			
94	Common	356		CE	
95	Transmission Lease Payments			DA	
96	TOTAL O & M EXPENSE	(ln 79 + ln 93 + ln 94 + ln 95)			
97	DEPRECIATION AND AMORTIZATION EXPENSE				
98	Transmission	336.7.f		TP	
99	Plus: Transmission Plant-in-Service Additions (Worksheet H)			DA	
100	General	336.10.f		W/S	
101	Intangible	336.1.f		W/S	
102	Common	336.11.f		CE	
103	TOTAL DEPRECIATION AND AMORTIZATIN	(sum lns 98 to 102)			
104	TAXES OTHER THAN INCOME	(Note M)			
105	Labor Related				
106	Payroll	262.x-263.x.i		W/S	
107	Plant Related				
108	Property	262.x-263.x.i		NP(h)	
109	Gross Receipts/Sales & Use	262.x-263.x.i		NA	
110	Other	262.x-263.x.i		GP(h)	
111	Payments in lieu of taxes			GP(h)	
112	TOTAL OTHER TAXES	114.14.c			
113	INCOME TAXES	(Note N)			
114	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =				
115	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =				
116	where WCLTD=(ln 158) and WACC = (ln 161)				
117	and FIT, SIT & p are as given in Note N.				
118	GRCF=1 / (1 - T) = (from ln 114)				
119	Amortized Investment Tax Credit (enter negative)				
120	Income Tax Calculation	(ln 115 * ln 123)			
121	ITC adjustment	(ln 118 * ln 119)		NP(h)	
122	TOTAL INCOME TAXES	(sum lns 120 to 121)			
123	RETURN ON RATE BASE (Rate Base*WACC)	(ln 73 * ln 161)			
124	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note H) (Worksheet B, ln 16)			DA	
125	REVENUE REQUIREMENT BEFORE TEXAS GROSS MARGIN TAX				
126	(sum lns 96, 103, 112, 122, 123, 124)				
127	TEXAS GROSS MARGIN TAX (NOTE O) (Worksheet J)			DA	
128	REVENUE REQUIREMENT INCLUDING GROSS MARGIN TAX				

AEP Transmission Formula Rate Template
Utilizing FERC Form 1 Cost Data for ______
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SUPPORTING CALCULATIONS

ln No.							
	TRANSMISSION PLANT INCLUDED IN SPP TARIFF						
129	Total transmission plant	(ln 19 + ln 20 + ln 21)					
130	Less transmission plant excluded from SPP Tariff	(Note P)					
131	Less transmission plant included in OATT Ancillary Services (Note Q)		(Worksheet L)				
132	Transmission plant included in SPP Tariff	(ln 129 - ln 130 - ln 131)					
133	Percent of transmission plant in SPP Tariff	(ln 132 / ln 129)				TP=	
				Payroll Billed from AEP			
134	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	Service Corp.			
135	Production	354.20,22.b			NA		
136	Transmission	354.21.b			TP		
137	Distribution	354.23.b			NA		
138	Other (Excludes A&E	354.24,25,26.b			NA		
139	Total	(sum lns 135 to 138)					
140	Transmission related amount					W/S=	
141	COMMON PLANT ALLOCATOR (CE)						
142	Electric	200.3.c			DA		
143	Gas	200.3.d			NA		
144	Other	200.3. e, f, g			NA		
145	Total	(sum lns 142 to 144)					
146	Electric related amount						
147	W/S Allocator					W/S	
148	Transmission related amount	(ln 146 * ln 147)				**CE=**	
149	WEIGHTED AVERAGE COST OF CAPITAL (WACC)						$
150		Long Term Interest (117, sum of 62c - 66c)					
151		Preferred Dividends (118.29.c) (positive number)					
152	Development of Common Stock:						
153		Proprietary Capital (112.16.c)					
154		Less Preferred Stock (ln 159)					
155		Less Account 219.1 (112.15.c)					
156		Common Stock (ln 153 - ln 154 - ln 155)					
					Cost		
157			$	%	(Note S)		Weighted
158	Long Term Debt (112, sum of 18.c - 21.c)						
159	Preferred Stock (112.3.c)						
160	Common Stock (ln 156)						
161	Total (sum lns 158 to 160)					WACC=	

AEP Transmission Formula Rate Template
Utilizing FERC Form 1 Cost Data for ______
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Letter	Notes
	General Notes: a) References to data from FERC Form 1 are indicated as: page#.line#.col.# b) If transmission owner ("TO") functionalizes its costs to transmission on its books, those costs are shown above and on any supporting workpapers rather than using the allocations above.
A	The revenue credits shall include a) amounts received directly from the SPP for PTP transmission services, b) direct assignment charges for transmission facilities, the cost of which has been included in the TCOS, and c) amounts from customers taking service under grandfathered agreements, where the demand is not included in the rate divisor. Revenues associated with FERC annual charges, gross receipts taxes, ancillary services or facilities excluded from the TCOS are not included 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	The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for facilities and any upgrades.
C	This additional revenue requirement is determined using a net plant carrying charge (fixed carrying charge or FCR) approach. Worksheet F shows the calculation of the additional incentive revenue requirement for each project receiving incentive rate treatment, as accepted by FERC. These individual additional revenue requirements shall be summed, for the projected year, and included here.
D	Reflects the transmission related portion of balances in Accounts 281, 282, 283, 190, 255 and, if applicable, 107. The balance of Account 255 is reduced by prior flow throughs and completely excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note M. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. Transmission allocations are shown on Worksheet C.
E	Include Account 182.3, Other Regulatory Assets, related to Transmission Service under this Tariff, if any. Also include any unamortized balances related to pre-commercial operation costs when recovery of abandonment costs are granted.
F	Identified as being transmission related or functionally booked to transmission.
G	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission on line 96.
H	Consistent with Paragraph 657 of Order 2003-A, the amount on line 72 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 124.
I	Removes the expense booked to transmission accounts included in the development of OATT ancillary services rates, including all of Account No. 561.
J	Removes cost of transmission service provided by others to the extent such service is not incurred to provide the SPP service at issue.
K	General Plant and Administrative & General expenses may be functionalized based on allocators other then the W/S allocator. Full documentation must be provided.
L	Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. Worksheet D allocates these expense items. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS.
M	Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts tax and taxes related to income are excluded.
N	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (ln 119) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0. Inputs Required: FIT = 0.00% SIT= 0.00% (State Income Tax Rate or Composite SIT. Worksheet J)) p = 0.00% (percent of federal income tax deductible for state purposes)
O	Effective January 1, 2007, Texas instituted a gross margin tax. This tax is calculated on the Texas allocated revenue of the Company, reduced by 30% to derive a "Gross Margin" for the Company. The tax rate of one percent is assessed on the resulting amount. The jurisdictional allocator is based on transmission demand allocators.
P	Removes plant excluded from the OATT because it does not meet the SPP's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.
Q	Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
R	Includes functional wages & salaries incurred by parent company service corporation for support of the operating company.
S	Long Term Debt cost rate = long-term interest (ln 150) / long term debt (ln 158). Preferred Stock cost rate = preferred dividends (ln 151) / preferred outstanding (ln 159).

AEP Transmission Formula Rate Template
Utilizing FERC Form 1 Cost Data for ______
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Company: ______________________________

Line No.			Total	Allocator	Transmission Amount
162	REVENUE REQUIREMENT (w/o incentives)	(ln 286)			
163	REVENUE CREDITS	(Note A)	Total	Allocator	
164	Transmission Credits	(Worksheet A)		DA	
165	Assoc. Business Development	(Worksheet A)		DA	
166	Total Revenue Credits				
167	REVENUE REQUIREMENT (w/o incentives) For All AEP Facilities	(ln 162 less ln 166)			
168	Revenue Requirement for SPP Base Plan Upgrades (w/o incentives)	(Worksheet G)		DA	
169	REVENUE REQUIREMENT EXCLUDING BASE PLAN UPGRADE ATRR	(ln 167 less ln 168)			
170	NET PLANT CARRYING CHARGE (w/o incentives) (Note B)				
171	Annual Rate	(ln 167 / ln 203 x 100)			
172	Monthly Rate	(ln 171 / 12)			
173	NET PLANT CARRYING CHARGE, W/O DEPRECIATION (w/o incentives) (Note B)				
174	Annual Rate	((ln 167 - ln 259) / ln 203 x 100)			
175	NET PLANT CARRYING CHARGE, W/O DEPRECIATION, INCOME TAXES AND RETURN (Note B)				
176	Annual Rate	((ln 167 - ln 259 - ln 283 - ln 284) / ln 203 x 100)			
177	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note C)	(Worksheet F)		NA	
178	**HISTORICAL YE 2006 TRANSMISSION REVENUE REQUIREMENT**	**(ln 169 + ln 177)**			

AEP Transmission Formula Rate Template
Utilizing FERC Form 1 Cost Data for ______
Historical Transmission Cost of Service

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Company: ________________________________

Line No.	(1) RATE BASE CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator	(5) Total Transmission
	GROSS PLANT IN SERVICE				
179	Production	205.46.g		NA	
180	Transmission	207.58.g		DA	
181	Plus: Transmission Plant-in-Service Additions (Worksheet H)		N/A	DA	N/A
182	Plus: Additional Trans Plant on Transferred Assets (Worksheet H)		N/A	DA	N/A
183	Distribution	207.75.g		NA	
184	General Plant	207.99.g (Note K)		W/S	
185	Intangible Plant	205.5.g		W/S	
186	Common	356		CE	
187	TOTAL GROSS PLANT	(sum lns 179 to 186)		GP(h)=	
				GTD=	
188	ACCUMULATED DEPRECIATION AND AMORTIZATION				
189	Production	219.20-24.c		NA	
190	Transmission	219.25.c		TP1=	
191	Plus: Transmission Plant-in-Service Additions (Worksheet H)		N/A	DA	N/A
192	Plus: Additional Projected Deprec on Transferred Assets (Worksheet H)		N/A	DA	N/A
193	Plus: Additional Transmission Depreciation for 2007 (ln 259)		N/A	TP1	N/A
194	Plus: Additional General & Intangible Depreciation for 2007 (ln 261 + ln 262)		N/A	W/S	N/A
195	Plus: Additional Accum Deprec on Transferred Assets (Worksheet H)		N/A	DA	N/A
196	Distribution	219.26.c		NA	
197	General Plant	219.28.c (Note K)		W/S	
198	Intangible Plant	219		W/S	
199	Common	356		CE	
200	TOTAL ACCUMULATED DEPRECIATION	(sum lns 189 to 199)			
201	NET PLANT IN SERVICE				
202	Production	(ln 179 - ln 189)			
203	Transmission	(ln 180 - ln 190)			
204	Plus: Transmission Plant-in-Service Additions	(ln 181 - ln 191)	N/A		N/A
205	Plus: Additional Trans Plant on Transferred Assets	(ln 182 - ln 192)	N/A		N/A
206	Plus: Additional Transmission Depreciation for 2007	(-ln 193)	N/A		N/A
207	Plus: Additional General & Intangible Depreciation for 2007	(-ln 194)	N/A		N/A
208	Plus: Additional Accum Deprec on Transferred Assets (Worksheet H)	(-ln 195)	N/A		N/A
209	Distribution	(ln 183 - ln 196)			
210	General Plant	(ln 184 - ln 197)			
211	Intangible Plant	(ln 185 - ln 198)			
212	Common	(ln 186 - ln 199)			
213	TOTAL NET PLANT IN SERVICE	(sum lns 202 to 212)		NP(h)=	
214	ADJUSTMENTS TO RATE BASE	(Note D)			
215	Account No. 281 (enter negative)	273.8.k (Worksheet C)		DA	
216	Account No. 282 (enter negative)	275.2.k (Worksheet C)		DA	
217	Account No. 283 (enter negative)	277.9.k (Worksheet C)		DA	
218	Account No. 190	234.8.c (Worksheet C)		DA	
219	Account No. 255 (enter negative)	267.8.h (Worksheet C)		DA	
220	Account 107 for Approved Multi-Year Projects	216.43.b (Worksheet K)		DA	
221	Other Additions/Deductions	(Note E)		DA	
222	TOTAL ADJUSTMENTS	(sum lns 215 to 221)			
223	PLANT HELD FOR FUTURE USE	214.x.d (Note F)		DA	
224	WORKING CAPITAL	(Note G)			
225	Cash Working Capital	(1/8 * ln 257)			
226	Transmission Materials & Supplies	227.8.c		TP	
227	A&G Materials & Supplies	227.11.c		W/S	
228	Undistributed Stores Expense (Acct 163)	227.16.c		GP(h)	
229	Prepayments (Account 165) - Labor Allocated	111.57.c (Worksheet I)		W/S	
230	Prepayments (Account 165) - Direct Allocated	111.57.c (Worksheet I)		DA	
231	Prepayments (Account 165) - Gross Plant	111.57.c (Worksheet I)		GP(h)	
232	TOTAL WORKING CAPITAL	(sum lns 225 to 231)			
233	IPP CONTRIBUTIONS FOR CONSTRUCTION	#REF!		DA	
234	RATE BASE (sum lns 213, 222, 223, 232, 233)				

Southwest Power Pool
FERC Electric Tariff
Fourth Revised Volume No. 1

pro forma Original Sheet No. 161D.11

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Utilizing FERC Form 1 Cost Data for ______
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Line No.	(1) EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator	(5) Total Transmission
	OPERATION & MAINTENANCE EXPENSE				
235	Transmission	321.112.b		TP	
236	Less: expenses 100% assigned to TO billed customers (Worksheet E, ln 14)			DA	
237	Less: Total Account 561 (Load Dispatch - Sch 1) (Note I)	321.84-92.b		TP	
238	Less: Account 565	321.96.b (Note J)		TP	
239	Plus: Acct 565 native load, zonal or pool	(Note J)		DA	
240	Transmission Subtotal (lns 235-236-237-238+239)				
241	Administrative and General	323.197.b (Note K)			
242	Less: Acc. 928, Reg. Com. Exp.	323.189.b			
243	Acct. 930.1, Gen. Advert. Exp.	323.191.b			
244	Acc. 924, Property Insurance	323.185.b			
245	Acc. 930.2, Misc. Gen. Exp.	323.192.b			
246	Acc. 935, Maint. of Gen. Plant	323.196.b		W/S	
247	Balance of A & G	(ln 241 - sum ln 242 to ln 246)		W/S	
248	Plus: Acct. 924, Property Insurance	(ln 244)		NP(h)	
249	Acct. 928 - Transmission Specific	(Note L) (Worksheet D)		TP	
250	Acct. 928 - Transmission Allocated	(Note L) (Worksheet D)		GP(h)	
251	Acct 930.1 - Only safety related ads	(Note L) (Worksheet D)		W/S	
252	Acct 930.2 - Misc Gen. Exp. - Trans	(Worksheet D)		TP	
253	Acct 930.2 - Misc Gen. Exp. - Allocated	(Worksheet D)		W/S	
254	A & G Subtotal	(sum lns 246 to 253)			
255	Common	356		CE	
256	Transmission Lease Payments			DA	
257	TOTAL O & M EXPENSE	(ln 240 + ln 254 + ln 255 + ln 256)			
258	DEPRECIATION AND AMORTIZATION EXPENSE				
259	Transmission	336.7.f		TP	
260	Plus: Transmission Plant-in-Service Additions (Worksheet H)		N/A	DA	N/A
261	General	336.10.f		W/S	
262	Intangible	336.1.f		W/S	
263	Common	336.11.f		CE	
264	TOTAL DEPRECIATION AND AMORTIZATION	(sum lns 259 to 263)			
265	TAXES OTHER THAN INCOME	(Note M)			
266	Labor Related				
267	Payroll	262.x-263.x.i		W/S	
268	Plant Related				
269	Property	262.x-263.x.i		NP(h)	
270	Gross Receipts/Sales & Use	262.x-263.x.i		NA	
271	Other	262.x-263.x.i		GP(h)	
272	Payments in lieu of taxes			GP(h)	
273	TOTAL OTHER TAXES	114.14.c			
274	INCOME TAXES	(Note N)			
275	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =				
276	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =				
277	where WCLTD=(ln 319) and WACC = (ln 322)				
278	and FIT, SIT & p are as given in Note N.				
279	GRCF=1 / (1 - T) = (from ln 275)				
280	Amortized Investment Tax Credit (enter negative)				
281	Income Tax Calculation	(ln 276 * ln 284)			
282	ITC adjustment	(ln 279 * ln 280)		NP(h)	
283	TOTAL INCOME TAXES	(sum lns 281 to 282)			
284	RETURN ON RATE BASE (Rate Base*WACC)	(ln 234 * ln 322)			
285	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note H) (Worksheet B, ln 16)			DA	
286	REVENUE REQUIREMENT BEFORE TEXAS GROSS MARGIN TAX				
287	(sum lns 257, 264, 273, 283, 284, 285)				
288	TEXAS GROSS MARGIN TAX (NOTE O) (Worksheet J)			DA	
289	REVENUE REQUIREMENT INCLUDING GROSS MARGIN TAX				

Issued by: L. Patrick Bourne, Director
Transmission and Regulatory Policy
Issued on:

Effective:

AEP Transmission Formula Rate Template
Utilizing FERC Form 1 Cost Data for ______
Historical Transmission Cost of Service

Company: ________________________________

SUPPORTING CALCULATIONS

ln No.							
	TRANSMISSION PLANT INCLUDED IN SPP TARIFF						
290	Total transmission plant	(ln 180)					
291	Less transmission plant excluded from SPP Tariff (Note P)						
292	Less transmission plant included in OATT Ancillary Services (Note Q)		(Worksheet L)				
293	Transmission plant included in SPP Tariff	(ln 290 - ln 291 - ln 292)					
294	Percent of transmission plant in SPP Tariff	(ln 293 / ln 290)				**TP=**	
295	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	Payroll Billed from AEP Service Corp.			
296	Production	354.20,22.b			NA		
297	Transmission	354.21.b			TP		
298	Distribution	354.23.b			NA		
299	Other (Excludes A&E	354.24,25,26.b			NA		
300	Total	(sum lns 296 to 299)					
301	Transmission related amount					**W/S=**	
302	COMMON PLANT ALLOCATOR (CE)						
303	Electric	200.3.c			DA		
304	Gas	200.3.d			NA		
305	Other	200.3. e, f, g			NA		
306	Total	(sum lns 303 to 305)					
307	Electric related amount						
308	W/S Allocator					W/S	
309	Transmission related amount	(ln 307 * ln 308)				**CE=**	
310	WEIGHTED AVERAGE COST OF CAPITAL (WACC)						$
311		Long Term Interest (117, sum of 62c - 66c)					
312		Preferred Dividends (118.29.c) (positive number)					
313	Development of Common Stock						
314		Proprietary Capital (112.16.c)					
315		Less Preferred Stock (ln 320)					
316		Less Account 219.1 (112.15.c)					
317		Common Stock (ln 314 - ln 315 - ln 316)					
318			$	%	Cost (Note S)		Weighted
319	Long Term Debt (112, sum of 18.c - 21.c)						
320	Preferred Stock (112.3.c)						
321	Common Stock (ln 317)						
322	Total (sum lns 319 to 321)					**WACC=**	

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TCOS
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HISTORICAL

Company: ________________________________

Letter	Notes
	General Notes: a) References to data from FERC Form 1 are indicated as: page#.line#.col.# b) If transmission owner ("TO") functionalizes its costs to transmission on its books, those costs are shown above and on any supporting workpapers rather than using the allocations above
A	The revenue credits shall include a) amounts received directly from the SPP for PTP transmission services, b) direct assignment charges for transmission facilities the cost of which has been included in the TCOS, and c) amounts from customers taking service under grandfathered agreements, where the demand is not included in the rate divisor. Revenues associated with FERC annual charges, gross receipts taxes, ancillary services or facilities excluded from the TCOS are not included 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	The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for facilities and any upgrades.
C	This additional revenue requirement is determined using a net plant carrying charge (fixed carrying charge or FCR) approach. Worksheet F shows the calculation of the additional incentive revenue requirement for each project receiving incentive rate treatment, as accepted by FERC. These individual additional revenue requirements shall be summed, for the projected year, and included here.
D	Reflects the transmission related portion of balances in Accounts 281, 282, 283, 190, 255 and, if applicable, 107. The balance of Account 255 is reduced by prior flow throughs and completely excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note M. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. Transmission allocations are shown on Worksheet C.
E	Include Account 182.3, Other Regulatory Assets, related to Transmission Service under this Tariff, if any. Also include any unamortized balances related to pre-commercial operation costs when recovery of abandonment costs are granted.
F	Identified as being transmission related or functionally booked to transmission.
G	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission on line 257.
H	Consistent with Paragraph 657 of Order 2003-A, the amount on line 233 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 285.
I	Removes the expense booked to transmission accounts included in the development of OATT ancillary services rates, including all of Account No. 561.
J	Removes cost of transmission service provided by others to the extent such service is not incurred to provide the SPP service at issue.
K	General Plant and Administrative & General expenses may be functionalized based on allocators other then the W/S allocator. Full documentation must be provided.
L	Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. Worksheet D allocates these expense items. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS.
M	Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts tax and taxes related to income are excluded.
N	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (ln 280) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.

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

Letter	Notes
O	Effective January 1, 2007, Texas instituted a gross margin tax. This tax is calculated on the Texas allocated revenue of the Company, reduced by 30% to derive a "Gross Margin" for the Company. The tax rate of one percent is assessed on the resulting amount. The jurisdictional allocator is based on transmission demand allocators.
P	Removes plant excluded from the OATT because it does not meet the SPP's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT
Q	Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
R	Includes functional wages & salaries incurred by parent company service corporation for support of the operating company.
S	Long Term Debt cost rate = long-term interest (ln 311) / long term debt (ln 319). Preferred Stock cost rate = preferred dividends (ln 312) / preferred outstanding (ln 320).

Worksheet List:

- **A** **Revenue Credits**
- **B** **IPP - System Upgrade Credit**
- **C** **ADIT & ITC Details**
- **D** **A&G Expense Detail**
- **E** **Transmission Expense Adjustments**
- **F** **ATRR Calculation for Non-Base Plan Projects**
- **G** **ATRR Calculation for SPP Base Plan Upgrades**
- **H** **Transmission Plant-in-Service Additions**
- **I** **Non-Tax Balance Sheet Adjustments**
- **J** **Tax**
- **K** **CWIP Balances on Multi-Year Projects**
- **L** **GSU Net Book Values**

ATTACHMENT T

Rate Sheets For Point-To-Point Transmission Service

Zone 1

Rate Sheet For Point-to-Point Transmission Service

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. Monthly delivery: $1528.30/MW of Reserved Capacity per month.
2. Weekly delivery: $ 352.66/MW of Reserved Capacity per week.
3. Daily delivery:

   On-Peak: $ 70.54/MW of Reserved Capacity per day.

   Off-Peak: $ 50.25/MW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in Section 2 above times the highest amount in megawatts of Reserved Capacity in any day during such week. For the purpose of the rate specified in Section 3 above, the Off-Peak Period shall be Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day and the On-Peak Period shall be all days that are not in the Off-Peak Period.

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: $1528.30/MW of Reserved Capacity per month.
2. Weekly delivery: $ 352.66/MW of Reserved Capacity per week.
3. Daily delivery:

   On-Peak: $ 70.54/MW of Reserved Capacity per day.

   Off-Peak $ 50.25/MW of Reserved Capacity per day.

4. Hourly delivery:

   On-Peak: $ 4.41/MW of Reserved Capacity per hour.

   Off-Peak $ 2.10/MW of Reserved Capacity per hour.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in Section 3 above times the highest amount in megawatts 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 megawatts of Reserved Capacity in any hour during such week.

For the purpose of the rate specified in Section 3 above, the Off-Peak Period shall be Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day and the On-Peak Period shall be all days that are not in the Off-Peak Period.

For the purpose of the rate specified in Section 4 above, On-Peak is all hours between HE 0700 and HE 2200, inclusive, Central Time Zone, excluding Sundays and holidays. Holidays shall be as defined by NERC, currently New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. Off-Peak is all hours not designated as On-Peak.

RESERVED

RESERVED