

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

American Electric Power Service Corporation) Docket Nos. ER07-_____-000
on behalf of:)
Public Service Company of Oklahoma)
Southwestern Electric Power Company)

DIRECT TESTIMONY OF
ROBERT L. PENNYBAKER
ON BEHALF OF THE AEP COMPANIES,
PUBLIC SERVICE COMPANY OF OKLAHOMA
AND
SOUTHWESTERN ELECTRIC POWER COMPANY

June 22, 2007

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1 **I. Introduction and Qualifications**

2 **Q. PLEASE STATE YOUR NAME, CURRENT POSITION, EMPLOYER, AND**
3 **BUSINESS ADDRESS?**

4 A. My name is Robert L. Pennybaker. I am employed by American Electric Power Service
5 Corporation (“AEPSC” or “AEP”), as Manager, Transmission and Interconnection
6 Services. My business address is 212 East Sixth Street, Tulsa, Oklahoma 74119.

7 **Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES AS MANAGER,**
8 **TRANSMISSION & INTERCONNECTION SERVICES?**

9 A. I am responsible for the development and implementation of transmission,
10 interconnection, and related agreements, and tariffs on behalf of the AEP operating
11 companies that provide service in the Southwest Power Pool (“SPP”) and the Electric
12 Reliability Council of Texas (“ERCOT”). My group administers interconnection and
13 transmission service agreements, and is responsible for coordinating with SPP and
14 ERCOT regarding interconnection, transmission, and operating agreements for customers
15 that access SPP and/or ERCOT services through connections to AEP transmission and
16 distribution facilities. I frequently represent Public Service Company of Oklahoma
17 (“PSO”) and Southwestern Electric Power Company (“SWEPCO”), collectively “the
18 AEP Companies,” in SPP forums, particularly relating to the SPP Open Access
19 Transmission Tariff (“OATT”) and related committee matters.

20 **Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND**
21 **BUSINESS EXPERIENCE?**

22 A. In 1990, I earned a Bachelor of Science degree in Electrical Engineering from the
23 University of Oklahoma (“OU”). In 1994, I received from Oklahoma City University a
24 Master's degree in Business Administration. I am a licensed Professional Engineer in the

1 State of Oklahoma. Oklahoma Gas and Electric Company employed me as an Engineer
2 Trainee in Distribution Design for sixteen months prior to graduating from OU in 1990.
3 That same year, I accepted the position of Planning Engineer with PSO in Facilities
4 Planning, where among other things, I helped plan and justify the expansion and
5 modification of PSO's transmission and substation systems to accommodate normal load
6 growth and new retail and wholesale load additions. In 1994, I transferred to Central and
7 South West Services, Inc., a service company subsidiary of Central and South West
8 Corporation ("CSW"), as Transmission Planning Engineer for both PSO and SWEPCO,
9 the electric operating companies of CSW in the SPP. In 1997, I was promoted to Senior
10 Engineer upon accepting a position in the Transmission Access group, where I assisted in
11 the administration of the CSW OATT with regard to services provided using the CSW
12 transmission facilities located in the SPP. I also assisted in the administration of other
13 transmission service and interconnection agreements. In June 2000, CSW was merged
14 with AEP and I continued in the same position in the merged company with a new title of
15 Regulatory Consultant. In March 2003, I was promoted to my present position.

16 **Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FEDERAL ENERGY**
17 **REGULATORY COMMISSION?**

18 A. Yes. I presented testimony to the Federal Energy Regulatory Commission ("FERC")
19 relating to the rate treatment of load connection facilities in *Northeast Texas Electric*
20 *Cooperative, Inc. et al. v. Central and South West Services*, FERC Docket No. EL01-73.

21 **II. Purpose and Scope of Testimony**

22 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

23 A. The purpose of my testimony is to explain and support the initial calculation of the

1 annual transmission revenue requirement (“ATRR”) for the AEP Companies under the
2 formula rate methodology AEP proposes in this case. I discuss how the Formula Rate is
3 used to calculate annual revenue requirements for new transmission projects that require
4 different treatment than pre-existing and other rolled-in zonal facilities under the SPP
5 OATT. I sponsor transmission cost-of-service (“TCOS”) studies based on the Formula
6 Rate for PSO and SWEPCO, AEP’s two operating companies in Zone 1 of SPP. I will
7 discuss the development of the revenue requirements for the AEP Companies, including
8 how the many components of transmission cost are assigned or allocated to the
9 transmission function. I explain and support the level of point-to-point (“PTP”)
10 transmission and other operating revenue credits for the transmission function. I also
11 support the reclassification of Generator Step-up (“GSU”) transformers from the
12 transmission function to the production function. Finally, I will discuss AEP’s proposal
13 in this filing regarding the revenue requirement and rates for ancillary service Schedule 1
14 – Scheduling, System Control and Dispatch Service.

15 **Q. PLEASE LIST THE EXHIBITS YOU ARE SPONSORING, IN ADDITION TO**
16 **THIS PREPARED DIRECT TESTIMONY?**

17 A. I am sponsoring Exhibit Nos:

18 AEP-201 AEP Revenue Requirement, Rate Design, and Transmission System Peak
19 Load Summaries;

20 AEP-202 Completed Formula for PSO – Initial Period Transmission Revenue
21 Requirement;

22 AEP-203 Completed Formula for SWEPCO – Initial Period Transmission Revenue
23 Requirement; and

24 AEP-204 Customer Billing Comparisons under Present and Proposed Rates, similar to
25 Statements BG and BH.

1 **III. Discussion of Cost-of-Service Exhibits**

2 **Q. PLEASE DISCUSS THE CONTENTS OF EXHIBIT NO. AEP-201?**

3 A. Exhibit No. AEP-201 is a summary of the TCOS provided in Exhibit Nos. AEP-202 for
4 PSO and AEP-203 for SWEPCO. On the first page, the first section (A) summarizes the
5 combined total Existing Zonal ATRR for the AEP portion of SPP Zone 1, showing the
6 proposed update to Section 1 (column 3) of Attachment H to the SPP OATT. The second
7 section (B) shows the calculations for the AEP component of the SPP Zone 1 rates for
8 PTP transmission service provided over the AEP Companies' systems. The third section
9 (C) lists the AEP Companies' ATRR to be collected by SPP for Base Plan Upgrades
10 ("BPU's") on the AEP system. The second page of this exhibit shows the calculations for
11 ancillary service Schedule 1 - Scheduling, System Control and Dispatch Service. The
12 last page of Exhibit No. AEP-201 shows historical and projected Zone 1 transmission
13 system peak loads used to develop the PTP transmission service and ancillary service
14 Schedule 1 rates.

15 **Q. WHAT TEST YEAR IS USED IN THE PSO AND SWEPCO TRANSMISSION**
16 **COST STUDIES?**

17 A. There are essentially two test years, as two versions of each cost study are presented for
18 each company. Each historic cost study relies on the 2006 FERC Form No. 1 reports
19 ("Form-1"), for annual expenses and rate base components as of year-end 2006, to
20 compute a "Historic" test year TCOS study. The projected cost study, presented first,
21 relies on the historic cost study and incorporates estimates of new transmission plant
22 additions through December 31, 2007. The projected cost studies for PSO and SWEPCO
23 include adjustments to transmission plant-in-service, transmission depreciation expense

1 and accumulated reserve for depreciation of transmission plant in order to produce a
2 “Projected” cost-of-service as of year-end 2007.

3 **Q. WHICH TEST YEAR ARE THE PROPOSED RATES BASED ON?**

4 A. The proposed revenue requirement and rates are based on the set of projected cost studies
5 estimating the revenue requirement as of December 31, 2007. Next year in May, AEP
6 will repopulate the formula rate templates with Form-1 data for 2007 to create an
7 “Actual” cost-of-service for PSO and SWEPCO as of the end of 2007. The difference
8 between the Projected and Actual revenue requirements as of year-end 2007 will be
9 “trued-up” in billings starting July 1, 2008. Also at that time, the “projected” revenue
10 requirements as of December 31, 2008 will be calculated by adding adjustments for new
11 transmission plant and depreciation to the Actual 2007 cost studies. AEP Witness Dennis
12 W. Bethel discusses the annual update and true-up procedures in his testimony.

13 **Q. PLEASE DESCRIBE THE FORMULA RATE THAT AEP IS PROPOSING AS**
14 **SHOWN IN EXHIBIT NOS. AEP-202 AND AEP-203?**

15 A. Each formula rate calculation, one for PSO and one for SWEPCO, produces a net annual
16 transmission revenue requirement that is the sum of the return on rate base, operation and
17 maintenance (“O&M”) expense, depreciation expense, taxes other than income taxes,
18 income taxes and revenue credits. Each line of the formula consists of all or many of the
19 following six columns of information or data:

- 20 1. the line number;
- 21 2. a description of the cost item or formulaic result of the calculation on the line;
- 22 3. a reference to one or more explanatory notes at the end of the formula, the
23 source of the input data (i.e., Form-1 page number, line, and column or

- 1 attachment number, SPP data, or AEP's records), or an instruction describing
2 a calculation (e.g., "Sum lines 5 to 9");
- 3 4. the actual data input Total for the particular Transmission Owner (shaded) or
4 calculation upon the data (unshaded);
- 5 5. the allocator name and number; and
- 6 6. the calculated transmission-related portion.

7 The numbered lines of the formula are grouped into the various rate base categories to
8 display the projected and historical year data on 10 pages which are described below.

- 9 1. Pages 1 through 5 contain the projected year cost-of-service, while the
10 comparable historic cost-of-service is shown in pages 6 through 10;
- 11 2. The Revenue Requirement Summary (including adjustments such as revenue
12 credits) and the various Carrying Charge Rates for the projected and historic cost
13 studies are shown on pages 1 and 6, respectively;
- 14 3. Pages 2 and 7, respectively, show the projected and historic year Plant in
15 Service, Accumulated Depreciation, Adjustment to Rate Base, Utility Plant Held
16 for Future Use, Working Capital, and net Credits for Independent Power Producer
17 ("IPP") Contributions to Construction ("IPP Credits");
- 18 4. Pages 3 and 8, respectively, show the projected and historic year Operations &
19 Maintenance Expense (including A&G), Depreciation & Amortization Expense,
20 Taxes Other than Income Taxes, Income Taxes, Return Calculations, and Interest
21 on IPP Credits; and
- 22 5. Pages 4 and 9, respectively, show "Supporting Calculations", including certain
23 projected and historic year functional Allocators used in the cost studies.
24 Although a number of allocation factors are developed on other pages of the
25 formula, the Transmission Plant ("TP") allocator and the labor ratio allocator
26 based on functional wages and salaries ("W/S") are developed on pages 4 and 9.
27 Also shown is the development of the capital structure and weighted cost of debt,
28 preferred stock, and common equity which make up the Weighted Average Cost

1 of Capital (“WACC”). In the SWEPCO TCOS, the Texas load share needed in
2 the Texas Gross Margin Tax calculation is supported.

3 6. Pages 5 and 10, respectively, contain detailed Notes providing explanations and
4 data referred to in the preceding pages by letters “A through S” in the initial
5 TCOS calculation.

6 7. Worksheets A through L provide additional opportunity to develop detailed data
7 required in the cost studies that, as reported in the Form-1 reports, is either
8 inadequate or requires further manipulation or calculations.

9 **Q. BRIEFLY DESCRIBE THE ADDITIONAL DATA PROVIDED ON**
10 **WORKSHEETS A THROUGH L?**

11 A. Worksheet A is reserved for calculations involving other operating revenues that are
12 applied as cost-of-service credits in the formula. Worksheet B contains for details
13 regarding IPP System Upgrade Credits. Worksheet C is reserved for details supporting
14 the Accumulated Deferred Income Taxes (ADIT) and Investment Tax Credits (ITC).
15 Worksheet D is used to provide needed detail on A&G expenses included in and
16 excluded from the cost studies. Worksheet E is reserved for details to support
17 adjustments to expenses that might be necessary when the AEP Companies incur costs as
18 a Load Serving Entity (LSE) that are not includable in TCOS, or otherwise. Worksheets
19 F and G will be discussed later in more detail. Worksheet H provides details on budgeted
20 transmission capital expenditures for plant expected to be placed in service during 2007.
21 Worksheet I is provided for balance sheet items that may require further separation
22 before allocation (e.g., Prepayments) or that may require adjustment when significant
23 changes occur late in the year (e.g., large preferred stock and/or debt issuances or
24 redemptions). Worksheet J is used to develop composite state income tax rates and other
25 special state tax rates. Worksheet K is reserved for details involving CWIP should a

1 current return on any such balances be approved in the future. Worksheet L shows
2 supporting information regarding the functionalization of GSUs from Transmission.

3 **Q. PLEASE EXPLAIN THE TERM “FUNCTIONALIZATION”?**

4 A. Functionalization is the process by which costs are separated according to the major
5 electric system functions of production, transmission, and distribution. The majority of
6 costs are recorded in the FERC Uniform System of Accounts on a functional basis and
7 therefore can be directly assigned to their functions; however, those plant and expense
8 items that are not recorded by function are assigned or allocated to functions based on a
9 review of the items involved or on the basis of appropriate plant or expense ratios. The
10 TCOS studies for PSO and SWEPCO, included as Exhibit Nos. AEP-202 and AEP-203,
11 contain the rate base and expense data used to develop the annual cost of the transmission
12 service at issue. Each item of rate base and expense is examined and, if appropriate, all
13 or a portion of the cost is assigned to the transmission function, with the remainder
14 assigned to the All Other category. Only the transmission function costs are at issue in
15 this proceeding.

16 **Q. HOW IS THE ANNUAL TRANSMISSION REVENUE REQUIREMENT**
17 **DEVELOPED?**

18 A. The annual transmission revenue requirement is developed, in traditional fashion, as the
19 sum of allowed income (after tax return on rate base), and expenses, including operation,
20 maintenance, administrative, depreciation and taxes. Return on rate base is the product of
21 the requested overall WACC and net rate base. The largest component of net rate base is
22 net electric plant in service, which is plant at original cost less accumulated depreciation
23 and amortization. Plant in service and accumulated depreciation balances are developed

1 as year-end balances. Rate base also includes General and Intangible Plant (“G&IP”),
2 Working Capital, subtractive adjustments related to Accumulated Deferred Investment
3 Tax Credit (ITC), Account 255, and Accumulated Deferred Income Taxes, Accounts 281,
4 282, and 283, and additive adjustments reflecting Account 190 balances. The
5 components of allowance for Working Capital include Cash Working Capital Allowance,
6 Material and Supplies, and Prepayments.

7 **Rate Base**

8 **Q. PLEASE DESCRIBE THE COMPONENTS OF PLANT AT ORIGINAL COST IN**
9 **SERVICE INCLUDED IN THE TCOS STUDY?**

10 A. Total Transmission Plant at original cost or “Gross Plant” in Service includes the
11 undepreciated value of Transmission Plant in service, as of December 31, 2006 in the
12 historic cost-of-service, and that value plus the expected plant in service additions
13 through December 31, 2007 for the projected cost-of-service. Functional G&IP costs,
14 based on the original cost in service at December 31, 2006 balances, are included in both
15 the historic and projected cost studies; that is, no adjustment was made for expected
16 additions to G&IP during 2007 in the projected cost studies.

17 **Q. HOW WERE GSU TRANSFORMER COSTS HANDLED IN THE COST**
18 **STUDIES?**

19 A. The original installed cost of Generator Step-up Transformers (“GSU”), a total of \$34.7
20 million, (i.e., \$15.6 million for PSO and \$19.1 million for SWEPCO), was determined
21 from plant accounting records. Adjustments were made to remove those costs from
22 transmission plant and other cost categories (see development and usage of the TP
23 allocator).

1 **Q. HOW WERE THE 2007 PLANT IN SERVICE ADDITIONS DETERMINED?**

2 A. The cost of new plant additions and the dates they were or are expected to be placed into
3 service were provided to me by Witness Pasternack and are further supported in his
4 testimony, Exhibit No. AEP-300. He also supplied the estimated in service cost of BPU's
5 (Exhibit No. AEP-309) and other projects expected to be added to plant in service during
6 2007. The total new plant additions were added to the December 31, 2006 balances to
7 determine the total projected December 31, 2007 balances of Gross Transmission Plant.

8 **Q. HOW WAS THE ACCUMULATED ALLOWANCE FOR TRANSMISSION**
9 **DEPRECIATION AND AMORTIZATION DETERMINED?**

10 A. The balances in transmission depreciation and amortization as of December 31, 2006
11 were allocated to the transmission function using the TP ratio, which adjusts the
12 depreciation balance to provide for depreciation related to the GSUs that were removed
13 from transmission costs. The transmission depreciation and amortization balance as of
14 December 31, 2007 was estimated by summing the December 31, 2006 balance, the 12-
15 month 2006 transmission depreciation expense (as an estimate of further depreciation of
16 the 12/31/06 balances during 2007), and amounts reflecting the average transmission
17 depreciation rates applied to the cost of new plant additions for PSO and SWEPCO,
18 weighted for the amount of such additions during each month of 2007 (Worksheet H).

19 **Q. HOW WERE ACCUMULATED DEPRECIATION AND AMORTIZATION**
20 **BALANCES FUNCTIONALIZED?**

21 A. The accumulated provision for depreciation and amortization of transmission plant in
22 service as of December 31, 2006 (and the 2007 addition related to that balance) was
23 functionalized to transmission via the TP ratio to reflect the removal of GSUs from
24 transmission plant in service. The amounts determined for 2007 related to new plant

1 additions were directly assigned to transmission, as none of those amounts are related to
2 excluded plant. The accumulated provision for depreciation and amortization of General
3 and Intangible Plant-in-Service was functionalized to transmission consistent with the
4 functional allocation of the original cost G&IP, using the labor (W/S) allocator.

5 **Q. HOW WERE GENERAL AND INTANGIBLE PLANT ALLOCATED TO THE**
6 **TRANSMISSION FUNCTION?**

7 A. General and Intangible Plant were functionalized to transmission using the PSO or
8 SWEPCO specific Labor Ratio, a wage and salary (W/S) allocator that also captures
9 functional wage and salary costs allocated to the companies from AEPSC.

10 **Q. HOW WERE ADJUSTMENTS TO RATE BASE FUNCTIONALIZED?**

11 A. Worksheet C provides detailed development by account of Accumulated Deferred
12 Income Taxes (ADIT), including functionalization of ADIT components by appropriate
13 allocation. Starting with ADIT balances in the Form-1, Worksheet C removes the
14 balances related to FASB 109, 106 and Other Comprehensive Income to provide ADIT
15 balances that only reflect utility operations. These resultant balances are then
16 functionalized based on labor, net plant, transmission, or transmission and distribution
17 plant allocators, as appropriate.

18 Based on elections made by the AEP Companies, Investment Tax Credits (ITC's)
19 from 1971 and later are taken as a direct reduction to the cost-of-service. If the ITC's
20 arose prior to 1971 they are included as an offset to rate base. Those specific ITC's are
21 shown on Worksheet C. The pre-1971 balances were provided by AEP's tax department,
22 and functionalized on net plant ("NP").

1 **Q. HOW WAS PLANT HELD FOR FUTURE USE FUNCTIONALIZED?**

2 A. Normally, the cost of plant recorded in Electric Plant Account 105, Electric Plant Held
3 for Future Use, would be directly assigned to transmission based on the specific purposes
4 for which the items of plant, typically land, were acquired. As of December 31, 2006
5 however, neither PSO nor SWEPCO had any transmission-related plant being held for
6 future use; thus none was assigned to the transmission function in the cost studies.

7 **Q. HOW WERE THE COMPONENTS OF WORKING CAPITAL**
8 **FUNCTIONALIZED?**

9 A. The Cash Working Capital Allowance for the transmission function is calculated as one-
10 eighth of transmission O&M expenses, excluding the costs in Account 565, Transmission
11 of Electricity by Others, and 561, Load Dispatching.

12 The allowance for transmission material and supplies (“M&S”) has three
13 components; Transmission M&S, allocated by the TP ratio; A&G Materials and Supplies,
14 a customer service and A&G supply allotment, functionally allocated using the Labor
15 Ratio; and Undistributed Stores Expense, allocated by the Gross Plant (“GP”) ratio.

16 Prepayments, detailed by item in Worksheet I, were grouped as being related to
17 labor or plant, or not to the transmission function. The functional Labor (W/S) and Gross
18 Plant (GP) ratios, respectively, were used to allocate the first two categories to
19 transmission.

20 **Q. HOW ARE THE COSTS OF TRANSMISSION SYSTEM UPGRADES FUNDED**
21 **BY IPP GENERATORS REFLECTED IN RATE BASE?**

22 A. The original cost and accumulated depreciation for IPP Upgrades are both included in the
23 rate base, but rate base offsets are also included which reduce the rate base for IPP
24 contributions that have not yet been returned through credits against the charges the IPPs,

1 or their customers, would otherwise have owed for transmission service provided to
2 deliver energy from the new generation facilities. Approximately \$25 million of facilities
3 classified as IPP interconnection-related system upgrades have been built by PSO and
4 SWEPCO in recent years. Through the end of 2006, AEP still had on its books
5 approximately \$22.2 million of the fund advances and interest; \$9.3 million in PSO and
6 \$12.9 million in SWEPCO. The balance of the IPP payments and accrued interest, net of
7 credits applied to related transmission service revenue, booked in Account 253, is
8 reflected in the TCOS studies as a reduction to rate base.

9 **Expenses**

10 **Q. PLEASE DESCRIBE HOW O&M EXPENSES WERE FUNCTIONALIZED?**

11 A. O&M expenses specifically identified as transmission-related in the Uniform System of
12 Accounts were allocated to the transmission function using the TP ratio. Two exceptions
13 to that general rule were made in order to exclude costs in Transmission Operation
14 Accounts 561, Load Dispatching and 565, Transmission of Electricity by Others, from
15 the cost of transmission service. Certain of the costs booked to the various sub-accounts
16 of Account 561, Load Dispatching, are includable in the rates for Ancillary Service
17 Schedule 1, and that subject is addressed later. The costs booked to Account 565 were
18 examined, and none were found to be of the type that may be included in the charges for
19 transmission service to others.

20 **Q. HAVE ADJUSTMENTS BEEN MADE TO O&M EXPENSES TO REFLECT THE**
21 **REMOVAL OF GSUs FROM THE TRANSMISSION FUNCTION?**

22 A. Yes. Transmission O&M expenses have been reduced by the ratio of gross transmission
23 plant excluding GSUs to gross transmission plant including GSUs ("TP" ratio). Also,

1 that ratio is reflected throughout the cost-of-service, as appropriate, so as to remove the
2 costs associated with GSUs from the TCOS.

3 **Q. HOW WERE A&G EXPENSES ALLOCATED TO THE TRANSMISSION**
4 **FUNCTION?**

5 A. Labor related items, such as salaries, employee health care and pensions, office supplies,
6 and outside services were assigned to functions based on wage and salary (W/S) ratios.
7 Account 924, Property Insurance, was functionalized based on net plant (NP) ratios.
8 Expenses associated with transmission work for third parties, recorded in Account 930.2,
9 Miscellaneous General Expense, were offset by inclusion of credits reflecting the
10 revenues received for such work. Advertising expenses, other than safety-related costs,
11 were excluded. Regulatory Commission Expenses, Account 928, were excluded if
12 directly related to retail rate setting activities; otherwise a GP allocation was used.
13 Account 935, Maintenance of General Plant, and all other A&G expenses were
14 functionalized based on the Labor ratio.

15 **Q. HOW WERE DEPRECIATION EXPENSES FOR TRANSMISSION, GENERAL,**
16 **AND INTANGIBLE PLANT DETERMINED AND FUNCTIONALIZED TO**
17 **TRANSMISSION?**

18 A. Depreciation expense is booked by plant account, and thus is directly assigned to the
19 production, transmission, distribution, and general plant categories. The TP ratio was
20 applied to transmission plant whereas the W/S (labor) ratio was used to allocate general
21 and intangible plant depreciation expense.

22 **Q. HOW WAS THE DEPRECIATION EXPENSE FOR 2007 CAPITAL**
23 **EXPENDITURES DETERMINED?**

24 A. The depreciation for plant placed in service in 2007 was calculated based on an annual

1 composite depreciation rate. The composite rate was calculated separately for PSO and
2 SWEPCO as the historic year transmission plant depreciation expense divided by the
3 average of the beginning and ending 2006 balance of gross transmission plant in service.
4 The cost of plant placed in service each month is multiplied by the composite annual
5 transmission depreciation rate to give an estimate of the annual depreciation amount for
6 each month's plant additions. The estimated annual amounts were then converted to
7 monthly amounts, and then multiplied by the number of months that depreciation will be
8 taken during 2007 on a given month's plant in service to obtain a reasonable estimate of
9 accumulated depreciation for new plant added in 2007. Depreciation is assumed to start
10 in the month after the plant is placed into service. Based on this convention, plant placed
11 in service in January or December 2007 will be accorded eleven (11) or zero (0) months
12 of depreciation, respectively.

13 **Q. HOW ARE TAXES OTHER THAN INCOME TAXES INCLUDED IN THE**
14 **FORMULA?**

15 A. Taxes other than Income Taxes consist of real estate and property taxes, payroll-related
16 taxes and certain other taxes that can vary by company or state. The tax details contained
17 in Form-1 pages 262 through 263, column (i), were summarized as to major types, e.g.,
18 labor related, plant related, and other categories, and then the group totals were
19 functionalized. Payroll taxes were functionalized based on the W/S (labor) ratio.
20 Property taxes were functionalized proportionate to functional net plant (NP). Other non-
21 income taxes were functionalized in proportion to functional gross plant (GP).

22 **Q. HOW ARE INCOME TAXES COMPUTED IN THE FORMULA?**

23 A. Federal and state income taxes are developed so as to provide for the opportunity to earn

1 the allowable net income, which, as mentioned earlier, is the product of the requested
2 overall WACC and net rate base.

3 The tax components are Federal Income Tax Rate (“FIT”), State Income Tax (or a
4 composite) (“SIT”), and the percent (“p”), if any, of federal income tax deductible in the
5 calculation of state income tax. The composite federal/state income tax rate, “T”, is
6 calculated by the formula: $T = 1 - \{[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)\}$. After
7 calculating the composite tax rate “T”, the Effective Income Tax rate (“EIT”) is
8 calculated by the formula: $EIT = (T / 1 - T) * [1 - (WCLTD / WACC)]$. The factor “[1 -
9 (WCLTD / WACC)]” adjusts the composite income tax rate in recognition that interest
10 on debt is a deductible expense for tax purposes, and thus the composite tax rate
11 effectively applies only to the equity component of income. Worksheet J and Note N
12 give additional details regarding tax rates and deductibility of federal taxes for state
13 purposes. Louisiana permits federal taxes as a state tax deduction, but other states where
14 PSO and SWEPCO pay income taxes presently do not.

15 The investment tax credit (“ITC”) adjustment is calculated by multiplying the
16 amortization of the ITC credit by the Gross Revenue Conversion Factor (“GRCF”) which
17 is calculated by the formula: $GRCF = 1 / (1 - T)$. That product is functionalized to
18 transmission by the NP ratio. Because of the elections made by the AEP Companies
19 regarding regulatory treatment of ITC, its amortization is taken as a reduction of
20 recoverable tax expense. Because ITC is a tax credit, it needs to be grossed up by the
21 GRCF to adjust its impact on the cost-of-service to a before tax basis. This resulting
22 amount is then functionalized to transmission by functional net plant (NP).

1 **Q. WHY IS INTEREST ON IPP CONTRIBUTIONS FOR CONSTRUCTION**
2 **INCLUDED AS AN EXPENSE?**

3 A. As mentioned earlier, IPP contributions for construction (including interest) are included
4 as a rate base offset. Since this offset includes accumulated interest, the interest expense
5 is included in the TCOS.

6 **Q. WHAT IS THE LAST EXPENSE ITEM IN THAT SECTION, THE TEXAS**
7 **GROSS MARGIN TAX?**

8 A. In January 2007, the state of Texas began assessing a gross margin tax on businesses
9 operating in that state. It is considered an income tax, but because it is assessed on the
10 basis of revenues reduced by 30%, it cannot be incorporated in the income tax
11 calculations described above, but must be calculated after the revenue requirement is
12 determined. To calculate this tax, the template multiplies the revenue requirement by
13 70%, to reflect the 30% reduction noted above. An allocation factor based on wholesale
14 loads is used to determine how much of that amount is revenue in Texas. Finally, this
15 amount is multiplied by the tax rate of one percent, and this resultant amount is added to
16 the revenue requirement. The details of these computations have been incorporated in
17 Worksheet J.

18 **Q. PLEASE DISCUSS HOW THE WEIGHTED AVERAGE COST OF CAPITAL**
19 **(“WACC”) WAS DERIVED?**

20 A. Except for ROE (i.e., the cost rate for common equity recommended by AEP Witness
21 William E. Avera in Exhibit No. AEP-400), all of the input data are from Form-1.

22 The long-term debt (“LTD”) cost rate is developed by dividing the LTD interest
23 expense by total LTD outstanding. LTD interest expense includes not only the interest
24 expense based on the stated interest rate on the debt, but it also includes the amortization

1 of gains on losses on reacquired debt, issuance expenses, and issuance discount or
2 premium. The LTD outstanding will be the face amount of debt. The preferred cost rate
3 is dividends on preferred stock, plus any gains or losses on early redemption of shares,
4 divided by the face value of the outstanding shares. The formula provides for
5 synchronization of the preferred stock dividends with the historic year ended preferred
6 stock outstanding issuances when significant issuances or redemptions of preferred stock
7 during the year would yield an unreliable cost rate.

8 The common equity component of the capital structure is developed as total
9 booked proprietary capital less the balance recorded in Account No. 219, Accumulated
10 Other Comprehensive Income, and less preferred stock. Total capitalization is the sum of
11 LTD, preferred stock, and common equity. Total capitalization divided into LTD,
12 preferred stock, and common equity yields the debt, preferred stock, and common equity
13 capitalization ratios. The WACC is the sum of the weighted cost rates for LTD, preferred
14 stock and common equity. Return on Rate Base is the product of WACC and Rate Base.

15 **Q. WHAT IS THE PURPOSE OF WORKSHEETS F AND G?**

16 A. Worksheet F and G both calculate project specific annual revenue requirements, but their
17 use in the Formula Rate differs. Worksheet G is used to calculate project specific annual
18 revenue requirements (with or without incentive ROE) for SPP Base Plan Upgrades
19 constructed by PSO or SWEPCO. Worksheet F, on the other hand, is used as needed to
20 determine “non-Base Plan Upgrade” revenue requirements, with and without any FERC-
21 approved project-specific ROE incentive.

22 **Q. PLEASE DESCRIBE WORKSHEET G?**

23 A. SPP collects the approved annual revenue requirements of BPU through a regional rate

1 (Schedule 11) that charges 33% of the BPU revenue requirements to all SPP customers,
2 and the remainder, on a project-by-project basis, to benefiting zone(s). To harmonize the
3 project specific revenue requirements with the Existing Zonal ATRR, each BPU projects'
4 revenue requirement is computed on Worksheet G (at an ROE synchronized to the zonal
5 TCOS, and with an incentive ROE if applicable) and then the total annual revenue
6 requirement (w/o incentives) for all BPU projects is subtracted from the zonal TCOS, in
7 recognition that those costs will be recovered in the regional rate (i.e., SPP OATT
8 Schedule 11). It should be noted that certain BPU projects, those costing \$100,000 or
9 less, are not allocated 33% to the SPP region but are instead allocated 100% to the zone
10 in which the BPU project is located. Worksheet G contains sufficient information for
11 each BPU to enable SPP to (a) properly allocate the ATRR of each BPU to the region
12 and/or benefiting zone(s) pursuant to Attachment J of the SPP OATT and (b) collect such
13 ATRR from customers under Schedule 11.

14 **Q. PLEASE DESCRIBE WORKSHEET F?**

15 A. As explained above, Worksheet F is used as needed to determine “non-Base Plan
16 Upgrade” revenue requirements, with and without any FERC-approved project-specific
17 ROE incentive. If a non-Base Plan Upgrade is rolled-in to the zonal revenue
18 requirement, then Worksheet F will be used to calculate the incentive revenue, if any, to
19 add to the zonal TCOS. If a non-Base Plan Upgrade is directly assigned, in whole or in
20 part, to benefiting parties or zones, then the portion of the revenue requirement to be
21 recovered from such parties (without incentives) will be subtracted from the zonal TCOS.
22 With these adjustments for allocated projects, the zonal ATRR will not subsidize or be
23 subsidized by the allocated project costs. For purely illustrative purposes, Worksheet F

1 has been filled in for PSO's Tulsa EHV project. The illustrative Worksheet F shows the
2 ATRR for the Tulsa EHV project with and without an incentive ROE award. For the
3 illustration, the incentive ROE has been set at 160 basis points above the 11.9%
4 recommended ROE in order to show how the worksheet operates and the additional
5 revenue requirement that would result if an incentive ROE was awarded.

6 **Q. PLEASE CONTINUE YOUR DISCUSSION OF THE FORMULA RATE**
7 **CALCULATIONS FOR PSO AND SWEPCO?**

8 A. The notes on pages 5 and 10 of Exhibit Nos. AEP-202 and AEP-203 provide additional
9 detail or instructions concerning formula input data. This data often cannot be taken
10 directly from Form-1 without modification, which requires additional details to reconcile
11 formula inputs to the reported data.

12 **Q. PLEASE DISCUSS HOW AEP HAS POPULATED THE FORMULA FOR THE**
13 **INITIAL RATE PERIOD?**

14 A. The proposed initial rate period is the 10-month period September 1, 2007 through June
15 30, 2008. A Formula Rate was populated separately for PSO and SWEPCO using each
16 company's 2006 Form-1. Since the Formula Rate provides for the inclusion of projected
17 "current year" transmission plant-in-service additions, these capital additions are
18 specified by month on Worksheet H where the estimated calendar 2007 depreciation
19 expense is calculated. The year-end balance of the plant-in-service additions and the
20 estimated 2007 depreciation expense values are carried back to Exhibit Nos. AEP-202
21 and AEP-203 and reflected in rate base and expense. The only other adjustments made to
22 the actual costs involve adding to the accumulated reserve for depreciation amounts to
23 simulate the additional depreciation of transmission and transmission-related general and
24 intangible plant-in-service during 2007.

1 **IV. Overall TCOS, Proposed Rates and Revenue Comparisons**

2 **Q. PLEASE SUMMARIZE THE OVERALL TCOS AND THE DETERMINATION**
3 **OF THE REVENUE REQUIREMENT USED IN THE CALCULATION OF**
4 **TRANSMISSION RATES FOR THE AEP ZONE?**

5 A. A summary (Exhibit No. AEP-201) was prepared to consolidate the TCOS results for
6 PSO and SWEPCO and shows that the overall TCOS is \$161.2 million. After credits for
7 transmission-related Other Operating revenues from applicable Grandfathered non-
8 OATT contracts and SPP point-to-point transmission service, the Network Integration
9 Transmission Service (“NITS”) rate design revenue requirement would be \$141.7
10 million. After subtracting the Base Plan Upgrade ATRR to be collected under Schedule
11 11 of the SPP OATT, the Existing Zonal ATRR (w/o incentives) to be collected under
12 Schedule 9 is \$140,261,459. AEP is not requesting project specific incentives in this
13 filing so there is no additional ATRR amount shown for incentives, and since this is the
14 initial rate period, no amount is shown for the prior year true-up.

15 **V. Rate Design Comparisons**

16 **Q. DID YOU PREPARE CUSTOMER BILLING COMPARISONS, SIMILAR TO**
17 **STATEMENTS BG AND BH?**

18 A. Yes, I did. The comparison of the customer billings under the present and proposed rates
19 are attached as Exhibit No. AEP-204.

20 **Q. WHAT AVERAGE INCREASE WILL NITS CUSTOMERS EXPERIENCE?**

21 A. Exhibit No. AEP-204 shows that, based on calendar year 2006, customers can expect an
22 annual increase in their NITS bill of between 50.2% and 55.9%. For calendar year 2007,
23 the expected increases range from 58.1% to 64.3%. The variations in the monthly

1 increases will be larger, with increases in peak load months as low as 20.4% (July 2006),
2 and off-peak months as high as 103% (November 2007, projected). This variation is not
3 unexpected. The present rate is the same each month during a calendar year, and changes
4 each January inversely with the change in the 12-CP load of the prior year compared to
5 the 12-CP load of the next previous year. The proposed rate is the ATRR for NITS
6 resulting from the Formula Rate, and is allocated to NITS customers each month based
7 on the monthly Network Load Ratio Share of each customer. Whereas the present rate
8 produces revenues for the AEP Companies and costs for the NITS customers that vary
9 each month with the customers' monthly Network Load, the proposed rate will stabilize
10 revenues and costs, respectively, for the AEP Companies and the NITS customers. The
11 variation of average increases among customers is related to the degree of variation of
12 their load from month to month, while the variation in the average increase by year, 53%
13 for 2006 and 61.3% for 2007, results from the stability of the proposed rate revenue
14 production compared to the variability of the present rate revenues.

15 **Q. HOW DID YOU PROJECT THE CUSTOMER LOADS?**

16 A. To the extent available, data from AEP's economic forecasting group was utilized. For
17 the few customers for which internal forecast data was not available, a 2% growth rate
18 was applied.

19 **VI. Ancillary Services**

20 **Q. HOW WERE THE REVENUE REQUIREMENT AND RATES FOR SERVICE --**
21 **SCHEDULE 1 - SCHEDULING SYSTEM CONTROL AND DISPATCH**
22 **SERVICE DERIVED?**

23 A. The AEP Companies record their costs for transmission dispatch in Account 561, Load

1 Dispatching. Certain sub-accounts are subtracted from the entire Account 561 balance to
2 develop AEP's internal costs for Load Dispatching. The amount of Schedule 1 revenues
3 received from SPP's billing of its PTP customers is also taken as a credit to determine the
4 net AEP revenue requirement for Schedule 1. The projected 12CP load (shown on page 3
5 of Exhibit No. AEP-201) for the AEP pricing zone is then used to develop the Schedule 1
6 rates as shown in the second section on Page 2 of Exhibit No. AEP-201.

7 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

8 A. Yes.

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

American Electric Power Service Corporation on
behalf of:

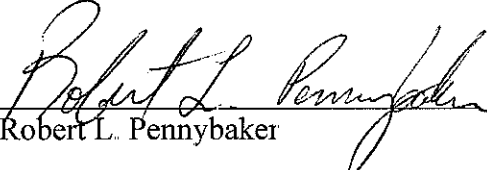
Public Service Company of Oklahoma

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 Robert L. Pennybaker 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.

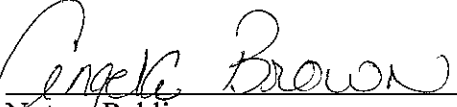

Robert L. Pennybaker

Subscribed and sworn to before me this

18 day of June, 2007.

My Commission expires:

2-27-10


Notary Public

AEP Transmission Formula Rate Template
Utilizing FERC Form 1 Data
For rates effective September 1, 2007

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)	161,216,649	\$64,482,397	\$96,734,252
	(TCOS Line 1)			
2	LESS: REVENUE CREDITS	19,519,877	\$7,495,192	\$12,024,685
	(TCOS Line 5)			
3	CURRENT YEAR ZONE 1 AEP NETWORK SERVICE REVENUE REQUIREMENT	\$141,696,772	\$56,987,205	\$84,709,567
	(TCOS Line 6)			
4	LESS: REVENUE REQUIREMENTS INCLUDED IN LINE 1 FOR:			
5	BASE PLAN UPGRADES (W/O INCENTIVES)	1,435,313	104,354	1,330,959
6	REQUESTED UPGRADES (W/O INCENTIVES)	-	-	-
7	ECONOMIC UPGRADES (W/O INCENTIVES)	-	-	-
8	SUBTOTAL	1,435,313	104,354	1,330,959
9	EXISTING ZONAL ATRR (W/O INCENTIVES)	140,261,459	56,882,851	83,378,608
	(Line 3- Line 8)			
10	INCENTIVE REVENUE REQUIREMENT FOR ZONAL PROJECTS	-	-	-
	(TCOS In 16)			
11	EXISTING ZONAL ATRR (W/ INCENTIVES)	140,261,459	56,882,851	83,378,608
	(Line 9 + Line 10)			
12	HISTORICAL YEAR (2006) ACTUAL ATRR	129,336,984	50,017,194	79,319,790
13	PROJECTED (2006) ATRR FROM PRIOR YEAR	129,336,984	50,017,194	79,319,790
14	PRIOR YEAR TRUE-UP	-	-	-
15	INTEREST ON PRIOR YEAR TRUE UP	-	-	-
16	EXISTING ZONAL ATRR FOR SPP OATT ATTACHMENT H, SEC. 1, COL. 1	\$140,261,459	\$56,882,851	\$83,378,608
	(Ln 11 + Ln 14 + Ln 15)			
B. Point-to-Point Service				
17	2007 Projected AEP West Zone SPP Average 12-Mo. Peak Demand	7,855.31	MW	
	(Load WS, In 11)			
18	Annual Point-to-Point Rate in \$/MW - Year	\$17,855.62		
19	Monthly Point-to-Point Rate in \$/MW - Month	\$1,487.97		
20	Weekly Point-to-Point Rate in \$/MW - Weekly	\$343.38		
21	Daily On-Peak Point-to-Point Rate in \$/MW - Day	\$68.68		
22	Daily Off-Peak Point-to-Point Rate in \$/MW - Day	\$48.92		
23	Hourly On-Peak Point-to-Point Rate in \$/MW - Hour	\$4.29		
24	Hourly Off-Peak Point-to-Point Rate in \$/MW - Hour	\$2.04		
C. SPP Regional Service				
25	BASE PLAN UPGRADE ATRR W/O INCENTIVES	1,435,313	104,354	1,330,959
26	ADDITIONAL ATRR FOR FERC-APPROVED INCENTIVES ON BPU	-	-	-
27	BASE PLAN UPGRADE ATRR FOR SPP COLLECTION UNDER SCHEDULE 11	\$ 1,435,313	104,354	1,330,959

AEP Transmission Formula Rate Template
Utilizing FERC Form 1 Data
For rates effective September 1, 2007

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)	\$10,862,360	\$5,051,682	\$5,810,678
2	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)	\$7,096,893	\$3,223,557	\$3,873,336
3	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.6)	\$46,547	\$46,547	\$0
4	Total 561 Internally Developed Costs (Line 1 - Line 2 - Line 3)	\$3,718,920	\$1,781,578	\$1,937,342
5	Less: PTP Service Credit	461,847	227,686	234,161
6	EXISTING ZONAL ARR (Line 4 - Line 5)	3,257,073	1,553,892	1,703,181
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	\$3,257,073	\$1,553,892	\$1,703,181

B. Schedule 1 Rate Calculations

12	2007 Projected AEP West Zone SPP Average 12-Mo. Peak Demand	7,855.31 MW	(LOAD WS, Line 11)
13	Annual Point-to-Point Rate in \$/MW - Year	\$414.63	(Line 11 / Line 12)
14	Monthly Point-to-Point Rate (ln 13 / 12) \$/MW - Month	\$34.55	(Line 13 / 12)
15	Weekly Point-to-Point Rate (ln 13 / 52) \$/MW - Weekly	\$7.97	(Line 13 / 52)
16	Daily Off-Peak Point-to-Point Rate (ln 13 / 365) \$/MW - Day	\$1.14	(Line 13 / 365)
17	Hourly Off-Peak Point-to-Point Rate (ln 13 / 8760) \$/MW - Hour	\$0.05	(Line 13 / 8760)

AEP Companies: PSO and SWEPCO
Network Load for January Through December, 2007
Based on West Zone-SPP Monthly Transmission System Firm Peak Demands ⁽¹⁾ for the Twelve Months Ended December 31, 2006

Projected Combined Load Worksheet

Line No.	SPP Load Responsibility	Peak Day Peak Hour												12 Month Average MW
		1/16/2007 1900	2/16/2007 800	3/15/2007 800	4/30/2007 1500	5/14/2007 1600	6/21/2007 1600	7/10/2007 1600	8/1/2007 1600	9/1/2007 1600	10/1/2007 1500	11/1/2007 1900	12/1/2007 800	
1	PSO	2,603.00	2,775.00	2,291.00	2,559.00	3,060.00	3,621.45	4,107.39	4,135.24	3,475.37	2,744.50	2,274.02	2,484.49	3,010.87
2	SWEPCO	3,736.00	3,928.00	3,115.00	3,209.00	3,806.00	4,453.80	4,843.51	4,749.75	4,346.29	3,623.68	3,136.62	3,470.41	3,868.17
3	TNCN	20.00												1.67
4	OMPA	85.00	87.00	67.00	77.00	111.00	139.71	162.82	171.23	127.10	121.85	95.59	87.19	111.04
5	NTEC	704.00	776.00	566.00	384.00	501.00	677.92	677.92	670.20	575.44	399.88	459.38	533.71	577.12
6	ETEC	96.00	101.00	71.00	45.00	61.00	81.38	81.38	81.38	67.64	48.73	67.78	72.78	72.43
7	TEXLA	101.00	108.00	88.00	61.00	82.00	110.90	110.90	110.90	94.55	74.49	87.17	100.38	93.37
8	Greenbelt	6.00	4.00	2.00	2.00	3.00	6.30	8.40	6.30	4.20	5.25	6.30	5.25	4.92
9	Lighthouse	2.00	3.00	-	1.00	2.00	2.10	2.10	3.15	1.05	2.10	2.10	1.05	1.72
10	Coffeyville, KS (OATT Firm PTP) ⁽²⁾	114.00	114.00	114.00	114.00	114.00	114.00	114.00	114.00	114.00	114.00	114.00	114.00	114.00
11 Zone 1 - System Firm Peak Demands		7,467.00	7,996.00	6,314.00	6,452.00	7,735.00	9,198.66	10,108.42	10,042.16	8,805.65	7,134.43	6,241.10	6,869.25	7,855.31

Historical Combined Load Worksheet

Line No.	SPP Load Responsibility	Peak Day Peak Hour												12 Month Average MW
		1/11/2006 800	2/18/2006 2000	3/24/2006 800	4/17/2006 1600	5/25/2006 1600	6/21/2006 1600	7/19/2006 1600	8/9/2006 1600	9/16/2006 1600	10/3/2006 1500	11/30/2006 1900	12/8/2006 800	
12	PSO	2,362.85	2,546.67	2,243.91	3,283.68	3,716.91	3,637.03	4,191.37	4,232.13	3,335.39	3,302.54	2,734.28	2,689.52	3,189.69
13	SWEPCO	3,121.27	3,348.35	2,965.38	3,749.92	4,146.96	4,206.65	4,808.81	4,717.66	3,808.32	3,830.66	3,377.96	3,718.98	3,816.74
14	TNCN	16.82	17.79	16.85	24.85	27.82	26.76	28.70	28.70	22.85	22.82	16.76	23.82	23.05
15	OMPA	74.15	80.33	72.09	114.32	141.09	136.97	167.87	167.87	124.61	119.46	93.72	85.48	114.14
16	NTEC	563.34	529.35	540.68	515.96	541.71	579.81	682.80	658.08	583.93	490.22	653.96	710.61	587.54
17	ETEC	66.94	61.79	59.73	59.73	63.85	70.03	80.33	79.30	75.18	62.82	88.57	89.60	71.49
18	TEXLA	84.45	86.51	76.21	82.39	85.48	86.51	105.06	101.96	88.57	79.30	86.51	96.81	88.31
19	Greenbelt	5.15	5.15	3.09	5.15	5.15	6.18	6.18	6.18	4.12	5.15	6.18	5.15	5.32
20	Lighthouse	1.03	2.06	2.06	1.03	1.03	2.06	2.06	3.09	1.03	2.06	2.06	1.03	1.63
21	Coffeyville, KS (OATT Firm PTP) ⁽²⁾	114.00	114.00	114.00	114.00	114.00	114.00	114.00	114.00	114.00	114.00	114.00	114.00	114.00
22 Zone 1 - System Firm Peak Demands		6,412.00	6,792.00	6,094.00	7,950.00	8,844.00	8,866.00	10,181.00	10,109.00	8,158.00	8,028.00	7,174.00	7,533.00	8,011.92

Line No.	Supporting Data	Peak Day Peak Hour												12 Month Average MW
		1/11/2006 800	2/18/2006 2000	3/24/2006 800	4/17/2006 1600	5/25/2006 1600	6/21/2006 1600	7/19/2006 1600	8/9/2006 1600	9/16/2006 1600	10/3/2006 1500	11/30/2006 1900	12/8/2006 800	
23	PSO: PSO Native Load	2,320.85	2,497.67	2,200.91	3,232.68	3,656.91	3,579.03	4,123.37	4,164.13	3,276.39	3,247.54	2,675.28	2,631.52	3,189.69
24	KAMO	24.00	29.00	26.00	29.00	33.00	33.00	40.00	42.00	33.00	29.00	33.00	27.00	3,816.74
25	WFEC	18.00	20.00	17.00	22.00	25.00	25.00	28.00	26.00	26.00	26.00	26.00	21.00	23.05
26	PSO Load Responsibility	2,362.85	2,546.67	2,243.91	3,283.68	3,716.91	3,637.03	4,191.37	4,232.13	3,335.39	3,302.54	2,734.28	2,689.52	3,189.69
27	SWEPCO: SWEPCO Native Load	3,308.25	3,423.25	3,153.35	3,830.11	4,173.27	4,294.78	4,875.42	4,792.50	3,957.33	3,901.26	3,570.14	3,919.47	3,868.17
28	Less: NTEC	(563.34)	(529.35)	(540.68)	(515.96)	(541.71)	(579.81)	(682.80)	(658.08)	(583.93)	(490.22)	(653.96)	(710.61)	587.54
29	Less: ETEC	(66.94)	(61.79)	(59.73)	(59.73)	(63.85)	(70.03)	(80.33)	(79.30)	(75.18)	(62.82)	(88.57)	(89.60)	71.49
30	Less: TEXLA	(84.45)	(86.51)	(76.21)	(82.39)	(85.48)	(86.51)	(105.06)	(101.96)	(88.57)	(79.30)	(86.51)	(96.81)	88.31
31	AECG	508.75	577.75	470.65	547.89	645.73	628.22	718.68	741.50	574.67	542.74	615.96	673.53	673.53
32	Lagen (Formerly Cajun)	13.00	15.00	12.00	13.00	13.00	14.00	17.00	16.00	16.00	13.00	15.00	17.00	17.00
33	Lafayette	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00
34	Doler Hills Aux. Load (not self-generated)	0.00	4.00	0.00	11.00	0.00	0.00	0.00	2.00	0.00	0.00	0.00	0.00	0.00
35	SWEPCO Load Responsibility	3,121.27	3,348.35	2,965.38	3,749.92	4,146.96	4,206.65	4,808.81	4,717.66	3,808.32	3,830.66	3,377.96	3,718.98	3,816.74
36	TNC	18.82	17.79	16.85	24.85	27.82	26.76	28.70	28.73	22.85	22.82	16.76	23.82	23.82
37	TNC North Load Responsibility	18.82	17.79	16.85	24.85	27.82	26.76	28.70	28.73	22.85	22.82	16.76	23.82	23.82
38	Coffeyville Actual Load ⁽²⁾	92.00	88.00	87.00	101.00	109.00	91.00	18.00	76.00	97.00	104.00	91.00	95.00	95.00

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 losses
(2) Netload from East and West Coffeyville ties, not included in AEP Control Area.

AEP Transmission Formula Rate Template
Utilizing FERC Form 1 Cost Data for 2006
Plus Capital Additions for 2007

PSO TCOS
Page 1 of 10
PROJECTED

PUBLIC SERVICE COMPANY OF OKLAHOMA

Line No.						Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(In 128)				\$64,482,397
2	REVENUE CREDITS	(Note A)	<u>Total</u>		<u>Allocator</u>	
3	Transmission Credits	(Worksheet A)	6,311,305		DA 1.00000	\$ 6,311,305
4	Assoc. Business Development	(Worksheet A)	<u>1,183,887</u>		DA 1.00000	<u>\$ 1,183,887</u>
5	Total Revenue Credits		7,495,192			\$ 7,495,192
6	REVENUE REQUIREMENT (w/o incentives) For All AEP Facilities	(In 1 less In 5)				\$ 56,987,205
7	Revenue Requirement for SPP Base Plan Upgrades (w/o incentives)	(Worksheet G)	104,354		DA 1.00000	\$ 104,354
8	REVENUE REQUIREMENT EXCLUDING BASE PLAN UPGRADE ATRR	(In 6 less In 7)				\$ 56,882,850
9	NET PLANT CARRYING CHARGE (w/o incentives)	(Note B)				
10	Annual Rate	(In 6 / In 42 x 100)				19.44%
11	Monthly Rate	(In 10 / 12)				1.62%
12	NET PLANT CARRYING CHARGE, W/O DEPRECIATION (w/o incentives)	(Note B)				
13	Annual Rate	((In 6 - In 98) / In 42 x 100)				16.20%
14	NET PLANT CARRYING CHARGE, W/O DEPRECIATION, INCOME TAXES AND RETURN	(Note B)				
15	Annual Rate	((In 6 - In 98 - In 122 - In 123) / In 42 x 100)				5.37%
16	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's	(Note C) (Worksheet F)			NA	\$ -
17	PROJECTED YE 2007 TRANSMISSION REVENUE REQUIREMENT	(In 8 + In 16)				<u><u>\$ 56,882,850</u></u>

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Line No.	(1) RATE BASE CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator	(5) Total Transmission
18	GROSS PLANT IN SERVICE				
18	Production	205.46.g	1,091,910,339	NA 0.00000	-
19	Transmission	207.58.g	503,637,781	DA	488,049,557
20	Plus: Transmission Plant-in-Service Additions (Worksheet H)		66,955,398	DA 1.00000	66,955,398
21	Plus: Additional Trans Plant on Transferred Assets (Worksheet H)		-	DA 1.00000	-
22	Distribution	207.75.g	1,215,235,727	NA 0.00000	-
23	General Plant	207.99.g (Note K)	164,261,554	W/S 0.06861	11,270,576
24	Intangible Plant	205.5.g	55,619,706	W/S 0.06861	3,816,268
25	Common	356	-	CE 0.06861	-
26	TOTAL GROSS PLANT	(sum Ins 18 to 25)	3,097,620,505	GP(p)= 0.184042 GTD(p)= 0.29300	570,091,799
27	ACCUMULATED DEPRECIATION AND AMORTIZATION				
28	Production	219.20-24.c	683,138,508	NA 0.00000	-
29	Transmission	219.25.c	197,407,779	TP1= 0.98762	194,964,426
30	Plus: Transmission Plant-in-Service Additions (Worksheet H)		555,370	DA 1.00000	555,370
31	Plus: Additional Projected Deprec on Transferred Assets (Worksheet H)		-	DA 1.00000	-
32	Plus: Additional Transmission Depreciation for 2007 (In 98)		9,762,903	TP1 0.98762	9,642,066
33	Plus: Additional General & Intangible Depreciation for 2007 (In 100 + In 101)		13,864,258	W/S 0.06861	951,277
34	Plus: Additional Accum Deprec on Transferred Assets (Worksheet H)		-	DA 1.00000	-
35	Distribution	219.26.c	391,382,162	NA 0.00000	-
36	General Plant	219.28.c (Note K)	99,598,103	W/S 0.06861	6,833,784
37	Intangible Plant	219	-	W/S 0.06861	-
38	Common	356	-	CE 0.06861	-
39	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 28 to 38)	1,395,709,083		212,946,923
40	NET PLANT IN SERVICE				
41	Production	(In 18 - In 28)	408,771,831		-
42	Transmission	(In 19 - In 29)	306,230,002		293,085,130
43	Plus: Transmission Plant-in-Service Additions (In 20 - In 30)		66,400,028		66,400,028
44	Plus: Additional Trans Plant on Transferred Assets (In 21 - In 31)		-		-
45	Plus: Additional Transmission Depreciation for 2007 (-In 32)		(9,762,903)		(9,642,066)
46	Plus: Additional General & Intangible Depreciation for 2007 (-In 33)		(13,864,258)		(951,277)
47	Plus: Additional Accum Deprec on Transferred Assets (Worksheet H) (-In 34)		-		-
48	Distribution	(In 22 - In 35)	823,853,565		-
49	General Plant	(In 23 - In 36)	64,663,451		4,436,792
50	Intangible Plant	(In 24 - In 37)	55,619,706		3,816,268
51	Common	(In 25 - In 38)	-		-
52	TOTAL NET PLANT IN SERVICE	(sum Ins 41 to 51)	1,701,911,422	NP(p)= 0.209849	357,144,876
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)	(368,700,205)	DA	(61,202,976)
56	Account No. 283 (enter negative)	277.9.k (Worksheet C)	(111,675,546)	DA	(12,887,039)
57	Account No. 190	234.8.c (Worksheet C)	56,729,521	DA	5,453,603
58	Account No. 255 (enter negative)	267.8.h (Worksheet C)	(244,715)	DA	(40,622)
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 Ins 54 to 60)	(423,890,945)		(68,677,034)
62	PLANT HELD FOR FUTURE USE	214.x.d (Note F)	-	DA 1.00000	-
63	WORKING CAPITAL	(Note G)			
64	Cash Working Capital	(1/8 * In 96)	8,962,546		1,866,559
65	Transmission Materials & Supplies	227.8.c	723,566	TP 0.97268	703,799
66	A&G Materials & Supplies	227.11.c	254,023	W/S 0.06861	17,429
67	Undistributed Stores Expense (Acct 163)	227.16.c	-	GP(h) 0.16600	-
68	Prepayments (Account 165) - Labor Allocated	111.57.c (Worksheet I)	78,892,824	W/S 0.06861	5,413,120
69	Prepayments (Account 165) - Direct Allocated	111.57.c (Worksheet I)	-	DA 1.00000	-
70	Prepayments (Account 165) - Gross Plant	111.57.c (Worksheet I)	4,360,024	GP(h) 0.16600	723,749
71	TOTAL WORKING CAPITAL	(sum Ins 64 to 70)	93,192,983		8,724,657
72	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note H) (Worksheet B, In 18)	(9,338,998)	DA 1.00000	(9,338,998)
73	RATE BASE (sum Ins 52, 61, 62, 71, 72)		1,361,874,462		287,853,501

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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					
74	Transmission	321.112.b	20,090,328	TP 0.97268	19,541,474
75	Less: expenses 100% assigned to TO billed customers (Worksheet E, In 14)		-	DA 1.00000	-
76	Less: Total Account 561 (Load Dispatch - Sch 1) (Note I)	321.84-92.b	5,051,682	TP 0.97268	4,913,673
77	Less: Account 565	321.96.b (Note J)	4,494,008	TP 0.97268	4,371,235
78	Plus: Acct 565 native load, zonal or pool	(Note J)	-	DA 1.00000	-
79	Transmission Subtotal (Ins 74-75-76-77+78)		10,544,638		10,256,566
80	Administrative and General	323.197.b (Note K)	61,454,939		
81	Less: Acc. 928, Reg. Com. Exp.	323.189.b	1,277,675		
82	Acct. 930.1, Gen. Advert. Exp.	323.191.b	818,156		
83	Acc. 924, Property Insurance	323.185.b	916,650		
84	Acc. 930.2, Misc. Gen. Exp.	323.192.b	3,071,898		
85	Acc. 935, Maint. of Gen. Plant	323.196.b	6,514,476	W/S 0.06861	446,982
86	Balance of A & G	(In 80 - sum In 81 to In 85)	48,856,084	W/S 0.06861	3,352,192
87	Plus: Acct. 924, Property Insurance	(In 83)	916,650	NP(h) 0.18160	166,468
88	Acct. 928 - Transmission Specific	(Note L) (Worksheet D)	-	TP 0.97268	-
89	Acct. 928 - Transmission Allocated	(Note L) (Worksheet D)	19,958	GP(h) 0.16600	3,313
90	Acct 930.1 - Only safety related ads.	(Note L) (Worksheet D)	307,490	W/S 0.06861	21,098
91	Acct 930.2 - Misc Gen. Exp. - Trans	(Worksheet D)	647,133	TP 0.97268	629,454
92	Acct 930.2 - Misc Gen. Exp. - Allocated	(Worksheet D)	822,040	W/S 0.06861	56,403
93	A & G Subtotal	(sum Ins 84 to 90)	61,155,730		4,675,909
94	Common	356	-	CE 0.06861	-
95	Transmission Lease Payments		-	DA 1.00000	-
96	TOTAL O & M EXPENSE	(In 79 + In 93 + In 94 + In 95)	71,700,368		14,932,474
DEPRECIATION AND AMORTIZATION EXPENSE					
97	Transmission	336.7.f	9,762,903	TP 0.97268	9,496,187
99	Plus: Transmission Plant-in-Service Additions (Worksheet H)		555,370	DA 1.00000	555,370
100	General	336.10.f	6,492,400	W/S 0.06861	445,467
101	Intangible	336.1.f	7,371,858	W/S 0.06861	505,810
102	Common	336.11.f	-	CE 0.06861	-
103	TOTAL DEPRECIATION AND AMORTIZATIN	(sum Ins 98 to 102)	24,182,531		11,002,834
TAXES OTHER THAN INCOME					
104	Labor Related	(Note M)			
106	Payroll	262.x-263.x.i	3,915,903	W/S 0.06861	268,684
107	Plant Related				
108	Property	262.x-263.x.i	32,312,415	NP(h) 0.18160	5,868,087
109	Gross Receipts/Sales & Use	262.x-263.x.i	(4,095,879)	NA 0.00000	-
110	Other	262.x-263.x.i	486,240	GP(h) 0.16600	80,714
111	Payments in lieu of taxes		-	GP(h) 0.16600	-
112	TOTAL OTHER TAXES	114.14.c	32,618,679		6,217,485
INCOME TAXES					
113		(Note N)			
114	$T=1 - \{(1 - \text{SIT}) * (1 - \text{FIT})\} / (1 - \text{SIT} * \text{FIT} * p) =$		33.71%		
115	$\text{EIT}=(T/(1-T)) * (1-(\text{WCLTD}/\text{WACC})) =$		33.93%		
116	where WCLTD=(In 158) and WACC = (In 161)				
117	and FIT, SIT & p are as given in Note N.				
118	$\text{GRCF}=1 / (1 - T) =$ (from In 114)		1.5086		
119	Amortized Investment Tax Credit (enter negative)		(1,030,554)		
120	Income Tax Calculation	(In 115 * In 123)	38,385,700		8,113,419
121	ITC adjustment	(In 118 * In 119)	(1,554,649)	NP(h) 0.18160	(282,332)
122	TOTAL INCOME TAXES	(sum Ins 120 to 121)	36,831,051		7,831,087
123	RETURN ON RATE BASE (Rate Base*WACC)	(In 73 * In 161)	113,120,713		23,909,835
124	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note H) (Worksheet B, In 16)		588,681	DA 1.00000	588,681
125	REVENUE REQUIREMENT BEFORE TEXAS GROSS MARGIN TAX		279,042,023		64,482,397
126	(sum Ins 96, 103, 112, 122, 123, 124)				
127	TEXAS GROSS MARGIN TAX (NOTE O) (Worksheet J)		-	DA	-
128	REVENUE REQUIREMENT INCLUDING GROSS MARGIN TAX		279,042,023		64,482,397

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SUPPORTING CALCULATIONS

In								
<u>No.</u>	TRANSMISSION PLANT INCLUDED IN SPP TARIFF							
129	Total transmission plant	(In 19 + In 20 + In 21)					570,593,179	
130	Less transmission plant excluded from SPP Tariff	(Note P)					-	
131	Less transmission plant included in OATT Ancillary Services	(Note Q)	(Worksheet L)				15,588,224	
132	Transmission plant included in SPP Tariff	(In 129 - In 130 - In 131)					<u>555,004,955</u>	
133	Percent of transmission plant in SPP Tariff	(In 132 / In 129)				TP=	0.97268	
				Payroll Billed				
				from AEP				
134	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	Service Corp.				
135	Production	354.20,22.b	18,830,409	7,444,809	NA	0.00000	-	
136	Transmission	354.21.b	2,695,801	1,815,873	TP	0.97268	4,388,418	
137	Distribution	354.23.b	17,759,740	1,621,943	NA	0.00000	-	
138	Other (Excludes A&E)	354.24,25,26.b	7,443,597	6,346,261	NA	0.00000	-	
139	Total	(sum Ins 135 to 138)	<u>46,729,547</u>	<u>17,228,886</u>			<u>4,388,418</u>	
140	Transmission related amount					W/S=	0.06861	
141	COMMON PLANT ALLOCATOR (CE)							
142	Electric	200.3.c	2,943,500,299		DA	1.00000	2,943,500,299	
143	Gas	200.3.d	-		NA	0.00000	-	
144	Other	200.3. e, f, g	-		NA	0.00000	-	
145	Total	(sum Ins 142 to 144)	<u>2,943,500,299</u>				<u>2,943,500,299</u>	
146	Electric related amount						1.00000	
147	W/S Allocator					W/S	0.06861	
148	Transmission related amount	(In 146 * In 147)				CE=	0.06861	
149	WEIGHTED AVERAGE COST OF CAPITAL (WACC)						\$	
150		Long Term Interest (117, sum of 62c - 66c)					<u>34,911,851</u>	
151		Preferred Dividends (118.29.c) (positive number)					212,404	
152		Development of Common Stock:						
153		Proprietary Capital (112.16.c)					590,699,633	
154		Less Preferred Stock (In 159)					5,261,700	
155		Less Account 219.1 (112.15.c)					<u>(1,070,578)</u>	
156		Common Stock (In 153 - In 154 - In 155)					<u>586,508,511</u>	
157			\$	%	Cost	Weighted		
158	Long Term Debt (112, sum of 18.c - 21.c)		<u>671,360,000</u>	53.15%	0.0520	0.0276		
159	Preferred Stock (112.3.c)		5,261,700	0.42%	0.0404	0.0002		
160	Common Stock (In 156)		<u>586,508,511</u>	46.43%	0.1190	<u>0.0553</u>		
161	Total (sum Ins 158 to 160)		<u>1,263,130,211</u>			WACC=	0.0831	

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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 than 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 = | 30.25% |
| | SIT= | 4.96% (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). Common Stock cost rate (ROE) = 11.9%, the rate accepted by FERC in Docket No. ER07-XXX. It includes an additional 50 basis points for remaining a member of the SPP RTO.

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Line No.					Transmission Amount
162	REVENUE REQUIREMENT (w/o incentives)	(In 286)			\$57,616,740
163	REVENUE CREDITS	(Note A)	<u>Total</u>	<u>Allocator</u>	
164	Transmission Credits	(Worksheet A)	6,311,305	DA 1.00000	\$ 6,311,305
165	Assoc. Business Development	(Worksheet A)	<u>1,183,887</u>	DA 1.00000	<u>\$ 1,183,887</u>
166	Total Revenue Credits		7,495,192		\$ 7,495,192
	REVENUE REQUIREMENT (w/o incentives) For				
167	All AEP Facilities	(In 162 less In 166)			\$ 50,121,548
168	Revenue Requirement for SPP Base Plan Upgrades (w/o incentives)	(Worksheet G)	104,354	DA 1.00000	\$ 104,354
169	REVENUE REQUIREMENT EXCLUDING BASE PLAN UPGRADE ATRR	(In 167 less In 168)			\$ 50,017,194
170	NET PLANT CARRYING CHARGE (w/o incentives) (Note B)				
171	Annual Rate	(In 167 / In 203 x 100)			17.10%
172	Monthly Rate	(In 171 / 12)			1.43%
173	NET PLANT CARRYING CHARGE, W/O DEPRECIATION (w/o incentives) (Note B)				
174	Annual Rate	((In 167 - In 259) / In 203 x 100)			13.87%
175	NET PLANT CARRYING CHARGE, W/O DEPRECIATION, INCOME TAXES AND RETURN (Note B)				
176	Annual Rate	((In 167 - In 259 - In 283 - In 284) / In 203 x 100)			5.16%
177	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note C) (Worksheet F)			NA	\$ -
178	HISTORIC YE 2006 TRANSMISSION REVENUE REQUIREMENT	(In 169 + In 177)			<u>\$ 50,017,194</u>

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	(1)	(2)	(3)	(4)	(5)
Line No.	RATE BASE CALCULATION	Data Sources (See "General Notes")	TO Total	Allocator	Total Transmission
179	GROSS PLANT IN SERVICE				
179	Production	205.46.g	1,091,910,339	NA	0.00000
180	Transmission	207.58.g	503,637,781	DA	
181	Plus: Transmission Plant-in-Service Additions (Worksheet H)		N/A	DA	1.00000
182	Plus: Additional Trans Plant on Transferred Assets (Worksheet H)		N/A	DA	1.00000
183	Distribution	207.75.g	1,215,235,727	NA	0.00000
184	General Plant	207.99.g (Note K)	164,261,554	W/S	0.06836
185	Intangible Plant	205.5.g	55,619,706	W/S	0.06836
186	Common	356	-	CE	0.06836
187	TOTAL GROSS PLANT	(sum Ins 179 to 186)	3,030,665,107	GP(h)=	0.165997
				GTD=	0.29300
188	ACCUMULATED DEPRECIATION AND AMORTIZATION				
189	Production	219.20-24.c	683,138,508	NA	0.00000
190	Transmission	219.25.c	197,407,779	TP1=	0.98762
191	Plus: Transmission Plant-in-Service Additions (Worksheet H)		N/A	DA	1.00000
192	Plus: Additional Projected Deprec on Transferred Assets (Worksheet H)		N/A	DA	1.00000
193	Plus: Additional Transmission Depreciation for 2007 (In 259)		N/A	TP1	0.98762
194	Plus: Additional General & Intangible Depreciation for 2007 (In 261 + In 262)		N/A	W/S	0.06836
195	Plus: Additional Accum Deprec on Transferred Assets (Worksheet H)		N/A	DA	1.00000
196	Distribution	219.26.c	391,382,162	NA	0.00000
197	General Plant	219.28.c (Note K)	99,598,103	W/S	0.06836
198	Intangible Plant	219	-	W/S	0.06836
199	Common	356	-	CE	0.06836
200	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 189 to 199)	1,371,526,552		
201	NET PLANT IN SERVICE				
202	Production	(In 179 - In 189)	408,771,831		
203	Transmission	(In 180 - In 190)	306,230,002		
204	Plus: Transmission Plant-in-Service Additions (In 181 - In 191)		N/A		
205	Plus: Additional Trans Plant on Transferred Assets (In 182 - In 192)		N/A		
206	Plus: Additional Transmission Depreciation for 2007 (-In 193)		N/A		
207	Plus: Additional General & Intangible Depreciation for 2007 (-In 194)		N/A		
208	Plus: Additional Accum Deprec on Transferred Assets (Worksheet H) (-In 195)		N/A		
209	Distribution	(In 183 - In 196)	823,853,565		
210	General Plant	(In 184 - In 197)	64,663,451		
211	Intangible Plant	(In 185 - In 198)	55,619,706		
212	Common	(In 186 - In 199)	-		
213	TOTAL NET PLANT IN SERVICE	(sum Ins 202 to 212)	1,659,138,555	NP(h)=	0.181605
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)	(368,700,205)	DA	
217	Account No. 283 (enter negative)	277.9.k (Worksheet C)	(111,675,546)	DA	
218	Account No. 190	234.8.c (Worksheet C)	56,729,521	DA	
219	Account No. 255 (enter negative)	267.8.h (Worksheet C)	(244,715)	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 Ins 215 to 221)	(423,890,945)		
223	PLANT HELD FOR FUTURE USE	214.x.d (Note F)	-	DA	1.00000
224	WORKING CAPITAL	(Note G)			
225	Cash Working Capital	(1/8 * In 257)	8,962,546		
226	Transmission Materials & Supplies	227.8.c	723,566	TP	0.96905
227	A&G Materials & Supplies	227.11.c	254,023	W/S	0.06836
228	Undistributed Stores Expense (Acct 163)	227.16.c	-	GP(h)	0.16600
229	Prepayments (Account 165) - Labor Allocated	111.57.c (Worksheet I)	78,892,824	W/S	0.06836
230	Prepayments (Account 165) - Direct Allocated	111.57.c (Worksheet I)	-	DA	1.00000
231	Prepayments (Account 165) - Gross Plant	111.57.c (Worksheet I)	4,360,024	GP(h)	0.16600
232	TOTAL WORKING CAPITAL	(sum Ins 225 to 231)	93,192,983		
233	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note H) (Worksheet B, In 18)	(9,338,998)	DA	1.00000
234	RATE BASE (sum Ins 213, 222, 223, 232, 233)		1,319,101,595		

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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	20,090,328	TP 0.96905	19,468,507
236	Less: expenses 100% assigned to TO billed customers (Worksheet E, In 14)		-	DA 1.00000	-
237	Less: Total Account 561 (Load Dispatch - Sch 1) (Note I)	321.84-92.b	5,051,682	TP 0.96905	4,895,326
238	Less: Account 565	321.96.b (Note J)	4,494,008	TP 0.96905	4,354,913
239	Plus: Acct 565 native load, zonal or pool	(Note J)	-	DA 1.00000	-
240	Transmission Subtotal (Ins 235-236-237-238+239)		10,544,638		10,218,268
241	Administrative and General	323.197.b (Note K)	61,454,939		
242	Less: Acc. 928, Reg. Com. Exp.	323.189.b	1,277,675		
243	Acct. 930.1, Gen. Advert. Exp.	323.191.b	818,156		
244	Acc. 924, Property Insurance	323.185.b	916,650		
245	Acc. 930.2, Misc. Gen. Exp.	323.192.b	3,071,898		
246	Acc. 935, Maint. of Gen. Plant	323.196.b	6,514,476		
247	Balance of A & G	(In 241 - sum In 242 to In 246)	48,856,084	W/S 0.06836	445,313
248	Plus: Acct. 924, Property Insurance	(In 244)	916,650	W/S 0.06836	3,339,675
249	Acct. 928 - Transmission Specific	(Note L) (Worksheet D)	-	NP(h) 0.18160	166,468
250	Acct. 928 - Transmission Allocated	(Note L) (Worksheet D)	19,958	TP 0.96905	-
251	Acct 930.1 - Only safety related ads.	(Note L) (Worksheet D)	307,490	GP(h) 0.16600	3,313
252	Acct 930.2 - Misc Gen. Exp. - Trans	(Worksheet D)	647,133	W/S 0.06836	21,019
253	Acct 930.2 - Misc Gen. Exp. - Allocated	(Worksheet D)	822,040	TP 0.96905	627,103
254	A & G Subtotal	(sum Ins 246 to 253)	61,155,730	W/S 0.06836	56,193
255	Common	356	-	CE 0.06836	-
256	Transmission Lease Payments		-	DA 1.00000	-
257	TOTAL O & M EXPENSE	(In 240 + In 254 + In 255 + In 256)	71,700,368		14,877,352
DEPRECIATION AND AMORTIZATION EXPENSE					
258	Transmission	336.7.f	9,762,903	TP 0.96905	9,460,729
260	Plus: Transmission Plant-in-Service Additions (Worksheet H)		N/A	DA 1.00000	N/A
261	General	336.10.f	6,492,400	W/S 0.06836	443,804
262	Intangible	336.1.f	7,371,858	W/S 0.06836	503,921
263	Common	336.11.f	-	CE 0.06836	-
264	TOTAL DEPRECIATION AND AMORTIZATIN	(sum Ins 259 to 263)	23,627,161		10,408,453
TAXES OTHER THAN INCOME					
266	Labor Related	(Note M)			
267	Payroll	262.x-263.x.i	3,915,903	W/S 0.06836	267,681
268	Plant Related				
269	Property	262.x-263.x.i	32,312,415	NP(h) 0.18160	5,868,087
270	Gross Receipts/Sales & Use	262.x-263.x.i	(4,095,879)	NA 0.00000	-
271	Other	262.x-263.x.i	486,240	GP(h) 0.16600	80,714
272	Payments in lieu of taxes		-	GP(h) 0.16600	-
273	TOTAL OTHER TAXES	114.14.c	32,618,679		6,216,482
INCOME TAXES					
274		(Note N)			
275	$T = 1 - \{[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)\} =$		33.71%		
276	$EIT = (T / (1 - T)) * (1 - (WCLTD / WACC)) =$		33.93%		
277	where WCLTD = (In 319) and WACC = (In 322)				
278	and FIT, SIT & p are as given in Note N.				
279	$GRCF = 1 / (1 - T) =$ (from In 275)		1.5086		
280	Amortized Investment Tax Credit (enter negative)		(1,030,554)		
281	Income Tax Calculation	(In 276 * In 284)	37,180,107		6,538,747
282	ITC adjustment	(In 279 * In 280)	(1,554,649)	NP(h) 0.18160	(282,332)
283	TOTAL INCOME TAXES	(sum Ins 281 to 282)	35,625,458		6,256,416
284	RETURN ON RATE BASE (Rate Base*WACC)	(In 234 * In 322)	109,567,892		19,269,357
285	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note H) (Worksheet B, In 16)		588,681	DA 1.00000	588,681
286	REVENUE REQUIREMENT BEFORE TEXAS GROSS MARGIN TAX		273,728,238		57,616,740
287	(sum Ins 257, 264, 273, 283, 284, 285)				
288	TEXAS GROSS MARGIN TAX (NOTE O) (Worksheet J)		-	DA	-
289	REVENUE REQUIREMENT INCLUDING GROSS MARGIN TAX		273,728,238		57,616,740

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SUPPORTING CALCULATIONS

In								
<u>No.</u>	TRANSMISSION PLANT INCLUDED IN SPP TARIFF							
290	Total transmission plant	(In 180)					503,637,781	
291	Less transmission plant excluded from SPP Tariff	(Note P)					-	
292	Less transmission plant included in OATT Ancillary Services	(Note Q)	(Worksheet L)				15,588,224	
293	Transmission plant included in SPP Tariff	(In 290 - In 291 - In 292)					488,049,557	
294	Percent of transmission plant in SPP Tariff	(In 293 / In 290)				TP=	0.96905	
Payroll Billed from AEP Service Corp.								
295	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll					
296	Production	354.20,22.b	18,830,409	7,444,809	NA	0.00000	-	
297	Transmission	354.21.b	2,695,801	1,815,873	TP	0.96905	4,372,032	
298	Distribution	354.23.b	17,759,740	1,621,943	NA	0.00000	-	
299	Other (Excludes A&E)	354.24,25,26.b	7,443,597	6,346,261	NA	0.00000	-	
300	Total	(sum Ins 296 to 299)	46,729,547	17,228,886			4,372,032	
301	Transmission related amount					W/S=	0.06836	
302	COMMON PLANT ALLOCATOR (CE)							
303	Electric	200.3.c	2,943,500,299		DA	1.00000	2,943,500,299	
304	Gas	200.3.d	0		NA	0.00000	-	
305	Other	200.3. e, f, g	0		NA	0.00000	-	
306	Total	(sum Ins 303 to 305)	2,943,500,299				2,943,500,299	
307	Electric related amount						1.00000	
308	W/S Allocator					W/S	0.06836	
309	Transmission related amount	(In 307 * In 308)				CE=	0.06836	
310	WEIGHTED AVERAGE COST OF CAPITAL (WACC)						\$	
311	Long Term Interest (117, sum of 62c - 66c)						34,911,851	
312	Preferred Dividends (118.29.c) (positive number)						212,404	
313	Development of Common Stock:							
314	Proprietary Capital (112.16.c)						590,699,633	
315	Less Preferred Stock (In 320)						5,261,700	
316	Less Account 219.1 (112.15.c)						(1,070,578)	
317	Common Stock (In 314 - In 315 - In 316)						586,508,511	
318			\$	%	Cost (Note S)	Weighted		
319	Long Term Debt (112, sum of 18.c - 21.c)		671,360,000	53.15%	0.0520	0.0276		
320	Preferred Stock (112.3.c)		5,261,700	0.42%	0.0404	0.0002		
321	Common Stock (In 317)		586,508,511	46.43%	0.1190	0.0553		
322	Total (sum Ins 319 to 321)		1,263,130,211			WACC=	0.0831	

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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 than 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) (In 280) multiplied by (1/1-T). If the applicable tax rates are zero enter 0.
- | | | | |
|------------------|-------|--------|---|
| Inputs Required: | FIT = | 30.25% | |
| | SIT = | 4.96% | (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 (In 311) / long term debt (In 319). Preferred Stock cost rate = preferred dividends (In 312) / preferred outstanding (In 320). Common Stock cost rate (ROE) = 11.9%, the rate accepted by FERC in Docket No. ER07-XXX. It includes an additional 50 basis points for remaining a member of the SPP RTO.

PSO Worksheet A - Revenue Credits

	Total Company	Non- Transmission	Transmission
I. Account 450, Forfeited Discounts	2,898,977	\$2,898,977	\$0
II. Account 451, Miscellaneous Service Revenues	4,753,105	4,753,105	-
III. Account 454, Rent from Electric Property			
Account 4540001 - Rent from Elect Property-Aff		-	
Account 4540002 - Rent from Elect Property - Non-Aff	3,552,774	3,315,390	237,384
Account 4540003 - Rent from Elect Property - ABD - Aff	3,979,808	3,954,603	25,205
Account 4540004 - Rent from Elect Property - ABD - Non-Aff	82,243	51,744	30,499
Total Rents from Electric Property	7,614,825		293,088

(Revenue related to transmission facilities for pole attachments, rentals, etc. Provide data sources and explanations in Section VI, Notes below)

IV. Account 4560015, Revenues from Associated Business Development			
Account 4560015, Revenues from Associated Business Development	4,193,613	3,302,814	890,799
V. Total Other Operating Revenues To Reduce Revenue Requirement			1,183,887
VI. Account 456.0, Revenues from Transmission of Electricity of Others			\$19,682,953
(Provide data sources and any detailed explanations necessary in Section VII, Notes below)			
Less:			
TO's LSE Direct Assignment Revenue Credits			
TO's LSE Sponsored Upgrade Revenue Credits			
TO's LSE Network Upgrades for Generation Interconnection - Credits			\$921,476
TO's Point-To-Point Revenue for GFA's Associated with Load Included in the Divisor			\$2,160,038
Network Service Revenue (Schedule 9) Associated With Load Included in the Divisor			\$3,551,612
TO's Revenue Associated with Transmission Plant Excluded From SPP Tariff			
Wholesale Distribution charges			
TO's LSE Revenue from Ancillary Services Provided			\$2,516,879
Base Plan Revenue Received			
Other (Flow Through of ERCOT Ancillary Charges)			\$4,221,643
Other			

Net Transmission Credits \$6,311,305

VII. Total Worksheet A Revenue Credits \$7,495,192

VIII. Data Sources:

Data for this worksheet came from the FERC Form 1 and the Company's General Ledger.

PSO Worksheet B - IPP - System Upgrade Credit

<u>Line No.</u>	<u>Account 2530067</u>	<u>PSO</u>
1	Funds from IPP Customers	\$ (8,144,789)
2	Transimission Credits given back over the years:	
3		2002 \$ 90,104
4		2003 \$ (23,689)
5		2004 \$ 33,506
6		2005 \$ 90,819
7		2006 \$ <u>45,035</u>
8		\$ 235,776
9		
10	Net balance of IPP Funds Received Credited Back	<u>\$ (7,909,013)</u>
11	Interest Accrued over the years:	
12		2002 \$ -
13		2003 \$ (215,249)
14		2004 \$ (229,391)
15		2005 \$ (396,664)
16		2006 \$ <u>(588,681)</u>
17		\$ (1,429,985)
18	Net Funds from IPP Customers 12/31/2006 (FORM 1, P269, line 7(f))	<u><u>\$ (9,338,998)</u></u>

PSO Worksheet C - ADIT & ITC Details

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Acc. No.	Description	2006 YE Balance	100% Non-Transmission Related	100% Transmission Related	Transmission Plant Related	Transmission & Distribution Plant Related	Transmission Labor Related	Total Included in Ratebase (F)+(G)+(H)
Account 281								
	None	-	-	-	-	-	-	-
	Subtotal - Form 1, p273	-	-	-	-	-	-	-
	Less FASB 109 Above if not separately removec	-	-	-	-	-	-	-
	Less FASB 106 Above if not separately removec	-	-	-	-	-	-	-
	Less OCI & Non-Utility above, if not seperately removed.	-	-	-	-	-	-	-
	Total	-	-	-	-	-	-	-
	Transmission Allocator [GP or W/S]		0.0000%	100.0000%	16.5997%	29.3005%	6.8614%	
	Total		0	0	0	0	0	0
Account 282								
2821001	Accum Dfnd FIT - Utility Prop	368,700,205			368,700,205			
2823001	Acc Dfrd FIT FAS 109 Flow Thru	16,073,905	16,073,905					
2824001	Acc Dfrd FIT - SFAS 109 Excess	(13,848,583)	(13,848,583)					
	Subtotal - Form 1, p274	370,925,528	2,225,322	-	368,700,205	-	-	-
	Less FASB 109 Above if not separately removec	2,225,322	2,225,322	-	-	-	-	-
	Less FASB 106 Above if not separately removec	-	-	-	-	-	-	-
	Less OCI & Non-Utility above, if not seperately removed.	-	-	-	-	-	-	-
	Total	368,700,205	-	-	368,700,205	-	-	-
	Transmission Allocator [GP or W/S]		0.0000%	100.0000%	16.5997%	29.3005%	6.8614%	
	Total		0	0	61,202,976	0	0	61,202,976
Account 283								
2830015	ADIT-Fed-Hdg-CF-Int Rate	18,431	18,431					
2831001	Accum Deferred FIT - Other	56,419,546	18,231,463	0	11,239,234		26,948,850	
2831002	Accum Deferred SIT - Other	55,256,000			55,256,000			
2832001	Accum Dfrd FIT - Oth Inc & Ded	5,024,877	5,024,877					
2833001	Acc Dfd FIT FAS 109 Flow Thru	8,655,180	8,655,180					
	Subtotal - Form 1, p277	125,374,033	31,929,950	-	66,495,234	-	26,948,850	
	Less FASB 109 Above if not separately removec	8,655,180	8,655,180	-	-	-	-	
	Less FASB 106 Above if not separately removec	-	-	-	-	-	-	
	Less OCI & Non-Utility above, if not seperately removed.	5,043,307	5,043,307	-	-	-	-	
	Total	111,675,546	18,231,463	-	66,495,234	-	26,948,850	
	Transmission Allocator [GP or W/S]		0.0000%	100.0000%	16.5997%	29.3005%	6.8614%	
	Total		0	0	11,037,982	0	1,849,058	12,887,039
Account 190								
NOTE: Insert Amounts as Negative Numbers								
1900015	ADIT-Fed-Hdg-CF-Int Rate	(594,896)	(594,896)					
1901001	Accum Deferred FIT - Other	(56,729,521)	20,784,233		(30,675,457)		(5,269,833)	
1902001	Accum Dfnd FIT - Oth Inc & Ded	(3,190,490)	(3,190,490)					
1903001	Acc Dfd FIT - FAS109 Flow Thru	(14,130,295)	(14,130,295)					
1904001	Accum Dfd FIT - FAS 109 Excess	(7,456,929)	(7,456,929)					
	Subtotal - Form 1, p234	(82,102,131)	(4,588,377)	-	(30,675,457)	-	(5,269,833)	
	Less FASB 109 Above if not separately removec	(21,587,224)	(21,587,224)	-	-	-	-	
	Less FASB 106 Above if not separately removec	-	-	-	-	-	-	
	Less OCI & Non-Utility above, if not seperately removed.	(3,785,386)	(3,785,386)	-	-	-	-	
	Total	(56,729,521)	20,784,233	-	(30,675,457)	-	(5,269,833)	
	Transmission Allocator [GP or W/S]		0.0000%	100.0000%	16.5997%	29.3005%	6.8614%	
	Total		0	0	(5,092,021)	0	(361,582)	(5,453,603)
Account 255								
2550001	Accum Deferred ITC - Federal	25,997,261	25,997,261					
2550001	Accum Deferred ITC - Federal - Pre 1971 Balance	244,715			244,715			
	Subtotal - Form 1, p266.8f	26,241,976	25,997,261		244,715			
	Less Post 1971 ITC Property Under F2 Option	25,997,261	25,997,261					
	Total	244,715	-	-	244,715	-	-	-
	Transmission Allocator [GP or W/S]		0.0000%	100.0000%	16.5997%	29.3005%	6.8614%	
	Total		0	0	40,622	0	0	40,622

PSO Worksheet D - A&G Expense Detail

(A)	(B)	(C)	(D)	(E)	(F)	(G)
Item No.	Description	2006 Expense	100% Non-Transmission	100% Transmission Specific	Transmission Allocated	Explanation
	<u>Account 928</u>					
9280000	Reg Commission Expense - OCC Annual Fees	745,202	745,202	-	-	- Oklahoma Corporation Commission Assessment
9280002	Reg Commission Exp - Cause No. 20060285	476,287	476,287	-	-	Oklahoma Rate Case Filing
9280002	Reg Commission Exp - Cause No. 200600030	36,228	36,228	-	-	Determination of Use and Usefulness of Additional
9280002	Reg Commission Exp - Misc Filings	19,958	-	-	19,958	Baseload Generation before the OCC
	Total	1,277,675	1,257,717	-	19,958	Misc Filing Before the OCC
	<u>Account 930.1</u>					
9301001	Newspaper Advertising Space	371,256	362,879	-	8,377	Safety related: \$2,972.40 newspaper & \$5,405 radio
9301006	Spec Corporate Comm Info Proj	6	6	-	-	concerning metal theft messages
9301008	Direct Mail and Handouts	315	315	-	-	
9301009	Fairs, Shows, and Exhibits	507	507	-	-	
9301010	Publicity	2,021	2,021	-	-	
9301011	Dedications, Tours, & Openings	106	106	-	-	
9301013	Movies Slide Films & Speeches	72,939	72,939	-	-	
9301014	Video Communications	616	616	-	-	
9301015	Other Corporate Comm Exp	370,390	71,277	-	299,113	Advertising Expenses Related to Safety.
	Total	818,156	510,666	-	307,490	
	<u>Account 930.2</u>					
9302000	Misc General Expenses	713,295	-	-	713,295	
9302003	Corporate & Fiscal Expenses	94,323	-	-	94,323	
9302004	Research, Develop&Demonstr Exp	14,423	-	-	14,423	
9302007	Assoc Business Development Exp - Transmission	647,133	-	647,133	-	
9302007	Assoc Business Development Exp - Distribution	1,602,725	1,602,725	-	-	
	Total	3,071,898	1,602,725	647,133	822,040	

PSO Worksheet E - Transmission Expense Adjustments

2006

1	Other Expenses		
2	Direct Assignment Charge		\$0
3	Sponsored Upgrades Charge		\$0
4	Firm and Non-Firm Point-To-Point Charges		\$0
5	Base Plan Charges		\$0
6	Schedule 9 Charges		\$0
7	SPP Schedule 12 - FERC Assessment		\$0
8	SPP Schedule 1-A		\$0
9	SPP Annual Assessment		\$0
10	Ancillary Services Expenses		\$0
11	Other		\$0
12	Other		\$0
13	Other		\$0
14	Total	(sum of lines 2 through 13)	<u>\$0</u>

Adjustment to charges that are booked to transmission accounts that are the responsibility of the TO's LSE.

PSO Worksheet F - ATRR Calculation for Non-Base Plan Projects

I. Calculate Return and Income Taxes with 160 basis point ROE increase.

A. Determine 'R' with hypothetical 160 basis point increase in ROE for Identified Projects

ROE w/o incentives (Attachment H, In 160)			11.90%
Project ROE Incentive Adder			160
ROE with additional 160 basis point incentive			13.50%
Determine R (cost of long term debt, cost of preferred stock and percent is from Attachment H, Ins 158 through160)			
	<u>%</u>	<u>Cost</u>	<u>Weighted cost</u>
Long Term Debt	53.15%	0.0520	0.0276
Preferred Stock	0.42%	0.0404	0.0002
Common Stock	46.43%	0.1350	<u>0.0627</u>
		R =	0.0905

B. Determine Return using 'R' with hypothetical 160 basis point ROE increase for Identified Projects.

Rate Base (Attachment H, In 73)	287,853,501
R (from A. above)	0.0905
Return (Rate Base x R)	26,048,376

C. Determine Income Taxes using Return with hypothetical 160 basis point ROE increase for Identified Projects.

Return (from B. above)	26,048,376
CIT (Attachment H, In 115)	33.93%
Income Tax Calculation (Return x CIT)	8,839,099
ITC Adjustment (Attachment H, In 121)	(282,332)
Income Taxes	8,556,767

II. Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical 160 basis point ROE increase.

A. Determine Net Revenue Requirement less return and Income Taxes.

Net Revenue Requirement (Attachment H, In 6)	56,987,205
Return (Attachment H, In 123)	23,909,835
Income Taxes (Attachment H, In 122)	<u>7,831,087</u>
Net Revenue Requirement, Less Return and Taxes	25,246,283

B. Determine Net Revenue Requirement with hypothetical 160 basis point increase in ROE.

Net Revenue Requirement, Less Return and Taxes	25,246,283
Return (from I.B. above)	26,048,376
Income Taxes (from I.C. above)	<u>8,556,767</u>
Net Revenue Requirement, with 160 Basis Point ROE increase	59,851,426
Depreciation (Attachment H, In 98)	<u>9,496,187</u>
Net Rev. Req, w/160 Basis Point ROE increase, less Depreciation	50,355,239

C. Determine FCR with hypothetical 160 basis point ROE increase.

Net Transmission Plant (Attachment H, In 42)	293,085,130
Net Revenue Requirement, with 160 Basis Point ROE increase	59,851,426
FCR with 160 Basis Point increase in ROE	20.42%
Net Rev. Req, w / 160 Basis Point ROE increase, less Dep.	50,355,239
FCR with 160 Basis Point ROE increase, less Depreciation	17.18%
FCR less Depreciation (Attachment H, In 13)	<u>16.20%</u>
Incremental FCR with 160 Basis Point ROE increase, less Depreciat	0.98%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Period (P.206, In 58)	479,272,147
Transmission Plant @ End of Period (P.207, In 58)	<u>503,637,781</u>
	982,909,928
Average Balance of Transmission Investment	491,454,964
Annual Depreciation Rate (P. 336, In. 7, col. F)	<u>9,762,903</u>
Composite Depreciation Rate	1.99%
Depreciable Life for Composite Depreciation Rate	50.34
Round to nearest whole year	50

PSO Worksheet F - ATRR Calculation for Non-Base Plan Projects

IV. Determine the Revenue Requirement & Additional Revenue Requirement for facilities receiving incentives.

A. Facilities receiving incentives accepted by FERC in Docket No. **ER07-___-000** (e.g. ER05-925-000)

Project Description: Tulsa EHV

Details						
Investment	58,709,354	Current Year				2007
Service Year (yyyy)	2007	ROE increase accepted by FERC (Basis Points)				160
Service Month (1-12)	6	FCR w/o incentives, less depreciation				16.20%
Useful life	50	FCR w/incentives approved for these facilities, less dep.				17.18%
CIAC (Yes or No)	No	Annual Depreciation Expense				1,174,187
Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Revenue Requirement	Revenue Req't. with Incentives	Additional Rev. Requirement ##
2007	58,709,354	587,094	58,122,260	6,080,946	6,412,284	\$ 331,339
2008	58,122,260	1,174,187	56,948,073	10,401,956	10,958,491	\$ 556,534
2009	56,948,073	1,174,187	55,773,886	10,211,693	10,756,752	\$ 545,059
2010	55,773,886	1,174,187	54,599,699	10,021,430	10,555,014	\$ 533,584
2011	54,599,699	1,174,187	53,425,512	9,831,166	10,353,276	\$ 522,109
2012	53,425,512	1,174,187	52,251,325	9,640,903	10,151,538	\$ 510,634
2013	52,251,325	1,174,187	51,077,138	9,450,640	9,949,799	\$ 499,160
2014	51,077,138	1,174,187	49,902,951	9,260,377	9,748,061	\$ 487,685
2015	49,902,951	1,174,187	48,728,764	9,070,113	9,546,323	\$ 476,210
2016	48,728,764	1,174,187	47,554,577	8,879,850	9,344,585	\$ 464,735
2017	47,554,577	1,174,187	46,380,390	8,689,587	9,142,847	\$ 453,260
2018	46,380,390	1,174,187	45,206,203	8,499,324	8,941,108	\$ 441,785
2019	45,206,203	1,174,187	44,032,016	8,309,060	8,739,370	\$ 430,310
2020	44,032,016	1,174,187	42,857,828	8,118,797	8,537,632	\$ 418,835
2021	42,857,828	1,174,187	41,683,641	7,928,534	8,335,894	\$ 407,360
2022	41,683,641	1,174,187	40,509,454	7,738,270	8,134,155	\$ 395,885
2023	40,509,454	1,174,187	39,335,267	7,548,007	7,932,417	\$ 384,410
2024	39,335,267	1,174,187	38,161,080	7,357,744	7,730,679	\$ 372,935
2025	38,161,080	1,174,187	36,986,893	7,167,481	7,528,941	\$ 361,460
2026	36,986,893	1,174,187	35,812,706	6,977,217	7,327,203	\$ 349,985
2027	35,812,706	1,174,187	34,638,519	6,786,954	7,125,464	\$ 338,510
2028	34,638,519	1,174,187	33,464,332	6,596,691	6,923,726	\$ 327,036
2029	33,464,332	1,174,187	32,290,145	6,406,427	6,721,988	\$ 315,561
2030	32,290,145	1,174,187	31,115,958	6,216,164	6,520,250	\$ 304,086
2031	31,115,958	1,174,187	29,941,771	6,025,901	6,318,512	\$ 292,611
2032	29,941,771	1,174,187	28,767,583	5,835,638	6,116,773	\$ 281,136
2033	28,767,583	1,174,187	27,593,396	5,645,374	5,915,035	\$ 269,661
2034	27,593,396	1,174,187	26,419,209	5,455,111	5,713,297	\$ 258,186
2035	26,419,209	1,174,187	25,245,022	5,264,848	5,511,559	\$ 246,711
2036	25,245,022	1,174,187	24,070,835	5,074,584	5,309,820	\$ 235,236
2037	24,070,835	1,174,187	22,896,648	4,884,321	5,108,082	\$ 223,761
2038	22,896,648	1,174,187	21,722,461	4,694,058	4,906,344	\$ 212,286
2039	21,722,461	1,174,187	20,548,274	4,503,795	4,704,606	\$ 200,811
2040	20,548,274	1,174,187	19,374,087	4,313,531	4,502,868	\$ 189,336
2041	19,374,087	1,174,187	18,199,900	4,123,268	4,301,129	\$ 177,861
2042	18,199,900	1,174,187	17,025,713	3,933,005	4,099,391	\$ 166,387
2043	17,025,713	1,174,187	15,851,526	3,742,741	3,897,653	\$ 154,912
2044	15,851,526	1,174,187	14,677,339	3,552,478	3,695,915	\$ 143,437
2045	14,677,339	1,174,187	13,503,151	3,362,215	3,494,177	\$ 131,962
2046	13,503,151	1,174,187	12,328,964	3,171,952	3,292,438	\$ 120,487
2047	12,328,964	1,174,187	11,154,777	2,981,688	3,090,700	\$ 109,012
2048	11,154,777	1,174,187	9,980,590	2,791,425	2,888,962	\$ 97,537
2049	9,980,590	1,174,187	8,806,403	2,601,162	2,687,224	\$ 86,062
2050	8,806,403	1,174,187	7,632,216	2,410,898	2,485,485	\$ 74,587
2051	7,632,216	1,174,187	6,458,029	2,220,635	2,283,747	\$ 63,112
2052	6,458,029	1,174,187	5,283,842	2,030,372	2,082,009	\$ 51,637
2053	5,283,842	1,174,187	4,109,655	1,840,109	1,880,271	\$ 40,162
2054	4,109,655	1,174,187	2,935,468	1,649,845	1,678,533	\$ 28,687
2055	2,935,468	1,174,187	1,761,281	1,459,582	1,476,794	\$ 17,212
2056	1,761,281	1,174,187	587,094	1,269,319	1,275,056	\$ 5,737
2057	587,094	587,094	-	587,094	587,094	\$ -
Project Totals	58,709,354			292,614,279	306,721,272	14,106,994

This is the calculation of additional incentive revenue on projects deemed by the FERC to be eligible for an incentive return. This additional incentive requirement is applicable for the life of this specific project. Each year the revenue requirement calculated for SPP should be incremented by the amount of the incentive revenue calculated for that year on this project.

PSO Worksheet G - ATRR Calculation for SPP Base Plan Upgrades

I. Calculate Return and Income Taxes with 0 basis point ROE increase for Projects Qualified for Incentive.

A. Determine 'R' with hypothetical 0 basis point increase in ROE for Identified Projects

ROE w/o incentives (Attachment H, In 160)				11.90%
Project ROE Incentive Adder				-
ROE with additional 0 basis point incentive				11.90%
Determine R (cost of long term debt, cost of preferred stock and percent is from Attachment H, Ins 158 through 160)				
	<u>%</u>	<u>Cost</u>	<u>Weighted cost</u>	
Long Term Debt	53.15%	0.0520		0.0276
Preferred Stock	0.42%	0.0404		0.0002
Common Stock	46.43%	0.1190		<u>0.0553</u>
		R =		0.0831

B. Determine Return using 'R' with hypothetical 0 basis point ROE increase for Identified Projects.

Rate Base (Attachment H, In 73)	287,853,501
R (from A. above)	0.0831
Return (Rate Base x R)	23,909,835

C. Determine Income Taxes using Return with hypothetical 0 basis point ROE increase for Identified Projects.

Return (from B. above)	23,909,835
CIT (Attachment H, In 115)	33.93%
Income Tax Calculation (Return x CIT)	8,113,419
ITC Adjustment (Attachment H, In 121)	(282,332)
Income Taxes	7,831,087

II. Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical 0 basis point ROE increase.

A. Determine Net Revenue Requirement less return and Income Taxes.

Net Revenue Requirement (Attachment H, In 6)	56,987,205
Return (Attachment H, In 123)	23,909,835
Income Taxes (Attachment H, In 122)	<u>7,831,087</u>
Net Revenue Requirement, Less Return and Taxes	25,246,283

B. Determine Net Revenue Requirement with hypothetical 0 basis point increase in ROE.

Net Revenue Requirement, Less Return and Taxes	25,246,283
Return (from I.B. above)	23,909,835
Income Taxes (from I.C. above)	<u>7,831,087</u>
Net Revenue Requirement, with 0 Basis Point ROE increase	56,987,205
Depreciation (Attachment H, In 98)	<u>9,496,187</u>
Net Rev. Req. w/0 Basis Point ROE increase, less Depreciation	47,491,018

C. Determine FCR with hypothetical 0 basis point ROE increase.

Net Transmission Plant (Attachment H, In 42)	293,085,130
Net Revenue Requirement, with 0 Basis Point ROE increase	56,987,205
FCR with 0 Basis Point increase in ROE	19.44%
Net Rev. Req. w / 0 Basis Point ROE increase, less Dep.	47,491,018
FCR with 0 Basis Point ROE increase, less Depreciation	16.20%
FCR less Depreciation (Attachment H, In 13)	<u>16.20%</u>
Incremental FCR with 0 Basis Point ROE increase, less Depreciation	0.00%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Period (P.206, In 58)	479,272,147
Transmission Plant @ End of Period (P.207, In 58)	<u>503,637,781</u>
	982,909,928
Average Balance of Transmission Investment	491,454,964
Annual Depreciation Rate (P. 336, In. 7, col. F)	<u>9,762,903</u>
Composite Depreciation Rate	1.99%
Depreciable Life for Composite Depreciation Rate	50.34
Round to nearest whole year	50

PSO Worksheet G - ATRR Calculation for SPP Base Plan Upgrades

IV. Determine the Revenue Requirement, and Additional Revenue Requirement for facilities receiving incentives.

A. Base Plan Facilities

Facilities receiving incentives accepted by FERC in Docket No. [redacted] (e.g. ER05-925-000)

Project Description: 53rd & Garnett N. Tap - Tulsa Southeast 138 kV Line

Details						
Investment	134,233	Current Year				2007
Service Year (yyyy)	2007	ROE increase accepted by FERC (Basis Points)				-
Service Month (1-12)	6	FCR w/o incentives, less depreciation				16.20%
Useful life	50	FCR w/incentives approved for these facilities, less dep.				0.00%
CIAC (Yes or No)	No	Annual Depreciation Expense				2,685
Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	BPU Rev. Req't w/o Incentives	BPU Rev. Req't with Incentives **	Incentive Rev. Requirement ##
2007	134,233	1,342	132,891	13,903	13,903	\$ -
2008	132,891	2,685	130,206	23,783	23,783	\$ -
2009	130,206	2,685	127,521	23,348	23,348	\$ -
2010	127,521	2,685	124,837	22,913	22,913	\$ -
2011	124,837	2,685	122,152	22,478	22,478	\$ -
2012	122,152	2,685	119,467	22,043	22,043	\$ -
2013	119,467	2,685	116,783	21,608	21,608	\$ -
2014	116,783	2,685	114,098	21,173	21,173	\$ -
2015	114,098	2,685	111,413	20,738	20,738	\$ -
2016	111,413	2,685	108,729	20,303	20,303	\$ -
2017	108,729	2,685	106,044	19,868	19,868	\$ -
2018	106,044	2,685	103,359	19,433	19,433	\$ -
2019	103,359	2,685	100,675	18,998	18,998	\$ -
2020	100,675	2,685	97,990	18,563	18,563	\$ -
2021	97,990	2,685	95,305	18,128	18,128	\$ -
2022	95,305	2,685	92,621	17,693	17,693	\$ -
2023	92,621	2,685	89,936	17,258	17,258	\$ -
2024	89,936	2,685	87,251	16,823	16,823	\$ -
2025	87,251	2,685	84,567	16,388	16,388	\$ -
2026	84,567	2,685	81,882	15,953	15,953	\$ -
2027	81,882	2,685	79,197	15,518	15,518	\$ -
2028	79,197	2,685	76,513	15,083	15,083	\$ -
2029	76,513	2,685	73,828	14,648	14,648	\$ -
2030	73,828	2,685	71,143	14,213	14,213	\$ -
2031	71,143	2,685	68,459	13,778	13,778	\$ -
2032	68,459	2,685	65,774	13,343	13,343	\$ -
2033	65,774	2,685	63,090	12,908	12,908	\$ -
2034	63,090	2,685	60,405	12,473	12,473	\$ -
2035	60,405	2,685	57,720	12,038	12,038	\$ -
2036	57,720	2,685	55,036	11,603	11,603	\$ -
2037	55,036	2,685	52,351	11,168	11,168	\$ -
2038	52,351	2,685	49,666	10,732	10,732	\$ -
2039	49,666	2,685	46,982	10,297	10,297	\$ -
2040	46,982	2,685	44,297	9,862	9,862	\$ -
2041	44,297	2,685	41,612	9,427	9,427	\$ -
2042	41,612	2,685	38,928	8,992	8,992	\$ -
2043	38,928	2,685	36,243	8,557	8,557	\$ -
2044	36,243	2,685	33,558	8,122	8,122	\$ -
2045	33,558	2,685	30,874	7,687	7,687	\$ -
2046	30,874	2,685	28,189	7,252	7,252	\$ -
2047	28,189	2,685	25,504	6,817	6,817	\$ -
2048	25,504	2,685	22,820	6,382	6,382	\$ -
2049	22,820	2,685	20,135	5,947	5,947	\$ -
2050	20,135	2,685	17,450	5,512	5,512	\$ -
2051	17,450	2,685	14,766	5,077	5,077	\$ -
2052	14,766	2,685	12,081	4,642	4,642	\$ -
2053	12,081	2,685	9,396	4,207	4,207	\$ -
2054	9,396	2,685	6,712	3,772	3,772	\$ -
2055	6,712	2,685	4,027	3,337	3,337	\$ -
2056	4,027	2,685	1,342	2,902	2,902	\$ -
2057	1,342	1,342	-	1,342	1,342	\$ -
Project Totals		134,233		669,033	669,033	-

** This is the total amount that needs to be reported to SPP for billing to all regions.

This is the calculation of additional incentive revenue on projects deemed by the FERC to be eligible for an incentive return. This additional incentive requirement is applicable for the life of this specific project. Each year the revenue requirement calculated for SPP should be incremented by the amount of the incentive revenue calculated for that year on this project.

PSO Worksheet G - ATRR Calculation for SPP Base Plan Upgrades

A. Base Plan Facilities

Facilities receiving incentives accepted by FERC in Docket No.

(e.g. ER05-925-000)

Project Description: **Catoosa - 138kV Device**

Details						
Investment	387,742	Current Year				2007
Service Year (yyyy)	2006	ROE increase accepted by FERC (Basis Points)				-
Service Month (1-12)	6	FCR w/o incentives, less depreciation				16.20%
Useful life	50.00	FCR w/incentives approved for these facilities, less dep.				0.00%
CIAC (Yes or No)	No	Annual Depreciation Expense				7,755
Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	BPU Rev. Req't. w/o Incentives	BPU Rev. Req't. with Incentives **	Incentive Rev. Requirement ##
2006	387,742	3,877	383,865	40,161	40,161	\$ -
2007	383,865	7,755	376,110	68,699	68,699	\$ -
2008	376,110	7,755	368,355	67,442	67,442	\$ -
2009	368,355	7,755	360,600	66,186	66,186	\$ -
2010	360,600	7,755	352,845	64,929	64,929	\$ -
2011	352,845	7,755	345,090	63,673	63,673	\$ -
2012	345,090	7,755	337,336	62,416	62,416	\$ -
2013	337,336	7,755	329,581	61,160	61,160	\$ -
2014	329,581	7,755	321,826	59,903	59,903	\$ -
2015	321,826	7,755	314,071	58,646	58,646	\$ -
2016	314,071	7,755	306,316	57,390	57,390	\$ -
2017	306,316	7,755	298,561	56,133	56,133	\$ -
2018	298,561	7,755	290,807	54,877	54,877	\$ -
2019	290,807	7,755	283,052	53,620	53,620	\$ -
2020	283,052	7,755	275,297	52,363	52,363	\$ -
2021	275,297	7,755	267,542	51,107	51,107	\$ -
2022	267,542	7,755	259,787	49,850	49,850	\$ -
2023	259,787	7,755	252,032	48,594	48,594	\$ -
2024	252,032	7,755	244,277	47,337	47,337	\$ -
2025	244,277	7,755	236,523	46,081	46,081	\$ -
2026	236,523	7,755	228,768	44,824	44,824	\$ -
2027	228,768	7,755	221,013	43,567	43,567	\$ -
2028	221,013	7,755	213,258	42,311	42,311	\$ -
2029	213,258	7,755	205,503	41,054	41,054	\$ -
2030	205,503	7,755	197,748	39,798	39,798	\$ -
2031	197,748	7,755	189,994	38,541	38,541	\$ -
2032	189,994	7,755	182,239	37,284	37,284	\$ -
2033	182,239	7,755	174,484	36,028	36,028	\$ -
2034	174,484	7,755	166,729	34,771	34,771	\$ -
2035	166,729	7,755	158,974	33,515	33,515	\$ -
2036	158,974	7,755	151,219	32,258	32,258	\$ -
2037	151,219	7,755	143,465	31,002	31,002	\$ -
2038	143,465	7,755	135,710	29,745	29,745	\$ -
2039	135,710	7,755	127,955	28,488	28,488	\$ -
2040	127,955	7,755	120,200	27,232	27,232	\$ -
2041	120,200	7,755	112,445	25,975	25,975	\$ -
2042	112,445	7,755	104,690	24,719	24,719	\$ -
2043	104,690	7,755	96,935	23,462	23,462	\$ -
2044	96,935	7,755	89,181	22,206	22,206	\$ -
2045	89,181	7,755	81,426	20,949	20,949	\$ -
2046	81,426	7,755	73,671	19,692	19,692	\$ -
2047	73,671	7,755	65,916	18,436	18,436	\$ -
2048	65,916	7,755	58,161	17,179	17,179	\$ -
2049	58,161	7,755	50,406	15,923	15,923	\$ -
2050	50,406	7,755	42,652	14,666	14,666	\$ -
2051	42,652	7,755	34,897	13,409	13,409	\$ -
2052	34,897	7,755	27,142	12,153	12,153	\$ -
2053	27,142	7,755	19,387	10,896	10,896	\$ -
2054	19,387	7,755	11,632	9,640	9,640	\$ -
2055	11,632	7,755	3,877	8,383	8,383	\$ -
2056	3,877	3,877	-	3,877	3,877	\$ -
Project Totals		387,742		1,932,551	1,932,551	-

** This is the total amount that needs to be reported to SPP for billing to all regions.

This is the calculation of additional incentive revenue on projects deemed by the FERC to be eligible for an incentive return. This additional incentive requirement is applicable for the life of this specific project. Each year the revenue requirement calculated for SPP should be incremented by the amount of the incentive revenue calculated for that year on this project.

PSO Worksheet H - Transmission Plant-in-Service Additions

I. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Period (P.206, ln 58)	479,272,147
Transmission Plant @ End of Period (P.207, ln 58)	<u>503,637,781</u>
	982,909,928
Average Balance of Transmission Investment	491,454,964
Annual Depreciation Rate (P. 336, ln. 7, col. F)	9,762,903
Composite Depreciation Rate	1.99%
Round to 2% to Reflect a Composite Life of 50 Years	2.00%

II. Calculation of Property Placed in Service by Month and the Related Depreciation Expense

Month in Service	Capitalized Balance	Composite Annual Depreciation Rate	Annual Depreciation	Monthly Depreciation	No. Months Depreciation	First Year Depreciation Expense
January	\$ 1,708,751	2.00%	\$ 34,175	\$ 2,848	11	\$ 31,328
February	\$ 2,323,926	2.00%	\$ 46,479	\$ 3,873	10	\$ 38,730
March	\$ 308,821	2.00%	\$ 6,176	\$ 515	9	\$ 4,635
April	\$ 248,595	2.00%	\$ 4,972	\$ 414	8	\$ 3,312
May	\$ 358,309	2.00%	\$ 7,166	\$ 597	7	\$ 4,179
June	\$ 39,299,732	2.00%	\$ 785,995	\$ 65,500	6	\$ 393,000
July	\$ 1,739,793	2.00%	\$ 34,796	\$ 2,900	5	\$ 14,500
August	\$ 2,377,207	2.00%	\$ 47,544	\$ 3,962	4	\$ 15,848
September	\$ 5,871,966	2.00%	\$ 117,439	\$ 9,787	3	\$ 29,361
October	\$ 4,435,407	2.00%	\$ 88,708	\$ 7,392	2	\$ 14,784
November	\$ 3,415,621	2.00%	\$ 68,312	\$ 5,693	1	\$ 5,693
December	\$ 4,867,271	2.00%	\$ 97,345	\$ 8,112	0	\$ -
Investment	<u>\$ 66,955,398</u>			Depreciation Expense		<u>\$ 555,370</u>

III. Plant Transferred

\$ -	<== This input area is for original cost plant
\$ -	<== This input area is for accumulated depreciation that may be associated with capital expenditures. It would have an impact if a company had assets transferred from a subsidiary.
\$ -	<== This input area is for additional Depreciation Expense

PSO Worksheet I - Non-Tax Balance Sheet Adjustments

Preferred Stock Dividends-Effective Cost Based on YE Outstanding Shares

Preferred Stock	Shares Outstanding @ 12/31/06	Par Value	Book Value	Dividend Rate	Dividend
4.00% Series	44,548	100	4,454,800	4.00%	\$ 178,192
4.24% Series	8,069	100	806,900	4.24%	\$ 34,213
	<u>52,617</u>		<u>5,261,700</u>		<u>\$ 212,405</u>
				<u>4.04%</u>	

Effective Cost of Preferred Stock

Prepayments Account 165

Acc. No.	(A) Description	(B)	(C) 2006 YE Balance	(D) 100% Non-Transmission Related	(E) 100% Transmission Related	(F) Transmission Plant Related	(G) Transmission Labor Related	(H) Total Included in Ratebase (E)+(F)+(G)
1650001	Prepaid Insurance		1,109,721	(27,252)	995,250		141,724	1,136,973
165000206	Prepaid Taxes		3,175,000	-	3,175,000			3,175,000
1650004	Prepaid Interest		189,774		189,774			189,774
1650005	Prepaid Employee Benefits		3,002				3,002	3,002
1650006	Other Prepayments		188,483	188,483				
1650009	Prepaid Carry Cost-Factored AR		433,207	433,207				
1650010	Prepaid Pension Benefits		78,748,098				78,748,098	78,748,098
1650014	FAS 158 Qual Contra Asset		(48,587,398)	(48,587,398)				
			<u>35,259,888</u>	<u>(47,992,960)</u>	<u>0</u>	<u>4,360,024</u>	<u>78,892,824</u>	<u>83,252,848</u>

Subtotal - Form 1, p 112.57.c

Prepaid Ok State Taxes
Prepaid Facility Fee on 1.5B Securitization
OCC Assessment Fees - Retail Only
AR Factoring - Retail Only

I. DEVELOPMENT OF COMPOSITE STATE INCOME TAX RATES

Public Service Company of Oklahoma			
Calculation of Effective State Income Tax Rate			
For Tax Year 2007			
State Income Tax Rate - Oklahoma	Note 1	5.66%	
Apportionment Factor		86.7326%	
Effective Oklahoma State Income Tax Rate			4.9091%
State Income Tax Rate - Ohio	Note 2	8.50%	
Apportionment Factor		1.5778%	
Taxable Phase-Out Factor		40.00%	
Effective Ohio State Income Tax Rate			0.0536%
Total Effective State Income Tax Rate			<u><u>4.9627%</u></u>


Note 1 --- The Oklahoma State Income Tax Rate of 6% is reduced to 5.66% due to the deductibility of Oklahoma State Income Taxes on the Oklahoma State Income Tax Return.

Note 2 --- The Ohio State Income Tax is being phased-out over a 5 year period and is being replaced with a Commercial Activities Tax. The taxable portion of income is 40% in 2007.

II. CALCULATION OF TEXAS GROSS MARGIN TAX

Line #	REVENUE REQUIREMENT BEFORE TEXAS GROSS MARGIN TAX (In 284 of Template)	Actual		Projected	
		Total Company	Trans. Only	Total Company	Trans. Only
1	Apportionment Factor to Texas (ln12)	0.00%	0.00%	0.00%	0.00%
2	Apportioned Texas Revenues	\$0	\$0	\$0	\$0
3	Taxable Percentage of Revenue (70%)	70%	70%	70%	70%
4	Taxable, Apportioned Margin	-	-	-	-
5	Texas Gross Margin Tax Rate (1%)	1%	1%	1%	1%
6	Texas Gross Margin Tax Expense	-	-	-	-
7	Gross-up Required for Texas Gross Margin Expense (ln 6 * ln 3 * ln 1)/(1- ln 5) * ln 5)	-	-	-	-
8	Total Additional Gross Margin Tax Revenue Requirement	-	-	-	-
9	WHOLESALE LOAD ALLOCATOR (For Use in Gross Margin Tax Allocator)	-	-	-	-
10	Texas Jurisdictional Load	-	-	-	-
11	Total Load	-	-	-	-
12	Allocation Percentage (ln 10 / ln 11)	0.00%			

PSO Worksheet K - CWIP Balances on Multi-Year Projects

(A)	(B)	(C)
<u>Item No.</u>	<u>Description of Project</u>	<u>Capital Expenditure</u>
		-
		-
		-
		-
		-
		-
		-
		-
Total		-

Worksheet L - PSO and SWEPCO GSU Net Book Values as of December 31, 2006 **Page 1 of 1**

company	depreciation group	utility acct	vintage	orig cost	reserve	net book value
Public Service of Oklahoma - Gen Total		35200 Total		\$117,415.43	\$57,995.84	\$59,419.59
		35300 Total		\$15,470,808.94	\$2,385,356.82	\$13,085,452.12
		35200 Total		\$15,588,224.37	\$2,443,352.66	\$13,144,871.71
Southwestern Electric Pwr - Gen Total		35300 Total		\$592,468.46	\$400,015.31	\$192,453.15
		35300 Total		\$18,512,997.80	\$11,366,831.53	\$7,146,166.27
		35300 Total		\$19,105,466.26	\$11,766,846.84	\$7,338,619.42
Grand Total			\$34,693,690.63	\$14,210,199.50	\$20,483,491.13	
Total PSO Transmission				\$503,637,781	\$197,407,779	\$306,230,002
Less: GSU				\$15,588,224	\$2,443,353	\$13,144,872
PSO Transmission w/o GSUs				\$488,049,557	\$194,964,426	\$293,085,130
Total SWEPCO Transmission				\$668,007,833	\$264,848,192	\$403,159,641
Less: GSU				\$19,105,466	\$11,766,847	\$7,338,619
SWEPCO Transmission w/o GSUs				\$648,902,367	\$253,081,345	\$395,821,022

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SOUTHWESTERN ELECTRIC POWER COMPANY

Line No.			Total	Allocator	Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(Line 128)			\$96,734,252
2	REVENUE CREDITS	(Note A)			
3	Transmission Credits	(Worksheet A)	11,830,941	DA 1.00000	\$ 11,830,941
4	Assoc. Business Development	(Worksheet A)	193,744	DA 1.00000	\$ 193,744
5	Total Revenue Credits		12,024,685		\$ 12,024,685
6	REVENUE REQUIREMENT (w/o incentives) For All AEP Facilities	(In 1 less In 5)			\$ 84,709,567
7	Revenue Requirement for SPP Base Plan Upgrades (w/o incentives)	(Worksheet G)	1,330,959	DA 1.00000	\$ 1,330,959
8	REVENUE REQUIREMENT EXCLUDING BASE PLAN UPGRADE ATRR	(In 6 less In 7)			\$ 83,378,608
9	NET PLANT CARRYING CHARGE (w/o incentives)	(Note B)			
10	Annual Rate	(In 6 / In 42 x 100)			21.40%
11	Monthly Rate	(In 10 / 12)			1.78%
12	NET PLANT CARRYING CHARGE, W/O DEPRECIATION (w/o incentives)	(Note B)			
13	Annual Rate	((In 6 - In 98) / In 42 x 100)			16.93%
14	NET PLANT CARRYING CHARGE, W/O DEPRECIATION, INCOME TAXES AND RETURN	(Note B)			
15	Annual Rate	((In 6 - In 98 - In 122 - In 123) / In 42 x 100)			4.27%
16	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's	(Note C) (Worksheet F)		NA	\$ -
17	PROJECTED YE 2007 TRANSMISSION REVENUE REQUIREMENT	(In 8 + In 16)			\$ 83,378,608

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Line No.	(1) RATE BASE CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator	(5) Total Transmission
18	GROSS PLANT IN SERVICE				
18	Production	205.46.g	1,561,930,348	NA	0.00000
19	Transmission	207.58.g	668,007,833	DA	1.00000
20	Plus: Transmission Plant-in-Service Additions (Worksheet H)		43,523,480	DA	1.00000
21	Plus: Additional Trans Plant on Transferred Assets (Worksheet H)		11,109,284	DA	1.00000
22	Distribution	207.75.g	1,228,888,098	NA	0.00000
23	General Plant	207.99.g (Note K)	273,029,721	W/S	0.05129
24	Intangible Plant	205.5.g	62,748,915	W/S	0.05129
25	Common	356	-	CE	0.05129
26	TOTAL GROSS PLANT	(sum Ins 18 to 25)	3,849,237,679	GP(p)=	0.187246
				GTD(p)=	0.35216
27	ACCUMULATED DEPRECIATION AND AMORTIZATION				
28	Production	219.20-24.c	1,040,080,444	NA	0.00000
29	Transmission	219.25.c	264,848,192	TP1=	0.95557
30	Plus: Transmission Plant-in-Service Additions (Worksheet H)		308,839	DA	1.00000
31	Plus: Additional Projected Deprec on Transferred Assets (Worksheet H)		185,155	DA	1.00000
32	Plus: Additional Transmission Depreciation for 2007 (In 98)		18,184,293	TP1	0.95557
33	Plus: Additional General & Intangible Depreciation for 2007 (In 100 + In 101)		17,243,364	W/S	0.05129
34	Plus: Additional Accum Deprec on Transferred Assets (Worksheet H)		6,209,341	DA	1.00000
35	Distribution	219.26.c	489,179,741	NA	0.00000
36	General Plant	219.28.c (Note K)	113,057,198	W/S	0.05129
37	Intangible Plant	219	-	W/S	0.05129
38	Common	356	-	CE	0.05129
39	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 28 to 38)	1,949,296,567		
40	NET PLANT IN SERVICE				
41	Production	(In 18 - In 28)	521,849,904		
42	Transmission	(In 19 - In 29)	403,159,641		
43	Plus: Transmission Plant-in-Service Additions (In 20 - In 30)		43,214,641		
44	Plus: Additional Trans Plant on Transferred Assets (In 21 - In 31)		10,924,129		
45	Plus: Additional Transmission Depreciation for 2007 (-In 32)		(18,184,293)		
46	Plus: Additional General & Intangible Depreciation for 2007 (-In 33)		(17,243,364)		
47	Plus: Additional Accum Deprec on Transferred Assets (Worksheet H) (-In 34)		(6,209,341)		
48	Distribution	(In 22 - In 35)	739,708,357		
49	General Plant	(In 23 - In 36)	159,972,523		
50	Intangible Plant	(In 24 - In 37)	62,748,915		
51	Common	(In 25 - In 38)	-		
52	TOTAL NET PLANT IN SERVICE	(sum Ins 41 to 51)	1,899,941,112	NP(p)=	0.229961
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)	(307,979,166)	DA	(13,212,814)
56	Account No. 283 (enter negative)	277.9.k (Worksheet C)	(66,493,887)	DA	(5,369,957)
57	Account No. 190	234.8.c (Worksheet C)	27,397,837	DA	4,791,060
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 Ins 54 to 60)	(347,075,217)		(13,791,711)
62	PLANT HELD FOR FUTURE USE	214.x.d (Note F)	-	DA	1.00000
63	WORKING CAPITAL	(Note G)			
64	Cash Working Capital	(1/8 * In 96)	9,970,587		
65	Transmission Materials & Supplies	227.8.c	986,988	TP	0.97356
66	A&G Materials & Supplies	227.11.c	54,345	W/S	0.05129
67	Undistributed Stores Expense (Acct 163)	227.16.c	-	GP(h)	0.17553
68	Prepayments (Account 165) - Labor Allocated	111.57.c (Worksheet I)	78,728,628	W/S	0.05129
69	Prepayments (Account 165) - Direct Allocated	111.57.c (Worksheet I)	-	DA	1.00000
70	Prepayments (Account 165) - Gross Plant	111.57.c (Worksheet I)	1,452,800	GP(h)	0.17553
71	TOTAL WORKING CAPITAL	(sum Ins 64 to 70)	91,193,348		
72	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note H) (Worksheet B, In 18)	(12,929,557)	DA	1.00000
73	RATE BASE (sum Ins 52, 61, 62, 71, 72)		<u>1,631,129,686</u>		<u>417,402,626</u>

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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
74	OPERATION & MAINTENANCE EXPENSE				
74	Transmission	321.112.b	21,657,825	TP	0.97356
75	Less: expenses 100% assigned to TO billed customers (Worksheet E, In 14)		-	DA	1.00000
76	Less: Total Account 561 (Load Dispatch - Sch 1) (Note I)	321.84-92.b	5,810,678	TP	0.97356
77	Less: Account 565	321.96.b (Note J)	3,778,039	TP	0.97356
78	Plus: Acct 565 native load, zonal or pool	(Note J)	-	DA	1.00000
79	Transmission Subtotal (Ins 74-75-76-77+78)		12,069,108		11,750,020
80	Administrative and General	323.197.b (Note K)	68,328,903		
81	Less: Acc. 928, Reg. Com. Exp.	323.189.b	6,176		
82	Acct. 930.1, Gen. Advert. Exp.	323.191.b	744,644		
83	Acc. 924, Property Insurance	323.185.b	1,990,944		
84	Acc. 930.2, Misc. Gen. Exp.	323.192.b	1,209,974		
85	Acc. 935, Maint. of Gen. Plant	323.196.b	5,830,794	W/S	0.05129
86	Balance of A & G	(In 80 - sum In 81 to In 85)	58,546,371	W/S	0.05129
87	Plus: Acct. 924, Property Insurance	(In 83)	1,990,944	NP(h)	0.21575
88	Acct. 928 - Transmission Specific	(Note L) (Worksheet D)	-	TP	0.97356
89	Acct. 928 - Transmission Allocated	(Note L) (Worksheet D)	771	GP(h)	0.17553
90	Acct 930.1 - Only safety related ads.	(Note L) (Worksheet D)	310,782	W/S	0.05129
91	Acct 930.2 - Misc Gen. Exp. - Trans	(Worksheet D)	101,130	TP	0.97356
92	Acct 930.2 - Misc Gen. Exp. - Allocated	(Worksheet D)	914,794	W/S	0.05129
93	A & G Subtotal	(sum Ins 85 to 92)	67,695,587		3,892,639
94	Common	356	-	CE	0.05129
95	Transmission Lease Payments		-	DA	1.00000
96	TOTAL O & M EXPENSE	(In 79 + In 93 + In 94 + In 95)	79,764,695		15,642,659
97	DEPRECIATION AND AMORTIZATION EXPENSE				
98	Transmission	336.7.f	18,184,293	TP	0.97356
99	Plus: Transmission Plant-in-Service Additions (Worksheet H)		308,839	DA	1.00000
100	General	336.10.f	8,628,998	W/S	0.05129
101	Intangible	336.1.f	8,614,366	W/S	0.05129
102	Common	336.11.f	-	CE	0.05129
103	TOTAL DEPRECIATION AND AMORTIZATIN	(sum Ins 98 to 102)	35,736,496		18,896,710
104	TAXES OTHER THAN INCOME	(Note M)			
105	Labor Related				
106	Payroll	262.x-263.x.i	4,435,373	W/S	0.05129
107	Plant Related				
108	Property	262.x-263.x.i	36,577,094	NP(h)	0.21575
109	Gross Receipts/Sales & Use	262.x-263.x.i	5,130,693	NA	0.00000
110	Other	262.x-263.x.i	15,505,960	GP(h)	0.17553
111	Payments in lieu of taxes		-	GP(h)	0.17553
112	TOTAL OTHER TAXES	114.14.c	61,649,120		10,840,874
113	INCOME TAXES	(Note N)			
114	$T=1 - ((1 - SIT) * (1 - FIT)) / (1 - SIT * FIT * p)$		33.34%		
115	$EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =$		36.34%		
116	where WCLTD=(In 158) and WACC = (In 161)				
117	and FIT, SIT & p are as given in Note N.				
118	$GRCF=1 / (1 - T) =$ (from In 114)		1.5001		
119	Amortized Investment Tax Credit (enter negative)		(4,224,566)		
120	Income Tax Calculation	(In 115 * In 123)	53,616,687		13,720,397
121	ITC adjustment	(In 118 * In 119)	(6,337,482)	NP(h)	0.21575
122	TOTAL INCOME TAXES	(sum Ins 120 to 121)	47,279,205		12,353,074
123	RETURN ON RATE BASE (Rate Base*WACC)	(In 73 * In 161)	147,553,686		37,758,675
124	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note H) (Worksheet B, In 16)		997,107	DA	1.00000
125	REVENUE REQUIREMENT BEFORE TEXAS GROSS MARGIN TAX		372,980,309		96,489,099
126	(sum Ins 96, 103, 112, 122, 123, 124)				
127	TEXAS GROSS MARGIN TAX (NOTE O) (Worksheet J)		947,642	DA	245,153
128	REVENUE REQUIREMENT INCLUDING GROSS MARGIN TAX		<u>\$373,927,951</u>		<u>\$96,734,252</u>

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SUPPORTING CALCULATIONS

In No.	TRANSMISSION PLANT INCLUDED IN SPP TARIFF						
129	Total transmission plant	(In 19 + In 20 + In 21)					722,640,597
130	Less transmission plant excluded from SPP Tariff	(Note P)					-
131	Less transmission plant included in OATT Ancillary Services	(Note Q)	(Worksheet L)				19,105,466
132	Transmission plant included in SPP Tariff	(In 129 - In 130 - In 131)					<u>703,535,131</u>
133	Percent of transmission plant in SPP Tariff	(In 132 / In 129)				TP=	0.97356
Payroll Billed from AEP Service Corp.							
134	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll				
135	Production	354.20,22.b	25,306,201	7,847,347	NA	0.00000	-
136	Transmission	354.21.b	2,656,102	1,981,443	TP	0.97356	4,514,936
137	Distribution	354.23.b	18,326,508	1,700,476	NA	0.00000	-
138	Other (Excludes A&E)	354.24,25,26.b	12,753,589	17,462,934	NA	0.00000	-
139	Total	(sum Ins 135 to 138)	<u>59,042,400</u>	<u>28,992,199</u>			<u>4,514,936</u>
140	Transmission related amount					W/S=	0.05129
141	COMMON PLANT ALLOCATOR (CE)						
142	Electric	200.3.c	3,668,711,518		DA	1.00000	3,668,711,518
143	Gas	200.3.d	-		NA	0.00000	-
144	Other	200.3. e, f, g	-		NA	0.00000	-
145	Total	(sum Ins 142 to 144)	<u>3,668,711,518</u>				<u>3,668,711,518</u>
146	Electric related amount						1.00000
147	W/S Allocator						0.05129
148	Transmission related amount	(In 146 * In 147)				CE=	0.05129
149	WEIGHTED AVERAGE COST OF CAPITAL (WACC)						\$
150		Long Term Interest (117, sum of 62c - 66c)					<u>37,712,943</u>
151		Preferred Dividends (118.29.c) (positive number)					228,955
152		Development of Common Stock:					-
153		Proprietary Capital (112.16.c)					825,898,664
154		Less Preferred Stock (In 159)					4,696,600
155		Less Account 219.1 (112.15.c)					<u>(18,799,332)</u>
156		Common Stock (In 153 - In 154 - In 155)					<u>840,001,396</u>
157			\$	%	Cost (Note S)	Weighted	
158	Long Term Debt (112, sum of 18.c - 21.c)		<u>679,738,000</u>	44.59%	0.0555	0.0247	
159	Preferred Stock (112.3.c)		4,696,600	0.31%	0.0487	0.0002	
160	Common Stock (In 156)		<u>840,001,396</u>	55.10%	0.1190	0.0656	
161	Total (sum Ins 158 to 160)		<u>1,524,435,996</u>			WACC=	0.0905

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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 than 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 $p = \frac{\text{FIT}}{\text{FIT} + \text{SIT}}$ "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) (In 119) multiplied by $(1/1-T)$. If the applicable tax rates are zero enter 0.
- | | | | |
|------------------|-------|--------|---|
| Inputs Required: | FIT = | 31.03% | |
| | SIT = | 3.70% | (State Income Tax Rate or Composite SIT. Worksheet J) |
| | p = | 31.55% | (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 (In 150) / long term debt (In 158). Preferred Stock cost rate = preferred dividends (In 151) / preferred outstanding (In 159). Common Stock cost rate (ROE) = 11.9%, the rate accepted by FERC in Docket No. ER07-XXX. It includes an additional 50 basis points for remaining a member of the SPP RTO.

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Line No.			Total	Allocator	Transmission Amount
162	REVENUE REQUIREMENT (w/o incentives)	(In 286)			\$92,675,433.58
163	REVENUE CREDITS	(Note A)			
164	Transmission Credits	(Worksheet A)	11,830,941	DA 1.00000	\$ 11,830,941
165	Assoc. Business Development	(Worksheet A)	193,744	DA 1.00000	\$ 193,744
166	Total Revenue Credits		12,024,685		\$ 12,024,685
167	REVENUE REQUIREMENT (w/o incentives) For All AEP Facilities	(In 162 less In 166)			\$ 80,650,748
168	Revenue Requirement for SPP Base Plan Upgrades (w/o incentives)	(Worksheet G)	1,330,959	DA 1.00000	\$ 1,330,959
169	REVENUE REQUIREMENT EXCLUDING BASE PLAN UPGRADE ATRR	(In 167 less In 168)			\$ 79,319,790
170	NET PLANT CARRYING CHARGE (w/o incentives)	(Note B)			
171	Annual Rate	(In 167 / In 203 x 100)			20.38%
172	Monthly Rate	(In 171 / 12)			1.70%
173	NET PLANT CARRYING CHARGE, W/O DEPRECIATION (w/o incentives)	(Note B)			
174	Annual Rate	((In 167 - In 259) / In 203 x 100)			15.91%
175	NET PLANT CARRYING CHARGE, W/O DEPRECIATION, INCOME TAXES AND RETURN	(Note B)			
176	Annual Rate	((In 167 - In 259 - In 283 - In 284) / In 203 x 100)			4.18%
177	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's	(Note C) (Worksheet F)		NA	\$ -
178	HISTORIC YE 2006 TRANSMISSION REVENUE REQUIREMENT	(In 169 + In 177)			\$ 79,319,790

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SOUTHWESTERN ELECTRIC POWER COMPANY

Line No.	(1) RATE BASE CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator	(5) Total Transmission
179	GROSS PLANT IN SERVICE				
179	Production	205.46.g	1,561,930,348	NA 0.00000	-
180	Transmission	207.58.g	668,007,833	DA	\$648,902,367
181	Plus: Transmission Plant-in-Service Additions (Worksheet H)		N/A	DA 1.00000	N/A
182	Plus: Additional Trans Plant on Transferred Assets (Worksheet H)		N/A	DA 1.00000	N/A
183	Distribution	207.75.g	1,228,888,098	NA 0.00000	-
184	General Plant	207.99.g (Note K)	273,029,721	W/S 0.05117	13,971,482
185	Intangible Plant	205.5.g	62,748,915	W/S 0.05117	3,210,989
186	Common	356	-	CE 0.05117	-
187	TOTAL GROSS PLANT	(sum Ins 179 to 186)	3,794,604,915	GP(h)= 0.175535 GTD= 0.35216	666,084,837
188	ACCUMULATED DEPRECIATION AND AMORTIZATION				
189	Production	219.20-24.c	1,040,080,444	NA 0.00000	-
190	Transmission	219.25.c	264,848,192	TP1= 0.95557	\$253,081,345
191	Plus: Transmission Plant-in-Service Additions (Worksheet H)		N/A	DA 1.00000	N/A
192	Plus: Additional Projected Deprec on Transferred Assets (Worksheet H)		N/A	DA 1.00000	N/A
193	Plus: Additional Transmission Depreciation for 2007 (In 259)		N/A	TP1 0.95557	N/A
194	Plus: Additional General & Intangible Depreciation for 2007 (In 261 + In 262)		N/A	W/S 0.05117	N/A
195	Plus: Additional Accum Deprec on Transferred Assets (Worksheet H)		N/A	DA 1.00000	N/A
196	Distribution	219.26.c	489,179,741	NA 0.00000	-
197	General Plant	219.28.c (Note K)	113,057,198	W/S 0.05117	5,785,365
198	Intangible Plant	219	-	W/S 0.05117	-
199	Common	356	-	CE 0.05117	-
200	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 189 to 199)	1,907,165,575		258,866,710
201	NET PLANT IN SERVICE				
202	Production	(In 179 - In 189)	521,849,904		-
203	Transmission	(In 180 - In 190)	403,159,641		395,821,022
204	Plus: Transmission Plant-in-Service Additions (In 181 - In 191)		N/A		N/A
205	Plus: Additional Trans Plant on Transferred Assets (In 182 - In 192)		N/A		N/A
206	Plus: Additional Transmission Depreciation for 2007 (- In 193)		N/A		N/A
207	Plus: Additional General & Intangible Depreciation for 2007 (- In 194)		N/A		N/A
208	Plus: Additional Accum Deprec on Transferred Assets (Worksheet H) (- In 195)		N/A		N/A
209	Distribution	(In 183 - In 196)	739,708,357		-
210	General Plant	(In 184 - In 197)	159,972,523		8,186,117
211	Intangible Plant	(In 185 - In 198)	62,748,915		3,210,989
212	Common	(In 186 - In 199)	-		-
213	TOTAL NET PLANT IN SERVICE	(sum Ins 202 to 212)	1,887,439,340	NP(h)= 0.215752	407,218,127
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)	(307,979,166)	DA	(13,212,814)
217	Account No. 283 (enter negative)	277.9.k (Worksheet C)	(66,493,887)	DA	(5,369,957)
218	Account No. 190	234.8.c (Worksheet C)	27,397,837	DA	4,791,060
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 Ins 215 to 221)	(347,075,217)		(13,791,711)
223	PLANT HELD FOR FUTURE USE	214.x.d (Note F)	-	DA 1.00000	-
224	WORKING CAPITAL	(Note G)			
225	Cash Working Capital	(1/8 * In 257)	9,970,587		1,951,109
226	Transmission Materials & Supplies	227.8.c	986,988	TP 0.97140	958,759
227	A&G Materials & Supplies	227.11.c	54,345	W/S 0.05117	2,781
228	Undistributed Stores Expense (Acct 163)	227.16.c	-	GP(h) 0.17553	-
229	Prepayments (Account 165) - Labor Allocated	111.57.c (Worksheet I)	78,728,628	W/S 0.05117	4,028,703
230	Prepayments (Account 165) - Direct Allocated	111.57.c (Worksheet I)	-	DA 1.00000	-
231	Prepayments (Account 165) - Gross Plant	111.57.c (Worksheet I)	1,452,800	GP(h) 0.17553	255,017
232	TOTAL WORKING CAPITAL	(sum Ins 225 to 231)	91,193,348		7,196,369
233	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note H) (Worksheet B, In 18)	(12,929,557)	DA 1.00000	(12,929,557)
234	RATE BASE (sum Ins 213, 222, 223, 232, 233)		<u>1,618,627,914</u>		<u>387,693,228</u>

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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
235	OPERATION & MAINTENANCE EXPENSE				
235	Transmission	321.112.b	21,657,825	TP 0.97140	21,038,397
236	Less expenses 100% assigned to TO billed customers (Worksheet E, ln 14)		-	DA 1.00000	-
237	Less: Total Account 561 (Load Dispatch - Sch 1) (Note I)	321.84-92.b	5,810,678	TP 0.97140	5,644,489
238	Less Account 565	321.96.b (Note J)	3,778,039	TP 0.97140	3,669,985
239	Plus Acct 565 native load, zonal or pool	(Note J)	-	DA 1.00000	-
240	Transmission Subtotal (lns 235-236-237-238+239)		12,069,108		11,723,924
241	Administrative and General	323.197.b (Note K)	68,328,903		
242	Less: Acc. 928, Reg. Com. Exp.	323.189.b	6,176		
243	Acct. 930.1, Gen. Advert. Exp.	323.191.b	744,644		
244	Acc. 924, Property Insurance	323.185.b	1,990,944		
245	Acc. 930.2, Misc. Gen. Exp.	323.192.b	1,209,974		
246	Acc. 935, Maint. of Gen. Plant	323.196.b	5,830,794	W/S 0.05117	298,373
247	Balance of A & G	(ln 241 - sum ln 242 to ln 246)	58,546,371	W/S 0.05117	2,995,936
248	Plus: Acct. 924, Property Insurance	(ln 244)	1,990,944	NP(h) 0.21575	429,549
249	Acct. 928 - Transmission Specific	(Note L) (Worksheet D)	-	TP 0.97140	-
250	Acct. 928 - Transmission Allocated	(Note L) (Worksheet D)	771	GP(h) 0.17553	135
251	Acct 930.1 - Only safety related ads.	(Note L) (Worksheet D)	310,782	W/S 0.05117	15,903
252	Acct 930.2 - Misc Gen. Exp. - Trans	(Worksheet D)	101,130	TP 0.97140	98,238
253	Acct 930.2 - Misc Gen. Exp. - Allocated	(Worksheet D)	914,794	W/S 0.05117	46,812
254	A & G Subtotal	(sum lns 246 to 253)	67,695,587		3,884,947
255	Common	356	-	CE 0.05117	-
256	Transmission Lease Payments		-	DA 1.00000	-
257	TOTAL O & M EXPENSE	(ln 240 + ln 254 + ln 255 + ln 256)	79,764,695		15,608,871
258	DEPRECIATION AND AMORTIZATION EXPENSE				
259	Transmission	336.7.f	18,184,293	TP 0.97140	17,664,210
260	Plus: Transmission Plant-in-Service Additions (Worksheet H)		N/A	DA 1.00000	N/A
261	General	336.10.f	8,628,998	W/S 0.05117	441,563
262	Intangible	336.1.f	8,614,366	W/S 0.05117	440,814
263	Common	336.11.f	-	CE 0.05117	-
264	TOTAL DEPRECIATION AND AMORTIZATIN	(sum lns 259 to 263)	35,427,657		18,546,588
265	TAXES OTHER THAN INCOME	(Note M)			
266	Labor Related				
267	Payroll	262.x-263.x.i	4,435,373	W/S 0.05117	226,967
268	Plant Related				
269	Property	262.x-263.x.i	36,577,094	NP(h) 0.21575	7,891,568
270	Gross Receipts/Sales & Use	262.x-263.x.i	5,130,693	NA 0.00000	-
271	Other	262.x-263.x.i	15,505,960	GP(h) 0.17553	2,721,834
272	Payments in lieu of taxes		-	GP(h) 0.17553	-
273	TOTAL OTHER TAXES	114.14.c	61,649,120		10,840,369
274	INCOME TAXES	(Note N)			
275	$T=1 - \{[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)\} =$		33.34%		
276	$EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =$		36.34%		
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)		1.5001		
280	Amortized Investment Tax Credit (enter negative)		(4,224,566)		
281	Income Tax Calculation	(ln 276 * ln 284)	53,205,743		12,743,822
282	ITC adjustment	(ln 279 * ln 280)	(6,337,482)	NP(h) 0.21575	(1,367,322)
283	TOTAL INCOME TAXES	(sum lns 281 to 282)	46,868,261		11,376,500
284	RETURN ON RATE BASE (Rate Base*WACC)	(ln 234 * ln 322)	146,422,763		35,071,132
285	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note H) (Worksheet B, ln 16)		997,107	DA 1.00000	997,107
286	REVENUE REQUIREMENT BEFORE TEXAS GROSS MARGIN TAX		371,129,602		92,440,567
287	(sum lns 257, 264, 273, 283, 284, 285)				
288	TEXAS GROSS MARGIN TAX (NOTE O) (Worksheet J)		942,940	DA	234,867
289	REVENUE REQUIREMENT INCLUDING GROSS MARGIN TAX		\$372,072,542		\$92,675,434

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SUPPORTING CALCULATIONS

In No.	TRANSMISSION PLANT INCLUDED IN SPP TARIFF						
290	Total transmission plant	(In 180)					668,007,833
291	Less transmission plant excluded from SPP Tariff	(Note P)					-
292	Less transmission plant included in OATT Ancillary Services	(Note Q)	(Worksheet L)				19,105,466
293	Transmission plant included in SPP Tariff	(In 290 - In 291 - In 292)					<u>648,902,367</u>
294	Percent of transmission plant in SPP Tariff	(In 293 / In 290)				TP=	0.97140
295	WAGES & SALARY ALLOCATOR (W/S)	(Note R)		Payroll Billed from AEP			
296	Production	354.20,22.b	Direct Payroll	Service Corp.			
297	Transmission	354.21.b	25,306,201	7,847,347	NA	0.00000	-
298	Distribution	354.23.b	2,656,102	1,981,443	TP	0.97140	4,504,908
299	Other (Excludes A&E)	354.24,25,26.b	18,326,508	1,700,476	NA	0.00000	-
300	Total	(sum Ins 296 to 299)	12,753,589	17,462,934	NA	0.00000	<u>-</u>
			59,042,400	28,992,199			4,504,908
301	Transmission related amount					W/S=	0.05117
302	COMMON PLANT ALLOCATOR (CE)						
303	Electric	200.3.c	3,668,711,518		DA	1.00000	3,668,711,518
304	Gas	200.3.d	0		NA	0.00000	-
305	Other	200.3. e, f, g	0		NA	0.00000	-
306	Total	(sum Ins 303 to 305)	3,668,711,518				<u>3,668,711,518</u>
307	Electric related amount						1.00000
308	W/S Allocator					W/S	0.05117
309	Transmission related amount	(In 307 * In 308)				CE=	0.05117
310	WEIGHTED AVERAGE COST OF CAPITAL (WACC)						\$
311	Long Term Interest (117, sum of 62c - 66c)						<u>37,712,943</u>
312	Preferred Dividends (118.29.c) (positive number)						<u>228,955</u>
313	Development of Common Stock:						
314	Proprietary Capital (112.16.c)						<u>825,898,664</u>
315	Less Preferred Stock (In 320)						4,696,600
316	Less Account 219.1 (112.15.c)						<u>(18,799,332)</u>
317	Common Stock (In 314 - In 315 - In 316)						840,001,396
318			\$	%	Cost (Note S)	Weighted	
319	Long Term Debt (112, sum of 18.c - 21.c)		679,738,000	44.59%	0.0555	0.0247	
320	Preferred Stock (112.3.c)		4,696,600	0.31%	0.0487	0.0002	
321	Common Stock (In 317)		840,001,396	55.10%	0.1190	0.0656	
322	Total (sum Ins 319 to 321)		<u>1,524,435,996</u>			WACC=	0.0905

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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.
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- 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.
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- 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 than 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.
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- 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) (In 280) multiplied by (1/1-T). If the applicable tax rates are zero enter 0.

Inputs Required:	FIT =	31.03%	
	SIT=	3.70%	(State Income Tax Rate or Composite SIT. Worksheet J)
	p =	31.55%	(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.
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- S Long Term Debt cost rate = long-term interest (In 311) / long term debt (In 319). Preferred Stock cost rate = preferred dividends (In 312) / preferred outstanding (In 320). Common Stock cost rate (ROE) = 11.9%, the rate accepted by FERC in Docket No. ER07-XXX. It includes an additional 50 basis points for remaining a member of the SPP RTO.

SWEPCO Worksheet B - IPP - System Upgrade Credit

<u>Line No.</u>	<u>Account 2530067</u>	<u>SWEPCO</u>
1	Funds from IPP Customers	\$ (16,822,369)
2	Transimission Credits given back over the years:	
3		2002 -
4		2003 -
5		2004 2,725,318
6		2005 1,958,225
7		2006 <u>1,958,225</u>
8		6,641,768
9		
10	Net balance of IPP Funds Received Credited Back	<u>(10,180,601)</u>
11	Interest Accrued over the years:	
12		2002 -
13		2003 (275,500)
14		2004 (681,603)
15		2005 (794,747)
16		2006 <u>(997,107)</u>
17		(2,748,956)
18	Net Funds from IPP Customers 12/31/2006 (FORM 1, P269, line 10(f))	<u><u>(12,929,557)</u></u>

SWEPCO Worksheet D - A&G Expense Detail

(A) <u>Item No.</u>	(B) <u>Description</u>	(C) <u>2006 Expense</u>	(D) <u>100% Non-Transmission</u>	(E) <u>100% Transmission Specific</u>	(F) <u>Transmission Allocated</u>	(G) <u>Explanation</u>
	<u>Account 928</u>					
9280000	Reg Commission Expense - Docket No. 30957	5,405	5,405	-	-	- PUCT Renewable Energy Credit Compliance
9280002	Reg Commission Exp - Misc Filings	771	-	-	771	Misc Filing
	Total	6,176	5,405	-	771	
	<u>Account 930.1</u>					
9301000	General Advertising Expenses	243,915	67,797		176,118	Safety related advertising
9301001	Newspaper Advertising Space	177,227	138,132		39,095	Safety related advertising
9301002	Radio Station Advertising Time	12,962	11,387		1,575	Safety related advertising
9301003	TV Station Advertising Time	10,360	2,500		7,860	Safety related advertising
9301006	Spec Corporate Comm Info Proj	8	8		-	
9301008	Direct Mail and Handouts	316	316			
9301009	Fairs, Shows, and Exhibits	3,068	3,068			
9301010	Publicity	2,448	2,448			
9301011	Dedications, Tours, & Openings	142	142			
9301013	Movies Slide Films & Speeches	61,530	61,530			
9301014	Video Communications	859	859			
9301015	Other Corporate Comm Exp	231,810	145,675		86,134	Safety related advertising
	Total	744,644	433,862	-	310,782	
	<u>Account 930.2</u>					
9302000	Misc General Expenses	787,621.40			787,621	
9302003	Corporate & Fiscal Expenses	113,551.31			113,551	
9302004	Research, Develop&Demonstr Exp	13,621.70			13,622	
9302007	Assoc Business Development Exp - Transmission	101,130.40		101,130		
9302007	Assoc Business Development Exp - Distribution	194,048.83	194,049			
	Total	1,209,974	194,049	101,130	914,794	

SWEPSCO Worksheet E - Transmission Expense Adjustmnets

2006

1	Other Expenses			
2	Direct Assignment Charge			\$0
3	Sponsored Upgrades Charge			\$0
4	Firm and Non-Firm Point-To-Point Charges			\$0
5	Base Plan Charges			\$0
6	Schedule 9 Charges			\$0
7	SPP Schedule 12 - FERC Assessment			\$0
8	SPP Schedule 1-A			\$0
9	SPP Annual Assessment			\$0
10	Ancillary Services Expenses			\$0
11	Other			\$0
12	Other			\$0
13	Other			\$0
14	Total	(sum of lines 2 through 13)		<u>\$0</u>

Adjustment to charges that are booked to transmission accounts that are the responsibility of the TO's LSE.

SWEPCO Worksheet F - ATRR Calculation for Non-Base Plan Projects

I. Calculate Return and Income Taxes with 0 basis point ROE increase.

A. Determine 'R' with hypothetical 0 basis point increase in ROE for Identified Projects

ROE w/o incentives (Attachment H, In 160)			11.90%
Project ROE Incentive Adder			-
ROE with additional 0 basis point incentive			11.90%
Determine R (cost of long term debt, cost of preferred stock and percent is from Attachment H, Ins 158 through 160)			
	<u>%</u>	<u>Cost</u>	<u>Weighted cost</u>
Long Term Debt	44.59%	0.0555	0.0247
Preferred Stock	0.31%	0.0487	0.0002
Common Stock	55.10%	0.1190	<u>0.0656</u>
		WACC =	0.0905

B. Determine Return using 'R' with hypothetical 0 basis point ROE increase for Identified Projects.

Rate Base (Attachment H, In 73)	417,402,626
R (from A. above)	0.0905
Return (Rate Base x R)	37,758,675

C. Determine Income Taxes using Return with hypothetical 0 basis point ROE increase for Identified Projects.

Return (from B. above)	37,758,675
CIT (Attachment H, In 115)	36.34%
Income Tax Calculation (Return x CIT)	13,720,397
ITC Adjustment (Attachment H, In 121)	(1,367,322)
Income Taxes	12,353,074

II. Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical 0 basis point ROE increase.

A. Determine Net Revenue Requirement less return and Income Taxes.

Net Revenue Requirement (Attachment H, In 6)	84,709,567
Return (Attachment H, In 123)	37,758,675
Income Taxes (Attachment H, In 122)	12,353,074
Gross Margin Taxes (Attachment H, In 127)	<u>245,153</u>
Net Revenue Requirement, Less Return and Taxes	34,352,664

B. Determine Net Revenue Requirement with hypothetical 0 basis point increase in ROE.

Net Revenue Requirement, Less Return and Taxes	34,352,664
Return (from I.B. above)	37,758,675
Income Taxes (from I.C. above)	<u>12,353,074</u>
Net Revenue Requirement before Gross Margin Taxes, with 0 Basis Point ROE increase	84,464,414
Gross Margin Tax with 0 Basis Point ROE Increase (II C. below)	<u>245,153</u>
Revenue Requirement w/ Gross Margin Taxes	84,709,566
Less: Depreciation (Attachment H, In 98)	<u>17,703,529</u>
Net Rev. Req. w/0 Basis Point ROE increase, less Depreciation	<u>67,006,037</u>

C. Determine Gross Margin Tax with hypothetical 0 basis point increase in ROE.

Net Revenue Requirement before Gross Margin Taxes, with 0 Basis Point ROE increase (II B. above)	84,464,414
Addback Revenue Credits for Correct Gross Margin Tax Basis	<u>12,024,685</u>
Proper Basis for Calculating Gross Margin Tax	96,489,099
Gross Margin Taxes with 0 Basis Point ROE increase	
Apportionment Factor to Texas (Worksheet J, In 12)	<u>36.20%</u>
Apportioned Texas Revenues	34,932,370
Taxable Percentage of Revenue (70%)	<u>70%</u>
Taxable, Apportioned Margin	24,452,659
Texas Gross Margin Tax Rate	<u>1%</u>
Texas Gross Margin Tax Expense	244,527
Gross-up Required for Gross Margin Tax Expense	<u>626</u>
Total Additional Gross Margin Tax Revenue Requirement	245,153

SWEPCO Worksheet F - ATRR Calculation for Non-Base Plan Projects

D. Determine FCR with hypothetical 0 basis point ROE increase.

Net Transmission Plant (Attachment H, In 42)	395,821,022
Net Revenue Requirement, with 0 Basis Point ROE increase	84,709,566
FCR with 0 Basis Point increase in ROE	21.40%
Net Rev. Req. w / 0 Basis Point ROE increase, less Dep.	67,006,037
FCR with 0 Basis Point ROE increase, less Depreciation	16.93%
FCR less Depreciation (Attachment H, In 13)	<u>16.93%</u>
Incremental FCR with 0 Basis Point ROE increase, less Depreciation	0.00%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Period (P.206, In 58)	645,296,693
Transmission Plant @ End of Period (P.207, In 58)	<u>668,007,833</u>
	1,313,304,526
Average Balance of Transmission Investment	656,652,263
Annual Depreciation Rate (P. 336, In. 7, col. F)	<u>18,184,293</u>
Composite Depreciation Rate	2.77%
Depreciable Life for Composite Depreciation Rate	36.11
Round to nearest whole year	36.0

SWEPCO Worksheet F - ATRR Calculation for Non-Base Plan Projects

IV. Determine Revenue Requirement & Additional Revenue Requirement for facilities receiving incentives.

A. Facilities receiving incentives accepted by FERC in Docket No. ER07-___-000 (e.g. ER05-925-000)

Project Description:

Details						
Investment		Current Year				2007
Service Year (yyyy)	2007	ROE increase accepted by FERC (Basis Points)				-
Service Month (1-12)	6	FCR w/o incentives, less depreciation				16.93%
Useful life	36	FCR w/incentives approved for these facilities, less dep.				16.93%
CIAC (Yes or No)	No	Annual Depreciation Expense				-
Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Revenue Requirement	Revenue Req't. with Incentives **	Additional Rev. Requirement
2007	-	-	-	-	-	\$ -
2008	-	-	-	-	-	\$ -
2009	-	-	-	-	-	\$ -
2010	-	-	-	-	-	\$ -
2011	-	-	-	-	-	\$ -
2012	-	-	-	-	-	\$ -
2013	-	-	-	-	-	\$ -
2014	-	-	-	-	-	\$ -
2015	-	-	-	-	-	\$ -
2016	-	-	-	-	-	\$ -
2017	-	-	-	-	-	\$ -
2018	-	-	-	-	-	\$ -
2019	-	-	-	-	-	\$ -
2020	-	-	-	-	-	\$ -
2021	-	-	-	-	-	\$ -
2022	-	-	-	-	-	\$ -
2023	-	-	-	-	-	\$ -
2024	-	-	-	-	-	\$ -
2025	-	-	-	-	-	\$ -
2026	-	-	-	-	-	\$ -
2027	-	-	-	-	-	\$ -
2028	-	-	-	-	-	\$ -
2029	-	-	-	-	-	\$ -
2030	-	-	-	-	-	\$ -
2031	-	-	-	-	-	\$ -
2032	-	-	-	-	-	\$ -
2033	-	-	-	-	-	\$ -
2034	-	-	-	-	-	\$ -
2035	-	-	-	-	-	\$ -
2036	-	-	-	-	-	\$ -
2037	-	-	-	-	-	\$ -
2038	-	-	-	-	-	\$ -
2039	-	-	-	-	-	\$ -
2040	-	-	-	-	-	\$ -
2041	-	-	-	-	-	\$ -
2042	-	-	-	-	-	\$ -
2043	-	-	-	-	-	\$ -
						\$ -

This is the calculation of additional incentive revenue on projects deemed by the FERC to be eligible for an incentive return. This additional incentive requirement is applicable for the life of this specific project. Each year the revenue requirement calculated for SPP should be incremented by the amount of the incentive revenue calculated for that year on this project.

SWEPCO Worksheet G - ATRR Calculation for SPP Base Plan Upgrades

I. Calculate Return and Income Taxes with 0 basis point ROE increase for Projects Qualified for Incentive.

A. Determine 'R' with hypothetical 0 basis point increase in ROE for Identified Projects

ROE w/o incentives (Attachment H, In 160)			11.90%
Project ROE Incentive Adder			-
ROE with additional 0 basis point incentive			11.90%
Determine R (cost of long term debt, cost of preferred stock and percent is from Attachment H, Ins 158 through160)			
	<u>%</u>	<u>Cost</u>	<u>Weighted cost</u>
Long Term Debt	44.59%	0.0555	0.0247
Preferred Stock	0.31%	0.0487	0.0002
Common Stock	55.10%	0.1190	<u>0.0656</u>
		WACC =	0.0905

B. Determine Return using 'R' with hypothetical 0 basis point ROE increase for Identified Projects.

Rate Base (Attachment H, In 73)	417,402,626
R (from A. above)	0.0905
Return (Rate Base x R)	37,758,675

C. Determine Income Taxes using Return with hypothetical 0 basis point ROE increase for Identified Projects.

Return (from B. above)	37,758,675
CIT (Attachment H, In 115)	36.34%
Income Tax Calculation (Return x CIT)	13,720,397
ITC Adjustment (Attachment H, In 121)	(1,367,322)
Income Taxes	12,353,074

II. Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical 0 basis point ROE increase.

A. Determine Net Revenue Requirement less return and Income Taxes.

Net Revenue Requirement (Attachment H, In 6)	84,709,567
Return (Attachment H, In 123)	37,758,675
Income Taxes (Attachment H, In 122)	12,353,074
Gross Margin Taxes (Attachment H, In 127)	<u>245,153</u>
Net Revenue Requirement, Less Return and Taxes	34,352,664

B. Determine Net Revenue Requirement with hypothetical 0 basis point increase in ROE.

Net Revenue Requirement, Less Return and Taxes	34,352,664
Return (from I.B. above)	37,758,675
Income Taxes (from I.C. above)	<u>12,353,074</u>
Net Revenue Requirement before Gross Margin Taxes, with 0 Basis Point ROE increase	84,464,414
Gross Margin Tax with 0 Basis Point ROE Increase (II C. below)	<u>245,153</u>
Revenue Requirement w/ Gross Margin Taxes	84,709,566
Less: Depreciation (Attachment H, In 98)	<u>17,703,529</u>
Net Rev. Req, w/0 Basis Point ROE increase, less Depreciation	67,006,037

C. Determine Gross Margin Tax with hypothetical basis point increase in ROE.

Net Revenue Requirement before Gross Margin Taxes, with Basis Point ROE increase (II B. above)	84,464,414
Addback Revenue Credits for Correct Gross Margin Tax Basis Proper Basis for Calculating Gross Margin Tax	<u>12,024,685</u>
Gross Margin Taxes with Basis Point ROE increase	96,489,099
Apportionment Factor to Texas (Worksheet J, In 12)	<u>36.20%</u>
Apportioned Texas Revenues	34,932,370
Taxable Percentage of Revenue (70%)	<u>70%</u>
Taxable, Apportioned Margin	24,452,659
Texas Gross Margin Tax Rate	<u>1%</u>
Texas Gross Margin Tax Expense	244,527
Gross-up Required for Gross Margin Tax Expense	<u>626</u>
Total Additional Gross Margin Tax Revenue Requirement	245,153

SWEPCO Worksheet G - ATRR Calculation for SPP Base Plan Upgrades

D. Determine FCR with hypothetical 0 basis point ROE increase.

Net Transmission Plant (Attachment H, In 42)	395,821,022
Net Revenue Requirement, with 0 Basis Point ROE increase	84,709,566
FCR with 0 Basis Point increase in ROE	21.40%
Net Rev. Req. w / 0 Basis Point ROE increase, less Dep.	67,006,037
FCR with 0 Basis Point ROE increase, less Depreciation	16.93%
FCR less Depreciation (Attachment H, In 13)	<u>16.93%</u>
Incremental FCR with 0 Basis Point ROE increase, less Depreciation	0.00%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Period (P.206, In 58)	645,296,693
Transmission Plant @ End of Period (P.207, In 58)	<u>668,007,833</u>
	1,313,304,526
Average Balance of Transmission Investment	656,652,263
Annual Depreciation Rate (P. 336, In. 7, col. F)	<u>18,184,293</u>
Composite Depreciation Rate	2.77%
Depreciable Life for Composite Depreciation Rate	36.11 YEARS
Round to nearest whole year	36

SWEPCO Worksheet G - ATRR Calculation for SPP Base Plan Upgrades

IV. Determine Revenue Requirement & Additional Revenue Requirement for facilities receiving incentives.

A. Base Plan Facilities

Facilities receiving incentives accepted by FERC in Docket No. [redacted] (e.g. ER05-925-000)

Project Description: Tontitown - Elm Springs REC 161 kV line

Details						
Investment	979,957	Current Year				2007
Service Year (yyyy)	2007	ROE increase accepted by FERC (Basis Points)				-
Service Month (1-12)	5	FCR w/o incentives, less depreciation				16.93%
Useful life	36	FCR w/incentives approved for these facilities, less dep.				16.93%
CIAC (Yes or No)	No	Annual Depreciation Expense				27,221
Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	BPU Rev. Req't. w/o Incentives	BPU Rev. Req't. with Incentives**	Incentive Rev. Requirement##
2007	979,957	15,879	964,078	124,681	124,681	\$ (0)
2008	964,078	27,221	936,857	185,816	185,816	\$ (0)
2009	936,857	27,221	909,636	181,208	181,208	\$ (0)
2010	909,636	27,221	882,415	176,599	176,599	\$ (0)
2011	882,415	27,221	855,194	171,991	171,991	\$ (0)
2012	855,194	27,221	827,973	167,383	167,383	\$ (0)
2013	827,973	27,221	800,752	162,775	162,775	\$ (0)
2014	800,752	27,221	773,531	158,167	158,167	\$ (0)
2015	773,531	27,221	746,310	153,559	153,559	\$ (0)
2016	746,310	27,221	719,089	148,951	148,951	\$ (0)
2017	719,089	27,221	691,868	144,343	144,343	\$ (0)
2018	691,868	27,221	664,647	139,735	139,735	\$ (0)
2019	664,647	27,221	637,426	135,127	135,127	\$ (0)
2020	637,426	27,221	610,205	130,519	130,519	\$ (0)
2021	610,205	27,221	582,984	125,911	125,911	\$ (0)
2022	582,984	27,221	555,763	121,303	121,303	\$ (0)
2023	555,763	27,221	528,542	116,694	116,694	\$ (0)
2024	528,542	27,221	501,321	112,086	112,086	\$ (0)
2025	501,321	27,221	474,100	107,478	107,478	\$ (0)
2026	474,100	27,221	446,879	102,870	102,870	\$ (0)
2027	446,879	27,221	419,658	98,262	98,262	\$ (0)
2028	419,658	27,221	392,436	93,654	93,654	\$ (0)
2029	392,436	27,221	365,215	89,046	89,046	\$ (0)
2030	365,215	27,221	337,994	84,438	84,438	\$ (0)
2031	337,994	27,221	310,773	79,830	79,830	\$ (0)
2032	310,773	27,221	283,552	75,222	75,222	\$ (0)
2033	283,552	27,221	256,331	70,614	70,614	\$ (0)
2034	256,331	27,221	229,110	66,006	66,006	\$ (0)
2035	229,110	27,221	201,889	61,398	61,398	\$ (0)
2036	201,889	27,221	174,668	56,790	56,790	\$ (0)
2037	174,668	27,221	147,447	52,181	52,181	\$ (0)
2038	147,447	27,221	120,226	47,573	47,573	\$ (0)
2039	120,226	27,221	93,005	42,965	42,965	\$ (0)
2040	93,005	27,221	65,784	38,357	38,357	\$ (0)
2041	65,784	27,221	38,563	33,749	33,749	\$ (0)
2042	38,563	27,221	11,342	29,141	29,141	\$ (0)
2043	11,342	11,342	-	11,342	11,342	\$ -
Project Totals	979,957			3,897,765	3,897,765	(0)

** This is the total amount that needs to be reported to SPP for billing to all regions.

This is the calculation of additional incentive revenue on projects deemed by the FERC to be eligible for an incentive return. This additional incentive requirement is applicable for the life of this specific project. Each year the revenue requirement calculated for SPP should be incremented by the amount of the incentive revenue calculated for that year on this project.

SWEPSCO Worksheet H - Transmission Plant-in-Service Additions

I. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Period (P.206, ln 58)	645,296,693
Transmission Plant @ End of Period (P.207, ln 58)	<u>668,007,833</u>
	1,313,304,526
Average Balance of Transmission Investment	656,652,263
Annual Depreciation Rate (P. 336, ln. 7, col. F)	18,184,293
Composite Depreciation Rate	2.77%
Round to 2% to Reflect a Composite Life of 50 Years	2.00%

II. Calculation of Property Placed in Service by Month and the Related Depreciation Expense

Month in Service	Capitalized Balance	Composite Annual Depreciation Rate	Annual Depreciation	Monthly Depreciation	No. Months Depreciation	First Year Depreciation Expense
January	\$ 4,604,602	2.00%	\$ 92,092	\$ 7,674	11	\$ 84,414
February	\$ 7,700,892	2.00%	\$ 154,018	\$ 12,835	10	\$ 128,350
March	\$ 457,530	2.00%	\$ 9,151	\$ 763	9	\$ 6,867
April	\$ 420,445	2.00%	\$ 8,409	\$ 701	8	\$ 5,608
May	\$ 1,290,798	2.00%	\$ 25,816	\$ 2,151	7	\$ 15,057
June	\$ 3,615,301	2.00%	\$ 72,306	\$ 6,026	6	\$ 36,156
July	\$ 1,158,165	2.00%	\$ 23,163	\$ 1,930	5	\$ 9,650
August	\$ 1,334,063	2.00%	\$ 26,681	\$ 2,223	4	\$ 8,892
September	\$ 1,159,089	2.00%	\$ 23,182	\$ 1,932	3	\$ 5,796
October	\$ 1,801,492	2.00%	\$ 36,030	\$ 3,002	2	\$ 6,004
November	\$ 1,227,056	2.00%	\$ 24,541	\$ 2,045	1	\$ 2,045
December	\$ 18,754,045	2.00%	\$ 375,081	\$ 31,257	0	\$ -
Investment	<u>\$ 43,523,480</u>			Depreciation Expense		<u>\$ 308,839</u>

III. Plant Transferred from TNC

\$ 11,109,284	<== This input area is for original cost plant
\$ 6,209,341	<== This input area is for accumulated depreciation that may be associated with capital expenditures. It would have an impact if a company had assets transferred from a subsidiary.
\$ 185,155	<== This input area is for additional Depreciation Expense

SWEPSCO Worksheet J - Tax

I. DEVELOPMENT OF COMPOSITE STATE INCOME TAX RATES

Southwestern Electric Power Company

Calculation of Effective State Income Tax Rate
For Tax Year 2007

State Income Tax Rate - Louisiana	8.00%
Apportionment Factor	<u>31.5500%</u>
Effective Louisiana State Income Tax Rate	2.5240%
State Income Tax Rate - Arkansas	6.50%
Apportionment Factor	<u>15.7128%</u>
Effective Arkansas State Income Tax Rate	1.0213%
State Income Tax Rate - Oklahoma	Note 1
Apportionment Factor	<u>5.66%</u>
Effective Oklahoma State Income Tax Rate	<u>1.6906%</u>
State Income Tax Rate - Ohio	Note 2
Apportionment Factor	<u>8.50%</u>
Taxable Income Factor (Phase-Out)	<u>1.7153%</u>
Effective Ohio State Income Tax Rate	<u>40.00%</u>
	0.0583%

Total Effective State Income Tax Rate

3.6993%

Note 1 --- The Oklahoma State Income Tax Rate of 6% is reduced to 5.66% due to the deductibility of Oklahoma State Income Taxes on the Oklahoma State Income Tax Return.

Note 2 --- The Ohio State Income Tax is being phased-out over a 5 year period and is being replaced with a Commercial Activities Tax. The taxable portion of income is 40% in 2007.

II. CALCULATION OF TEXAS GROSS MARGIN TAX

Line # REVENUE REQUIREMENT BEFORE TEXAS GROSS MARGIN TAX (In 286 of Template)

	Actual		Projected	
	Total Company	Trans. Only	Total Company	Trans. Only
1 Apportionment Factor to Texas (ln12)	36.20%	36.20%	36.20%	36.20%
2 Apportioned Texas Revenues	\$134,361,673	\$33,466,663	\$135,031,692	\$34,932,370
3 Taxable Percentage of Revenue (70%)	70%	70%	70%	70%
4 Taxable, Apportioned Margin	94,053,171	23,426,664	94,522,185	24,452,659
5 Texas Gross Margin Tax Rate (1%)	1%	1%	1%	1%
6 Texas Gross Margin Tax Expense	940,532	234,267	945,222	244,527
7 Gross-up Required for Texas Gross Margin Expense ((ln 6 * ln 3 * ln 1)/(1- ln 5) * ln 5)	2,408	600	2,420	626
8 Total Additional Gross Margin Tax Revenue Requirement	<u>942,940</u>	<u>234,867</u>	<u>947,642</u>	<u>245,153</u>


9 WHOLESALE LOAD ALLOCATOR (For Use in Gross Margin Tax Allocator)

10 Texas Jurisdictional Load 1,589,230

11 Total Load 4,389,721

12 Allocation Percentage (ln 10 / ln 11) 36.20%

SWEPCO Worksheet K - CWIP Balances on Multi-Year Projects

(A)	(B)	(C)
<u>Item No.</u>	<u>Description of Project</u>	<u>Capital Expenditure</u>
		-
		-
		-
		-
		-
		-
		-
		-
		-
		-
Total		<input type="text" value="-"/>

Worksheet L - PSO and SWEPCO GSU Net Book Values as of December 31, 2006

company	depreciation group	utility acct	vintage	orig cost	reserve	net book value
Public Service of Oklahoma - Gen Total		35200 Total		\$117,415.43	\$57,995.84	\$59,419.59
		35300 Total		\$15,470,808.94	\$2,385,356.82	\$13,085,452.12
		35200 Total		\$15,588,224.37	\$2,443,352.66	\$13,144,871.71
Southwestern Electric Pwr - Gen Total		35300 Total		\$592,468.46	\$400,015.31	\$192,453.15
				\$18,512,997.80	\$11,366,831.53	\$7,146,166.27
		35300 Total		\$19,105,466.26	\$11,766,846.84	\$7,338,619.42
Grand Total			\$34,693,690.63	\$14,210,199.50	\$20,483,491.13	
Total PSO Transmission				\$503,637,781	\$197,407,779	\$306,230,002
Less: GSU				\$15,588,224	\$2,443,353	\$13,144,872
PSO Transmission w/o GSUs				\$488,049,557	\$194,964,426	\$293,085,130
Total SWEPCO Transmission				\$668,007,833	\$264,848,192	\$403,159,641
Less: GSU				\$19,105,466	\$11,766,847	\$7,338,619
SWEPCO Transmission w/o GSUs				\$648,902,367	\$253,081,345	\$395,821,022

American Electric Power
(Public Service Company of Oklahoma & Southwestern Electric Power Company)
Network Transmission Service
Comparison of Charges Under Present and Proposed Rates
CALENDAR YEAR -- 2006

SPP Zone 1 Transmission System Peak Loads

AEP (SPP) Load Responsibility, MW*	Jan 2006		Feb 2006		Mar 2006		Apr 2006		May 2006		Jun 2006		Jul 2006		Aug 2006		Sep 2006		Oct 2006		Nov 2006		Dec 2006		
	1/1/2006	1/11/2006	2/1/2006	2/18/2006	3/2/2006	3/24/2006	4/1/2006	4/17/2006	5/2/2006	5/25/2006	6/21/2006	6/21/2006	7/19/2006	8/9/2006	9/16/2006	10/3/2006	10/3/2006	11/30/2006	11/30/2006	1500	1500	1900	1900	800	800
PSO	2345	2227	2527	2227	3262	3692	4163	4206	4206	3309	3277	2708	2663	24	24	3,166	3,166	24	24	27	27	26	26	26	26
WFEC (on PSO) - converted to SPP nts Jun'07	18	20	20	17	22	25	25	28	28	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Total PSO	2363	2247	2547	2244	3284	3717	4191	4232	4191	3335	3303	2734	2690	2734	2734	2734	2734	2734	2734	2734	2734	2734	2734	2734	2734
SWEPCO	2613	2495	2778	2495	3202	3501	3976	4030	3578	3234	3288	3045	3045	3045	3045	3045	3045	3045	3045	3045	3045	3045	3045	3045	3045
AEECC (on SWEPCO) - converts to SPP nts Jan'08	509	578	471	548	646	646	628	742	779	742	543	616	674	616	616	616	616	616	616	616	616	616	616	616	616
Total SWEPCO	3121	3348	3348	2965	3750	4147	4207	4809	4718	3808	3831	3378	3719	3378	3378	3378	3378	3378	3378	3378	3378	3378	3378	3378	3378
TNC(North) - became part of SWEPCO Feb'07	19	18	18	17	25	28	29	29	29	23	23	17	24	23	23	23	23	23	23	23	23	23	23	23	23
ONPA	74	80	74	72	114	114	137	160	168	125	119	94	85	114	114	114	114	114	114	114	114	114	114	114	114
NTEC	563	529	541	516	542	590	683	658	594	480	480	654	711	598	598	598	598	598	598	598	598	598	598	598	598
ETEC	67	62	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
TEXLA	84	87	76	82	85	87	87	87	87	89	89	87	87	87	87	87	87	87	87	87	87	87	87	87	87
Greenbelt	5	5	5	3	4	5	5	5	5	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Lighthouse	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Coffeyville Reservation (AEP OATT Firm PTP)	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114
AEP West Zone - SPP Transmission System Firm Peak Demands, MW*	6412.00	6792.00	6094.00	6094.00	7950.00	8844.00	10181.00	10109.00	8158.00	8028.00	7174.00	8011.92	8011.92	8011.92	8011.92	8011.92	8011.92	8011.92	8011.92	8011.92	8011.92	8011.92	8011.92	8011.92	8011.92

*Monthly totals/subtotals may be off by 1 due to rounding of customer load data for display purposes

STATEMENT BG

PRESENT Rate Charges -- (CY2006)

Annual Transmission Rev. Requirement (Existing)	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579
Prior CY 12CP Divisor, MW (used for Existing rate)	7751	7751	7751	7751	7751	7751	7751	7751	7751	7751	7751	7751	7751	7751	7751	7751	7751	7751	7751	7751	7751	7751	7751	7751	7751
Network Transmission Service Rate \$/MW/Month:	953.44	953.44	953.44	953.44	953.44	953.44	953.44	953.44	953.44	953.44	953.44	953.44	953.44	953.44	953.44	953.44	953.44	953.44	953.44	953.44	953.44	953.44	953.44	953.44	953.44
Network Transmission Charges - SPP OATT Schedule 9.	\$ 2,235,817	\$ 2,409,343	\$ 2,123,311	\$ 3,110,121	\$ 3,520,100	\$ 3,443,825	\$ 3,969,171	\$ 4,010,169	\$ 3,154,933	\$ 3,124,423	\$ 2,581,916	\$ 2,539,011	\$ 2,539,011	\$ 2,539,011	\$ 2,539,011	\$ 2,539,011	\$ 2,539,011	\$ 2,539,011	\$ 2,539,011	\$ 2,539,011	\$ 2,539,011	\$ 2,539,011	\$ 2,539,011	\$ 2,539,011	\$ 2,539,011
PSO	\$ 17,162	\$ 19,069	\$ 16,208	\$ 23,836	\$ 23,836	\$ 23,836	\$ 26,696	\$ 24,789	\$ 24,789	\$ 24,789	\$ 24,789	\$ 24,789	\$ 24,789	\$ 24,789	\$ 24,789	\$ 24,789	\$ 24,789	\$ 24,789	\$ 24,789	\$ 24,789	\$ 24,789	\$ 24,789	\$ 24,789	\$ 24,789	\$ 24,789
WFEC (on PSO) - converted to SPP nts Jun'07	\$ 2,252,979	\$ 2,428,412	\$ 2,139,519	\$ 3,131,097	\$ 3,543,936	\$ 3,467,661	\$ 3,995,867	\$ 4,034,988	\$ 3,179,722	\$ 3,149,212	\$ 2,606,705	\$ 2,564,754	\$ 2,564,754	\$ 2,564,754	\$ 2,564,754	\$ 2,564,754	\$ 2,564,754	\$ 2,564,754	\$ 2,564,754	\$ 2,564,754	\$ 2,564,754	\$ 2,564,754	\$ 2,564,754	\$ 2,564,754	\$ 2,564,754
Total PSO	\$ 2,491,339	\$ 2,641,982	\$ 2,378,933	\$ 3,052,915	\$ 3,337,993	\$ 3,411,408	\$ 3,842,363	\$ 3,790,877	\$ 3,083,425	\$ 3,134,911	\$ 2,633,401	\$ 2,603,225	\$ 2,603,225	\$ 2,603,225	\$ 2,603,225	\$ 2,603,225	\$ 2,603,225	\$ 2,603,225	\$ 2,603,225	\$ 2,603,225	\$ 2,603,225	\$ 2,603,225	\$ 2,603,225	\$ 2,603,225	\$ 2,603,225
SWEPCO	\$ 485,301	\$ 551,088	\$ 449,070	\$ 522,485	\$ 615,922	\$ 598,760	\$ 742,730	\$ 707,452	\$ 548,228	\$ 517,718	\$ 587,319	\$ 642,619	\$ 642,619	\$ 642,619	\$ 642,619	\$ 642,619	\$ 642,619	\$ 642,619	\$ 642,619	\$ 642,619	\$ 642,619	\$ 642,619	\$ 642,619	\$ 642,619	\$ 642,619
AEECC (on SWEPCO) - converts to SPP nts Jan'08	\$ 2,975,666	\$ 3,192,117	\$ 2,826,950	\$ 3,575,400	\$ 3,953,916	\$ 4,011,122	\$ 4,585,093	\$ 4,498,330	\$ 3,630,700	\$ 3,652,629	\$ 3,220,720	\$ 3,545,843	\$ 3,545,843	\$ 3,545,843	\$ 3,545,843	\$ 3,545,843	\$ 3,545,843	\$ 3,545,843	\$ 3,545,843	\$ 3,545,843	\$ 3,545,843	\$ 3,545,843	\$ 3,545,843	\$ 3,545,843	\$ 3,545,843
Total SWEPCO	\$ 18,115	\$ 17,162	\$ 16,208	\$ 23,836	\$ 26,696	\$ 25,743	\$ 27,690	\$ 27,690	\$ 19,129	\$ 19,129	\$ 16,208	\$ 16,208	\$ 16,208	\$ 16,208	\$ 16,208	\$ 16,208	\$ 16,208	\$ 16,208	\$ 16,208	\$ 16,208	\$ 16,208	\$ 16,208	\$ 16,208	\$ 16,208	\$ 16,208
TNC(North) - became part of SWEPCO Feb'07	\$ 70,555	\$ 76,275	\$ 68,648	\$ 108,692	\$ 134,435	\$ 130,621	\$ 152,550	\$ 160,178	\$ 119,180	\$ 113,559	\$ 89,623	\$ 81,042	\$ 81,042	\$ 81,042	\$ 81,042	\$ 81,042	\$ 81,042	\$ 81,042	\$ 81,042	\$ 81,042	\$ 81,042	\$ 81,042	\$ 81,042	\$ 81,042	\$ 81,042
ONPA	\$ 536,787	\$ 504,370	\$ 515,811	\$ 491,975	\$ 516,764	\$ 552,995	\$ 651,200	\$ 675,322	\$ 556,809	\$ 467,186	\$ 623,500	\$ 677,896	\$ 677,896	\$ 677,896	\$ 677,896	\$ 677,896	\$ 677,896	\$ 677,896	\$ 677,896	\$ 677,896	\$ 677,896	\$ 677,896	\$ 677,896	\$ 677,896	\$ 677,896
NTEC	\$ 63,880	\$ 59,113	\$ 57,206	\$ 61,020	\$ 66,741	\$ 66,741	\$ 76,275	\$ 75,322	\$ 71,508	\$ 60,067	\$ 84,856	\$ 85,810	\$ 85,810	\$ 85,810	\$ 85,810	\$ 85,810	\$ 85,810	\$ 85,810	\$ 85,810	\$ 85,810	\$ 85,810	\$ 85,810	\$ 85,810	\$ 85,810	\$ 85,810
ETEC	\$ 80,089	\$ 82,949	\$ 72,461	\$ 78,182	\$ 81,042	\$ 82,949	\$ 100,111	\$ 97,251	\$ 84,856	\$ 75,322	\$ 82,949	\$ 92,484	\$ 92,484	\$ 92,484	\$ 92,484	\$ 92,484	\$ 92,484	\$ 92,484	\$ 92,484	\$ 92,484	\$ 92,484	\$ 92,484	\$ 92,484	\$ 92,484	\$ 92,484
TEXLA	\$ 4,767	\$ 4,767	\$ 2,860	\$ 3,814	\$ 4,767	\$ 5,721	\$ 7,628	\$ 5,721	\$ 3,814	\$ 4,767	\$ 5,721	\$ 4,767	\$ 4,767	\$ 4,767	\$ 4,767	\$ 4,767	\$ 4,767	\$ 4,767	\$ 4,767	\$ 4,767	\$ 4,767	\$ 4,767	\$ 4,767	\$ 4,767	\$ 4,767
Greenbelt	\$ 953	\$ 1,907	\$ 953	\$ 953	\$ 953	\$ 953	\$ 1,907	\$ 2,860	\$ 953	\$ 953	\$ 1,907	\$ 953	\$ 953	\$ 953	\$ 953	\$ 953	\$ 953	\$ 953	\$ 953	\$ 953	\$ 953	\$ 953	\$ 953	\$ 953	\$ 953
Lighthouse	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Coffeyville Reservation (AEP OATT Firm PTP)	\$ 6,004,765	\$ 6,368,025	\$ 5,702,523	\$ 7,471,155	\$ 8,323,528	\$ 8,344,506	\$ 9,598,281	\$ 9,529,633	\$ 7,670,424	\$ 7,545,524	\$ 6,792,239	\$ 7,076,433	\$ 7,076,433	\$ 7,076,433	\$ 7,076,433	\$ 7,076,433	\$ 7,076,433	\$ 7,076,433	\$ 7,076,433	\$ 7,076,433	\$ 7,076,433	\$ 7,076,433	\$ 7,076,433	\$ 7,076,433	\$ 7,076,433
Totals	\$ 6,004,765	\$ 6,368,025	\$ 5,702,523	\$ 7,471,155	\$ 8,323,528	\$ 8,344,506	\$ 9,598,281	\$ 9,529,633	\$ 7,670,424	\$ 7,545,524	\$ 6,792,239	\$ 7,076,433	\$ 7,076,433	\$ 7,076,433	\$ 7,076,433	\$ 7,076,433	\$ 7,076,433	\$ 7,076,433	\$ 7,076,433	\$ 7,076,433	\$ 7,076,433	\$ 7,076,433	\$ 7,076,433	\$ 7,076,433	\$ 7,076,433

NOTE: Loads and resultant charges rounded to nearest MW and \$, respectively.

STATEMENT BH

PROPOSED Rate Charges -- (CY2006)

Annual Transmission Rev. Requirement (Proposed)	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455
effective rate per MW-month (not used)	\$ 1,822.90	\$ 1,720.92	\$ 1,918.03	\$ 1,470.25	\$ 1,321.63	\$ 1,318.35	\$ 1,148.07	\$ 1,156.24	\$ 1,432.76	\$ 1,455.96	\$ 1,629.28	\$ 1,551.22	\$ 1,551.22	\$ 1,551.22	\$ 1,551.22	\$ 1,551.22	\$ 1,551.22	\$ 1,551.22	\$ 1,551.22	\$ 1,551.22	\$ 1,551.22	\$ 1,551.22	\$ 1,551.22	\$ 1,551.22
Network Transmission Charges - SPP OATT Schedule 																								

American Electric Power
(Public Service Company of Oklahoma & Southwestern Electric Power Company)
Network Transmission Service

Increase and Percent Increase -- Proposed vs Present Rates
CALENDAR YEAR -- 2006

	Jan 2006	Feb 2006	Mar 2006	Apr 2006	May 2006	Jun 2006	Jul 2006	Aug 2006	Sep 2006	Oct 2006	Nov 2006	Dec 2006	TOTALS
Network Transmission Charges													
(SPP OATT Schedule 9)													
PSO	\$ 2,038,891	\$ 1,939,409	\$ 2,148,135	\$ 1,685,821	\$ 1,359,341	\$ 1,318,040	\$ 810,226	\$ 852,987	\$ 1,586,069	\$ 1,646,761	\$ 1,830,174	\$ 1,591,892	\$ 18,807,746
WFEC (on PSO) - converted to SPP nts Jun'07	\$ 15,650	\$ 15,349	\$ 16,398	\$ 11,369	\$ 9,205	\$ 9,123	\$ 5,450	\$ 5,273	\$ 12,463	\$ 13,066	\$ 17,572	\$ 16,140	\$ 147,058
Total PSO	\$ 2,054,541	\$ 1,954,759	\$ 2,164,533	\$ 1,697,191	\$ 1,368,546	\$ 1,327,163	\$ 815,676	\$ 858,260	\$ 1,598,532	\$ 1,659,827	\$ 1,847,747	\$ 1,608,032	\$ 18,954,807
SWEPCO	\$ 2,271,907	\$ 2,126,674	\$ 2,406,644	\$ 1,654,812	\$ 1,289,017	\$ 1,305,634	\$ 784,341	\$ 806,343	\$ 1,550,120	\$ 1,652,289	\$ 1,866,670	\$ 1,820,245	\$ 19,534,686
AEECC (on SWEPCO) - converts to SPP nts Jan'08	\$ 442,557	\$ 443,601	\$ 454,321	\$ 283,210	\$ 237,848	\$ 229,161	\$ 151,613	\$ 150,480	\$ 275,609	\$ 272,869	\$ 416,317	\$ 402,904	\$ 3,760,490
Total SWEPCO	\$ 2,713,595	\$ 2,569,507	\$ 2,859,999	\$ 1,938,022	\$ 1,526,864	\$ 1,535,159	\$ 935,954	\$ 956,822	\$ 1,825,250	\$ 1,925,158	\$ 2,282,988	\$ 2,223,150	\$ 23,292,468
TNC(North)*	\$ 16,520	\$ 13,814	\$ 16,398	\$ 12,920	\$ 10,310	\$ 9,852	\$ 5,644	\$ 5,881	\$ 11,024	\$ 11,558	\$ 11,490	\$ 14,346	\$ 139,757
OMPA	\$ 64,340	\$ 61,398	\$ 69,450	\$ 58,916	\$ 51,914	\$ 49,992	\$ 31,140	\$ 34,071	\$ 59,915	\$ 59,800	\$ 63,529	\$ 50,812	\$ 665,277
NTEC	\$ 489,507	\$ 405,994	\$ 521,841	\$ 266,672	\$ 199,557	\$ 211,646	\$ 132,929	\$ 133,444	\$ 279,923	\$ 246,235	\$ 441,999	\$ 425,023	\$ 3,754,770
ETEC	\$ 58,255	\$ 47,584	\$ 57,876	\$ 31,009	\$ 23,564	\$ 25,543	\$ 15,570	\$ 16,021	\$ 35,949	\$ 31,659	\$ 60,150	\$ 53,800	\$ 456,980
TEXLA	\$ 73,035	\$ 66,771	\$ 73,309	\$ 42,378	\$ 31,296	\$ 31,747	\$ 20,436	\$ 20,686	\$ 42,660	\$ 39,699	\$ 58,798	\$ 57,984	\$ 558,799
Greenbelt	\$ 4,348	\$ 3,838	\$ 2,894	\$ 2,067	\$ 1,841	\$ 2,189	\$ 1,557	\$ 1,216	\$ 1,917	\$ 2,513	\$ 4,055	\$ 2,989	\$ 31,424
Lighthouse	\$ 870	\$ 1,535	\$ 1,929	\$ 517	\$ 369	\$ 730	\$ 389	\$ 609	\$ 480	\$ 503	\$ 1,352	\$ 598	\$ 9,881
Total NITS	\$ 5,475,880	\$ 5,125,967	\$ 5,769,195	\$ 4,049,691	\$ 3,214,262	\$ 3,193,657	\$ 1,959,295	\$ 2,027,011	\$ 3,856,129	\$ 3,976,952	\$ 4,772,106	\$ 4,436,733	\$ 47,856,878

% DIFFERENCE: Proposed Rates vs Present Rates -- (CY2006)

PSO	91.2%	80.5%	101.2%	54.2%	38.6%	38.3%	20.4%	21.3%	50.3%	52.7%	70.9%	62.7%	51.9%
WFEC (on PSO) - converted to SPP nts Jun'07	91.2%	80.5%	101.2%	54.2%	38.6%	38.3%	20.4%	21.3%	50.3%	52.7%	70.9%	62.7%	53.9%
Total PSO	91.2%	80.5%	101.2%	54.2%	38.6%	38.3%	20.4%	21.3%	50.3%	52.7%	70.9%	62.7%	51.9%
SWEPCO	91.2%	80.5%	101.2%	54.2%	38.6%	38.3%	20.4%	21.3%	50.3%	52.7%	70.9%	62.7%	53.2%
AEECC (on SWEPCO) - converts to SPP nts Jan'08	91.2%	80.5%	101.2%	54.2%	38.6%	38.3%	20.4%	21.3%	50.3%	52.7%	70.9%	62.7%	54.0%
Total SWEPCO	91.2%	80.5%	101.2%	54.2%	38.6%	38.3%	20.4%	21.3%	50.3%	52.7%	70.9%	62.7%	53.3%
TNC(North)*	91.2%	80.5%	101.2%	54.2%	38.6%	38.3%	20.4%	21.3%	50.3%	52.7%	70.9%	62.7%	50.2%
OMPA	91.2%	80.5%	101.2%	54.2%	38.6%	38.3%	20.4%	21.3%	50.3%	52.7%	70.9%	62.7%	55.9%
NTEC	91.2%	80.5%	101.2%	54.2%	38.6%	38.3%	20.4%	21.3%	50.3%	52.7%	70.9%	62.7%	55.8%
ETEC	91.2%	80.5%	101.2%	54.2%	38.6%	38.3%	20.4%	21.3%	50.3%	52.7%	70.9%	62.7%	55.3%
TEXLA	91.2%	80.5%	101.2%	54.2%	38.6%	38.3%	20.4%	21.3%	50.3%	52.7%	70.9%	62.7%	53.2%
Greenbelt	91.3%	80.5%	101.2%	54.2%	38.7%	38.3%	20.4%	21.3%	50.4%	52.8%	70.9%	62.7%	54.6%
Lighthouse	91.3%	80.5%	101.2%	54.2%	38.7%	38.3%	20.4%	21.3%	50.4%	52.8%	70.9%	62.7%	54.6%
Total NITS	91.2%	80.5%	101.2%	54.2%	38.6%	38.3%	20.4%	21.3%	50.3%	52.7%	70.9%	62.7%	53.0%

* became part of SWEPCO February 2007

American Electric Power
(Public Service Company of Oklahoma & Southwestern Electric Power Company)
Network Transmission Service
Comparison of Charges Under Present and Proposed Rates
CALENDAR YEAR -- 2007

AEP (SPP) Load Responsibility, MW*	SPP Zone 1 Transmission System Peak Loads												12-Month Average (MW)
	Jan 2007	Feb 2007	Mar 2007	Apr 2007	May 2007	Jun 2007	Jul 2007	Aug 2007	Sep 2007	Oct 2007	Nov 2007	Dec 2007	
PSO	2580	2749	2269	2540	3040	3596	4079	4109	3449	2718	27	2248	2457
WFEC (on PSO) - converted to SPP nts Jun'07	23	26	22	19	26	26	29	27	27	27	27	27	28
Total PSO	2603	2775	2291	2559	3060	3621	4107	4135	3475	2745	274	2274	2484
SWEPCO	3083	3225	2699	2788	3043	3254	3363	3760	3070	3070	2508	2783	3244
AEECC (on SWEPCO) - converts to SPP nts Jan'08	653	703	516	421	552	641	704	756	586	554	628	687	624
Total SWEPCO	3736	3928	3115	3209	3806	4454	4844	4750	4346	3624	3137	3470	3868
TNC(North) - became part of SWEPCO Feb'07	20	0	0	0	0	0	0	0	0	0	0	0	2
ONPA	85	87	67	77	111	140	163	171	127	127	122	96	111
NTEC	704	776	566	384	501	678	678	670	575	400	459	469	577
ETEC	96	101	71	45	56	81	81	81	68	50	66	66	72
TEXLA	101	108	88	61	82	102	111	111	95	74	87	87	93
Greenbelt	6	4	2	2	3	8	8	6	4	5	6	6	5
Lighthouse	2	2	1	1	2	2	3	3	1	1	1	2	2
Coffeyville Reservation (AEP OATT Firm PTP)	114	114	114	114	114	114	114	114	114	114	114	114	114
AEP West Zone - SPP Transmission System Firm Peak Demands, MW*	7467	7896	6314	6452	7735	9199	10108	10042	8806	7134	6241	6241	7855.31

*Monthly totals/subtotals may be off by 1 due to rounding of customer load data for display purposes

STATEMENT BG	PRESENT Rate Charges -- (CY2007)												12-Month Totals
Annual Transmission Rev. Requirement (Existing)	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579	\$ 88,681,579
Prior CY 12CP Divisor, MW (used for Existing rate)	8012	8012	8012	8012	8012	8012	8012	8012	8012	8012	8012	8012	8012
Network Transmission Service Rate \$/MW/Month: effective each CY Jan 1 through Dec 31	\$ 922.39	\$ 922.39	\$ 922.39	\$ 922.39	\$ 922.39	\$ 922.39	\$ 922.39	\$ 922.39	\$ 922.39	\$ 922.39	\$ 922.39	\$ 922.39	\$ 922.39
Network Transmission Charges - SPP OATT Schedule 9	\$ 2,379,766	\$ 2,535,650	\$ 2,092,903	\$ 2,342,871	\$ 2,804,066	\$ 3,316,914	\$ 3,762,429	\$ 3,790,101	\$ 3,181,923	\$ 2,507,956	\$ 2,073,533	\$ 2,266,312	\$ 33,052,924
PSO	\$ 21,215	\$ 23,982	\$ 20,293	\$ 17,525	\$ 18,448	\$ 23,982	\$ 26,749	\$ 24,905	\$ 24,905	\$ 24,905	\$ 24,905	\$ 24,905	\$ 277,641
WFEC (on PSO) - converted to SPP nts Jun'07	\$ 2,400,981	\$ 2,559,632	\$ 2,113,195	\$ 2,360,396	\$ 2,822,513	\$ 3,339,974	\$ 3,788,256	\$ 3,814,083	\$ 3,205,305	\$ 2,531,961	\$ 2,097,515	\$ 2,291,217	\$ 33,325,028
Total PSO	\$ 2,843,728	\$ 2,974,708	\$ 2,397,292	\$ 2,571,623	\$ 3,001,457	\$ 3,577,073	\$ 3,734,757	\$ 3,688,103	\$ 3,488,186	\$ 2,831,737	\$ 2,313,354	\$ 2,567,011	\$ 35,904,029
SWEPCO	\$ 602,321	\$ 648,440	\$ 475,953	\$ 388,226	\$ 509,159	\$ 591,252	\$ 732,378	\$ 697,327	\$ 540,521	\$ 511,004	\$ 457,921	\$ 463,682	\$ 6,909,624
AEECC (on SWEPCO) - converts to SPP nts Jan'08	\$ 3,446,049	\$ 3,623,148	\$ 2,873,245	\$ 2,959,950	\$ 3,510,616	\$ 4,108,325	\$ 4,468,057	\$ 4,381,353	\$ 4,008,707	\$ 3,342,741	\$ 2,893,537	\$ 3,200,693	\$ 42,816,421
Total SWEPCO	\$ 18,448	\$ 80,248	\$ 61,800	\$ 71,024	\$ 102,385	\$ 129,135	\$ 150,350	\$ 157,729	\$ 117,144	\$ 112,532	\$ 88,549	\$ 80,248	\$ 1,229,547
TNC(North) - became part of SWEPCO Feb'07	\$ 78,403	\$ 715,775	\$ 522,073	\$ 354,198	\$ 462,117	\$ 625,380	\$ 618,001	\$ 530,374	\$ 368,956	\$ 423,377	\$ 492,556	\$ 6,387,550	\$ 63,851,550
ONPA	\$ 88,549	\$ 93,161	\$ 65,490	\$ 41,508	\$ 74,714	\$ 74,714	\$ 74,714	\$ 74,714	\$ 62,723	\$ 46,120	\$ 60,878	\$ 67,334	\$ 801,559
NTEC	\$ 93,161	\$ 99,618	\$ 81,170	\$ 56,266	\$ 75,636	\$ 94,084	\$ 102,385	\$ 102,385	\$ 87,627	\$ 68,257	\$ 80,248	\$ 92,239	\$ 1,033,076
ETEC	\$ 5,534	\$ 3,680	\$ 1,845	\$ 1,845	\$ 2,767	\$ 5,534	\$ 7,379	\$ 5,534	\$ 3,680	\$ 4,612	\$ 5,534	\$ 4,612	\$ 52,576
TEXLA	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ 18,447
Greenbelt	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a
Lighthouse	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a
Coffeyville Reservation (AEP OATT Firm PTP)	\$ 6,792,333	\$ 7,178,039	\$ 5,718,819	\$ 5,846,108	\$ 7,029,534	\$ 8,379,913	\$ 9,218,366	\$ 9,156,566	\$ 8,017,415	\$ 6,476,101	\$ 5,651,484	\$ 6,230,743	\$ 85,685,421
Totals	\$ 11,510,004	\$ 11,519,699	\$ 11,477,417	\$ 11,481,932	\$ 11,516,186	\$ 11,543,603	\$ 11,556,631	\$ 11,554,601	\$ 11,537,139	\$ 11,503,314	\$ 11,474,951	\$ 11,494,469	\$ 138,169,946

NOTE: Loads and resultant charges rounded to nearest MW and \$, respectively.

STATEMENT BH	PROPOSED Rate Charges -- (CY2007)												12-Month Totals
Annual Transmission Rev. Requirement (Proposed)	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455	\$ 11,688,455
effective rate per MW-month (not used)	\$ 1,565.35	\$ 1,480.30	\$ 1,851.20	\$ 1,811.60	\$ 1,511.11	\$ 1,270.67	\$ 1,156.31	\$ 1,163.94	\$ 1,327.38	\$ 1,638.32	\$ 1,872.82	\$ 1,701.56	\$ 140,261,459
Network Transmission Charges - SPP OATT Schedule 9	\$ 4,038,598	\$ 4,069,347	\$ 4,200,365	\$ 4,601,469	\$ 4,593,792	\$ 4,569,158	\$ 4,716,780	\$ 4,782,699	\$ 4,577,956	\$ 4,453,213	\$ 4,210,166	\$ 4,180,890	\$ 52,994,423
PSO	\$ 36,003	\$ 38,468	\$ 40,726	\$ 34,420	\$ 30,222	\$ 33,036	\$ 33,534	\$ 31,427	\$ 35,638	\$ 44,237	\$ 50,567	\$ 47,645	\$ 456,143
WFEC (on PSO) - converted to SPP nts Jun'07	\$ 4,074,601	\$ 4,107,835	\$ 4,241,091	\$ 4,635,889	\$ 4,624,004	\$ 4,600,923	\$ 4,749,158	\$ 4,812,962	\$ 4,612,467	\$ 4,487,450	\$ 4,258,860	\$ 4,226,834	\$ 53,442,074
Total PSO	\$ 4,825,968	\$ 4,773,970	\$ 4,811,260	\$ 5,050,746	\$ 4,917,180	\$ 4,844,883	\$ 4,682,089	\$ 4,647,680	\$ 4,990,755	\$ 5,029,935	\$ 4,697,107	\$ 4,736,619	\$ 58,007,172
SWEPCO	\$ 1,022,172	\$ 1,040,651	\$ 955,217	\$ 762,884	\$ 834,134	\$ 814,469	\$ 918,147	\$ 879,951	\$ 777,815	\$ 907,682	\$ 1,176,150	\$ 1,169,016	\$ 11,268,088
AEECC (on SWEPCO) - converts to SPP nts Jan'08	\$ 5,848,141	\$ 5,814,621	\$ 5,766,477	\$ 5,813,430	\$ 5,751,294	\$ 5,659,352	\$ 5,601,393	\$ 5,528,795	\$ 5,788,570	\$ 5,937,617	\$ 5,875,129	\$ 5,904,635	\$ 69,269,454
Total SWEPCO	\$ 31,307	\$ 128,786	\$ 124,030	\$ 139,493	\$ 167,733	\$ 177,887	\$ 188,486	\$ 199,037	\$ 168,571	\$ 199,887	\$ 179,794	\$ 148,041	\$ 91,307
TNC(North) - became part of SWEPCO Feb'07	\$ 133,055	\$ 1,148,713	\$ 1,047,773	\$ 695,655	\$ 757,067	\$ 861,482	\$ 784,010	\$ 779,851	\$ 763,214	\$ 655,366	\$ 859,638	\$ 908,667	\$ 1,984,800
ONPA	\$ 150,273	\$ 149,510	\$ 131,435	\$ 81,522	\$ 84,622	\$ 102,920	\$ 93,665	\$ 94,281	\$ 90,258	\$ 81,921	\$ 123,608	\$ 124,219	\$ 1,308,234
NTEC	\$ 158,100	\$ 159,872	\$ 162,905	\$ 110,508	\$ 123,911	\$ 129,603	\$ 128,356	\$ 129,199	\$ 126,096	\$ 121,243	\$ 162,938	\$ 170,162	\$ 1,682,893
ETEC	\$ 9,392	\$ 5,921	\$ 3,702	\$ 3,623	\$ 4,533	\$ 7,624	\$ 9,251	\$ 6,984	\$ 5,309	\$ 8,192	\$ 11,237	\$ 8,508	\$ 84,276
TEXLA	\$ 3,131	\$ 4,441	\$ n/a	\$ 1,812	\$ 3,022	\$ 2,541	\$ 2,313	\$ 3,492	\$ n/a	\$ 1,638	\$ n/a	\$ 1,702	\$ 29,165
Greenbelt	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a
Lighthouse	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a	\$ n/a
Coffeyville Reservation (AEP OATT Firm PTP)	\$ 11,510,004	\$ 11,519,699	\$ 11,477,417	\$ 11,481,932	\$ 11,516,186	\$ 11,543,603	\$ 11,556,631	\$ 11,554,601	\$ 11,537,139	\$ 11,503,314	\$ 11,474,951	\$ 11,494,469	\$ 138,169,946
Totals	\$ 11,510,004	\$ 11,519,699	\$ 11,477,417	\$ 11,481,932	\$ 11,516,186	\$ 11,543,603	\$ 11,556,631	\$ 11,554,601	\$ 11,537,139	\$ 11,503,314	\$ 11,474,951	\$ 11,494,469	\$ 138,169,946

NOTE: Loads and resultant charges rounded to nearest MW and \$, respectively.

American Electric Power
(Public Service Company of Oklahoma & Southwestern Electric Power Company)
Network Transmission Service

Increase and Percent Increase -- Proposed vs Present Rates
CALENDAR YEAR -- 2007

	Jan 2007	Feb 2007	Mar 2007	Apr 2007	May 2007	Jun 2007	Jul 2007	Aug 2007	Sep 2007	Oct 2007	Nov 2007	Dec 2007	TOTALS
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	DIFFERENCE: Proposed Rates vs Present Rates -- (CY2007)												
Network Transmission Charges													
(SPP OATT Schedule 9)													
PSO	\$ 1,658,832	\$ 1,533,697	\$ 2,107,462	\$ 2,258,598	\$ 1,789,716	\$ 1,252,244	\$ 954,351	\$ 992,598	\$ 1,396,633	\$ 1,946,157	\$ 2,136,633	\$ 1,914,578	\$ 19,941,499
WFEC (on PSO) - converted to SPP nts Jun'07	\$ 14,788	\$ 14,506	\$ 20,433	\$ 16,895	\$ 11,774	\$ 9,054	\$ 6,785	\$ 6,522	\$ 10,933	\$ 19,332	\$ 25,662	\$ 21,818	\$ 178,502
Total PSO	\$ 1,673,620	\$ 1,548,203	\$ 2,127,896	\$ 2,275,493	\$ 1,801,491	\$ 1,260,949	\$ 960,902	\$ 998,879	\$ 1,407,162	\$ 1,965,489	\$ 2,161,345	\$ 1,935,617	\$ 20,117,046
SWEPCO	\$ 1,982,240	\$ 1,799,262	\$ 2,413,968	\$ 2,479,123	\$ 1,915,703	\$ 1,327,810	\$ 947,332	\$ 984,577	\$ 1,522,569	\$ 2,198,198	\$ 2,383,753	\$ 2,168,608	\$ 22,103,143
AECC (on SWEPCO) - converts to SPP nts Jan'08	\$ 419,851	\$ 392,211	\$ 479,264	\$ 374,358	\$ 324,975	\$ 223,217	\$ 185,769	\$ 182,624	\$ 237,294	\$ 396,678	\$ 596,889	\$ 535,334	\$ 4,348,464
Total SWEPCO	\$ 2,402,092	\$ 2,191,473	\$ 2,893,232	\$ 2,853,480	\$ 2,240,678	\$ 1,551,027	\$ 1,133,336	\$ 1,147,442	\$ 1,759,863	\$ 2,594,876	\$ 2,981,592	\$ 2,703,942	\$ 26,453,033
TNC(North)*	\$ 12,859	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 12,859
OMPA	\$ 54,652	\$ 48,538	\$ 62,230	\$ 68,469	\$ 65,348	\$ 48,752	\$ 38,136	\$ 41,308	\$ 51,427	\$ 87,355	\$ 91,245	\$ 67,793	\$ 725,253
NTEC	\$ 452,642	\$ 432,938	\$ 525,704	\$ 341,457	\$ 294,950	\$ 236,102	\$ 158,630	\$ 161,850	\$ 232,840	\$ 286,410	\$ 436,261	\$ 416,111	\$ 3,975,895
ETEC	\$ 61,724	\$ 56,349	\$ 65,945	\$ 40,014	\$ 32,968	\$ 28,206	\$ 18,951	\$ 19,567	\$ 27,535	\$ 35,801	\$ 62,730	\$ 56,885	\$ 506,675
TEXLA	\$ 64,939	\$ 60,254	\$ 81,735	\$ 54,242	\$ 48,275	\$ 35,519	\$ 25,971	\$ 26,814	\$ 38,469	\$ 52,986	\$ 82,690	\$ 77,923	\$ 649,817
Greenbelt	\$ 3,858	\$ 2,231	\$ 1,857	\$ 1,778	\$ 1,766	\$ 2,090	\$ 1,872	\$ 1,450	\$ 1,619	\$ 3,580	\$ 5,703	\$ 3,896	\$ 31,700
Lighthouse	\$ 1,286	\$ 1,674	\$ -	\$ 890	\$ 1,177	\$ 696	\$ 468	\$ 780	\$ 405	\$ 716	\$ 1,901	\$ 780	\$ 10,718
Total NITS	\$ 4,727,671	\$ 4,341,660	\$ 5,758,598	\$ 5,635,824	\$ 4,486,652	\$ 3,163,690	\$ 2,338,265	\$ 2,398,035	\$ 3,519,724	\$ 5,027,213	\$ 5,823,467	\$ 5,263,726	\$ 52,484,525

	% DIFFERENCE: Proposed Rates vs Present Rates -- (CY2007)												
Network Transmission Charges													
(SPP OATT Schedule 9)													
PSO	69.7%	60.5%	100.7%	96.4%	63.8%	37.8%	25.4%	26.2%	43.9%	77.6%	103.0%	84.5%	60.3%
WFEC (on PSO) - converted to SPP nts Jun'07	69.7%	60.5%	100.7%	96.4%	63.8%	37.8%	25.4%	26.2%	43.9%	77.6%	103.0%	84.5%	64.3%
Total PSO	69.7%	60.5%	100.7%	96.4%	63.8%	37.8%	25.4%	26.2%	43.9%	77.6%	103.0%	84.5%	60.4%
SWEPCO	69.7%	60.5%	100.7%	96.4%	63.8%	37.8%	25.4%	26.2%	43.9%	77.6%	103.0%	84.5%	61.6%
AECC (on SWEPCO) - converts to SPP nts Jan'08	69.7%	60.5%	100.7%	96.4%	63.8%	37.8%	25.4%	26.2%	43.9%	77.6%	103.0%	84.5%	62.9%
Total SWEPCO	69.7%	60.5%	100.7%	96.4%	63.8%	37.8%	25.4%	26.2%	43.9%	77.6%	103.0%	84.5%	61.8%
TNC(North)*	69.7%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
OMPA	69.7%	60.5%	100.7%	96.4%	63.8%	37.8%	25.4%	26.2%	43.9%	77.6%	103.0%	84.5%	59.0%
NTEC	69.7%	60.5%	100.7%	96.4%	63.8%	37.8%	25.4%	26.2%	43.9%	77.6%	103.0%	84.5%	62.2%
ETEC	69.7%	60.5%	100.7%	96.4%	63.8%	37.8%	25.4%	26.2%	43.9%	77.6%	103.0%	84.5%	63.2%
TEXLA	69.7%	60.5%	100.7%	96.4%	63.8%	37.8%	25.4%	26.2%	43.9%	77.6%	103.0%	84.5%	62.9%
Greenbelt	69.7%	60.5%	100.7%	96.4%	63.8%	37.8%	25.4%	26.2%	43.9%	77.6%	103.1%	84.5%	60.3%
Lighthouse	69.7%	60.5%	#DIV/0!	96.5%	63.8%	37.7%	25.4%	26.2%	43.9%	77.7%	103.0%	84.6%	58.1%
Total NITS	69.7%	60.5%	100.7%	96.4%	63.8%	37.8%	25.4%	26.2%	43.9%	77.6%	103.0%	84.5%	61.3%

* became part of SWEPCO February 2007