A. The APSC's decision on EAI's Market Mechanics should have no affect on the capital projects in this Texas docket. The APSC does many things differently from the PUCT. The Intervenors' are suggesting that the PUCT blindly follow the rulings of a regulatory body in another state, regardless of the reasoning in that ruling. It is not good regulatory policy when the first state regulatory commission to decide an issue gets to dictate the result for all other state regulatory commissions.

Q. IN REGARD TO THE INTERVENOR'S FOURTH POINT, WOULD THE RECOGNITION OF AFUDC ON UNAMORTIZED TTC COSTS RESULT IN A DOUBLE RECOVERY OF COSTS?

A. No. AFUDC is a component cost of the TTC capital projects while those projects were not being recovered through rates by the Texas customers. The Intervenors' argument is no more valid than the argument that the return of AFUDC through depreciation of Plant in Service is a double recovery since there is a return on those dollars in Plant in Service. EGSI's current rate base includes the AFUDC that accrued on capital projects (such as transmission lines) while those projects were under construction, and EGSI's base rates include a rate of return on its rate base, including the accrued AFUDC on those projects that have been placed in service. No one argues that this regulatory practice produces a double recovery. But that is the logic of the Intervenors' argument.

Q. TURNING NOW TO THE INTERVENORS' FINAL ARGUMENT, DO YOU AGREE WITH THE INTERVENORS THAT AFUDC IS NOT A REASONABLE AND NECESSARY TTC COST?

A. No. EGSI has incurred the cost of the AFUDC that has accrued on the TTC capital projects, and has not otherwise recovered those costs (the AFUDC) of financing those TTC capital projects. PURA § 39.454 allows EGSI to recover its TTC costs incurred before June 18, 2005 to the extent those costs have not been previously recovered.

> An electric utility subject to this subchapter is entitled to recover, as provide by this section, all reasonable and necessary expenditure made or incurred before the effective date of this section to comply with this chapter, to the extent the costs have not otherwise been recovered.

The statute does not specify that any other criteria should be considered other than that the cost was incurred and that they were reasonable and necessary. Obviously, the Company must use borrowed and equity funds (reflected in the AFUDC rate) to construct TTC assets and those funds have a cost.

VI. CAPITAL OVERHEAD CHARGES

Q. WHAT SUBJECT DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. I discuss the capital overheads included in the TTC capital costs. Messrs. Pous and Arndt and Dr. Szerszen recommend that the Commission remove those overhead charges from the TTC capital costs.[21]

Q. WHAT ARE THEIR REASONS FOR RECOMMENDING THE DISALLOWANCE OF THE CAPITAL OVERHEAD CHARGES?

A. Mr. Arndt argues that the capital overhead charges are general management and administrative time not associated with any particular project and, thus, are not "directly related to TTC costs not otherwise recovered." Mr. Pous argues that the costs are for fixed assets and administrative time for engineering personnel not associated with a particular project. Hence, in his view, the charges are not "reasonable or necessary as it relates to TTC activities." Dr. Szerszen argues that "EGSI does not explain why these overheads were incurred and how they are related to TTC activities" and, therefore, should be disallowed.

Q. DO YOU AGREE WITH THEIR ARGUMENTS?

[21] Direct Testimony of Michael L. Arndt at page 4, lines 21 – 26, and at page 27, line 18 through page 29, line 9; Direct Testimony of Jacob Pous at page 6, line 38 through page 7, line 3; Direct Testimony of Carol Szerszen at page 22, line 17 through page 23, line 2.

A. No. The Uniform System of Accounts allows the recovery of capital overhead charges. Electric Plant Instruction 3.A(11) defines Engineering and Supervision as follows:

> *Engineering and supervision* includes the portion of the pay and expenses of engineers, surveyors, draftsmen, inspectors, superintendents and their assistants applicable to construction work.[22]

Electric Plant Instruction 3.A(12) defines General Administration Capitalized as follows:

> *General administration capitalized* includes the portion of the pay and expenses of the general officers and administrative and general expenses applicable to construction work.[23]

Electric Plant Instruction 3.A(13) defines Engineering services as follows:

> *Engineering services* includes amounts paid to other companies, firms, or individuals engaged by the utility to plan, design, prepare estimates, supervise, inspect, or give general advice and assistance in connection with construction work. [24]

The costs at issue fall into one of these three categories. NARUC interpretation No. 60 states:

> The amounts of administrative and general expenses which are capitalizable are only those costs which have a provable relationship to construction.

These amounts were charged to construction overhead accounts because they have a provable relationship to construction regardless of whether

---

[22] Federal Energy Regulatory Commission, Uniform System of Accounts, 18 C.F.R. Part 101, Electric Plant Instruction 3.A.(11). The complete Instruction 3.A, components of construction costs, is provided in my workpapers to this testimony.

[23] Federal Energy Regulatory Commission, Uniform System of Accounts, 18 C.F.R. Part 101, Electric Plant Instruction 3.A.(12).

they were specifically related to these particular projects. The amounts were then allocated to all construction activity, including these particular TTC projects. They have not been recovered previously because these projects have never been included in rate base and the costs were never charged to expense.

These costs meet the requirements of PURA Section 39.454 for recovery because they were incurred, are reasonable and necessary, and have not otherwise been recovered. EGSI should be allowed to recover these costs as part of its recovery of TTC costs under PURA Section 39.454.

VII. CARRYING COSTS ON TTC O&M EXPENSES

Q. WHAT SUBJECT DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. I discuss the carrying costs that are applied to the TTC O&M expenses. Dr. Szerszen and Messrs. Pollock, Arndt, and Pous recommend that the Commission disallow these carrying costs.[25]

Q. DO YOU AGREE WITH THEIR RECOMMENDATION?

---

[24] Federal Energy Regulatory Commission, Uniform System of Accounts, 18 C.F.R. Part 101, Electric Plant Instruction 3.A.(13).

[25] Direct Testimony of Carol Szerszen at page 18, line 1 through page 19, line 5; Direct Testimony of Jeffry Pollock at page 44, line 18 through page 47, line 13; Direct Testimony of Michael L. Arndt at page 4, lines 5 – 8, and at page 14, line 16 through page 20, line 4; Direct Testimony of Jacob Pous at page 6, lines 12 – 20, and at page 20, line 12 through page 22, line 11.

A. No. As I previously described, the statue allows carrying costs. These O&M costs were incurred over a number of years and it is reasonable for the Company to reflect the time value of money in this filing.

VIII. CARRYING COSTS OVER THE FIFTEEN-YEAR RECOVERY PERIOD

Q. WHAT SUBJECT DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. I discuss the carrying costs to be applied to the TTC costs to be collected over the fifteen-year cost recovery period. The Company has used its overall cost of capital from its most recent base rate case, a 12.71% pre-tax rate of return (rate of return of 9.67%).

Q. WHAT CARRYING COSTS DO THE INTERVENOR WITNESSES RECOMMEND?

A. All of the Intervenor witnesses use a carrying cost well below the Company's overall cost of capital.

Dr. Szerszen and Clarence Johnson, on behalf of OPC, recommend an after-tax carrying cost of 7.55% (pre-tax rate of return of 6%), which is based upon the current yield for Triple B rated utility bonds.[26] Mr. Johnson testified that this carrying cost is reasonable

[26] Direct Testimony of Carol Szerszen at page 26, line 1 through page 27, line 9; Direct Testimony of Clarence Johnson at page 5, lines 8 – 9, and at page 18, line 15 through page 21, line 17.

because it is greater than the carrying cost of 0% that applies to cancelled plant.

Mr. Pollock recommends a pre-tax rate of return of 7.63%. He testifies that the carrying cost should be based on the Company actual capital structure and cost of capital as of December 31, 2004, with the return on equity reduced to the cost of long-term debt.[27]

Messrs. Pous and Arndt recommend that the Commission use the interest rate applicable to fuel cost under-recovery balances, which currently is 3.06%, and that the Commission adjust the TTC carrying costs each year when it resets the interest rate applicable to fuel cost under-recovery balances.[28]

Q. DO YOU AGREE WITH THESE RECOMMENDATIONS?

A. No. These recommendations are too low because they fail to reflect the Company's cost of money as approved by the Commission. The carrying costs should be the overall cost of capital approved in the Company's most recent base rate case. Under the Commission's stranded cost true-up rule, the carrying costs during the recovery period are the utility's weighted overall cost of capital established in the utility's unbundled cost

[27] Direct Testimony of Jeffry Pollock at page 8, lines 10-16; and at page 64, line 5 through page 66, line 22.

[28] Direct Testimony of Jacob Pous at page 7, lines 22 – 38, and at page 41, line 5 through page 45, line 22; Direct Testimony of Michael L. Arndt at page 22, lines 1 - 16.

of service ("UCOS") case.[29] The Commission applied that rule in last summer's CenterPoint Energy competition transition charge ("CTC") case and used CenterPoint's approved weighted overall cost of capital as the carrying cost over the recovery period.[30] Likewise, here in this TTC case, the principal should hold that the carrying cost is EGSI's overall cost of capital approved in EGSI's most recent approved base rate case, Docket No. 20150. To allow a carrying cost less than the weighted average cost of capital over the 15-year recovery period equates to allocating a portion of capital, in this case lower cost capital, to a particular asset. If this were done, then it only follows that the allowed return on the remaining assets of EGSI must increase above the weighted average cost of capital in order to preserve the opportunity to earn the Commission's overall allowed return. This cannot be accomplished, however, due to the rate freeze currently in force. Thus, to allow a carrying charge that is less than the weighted average cost of capital on the TTC costs over the 15-year recovery period is equivalent to denying the opportunity to earn the company's weighted average cost of capital.

---

[29] P.U.C. Subst. R. 25.263(l)(3) and (m). The complete Rule is provided in my workpapers to this testimony.

[30] *Application of CenterPoint Energy Houston Electric, LLC for a Competition Transition Charge*, Docket No. 30706, Order at pages 8 – 12 and 36 (FoFs 19 – 21) (July 14, 2005). The relevant pages from the Order are provided in my workpapers to this testimony.

Q. MORE SPECIFICALLY, DO YOU AGREE WITH THE INTERVENOR WITNESSES THAT THE COST OF EQUITY SHOULD BE REMOVED FROM THE CARRYING COSTS?

A. No. For the reason I just stated, the carrying costs should include the cost of equity, as reflected in the overall cost of capital approved in Docket No. 20150.

In addition, the Intervenors are giving conflicting messages about the Company's risk associated with recovering the TTC costs. Dr. Szerszen and Messrs. Pous and Pollock all say that the Company faces no realistic risk associated with cost recovery. For that reason, they eliminate the cost of equity from the carrying costs. Yet, Mr. Johnson and State of Texas witness Kelso King both propose that cost recovery be tracked by rate class and that the risk of not recovering a portion of the authorized TTC costs be imposed on the Company.[31] If Messrs. Johnson's and King's proposal were accepted, then it would undercut the Intervenors' position that the Company faces no risk associated with recovering its authorized TTC costs.

In contrast to Dr. Szerszen and Messrs. Pous and Pollock, Staff witness Robert V. Manning recognizes that EGSI faces a legitimate risk

---

[31] Cross-Rebuttal Testimony of Kelso King at page 11, line 9 through page 14, line 2; Direct Testimony of Kelso King at page 22, line 12 through page 23, line 20; Cross-Rebuttal Testimony of Clarence Johnson at page 18, line 20 through page 19, line 13.

that it may be unable to recover a portion of its approved TTC costs.[32] Consequently, it is unreasonable for the Intervenor witnesses to eliminate the return on equity from the carrying costs.

Q. MR. JOHNSON SAYS THAT THE COMMISSION SHOULD ELIMINATE THE COST OF EQUITY FROM THE CARRYING COSTS IN ORDER TO BALANCE TWO CONSIDERATIONS: THE COMMISSION'S HISTORIC PRACTICE OF ALLOWING NO CARRYING COSTS DURING THE RECOVERY OF CANCELLED PLANT COSTS; AND THE LANGUAGE IN PURA SECTION 39.454 THAT REQUIRES APPROPRIATE CARRYING COSTS DURING THE RECOVERY OF THE TTC COSTS. DO YOU AGREE WITH HIS RATIONALE FOR ELIMINATING THE COST OF EQUITY FROM THE CARRYING COSTS?

A. No. Mr. Johnson assumes that the recovery of TTC costs is akin to the recovery of cancelled plant costs and, from that assumption, argues that the Commission should reduce the carrying costs allowed under PURA Section 39.454. Mr. Johnson, however, has testified, in this case, that the TTC costs are not normal utility costs,[33] but instead are "analogous to the 'qualified costs' which may be securitized under Chapter 39."[34] Thus, Mr. Johnson's analogy to cancelled plant costs is misplaced, as is his attempt

[32] Direct Testimony of Robert V. Manning at page 11, line 20 through page 13, line 5.

[33] Cross-Rebuttal Testimony of Clarence Johnson at page 11, lines 5-10.

[34] *Id.* at page 11, line 22 through page 12, line 1.

to graft the treatment of cancelled plant carrying costs onto the recovery of TTC costs. As I have mentioned, the carrying cost set out in the Commission's stranded cost recovery rule is the applicable carrying cost during EGSI's recovery of its TTC costs.

Q. DO YOU AGREE WITH MR. POUS THAT THE CARRYING COST DURING THE TTC COST RECOVERY PERIOD SHOULD BE BASED UPON THE INTEREST RATE IN THE FUEL RULE AND RESET EVERY YEAR?

A. No. Mr. Pous's suggestion would lead to an unreasonably low carrying cost. The rationale behind the interest rate in the fuel rule is that fuel costs are financed through relatively short-term debt and the under-recovery and over-recovery balances are recovered over a relatively short period of time. In contrast, the TTC costs were financed through the Company's overall capital structure and cost of capital.

IX. AFUDC ASSOCIATED WITH STAFF'S ADJUSTMENTS

Q. WHAT SUBJECT DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. I discuss the AFUDC impact of Staff witness Adrianne G. Brandt's adjustments to the Company's Retail Market TTC costs. Staff witness Anna Givens has calculated an AFUDC impact based on the information she had available to her and suggested that the Company recalculate this amount.[35]

Q. HAVE YOU RECALCULATED THIS AMOUNT?

A. Yes. The actual amount of AFUDC costs associated with these adjustments through February 28, 2006 is $334,053 as shown on Exhibit JDW-R-3. The Company did not begin recording AFUDC on these Retail Market TTC costs until these costs were transferred to EGSI's books in December 2004.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, at this time.

---

[35] Direct Testimony of Anna Givens at page 16, lines 19 – 22.

PUC PROJECT NO. 22276

RECEIVED
01 FEB 2? PM 3:02
FILING CLERK

1999 ELECTRIC UTILTIES' ANNUAL REPORT FILED PURSUANT TO § 39.257 OF PURA	§ § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER

This Order addresses the annual reports for the 1999 calendar year filed by electric utilities[1] and the disagreements with those reports filed by Commission Staff (Staff) and the Office of Public Utility Counsel (OPC). All of the issues raised in these disagreements were limited to questions of law and policy. As discussed in this Order, the Commission resolves all disputes and finalizes the annual reports for calendar year 1999. The Commission also orders each utility to recalculate its annual revenues and expenses to determine its excess earnings in conformance with this Order, and to file the revised reports in this docket.

I. Background

PURA § 39.257 requires electric utilities to file annual reports with the Commission in order to identify differences between adjusted annual revenues and annual costs.[2] For a utility with stranded costs, any positive differences identified in the report must be applied against the net book value of generation assets.[3] Utilities without stranded costs must use any excess earnings to improve transmission and distribution facilities, add pollution control equipment, or return the excess to ratepayers.[4]

---

[1] TXU Electric Company (TXU), Southwestern Public Service Company (SPS), West Texas Utilities Company (WTU), Southwestern Electric Power Company (SWEPCO), Central Power and Light Company (CPL), Texas-New Mexico Power Company (TNMP), Reliant Energy HL&P, Inc. (Reliant), TXU SESCO Company (TXU SESCO), and Entergy Gulf States, Inc. (Entergy).

[2] Public Utility Regulatory Act, TEX. UTIL. CODE ANN. §§ 39.257(a) (Vernon 1998 & Supp. 2000) (PURA).

[3] *See Id.* § 39.254.

[4] *See Id.* § 39.255.

89

412

In accordance with PURA § 39.261, Staff and the OPC are charged with reviewing the annual reports and bringing any disagreements with the reports to the Commission.[5] The Commission is required to resolve any disagreements with and finalize the annual reports and to reflect the results in the setting of a competition transition charge and in the 2004 true-up proceeding.[6]

Annual reports for the 1999 calendar year were filed by the utilities on March 30, 2000, except TXU SESCO who filed on June 12, 2000, and SPS who filed on April 4, 2000. Revisions to the initial reports were filed by all of the utilities except TXU from April 24 through July 17, 2000. OPC and Staff both filed a notice of disagreement covering every utility's annual report on September 26, 2000. SWEPCO filed an additional revision on December 27, 2000.

Staff met informally with each of these utilities to resolve the disputed issues. Subsequent to these meetings, the utilities filed lists identifying the remaining disagreements on November 6, 2000. Briefs and reply briefs addressing the contested issues were filed by the parties on December 20, 2000, and January 12, 2001, respectively. Reliant filed its response to the Staff Brief on January 19, 2001.

On January 18, 2001, TXU filed a motion requesting additional time to conduct negotiations regarding the federal income tax issue and other miscellaneous issues. A stipulation and partial settlement agreement between Staff and CP&L, TXU, and SWEPCO was filed on January 19, 2001.

The Commission considered the positions and arguments of the parties in open meeting on January 25, 2001. The Commission tentatively resolved all issues except the issues concerning the treatment of federal income taxes and the treatment of imputed revenues for SPS. The Commission granted TXU's request for more time to address the income tax issue. After additional discussions, an agreement concerning the treatment of federal income tax was reached

---

[5] *Id.* § 39.261(a), (b).

[6] *Id.* § 39.261(c).

between Staff, CPL, TXU, Reliant, Entergy and TNMP and filed on February 7, 2001. In addition, on the same day Reliant filed an agreement with Staff regarding treatment of its imputed revenue.

On February 8, 2001, the Commission met in open meeting and considered the remaining issues and proposed settlements.

II. Discussion

Through informal discussions, parties narrowed their disagreements regarding the annual reports to the following issues:

- the proper rate of return to be used in the estimation of excess revenues (specific to Reliant, CP&L, and Entergy);
- the treatment of revenue-related state taxes and the treatment of previously non-regulated generating facilities (specific to TXU);
- return and capital structure relevant to the treatment of federal income taxes (all utilities except SWEPCO);
- definition and treatment of capital additions to net plant in service (generic to all utilities); and
- the treatment of imputed revenues (specific to SPS).

A. Rate of Return

PURA § 39.258 requires that a utility, for purposes of calculating annual costs in the annual report, use "the cost of capital approved in the electric utility's most recent rate proceeding before the Commission in which the cost of capital was specifically adopted . . . ."[7] Staff and OPC disagree with Reliant, TXU and Entergy on which Commission proceeding is the appropriate one to take the cost of capital from.

[7] PURA § 39.258(7).

Reliant—Return

In 1995, in Docket No. 12065,[8] the Commission approved a range for rate of return from 9.77% to 10.28%, the midpoint of which is 10.03%.[9] Three years later, in Docket No. 18465,[10] the Commission adopted a rate of return of 9.844%.[11] Staff claimed that the rate adopted by the Commission in Docket No. 18465 was the appropriate rate of return because that was Reliant's last rate proceeding. Reliant argued that the rate approved in Docket No. 18465 was the result of an accounting order rather than an actual ratemaking proceeding. Reliant argued, therefore, that the appropriate rate of return is the rate established in Docket No. 12065.

The Commission disagrees with Reliant's position that Docket No. 18465 was not a rate proceeding. While rate proceeding is not defined, ratemaking proceeding is defined as "[a] proceeding in which a rate may be changed."[12] Docket No. 18465 both affected rates paid by customers through revisions made to Reliant's base rate credits and effected a different rate of return. Because that proceeding changed the base rates charged to customers, the Commission concludes that Docket No. 18645 constitutes a ratemaking proceeding. Further, the Commission concludes that a ratemaking proceeding is a rate proceeding for purposes of PURA § 39.258(7). Consequently, the Commission concludes that the cost of capital of 9.844% established by the Commission in Docket No. 18465 is the appropriate rate for purposes of the annual report.

Reliant—Imputed Income

On a related issue, Reliant maintained that the Commission in Docket No. 18645 reduced the company's rate of return from the 9.95% rate stipulated by the parties to account for imputed revenues. In a stipulation filed on February 7, 2001, Reliant and Staff agreed that using the 9.844% rate of return along with the revenue imputation shown in Schedule II of Reliant's 1999

---

[8] *Complaint of Kenneth D. Williams Against Houston Lighting & Power Company*, Docket No. 12065, 21 P.U.C. BULL. 148 (August 1, 1995) (Docket No. 12065).

[9] *Id.*, Finding of Fact No. 49A, 21 P.U.C. BULL. at 245.

[10] *Application of Houston Lighting & Power Company for a Change in Accounting Procedures and Approval of Certain Base Rate Credits*, Docket No. 18465 (June 25, 1998) (Docket No. 18465).

[11] *Id.*, Order on Rehearing, Findings of Fact Nos. 46, 48C, 53.

[12] PURA § 11.003(17).

annual report would result in a double counting of imputed revenues. Staff and Reliant agreed to an adjustment obtained by the following method:

1. Calculate return by multiplying invested capital by 9.844%;
2. Calculate return by multiplying invested capital by 9.95%; and
3. Subtract (1) from (2) and multiply the difference by 1.53846154.

The result, up to the amount shown in Schedule II, column (i), Revenue Imputation 36.007(d), would be entered in column (k), Adjustments Related to Implementation of SB7.[13]

The Commission concurs that without the proposed adjustment Reliant would be subjected to a double counting of imputed revenues. Accordingly, the Commission finds that the proposed adjustment is reasonable and that Reliant shall include an adjustment for imputed revenues as stipulated in its February 7, 2001 agreement.

CP&L

In Docket No. 14965,[14] CPL's last rate proceeding, the Commission approved a rate of return of 8.77% that reflects a blend of different returns on equity for different classes of capital: ECOM and non-ECOM.[15] Staff advocated using the 8.77% blended rate as approved in that docket. CPL argued that using the blended rate would treat it differently than every other utility in this proceeding. In addition, CPL asserted that the blended rate was a mechanism to reduce CPL's potentially stranded costs, but that this method conflicts with recent amendments of PURA that instituted a comprehensive mechanism to recover a utility's stranded costs. CPL's proposed remedy is to use the 9.13% rate found by the Commission in Docket No. 14965 to be a reasonable rate for non-ECOM capital.

The Commission agrees that the ECOM component of return should not be applied again in the calculation of annual cost for the annual report. One purpose of the annual report is to apply excess earnings to reduce stranded costs. Using the blended rate would result in the

---

[13] Stipulation Addressing a Revenue Imputation Issue in HL&P's Annual Report at 3 (Feb. 7, 2001).

[14] *Application of Central Power and Light Company for Authority to Change Rates,* Docket No. 14965, (March 31, 1997) (Docket No. 14965).

[15] *Id.*, Second Order on Rehearing, Finding of Fact Nos. 43-45, 113A-114.

416

inequitable treatment of CP&L in comparison to other utilities. Accordingly, the Commission concludes that the appropriate rate of return for purposes of its annual report is 9.13%, the rate determined to be reasonable for the non-ECOM portion of the company's invested capital in Docket No. 14965.

Entergy

In Docket No. 16705,[16] the Commission established rate of return at 9.76%.[17] In a subsequent rate proceeding, Docket No. 20150,[18] the Commission approved a stipulated rate of return of 9.67%.[19] Entergy used the higher 9.76% rate to calculate its cost in the annual report. Staff argued that Docket No. 20150 is the most recent case in which the Commission set Entergy's cost of capital and, therefore, the appropriate rate is 9.67%. Entergy contended that the rate of return approved in Docket No. 16705 is the appropriate rate in that it was the most recently *litigated* rate proceeding before the Commission. Entergy maintains that Docket No. 20150 should not be used because the settlement specified that it would have no precedential value.

The Commission rejects Entergy's argument. PURA § 39.258 requires that a utility use the cost of capital established by the Commission in the utility's "most recent rate proceeding before the commission" for purposes of the annual report.[20] The Commission finds that Docket No. 20150 is Entergy's most recent rate proceedings and, therefore, that the 9.67% cost of capital set in that docket must be used for purposes of calculating expenses in Entergy's annual report.

---

[16] ***Application of Entergy Texas for Approval of its Transition to Competition Plan and the Tariffs Implementing the Plan, and for the Authority to Reconcile Fuel Costs, to Set Revised Fuel Factors, and to Recover a Surcharge for Under-Recovered Fuel Costs***, Docket No. 16705 (Oct. 14, 1998) (Docket No. 16705).

[17] ***Id.***, Second Order on Rehearing, Finding of Fact No. 135.

[18] ***Application of Entergy Gulf States, Inc. for Authority to Change Rates***, Docket No. 20150 (June 30, 1999) (Docket No. 20150).

[19] ***Id.***, Final Order, Finding of Fact No. 48.

[20] PURA § 39.258(7).

417

B. State Income Taxes (TXU)

In calculating its annual costs, a utility is allowed an expense for "taxes and fees, including municipal franchise fees to the extent not included in Subdivision (1), other than federal income taxes, and assessments incurred that year."[21] TXU and Staff disagreed over the reach of the phrase "incurred that year." Staff contended that state income tax (SIT) expenses are limited to those amounts actually incurred by TXU during the reporting year. TXU maintained that SIT should respond to revenue adjustments for the reporting year. Specifically, TXU referred to a disallowance of fuel expenses in the amount of $52 million[22] that would result in higher net income for the year and, therefore, higher SIT expense. Because the fuel expense was a disallowed cost, TXU argued that the tax benefit of that expense should have been removed as well. Adjustments to revenue would affect the tax actually paid, and thus an accurate representation of the related tax cost should take into account such adjustments.

The Commission concludes that the phrase "incurred in that year" is not limited to amounts actually paid but encompasses amounts that accrue in that year. Accordingly, TXU may adjust the SIT expense to reflect known changes to revenue in its annual report.

C. Sandow Unit 4 (TXU)

TXU's Sandow Unit 4 is operated by the utility solely for Alcoa and is not used to provide electric service to ratepayers. Staff argued that historically, non-regulated revenues and expenses were not included in the calculation of a utility's annual earnings. For this reason, the unit has been excluded from the Commission's previous analyses of TXU's revenue requirements. TXU maintained that PURA § 39.257 does not require the removal of non-regulated costs when calculating a utility's annual report. As a result, it argues that previously non-regulated revenues and expenses may now be included.

---

[21] *See Id.* § 39.258(5).

[22] *See Application of TXU Electric Company for the Reconciliation of Fuel Costs*, Docket No. 20285, Finding of Fact No. 12 (Aug. 6, 1999).

418

The Commission rejects TXU's suggested interpretation of the statute. The Sandow unit is not included in TXU's invested capital because, from a regulatory standpoint, it is not used and useful to the public.[23] Accordingly, the Commission concludes that the Alcoa-dedicated Sandow unit shall be excluded from TXU's annual report.

D. Federal Income Taxes

A utility is allowed to include in its annual costs a "federal tax expense, computed according to the stand-alone methodology and using the actual capital structure and actual cost of debt as of December 31 of the report year."[24] This provision makes no explicit reference to a specific rate of return. In contrast, the expense for return on invested capital that is calculated using the invested capital as of December 31 of the report year times the cost of capital approved in the utilities last rate proceeding.[25]

The utilities in this docket used the same rate of return to calculate both the federal income tax (FIT) expense and the return expense. Consequently, the rate of return utilities used for FIT is inconsistent with the capital structure and cost of debt that PURA says must be used in calculating FIT expenses.

Staff argued that an updated rate of return should be used for the calculation of FIT expense that would be consistent with the required update of capital structure and cost of debt. Staff noted that an updated return would differ from the rate of return required in calculating the return expense. The FIT expenses calculated under these two approaches would differ to the degree that the utility refinanced its debt since the last time the Commission determined the utility's cost of capital. Staff's approach would result in the calculation of a lower amount of taxable income and, therefore, a lower FIT expense.

---

[23] *See* PURA § 36.051.

[24] *Id.* § 39.258(6).

[25] *See Id.* § 39.258(7).

On February 7, 2001, Staff, CPL, TXU, Reliant, Entergy and TNMP agreed to a compromise in the approach taken to FIT expense calculation. Under that agreement, the amount of FIT expense will be the average of the amount calculated under both proposed methods.[26] The agreement commits these utilities to use this method in future annual reports.

The Commission finds that the rate of return and its component parts—return on equity, cost of debt, and capital structure—are treated inconsistently in PURA § 39.258(6) and (7). The Commission concludes that this statutory ambiguity prevents either of the competing positions from dominating the other. Accordingly, the Commission finds that the agreement between Staff and the utilities regarding the calculation of FIT expenses in the utilities' annual reports under PURA § 39.258 is reasonable. The Commission further finds that the return on equity set in the agreement for Reliant and Entergy are reasonable. CPL, TXU, Reliant, Entergy, and TNMP shall calculate FIT expense for purposes of the annual report as provided in the February 7, 2000 agreement.

E. Capital Additions

Defining the Term "Capital Additions to a Plant"

PURA provides that "capital additions to a plant in an amount less than [1.5%] of the electric utility's net plant in service ... are presumed prudent."[27] OPC maintained that, because PURA § 39.257 contains no language specifically excluding transmission and distribution (T&D) plant, the 1.5% threshold pertains to the total capital expenditures for transmission, distribution, and generation collectively.[28]

Utilities maintained that the 1.5% pertains only to generation plant and that disallowing T&D investment would penalize utilities that added transmission capacity. Staff agreed with the utilities' position and noted that including non-generation plant under the 1.5% threshold would have resulted in significant disallowances for expenses.

---

[26] Stipulation Among the Parties Affected by the Federal Income Tax Issue at 2-3.

[27] PURA § 39.259(b).

[28] Office of the Public Utility Counsel's Reply Brief on Contested Issues at 1 and 6.

420

The Commission finds that, in enacting this presumption, the Legislature intended to limit the recovery of new additions to generation plant through annual costs in the annual report to those amounts necessary to preserve the normal usefulness of existing generation plant during the freeze period. Including T&D within the presumption would limit the amount of investment for generation-plant upkeep, and would also limit the capital expenditures needed to adequately prepare T&Ds for deregulation. In addition, the prudence of capital expenditures relating to T&D plant will be addressed separately in the transmission cost of service (TCOS) proceedings.

Cap versus Safe Harbor

Another disputed issue relating to capital additions concerns whether or not the 1.5% threshold should be treated as a cap. In order to make this determination, the Commission must again examine the language provided in PURA § 39.259(b). According to SPS, the statute simply eliminates the need to conduct a prudency hearing for expenditures falling below the threshold.[29] In the event that a utility exceeds the 1.5% limitation, the utility bears the burden of providing evidence that its expenditures above this amount were prudent.[30] For this reason, SPS maintains that a prudency determination is a contested matter and therefore, a utility is entitled to an evidentiary hearing in order to rebut the presumption. The alternate interpretation, as argued by Staff, excludes any capital addition that exceeds 1.5% of the utility's total net invested capital.[31]

Again, during the rate freeze, the 1.5% threshold is intended to permit utilities a limited recovery of expenses needed to undertake routine maintenance and upkeep of generation plant without the need for Commission approval. Utilities will be allowed to recover any stranded costs of generation plant through other mechanisms. The market value of generation plant will to be recovered through market prices. Accordingly, the Commission concludes that the 1.5% threshold in PURA § 39.259(b) was intended to be a cap, therefore additions in generation plant in excess of the cap cannot be recovered through the annual report.

---

[29] SPS Reply Brief at 2.

[30] SPS Reply Brief at 2-3.

[31] Commission Staff's Brief at 2.

421

The Commission notes that the determinations made in this proceeding relating to invested capital are applicable only to the annual report. Inclusion of any capital additions used for the purpose of calculating the annual report will not be dispositive of a prudence determination made in a subsequent rate case. Consequently, a utility that has exceeded the capital additions threshold is not entitled to an evidentiary hearing to show that those expenditures were prudent.

In summary, the presumption of prudence given by PURA § 39.259(b) to capital additions to a plant in an amount less than 1.5 % of the electric utility's net plant in service on December 31, 1998, less plant items previously excluded by the Commission, for each of the years 1999 through 2001 (1) applies only to generation plant and does not apply to capital additions made to transmission and distribution facilities, and (2) constitutes an upper limit on capital additions to generation, as there is no provision in PURA for any further findings of prudence pursuant to the annual report. A utility may update its net plant in service to reflect changes in invested capital for transmission and distribution, subject to review in future rate and cost of service proceedings.

F. <u>Revenue Imputation by SPS</u>

The annual report for 1999 submitted by SPS showed unadjusted imputed revenues of $4,392,157. SPS also claimed a system benefit adjustment of $14,464,213, resulting in a negative imputation of $10,072,055. Staff maintained that SPS' system benefit adjustment was unreasonable and contrary to PURA § 36.007(d).

Imputed revenues, which are used to account for discounted rates, may be adjusted if the discount results in overall system benefits. It is incumbent on the utility, however, to demonstrate such benefits and to prove that its discounted rates do not burden other ratepayers. PURA specifies that allocable costs not recovered by the discounted rates must not be borne by other ratepayers.[32] In neither its annual report nor in the accompanying work papers did SPS justify any claim of system benefit.

The Commission finds that SPS has failed to meet its burden and, accordingly, that the system benefit adjustment claimed by SPS is not justified. The proper net revenue imputation on Schedule II-A of SPS' 1999 annual report is $4,392,157.

III. Ordering Paragraphs

In accordance with PURA § 39.261(c), this Order serves to resolve the above-stated disagreements related to the 1999 annual report consistent with the requirements of PURA § 39.258.

1. This Order adopts and finalizes the annual reports for the 1999 calendar year as filed by the utilities, subject to the adjustments and findings discussed herein.

2. All utilities shall update their 1999 annual reports in accordance with the findings in this Order. Updated reports shall be filed with the Commission under Docket No. 22276 no later than February 28, 2001.

3. All other motions, requests for specific findings of fact or conclusions of law, and any other requests for general or specific relief, if not expressly granted herein, are hereby denied for want of merit.

[32] *See* PURA § 36.007(d).

SIGNED AT AUSTIN, TEXAS the 23rd day of February 2001.

PUBLIC UTILITY COMMISSION OF TEXAS

PAT WOOD, III, CHAIRMAN

JUDY WALSH, COMMISSIONER

BRETT A. PERLMAN, COMMISSIONER

Q:\opd\ORDERS\FINAL\22000\22276FO.DOC

P.U.C. DOCKET NO. 23806

2000 ELECTRIC UTILITIES ANNUAL REPORT PURSUANT TO PURA § 39.257	**§ § §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER

This Order addresses the annual reports for the 2000 calendar year filed by Texas-New Mexico Power Company (TNMP), TXU SESCO Company (TXU SESCO), Entergy Gulf States, Inc. (Entergy), Sharyland Utilities (Sharyland), and Reliant Energy HL&P (Reliant). This order finalizes the 2000 Annual Reports as filed by the following utilities:

1. TNMP as filed on March 29, 2001
2. TXU SESCO as filed on March 30, 2001
3. Entergy as filed on May 9, 2001
4. Sharyland as filed on August 1, 2001
5. Reliant as filed on July 30, 2001

PURA § 39.257 requires electric utilities to file annual reports with the Commission in order to identify differences between adjusted annual revenues and annual costs.[1] For a utility with stranded costs, any positive differences identified in the report must be applied against the net book value of generation assets.[2] Utilities without stranded costs must use any excess earnings to improve transmission and distribution facilities, add pollution control equipment, or return the excess to ratepayers.[3]

[1] Public Utility Regulatory Act, Tex. Util. Code Ann. §§ 11.001-64.158 (Vernon 1998 & Supp. 2001) (PURA).

[2] *See Id.* § 39.254.

[3] *See Id.* § 39.255.

146

425

In accordance with PURA § 39.261, Staff and the OPC are charged with reviewing the annual reports and bringing any disagreements with the reports to the Commission not later than 180 days after the annual reports are filed.[4] The Commission is required to resolve any disagreements with and finalize the annual reports and to reflect the results in the setting of a competition transition charge and in the 2004 true-up proceeding.[5]

Annual reports for the 2000 calendar year were filed by Texas-New Mexico Power Company (TNMP), Reliant Energy HL&P (Reliant), TXU, WTU, SWEPCO, and CPL on March 30, 2001. On April 2, 2001, Southwestern Public Service Company (SPS) and Entergy Gulf States, Inc. (Entergy) filed their 2000 Annual Reports. On June 21, 2001, Staff filed an explanatory memorandum and proposed schedule for processing the 2000 Annual Reports. At its June 28, 2001 open meeting, the Commission approved Staff's proposed schedule for processing the 2000 Annual Reports. On July 23, 2001, Staff filed a letter advising the Commission that the parties had reached unanimous agreement to extend the existing deadlines in this case by one week. In addition, Staff, SPS, and OPC agreed that it was not necessary to complete the evaluation of the annual report issues for SPS under the same procedural schedule due to the amendment of PURA §§ 39.401-410, which delayed competition in SPS' service territory until at least 2007. Staff and OPC were to notify the utilities of any unresolved disagreements by July 31, 2001. On August 9, 2001 and August 16, 2001, the initial and reply briefs were due, respectively.

Staff and OPC filed their preliminary list of disagreements on July 6, 2001. Staff met informally with each of these utilities to resolve the disputed issues. Subsequently, on July 31, 2001, Staff and OPC filed lists identifying disagreements with TXU, CPL, SWEPCO, WTU and Sharyland. Reliant filed a revised Annual Report on July 30, 2001. Sharyland filed a revised Annual Report on August 1, 2001. Initial and reply briefs were filed on August 9, 2001 and

[4] *Id.* § 39.261(a), (b).

[5] *Id.* § 39.261(c).

August 16, 2001, respectively, by Staff, OPC, TXU, and the AEP companies. The Commission finalized the annual reports of those utilities in a previous order.[6]

No parties filed initial or reply briefs regarding the 2000 Annual Reports of TNMP, TXU SESCO, Entergy, Sharyland, or Reliant nor has Staff or OPC filed any disagreements with the annual reports. Furthermore, on September 14, 2001, Staff filed a memorandum advising the Commission that Staff had reviewed the 2000 Annual Reports, as filed by the above-mentioned utilities, and had no objections.

In accordance with PURA § 39.261(c), through this Order, the Commission finalizes the 2000 Annual Reports of TNMP, TXU SESCO, Entergy, Sharyland, and Reliant, consistent with the requirements of PURA § 39.258.

[6] *2000 Electric Utilities Annual Report Pursuant to PURA § 39.257*, Docket No. 23806 (Sept. 3, 2001).

SIGNED AT AUSTIN, TEXAS the 24th day of September 2001.

PUBLIC UTILITY COMMISSION OF TEXAS

MAX YZAGUIRRE, CHAIRMAN

BRETT A. PERLMAN, COMMISSIONER

REBECCA KLEIN, COMMISSIONER

Q:\opd\ORDERS\FINAL\23000\23806FO_remaining.doc

428

P.U.C. PROJECT NO. 25593

2001 ELECTRIC UTILITIES ANNUAL REPORT PURSUANT TO PURA § 39.257	**§ §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER

This Order addresses the annual reports for the 2001 calendar year filed pursuant to PURA[1] § 39.257 by Texas-New Mexico Power Company (TNMP); Central Power and Light Company (CPL), Southwestern Electric Power Company (SWEPCO), and West Texas Utilities Company (WTU) (collectively, AEP Companies); Entergy Gulf States, Inc. (Entergy); Sharyland Utilities, L.P. (Sharyland); Reliant Energy HL&P (Reliant); and TXU SESCO Company (TXU SESCO). In this Order, the Commission finalizes the uncontested annual reports of TNMP, Entergy, Sharyland, Reliant, and TXU SESCO pursuant to PURA § 39.261. It also addresses Commission Staff's (Staff) disagreement with the annual reports of the AEP Companies,[2] resolves the disagreement, and finalizes the reports as discussed herein. Additionally, it orders the AEP Companies to recalculate their annual revenues and expenses to determine their excess earnings in conformance with this Order and to file in this docket revised reports reflecting such recalculation.

I. Background

PURA § 39.257 requires electric utilities to file annual reports with the Commission in order to identify differences between adjusted annual revenues and annual costs. For a utility with stranded costs, any positive differences identified in the report must be applied against the net book value of generation assets.[3] Utilities without stranded costs must use any excess earnings to improve transmission and distribution facilities, add pollution control equipment, or return the excess to ratepayers.[4]

[1] Public Utility Regulatory Act, Tex. Util. Code Ann. §§ 11.001-64.158 (Vernon 1998 & Supp. 2003) (PURA).

[2] Staff argues that the AEP Companies' adjustments to accumulated deferred federal income taxes (ADFIT) related to deferred fuel balances are inconsistent with PURA § 39.259.

[3] *See Id.* § 39.254.

[4] *See Id.* § 39.255.

54

429

Pursuant to PURA § 39.261, Staff and the Office of Public Utility Counsel (OPC) are each charged with reviewing the annual reports and communicating to an electric utility in writing, not later than the 180th day after the date the report is filed, any disagreements it has with a report.[5] The Commission is required to resolve any disagreements with and finalize the annual reports and to reflect the results in the setting of a competition transition charge and in the 2004 true-up proceeding.[6]

Annual reports for the 2001 calendar year were filed by TNMP and the AEP Companies on March 28, 2002; by Entergy on March 29, 2002; and by Sharyland, Reliant, and TXU SESCO on April 1, 2002.[7] On July 8, 2002, Staff filed an explanatory memorandum and a proposed schedule for processing the 2001 Annual Reports, which was approved as modified per discussion by the Commission at its July 8, 2002 open meeting. On August 12, 2002, Staff and OPC each filed a preliminary list of disagreements with the annual reports, and on September 30, 2002, Staff filed a finalized list of disagreements, noting only one disagreement, which dealt with the reports of the AEP Companies. OPC did not file a finalized list of disagreements. On October 14, 2002, Staff and AEP filed a joint motion regarding the filing of briefs in the disagreement with the reports of the AEP Companies, noting that the disputed issue is identical to one that Staff disputed last year in the AEP Companies' annual reports for the 2000 calendar year and requesting that no new briefing be done on the issue.

The Commission considered Staff's lone issue of disagreement with the annual reports of the AEP Companies at its November 7, 2002 open meeting and again at its November 21, 2002 open meeting, where it reaffirmed and approved the decision it made last year in Project No.

---

[5] *Id.* § 39.261(a), (b).

[6] *Id.* § 39.261(c).

[7] Oncor Electric Delivery Company is not required to file an annual report pursuant to PURA § 39.257 for the 2001 calendar year because of the settlement approved by the Commission in Docket No. 25230. *See Joint Application for Approval of Application Regarding TXU Electric Company Transition to Competition Issues*, Docket No. 25230, Order (Jun. 20, 2002). Also, Southwestern Public Service Company is not required to file an annual report for the 2001 calendar year because of the Commission's order in its review of Southwestern Public Service Company's annual report for the 2000 calendar year. *See 2001 Electric Utilities' Annual Report Pursuant to PURA § 39.257*, Project No. 23806, Order (Jan. 15, 2002).

23806 with regard to the identical issue of disagreement by Staff with the annual reports of the AEP Companies.[8]

II. Commission Decision Regarding ADIT

Staff argued that the AEP Companies inappropriately removed Accumulated Deferred Income Taxes (ADIT) related to fuel under-recoveries from their rate base in the 2001 Annual Reports. Staff maintained that these adjustments are inconsistent with 1) Commission precedent in prior rate cases; 2) Commission precedent in previous earnings monitoring proceedings; 3) Commission rulings on the 1999 Annual Reports; 4) the Commission's fuel rules; and 5) PURA §§ 39.257-259. AEP argued that fuel-related ADITs and the regulatory assets are offsetting balances that arise from the same source and should therefore be treated consistently. In addition, AEP argued that the treatment of ADITs and their related fuel balances was based on the treatment of CPL's last rate case, Docket No. 14965. The Commission agrees with Staff and, as decided last year in finalizing the year 2000 annual reports, finds that fuel related ADITs are appropriately accounted for in the Annual Report.

III. Ordering Paragraphs

In accordance with PURA § 39.261(c) and consistent with the requirements of PURA § 39.258, the Commission finalizes the following annual reports for the 2001 calendar year filed pursuant to PURA § 39.257.

1. The uncontested annual reports for Texas-New Mexico Power Company; Entergy Gulf States, Inc.; Sharyland Utilities, L.P.; Reliant Energy HL&P; and TXU SESCO Company are finalized.

[8] *See 2001 Electric Utilities' Annual Report Pursuant to PURA § 39.257*, Project No. 23806, Order (Jan. 15, 2002).

2. The disagreement with the annual reports for Central Power and Light Company, Southwestern Electric Power Company, and West Texas Utilities Company is resolved, and these annual reports are finalized, subject to the adjustments and findings discussed herein.

3. Central Power and Light Company, Southwestern Electric Power Company, and West Texas Utilities Company shall recalculate their annual revenues and expenses to determine their excess earnings in conformance with this Order. Updated reports shall be filed with the Commission under Project No. 25593 no later than December 30, 2002.

4. All other motions, requests for specific findings of fact or conclusions of law, and any other requests for general or specific relief, if not expressly granted herein, are hereby denied for want of merit.

SIGNED AT AUSTIN, TEXAS the 19th day of December 2002.

PUBLIC UTILITY COMMISSION OF TEXAS

REBECCA KLEIN, CHAIRMAN

BRETT A. PERLMAN, COMMISSIONER

JULIE CARUTHERS PARSLEY, COMMISSIONER

Q:\PD\ORDERS\FINAL\25000\25593FO.doc

Entergy Gulf States, Inc.
Percentage of ESI Payroll Billed to EGSI

	Dkt. 20150 12 ME 6/30/1998	CY 1998	CY 1999	CY 2000	CY 2001	CY 2002	CY 2003	CY 2004	6 ME 6/30/2005
(Source of Data)	Cities 3-5	Cities 3-2	Cities 2-2	Cities 2-6	Cities 2-10	Cities 2-14	Cities 2-18	Cities 2-22	Cities 2-26
Total ESI Payroll									
O&M	166,527,781	188,462,118	193,251,305	158,854,139	166,781,626	199,280,223	222,862,912	199,923,266	119,956,630
Capital	17,798,063	21,641,257	25,636,488	23,442,025	32,383,863	40,508,414	51,220,292	41,742,407	23,943,689
Other	18,856,459	9,306,365	9,451,473	24,140,538	28,365,046	32,303,688	39,976,852	36,589,248	18,367,999
Total	203,182,303	219,409,740	228,339,266	206,436,702	227,530,535	272,092,325	314,060,056	278,254,921	162,268,318
Total ESI Payroll to EGSI Electric									
O&M	38,254,124	46,195,999	50,431,963	44,259,101	44,529,359	49,574,606	54,619,660	48,707,414	29,456,039
Capital	4,348,359	5,668,604	6,242,466	6,678,440	9,723,317	10,702,903	13,573,597	11,461,954	6,434,736
Other	1,873,221	1,778,456	2,402,882	1,233,434	2,805,640	3,107,670	3,593,236	4,653,104	1,787,650
Total	44,475,704	53,643,059	59,077,311	52,170,975	57,058,316	63,385,179	71,786,493	64,822,472	37,678,425
Percentage Billed to EGSI	21.9%	24.4%	25.9%	25.3%	25.1%	23.3%	22.9%	23.3%	23.2%

Entergy Gulf States, Inc.
Calculation of AFUDC
Staff witness Adrianne G. Brandt

Staff Disallowances:

Billing Expert	1,531,811
Load Forecasting	181,399
Trading and Risk Management	1,328,033
Total Disallowance	3,041,243

	AFUDC Rate	
December 2004	8.362%	21,192
January 2005	8.505%	21,555
February 2005	8.505%	21,555
March 2005	8.505%	21,555
April 2005	8.505%	21,555
May 2005	8.505%	21,555
June 2005	8.505%	22,469
July 2005	8.505%	22,469
August 2005	8.505%	22,469
September 2005	8.505%	22,469
October 2005	8.505%	22,469
November 2005	8.505%	22,469
December 2005	8.505%	23,424
January 2006	8.505%	23,424
February 2006	8.505%	23,424
Total		334,053

SOAH DOCKET NO. 473-06-0092
PUC DOCKET NO. 31544

APPLICATION OF ENTERGY	§	PUBLIC UTILITY COMMISSION
GULF STATES, INC. FOR	§	
RECOVERY OF TRANSITION	§	
TO COMPETITION COSTS	§	OF TEXAS

REBUTTAL TESTIMONY

OF

MYRA L. TALKINGTON

ON BEHALF OF

ENTERGY GULF STATES, INC.

FEBRUARY 10, 2006

SOAH DOCKET NO. 473-06-0092

PUC DOCKET NO. 31544

APPLICATION OF
ENTERGY GULF STATES, INC.
FOR RECOVERY OF
TRANSITION TO COMPETITION COSTS

REBUTTAL TESTIMONY OF MYRA L. TALKINGTON

TABLE OF CONTENTS

I. WITNESS INTRODUCTION AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Myra L. Talkington. My business address is Entergy Services, Inc., 425 West Capitol Avenue, Little Rock, Arkansas 72201.

Q. ARE YOU THE SAME MYRA L. TALKINGTON WHO FILED DIRECT TESTIMONY IN THIS DOCKET ON AUGUST 24, 2005?

A. Yes. For both my direct and rebuttal testimony, I am testifying on behalf of Entergy Gulf States, Inc. ("EGSI" or the "Company").

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I respond to the following issues raised by various Intervenor witnesses:

1. In the Company's filing, the allocation of transition costs to rate classes is based in part on the energy usage (kWh) as measured at the meter, without an adjustment for line losses between the source (that is, the generating site or point of delivery) and the meter. Texas Industrial Energy Consumers ("TIEC") witness Jeffry Pollock states that the energy portion of the allocation factor should be adjusted for line losses. In my rebuttal testimony, I agree with Mr. Pollock's assessment.

2. TIEC witness Pollock recommends the use of a cost-causation approach to allocate transition costs to customer classes. In Exhibit JP-8, Mr. Pollock has identified certain costs he believes should be allocated to customer classes based on a Production Demand, Energy, Customer, Base Revenue or Other allocation factors. However, in JP-9, Mr. Pollock has erroneously used the Base Revenue allocation factor for the costs he deems to be Customer-related. In my rebuttal testimony, I quantify the amount of this error.

3. As I explained in my Direct Testimony, the discount provided under the Rider for Institutes of Higher Education ("Rider IHE")

does not apply to Rider TTC. State witness Kelso King, however, argues that the Rider IHE discount should apply to Rider TTC. In my rebuttal testimony, I explain that the Commission should reject Mr. King's argument.

Q. DO YOU SPONSOR ANY REBUTTAL EXHIBITS?

A. Yes. My rebuttal exhibit is listed in the table of contents to this testimony.

II. MEASURING ENERGY USAGE AT THE METER AND LINE LOSSES

Q. WHAT TOPIC DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. I respond to Mr. Pollock regarding the development of the energy allocation factor. Mr. Pollock states that energy usage for each rate class should be adjusted for line losses.[1]

Q. WHAT ARE LINE LOSSES?

A. As energy is transmitted over the transmission and distribution grid from the power plant (for generated power) or from the point of delivery (for purchased power) to the customers' meters, energy loss occurs due to electrical resistance in the wires. Thus, the amount of energy delivered at the meters will be slightly less than the energy placed onto the grid at the power plants and points of delivery. These energy losses are referred to as line losses.

[1] Direct Testimony of Jeffry Pollock at page 57, line 12 through page 58, line 7.

Q. HOW DID EGSI ACCOUNT FOR LINE LOSSES IN THE DEVELOPMENT OF THE ENERGY ALLOCATION FACTOR?

A. Company witness Phillip R. May recommended the use of 50 percent fixed production (Average and Excess / Four Coincident Peaks ("A&E 4CP")) and 50 percent variable production (energy) to allocate transition costs among the rate classes in Rider TTC. Based on that recommendation, I correctly developed the A&E 4CP as described in my direct testimony. However, for the energy portion of the 50/50 split, I failed to apply loss factors to the annual energy consumption.

Q. DO YOU AGREE WITH MR. POLLOCK'S POSITION THAT THE BILLING DETERMINANTS BASED UPON ENERGY USAGE SHOULD BE ADJUSTED FOR LINE LOSSES?

A. Yes, Mr. Pollock correctly calculated the energy portion of the allocation factors as shown on Exhibit JP-6.

III.
INCORRECT USE OF ALLOCATION FACTOR BY TIEC WITNESS POLLOCK

Q. WHAT IS THE PURPOSE OF THIS PORTION OF YOUR TESTIMONY?

A. In this portion of my testimony, I point out that Mr. Pollock seemingly applied the incorrect allocation factor to certain costs he deems to be Customer-related.

Q. PLEASE EXPLAIN.

A. In Exhibit JP-8, Mr. Pollock has identified certain costs he believes should be allocated to customer classes based on a Production Demand, Energy, Customer, Base Revenue or Other allocation factor. However, in JP-9, Mr. Pollock has allocated costs he deems to be Customer-related based on the allocation factors he developed using Base Revenues.

Q. ARE YOU ADDRESSING THE MERITS OF MR. POLLOCK'S ALLOCATION METHODOLOGY?

A. No. I am not commenting on the methodology that Mr. Pollock proposes. Company witness May discusses the Company's position on allocation methodology. I am commenting only on the calculation of the allocation of costs. However, if the Commission were to accept Mr. Pollock's methodologies, this correction would need to be taken into consideration.

Q. WHAT IS THE RESULT OF CORRECTING MR. POLLOCK'S CALCULATION ERROR?

A. Exhibit MLT-R-1 quantifies the result of correcting Mr. Pollock's error. This exhibit shows the Customer-related costs allocated to the respective customers classes using the "No. of Customer" allocation factors rather than the "Base Revenue" allocation factors.

IV. THE DISCOUNT UNDER RIDER IHE DOES NOT APPLY TO RIDER TTC

Q. WHAT ISSUE DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. I explain that the Commission should reject Mr. King's position that the 20% discount under Rider IHE applies to Rider TTC.[2] As I will explain, the discount under Rider IHE applies only to base rates. Rider TTC is not a base rate. Therefore, the discount does not apply to Rider TTC.

Q. WHAT IS RIDER IHE?

A. Under Public Utility Regulatory Act ("PURA") § 36.351, an electric utility such as EGSI must provide State institutions of higher education with "a 20-percent reduction of the utility's base rates that would otherwise be paid under the applicable tariffed rate." This 20-percent reduction is referred to as the IHE discount.

Q. WHAT IS THE BASIS FOR MR. KING'S POSITION THAT THE IHE DISCOUNT APPLIES TO RIDER TTC?

A. Mr. King states that the costs to be recovered under Rider TTC are part of base rates. He also refers to the Proposals For Decision ("PFDs") in Docket Nos. 22350 and 22355 in which the Administrative Law Judges recommended that the discount under Rider IHE applies to the

[2] Direct Testimony of Kelso King at page 3, lines 18 -20; and page 24, line 1 through page 26, line 11.

Competition Transition Charge ("CTC"), which was a rate separate from the Transmission & Distribution base rates determined in the unbundled cost of service cases, designed to allow the utility to recover its estimated stranded costs. He refers to those PFDs because the settlement in EGSI's unbundled cost of service ("UCOS") case, Docket No. 22356, relies upon Docket Nos. 22350 and 22355 to determine whether the IHE discount applies to the CTC.

Q. DID THE COMMISSION ADOPT EITHER OF THESE PFDS?

A. No. As Mr. King acknowledges in his testimony, the Commission did not adopt the portions of the PFDs that he quotes from and, indeed, the Commission stated that it was not ruling on whether Rider IHE applied to the CTC.

Q. HAS THE COMMISSION ISSUED A FINAL ORDER IN EGSI'S UCOS CASE, DOCKET NO. 22356?

A. No. The Commission has never issued a final order in that docket.

Q. IN YOUR DIRECT TESTIMONY, YOU INDICATED THAT THE COMMISSION HAS DEFINED THE TERM "BASE RATE."[3] DOES MR. KING REFER TO OR DISCUSS THE COMMISSION'S DEFINITION OF A BASE RATE?

A. No. He does not address the Commission's definition of a base rate.

Q. WHAT IS THE COMMISSION'S DEFINITION OF A BASE RATE?

A. The Commission's substantive rules states that, generally, a base rate is a rate designed to recover the cost of service other than costs separately identified and recovered through a rider or other schedule.

> **Base rate** — Generally, a rate designed to recover the cost of service other than certain costs separately identified and recovered through a rider, rate schedule, or other schedule. For bundled utilities, these separately identified costs may include items such as a fuel factor, power cost recovery factor, and surcharge. Distribution service providers may have separately identified costs such as the system benefit fee, transition costs, the excess mitigation charge, transmission cost recovery factors, and the competition transition charge.[4]

This definition of a base rate refers to a rate designed to recover the "cost of service." The Commission also has a rule that describes the components of the cost of service (P.U.C. SUBST. R. 25.231). Under that Commission rule, the cost of service refers to the costs that are determined based upon a full review of an electric utility's expenses, rate base, and rate of return.

> **Components of cost of service.** Except as provided for in subsection (c)(2) of this section, relating to invested capital; rate base, and §23.23(b) of this title, (relating to Rate Design), rates are to be based upon an electric utility's cost of rendering service to the public during a historical test year, adjusted for known and

[3] Direct Testimony of Myra L. Talkington at page 6, line 2.

[4] P.U.C. SUBST. R. 25.5(10).

measurable changes. The two components of cost of service are allowable expenses and return on invested capital.[5]

Q. BASED UPON THE COMMISSION'S DEFINITION OF A BASE RATE, DO YOU AGREE WITH MR. KING THAT RIDER TTC CONTAINS BASE RATE COSTS?

A. No. In contrast to a full review of EGSI's cost of service, this current TTC docket is not conducting a full review of EGSI's expenses, rate base, and rate of return during a test year for the purpose of establishing an on-going cost of service to recover recurring costs.

Moreover, according to PURA § 39.454, the TTC costs under review in this docket are designed and intended to be recovered through a rider and not a base rate case. For this additional reason, the TTC costs and Rider TTC do not fall within the Commission's definition of a "base rate."

Thus, the Commission is not establishing a base rate in Rider TTC.

Q. SHOULD THE IHE DISCOUNT APPLY TO RIDER TTC?

A. No. For the reasons I have discussed, Rider IHE does not apply to Rider TTC.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, at this time.

---

[5] P.U.C. SUBST. R. 25.231(a).

ENTERGY GULF STATES, INC.
Quantification of Error on Exhibit JP-9

Total "Customer-Related" Costs (1) $ 71,721,567

	Allocation per Exhibit JP-9		Corrected Allocation		Difference
	Base Revenue Allocation Factors (2)	Allocation of Costs	No. of Customers Allocation Factors (3)	Allocation of Costs	
Residential Service	49.4222%	$ 35,446,403	87.8270%	$ 62,990,901	$ 27,544,498
Small General Service	3.7272%	$ 2,673,218	7.1256%	$ 5,110,592	$ 2,437,374
General Service	21.1861%	$ 15,194,997	4.5631%	$ 3,272,727	$ (11,922,270)
Large General Service	6.6027%	$ 4,735,592	0.0798%	$ 57,234	$ (4,678,358)
Large Industrial Power Service	17.1434%	$ 12,295,511	0.0162%	$ 11,619	$ (12,283,892)
Interruptible Service	0.5136%	$ 368,368	0.0027%	$ 1,936	$ (366,432)
Street and Outdoor Lighting	1.4047%	$ 1,007,476	0.3856%	$ 276,558	$ (730,918)
Total	100.0000%	$ 71,721,567	100.0000%	$ 71,721,567	

Sources:
(1) Exhibit JP-8, Page 2 of 2, Line 40, Column (5)
(2) Exhibit JP-10, Column (4)
(3) Exhibit JP-10, Column (5)