account other factors in determining the level of collection to adequately fund for the decommissioning costs.

As Mr. Kiser also pointed out, decommissioning funds will be placed in a trust fund external to TCC and used in the public interest to safely retire the plant and dispose of hazardous materials. As a result, it is best to employ a cautious approach when establishing the level of decommissioning expense. Underfunding should be of greater concern to the Commission than overfunding of decommissioning expense. Any funds remaining in the trust at the conclusion of the decommissioning process will be returned to customers in a manner to be determined by the Commission. None of the trust funds will ever inure to the benefit of TCC.[369]

For the above reasons, the Commission should reverse the ALJs and allow collection of $8.16 million for decommissioning funding.

R. Third Party Contract Margin Sharing Proposal

Exception No. 22

> The ALJs erred in proposing findings of fact and a conclusion of law that all revenues TCC received from providing "other services" should be credited to its cost of service when all net profits (which is the amount the ALJs recommended) should be credited in this case. (FOF 208, 209; COL 41)

Two proposed findings of fact and a conclusion of law should be changed to rectify an internal inconsistency between the PFD's interpretation of the "other services" rule in P.U.C. SUBST. R. 25.342(f)(l)(D)(ii)(III) and the PFD's recommendation concerning the treatment of revenues TCC received in providing transmission-related construction services for other utilities. TCC's test year profits (margins) from these services were $2.7 million. This is the amount that the PFD recommends be credited to TCC's cost of service.[370] Under the "other services" rule, this is the correct amount to credit to TCC's cost of service if TCC's request to share these margins 50/50 with customers is rejected, as the PFD recommends.

Despite recommending a cost of service credit equal to all of the test year margins, the PFD otherwise maintains that all revenues, and not net revenues, should be credited to the cost of

[369] TCC Exh. 86, Rebuttal Testimony of Steven Kiser, at 1, line 4 through 6, line 7.

[370] PFD at 120, proposed FoF 209.

service calculation under the "other services" rule.[371] The reason it would not be proper to credit all revenues from these services in the particular circumstances of this case is that the costs incurred and revenues received concerning these services were not recorded in TCC's cost of service.[372] For example, any labor cost associated with performing these services is tracked separately but is not included in TCC's cost of service.[373] If all revenues were to be credited to the cost of service, then all costs incurred to generate those revenues should also be included in the cost of service. TCC emphasizes, however, that crediting the cost of service with profits or margins produces the same effect as if both total revenues and costs from these services were used to establish rates. In this connection, no party recommended that total revenues be used as a cost of service credit. All the recommendations centered on the appropriate level of margins that should be credited.

Accordingly, the word "revenues" in the second sentence of Finding of Fact 208 and the word "revenue" in Finding of Fact 209 should be replaced with "margins." The following sentence should be added to proposed Conclusion of Law 42: "If, however, the costs and revenues of providing the other service are not included in the calculation of rates, then the test year margins (revenues minus costs) received from the service should be credited to the cost of service calculation."

S. Rate Case Expenses

No exceptions filed.

T. Miscellaneous Issues

No exceptions filed.

VII. Quality and Reliability of Service

A. Quality of Service

1. Dr. Goodfriend's Testimony

No exceptions filed.

2. Other Quality of Service Evidence

No exceptions filed.

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[371] PFD at 120. Proposed FoF 208 and 209 and CoL 42 reflect this position.

[372] Tr. 5 at 863, lines 6-23.

[373] Tr. 5 at 824, lines 17-23.

B. Reliability of Service

Exception No. 23

> The ALJs erred by adopting reliability penalties for the years 2001, 2002, and 2003 in the amounts of \$1,081,860, \$1,095,920, and \$1,093,570, respectively.

The issue of TCC's reliability of service was contested only by Cities. In Cities' direct case, they proposed a quality of service penalty of 25 basis points to TCC's return on equity for inadequate reliability and requested that the Commission calculate and require the payment of penalties accumulated by TCC under the ISA reliability standards.

The ALJs correctly rejected the Cities' request for a reliability penalty to TCC's return on equity, but erroneously decided the issue of how penalties should be calculated pursuant to the ISA standards.

For a variety of reasons, the Commission should not decide the issue of the calculation of penalties in this docket. The question of how penalties are to apply is an issue in Docket No. 25157 where a stipulation between TCC, TNC, SWEPCO and the Commission Staff is being considered that will resolve this issue consistently for the AEP Companies. Both consistency and efficiency of resources support this result. Alternatively, the ALJs' proposed calculation of penalties is erroneous and is inconsistent with Commission precedent.

Docket No. 25157

It is extremely inappropriate for the Commission to decide the issue of how penalties should be calculated in this docket because of the pendency of Docket No. 25157. That docket was initiated in December 2001 to address issues relating to the quality of service plan established in the ISA and to conform the ISA to newly amended Commission rules and the changes caused by industry restructuring. The ISA applies to all AEP Texas companies, not just TCC. Included within the issues raised in Docket No. 25157 are the proper calculation of service quality credits given the changes to the Commission's Service Quality Rule and the appropriate method for channeling those credits to end-use customers given the changes to the electric industry brought on by Senate Bill 7.

The PFD in this case purports to decide these same issues as they relate to TCC without regard to Docket No. 25157 and the non-unanimous agreement reached between AEP and

Commission Staff that is the subject of that docket.[374] This is error. By deciding issues properly within the scope of Docket No. 25157, the PFD undermines the Commission's ability to determine whether the agreement reached between Commission Staff and AEP fairly and reasonably resolves these issues. The PFD further usurps the authority granted to the ALJ in Docket No. 25157 to conduct and direct that proceeding. The Commission should reject the PFD's assertion of jurisdiction over these issues and decide them in Docket No. 25157 as they relate to all AEP Texas companies, not just TCC.

The inconsistency between the PFD and the already pending Commission service quality proceeding is further demonstrated by the PFD's failure to address one of the central issues raised by AEP's petition in Docket No. 25157. That issue is how to make payments to end-use customers given that the current payment method under the ISA is unworkable. As Mr. Roper explains in his testimony,[375] as a result of industry restructuring TCC no longer has a direct billing relationship with its end-use customers. Therefore, it cannot directly credit end-use customers for service quality credits, as envisioned by the ISA. TCC can only give such credits to each end-use customer's respective REP, which may or may not decide to pass those credits along to end-use customers. Recognizing this problem, the Commission ALJ in Docket No. 25157 issued a stay on payment of service quality credits until such time as a workable methodology for channeling payments to end-use customers was in place. That stay is still in effect.[376]

Requiring TCC, and only TCC, to return credits before the Commission has approved an appropriate methodology in Docket No. 25157 violates the stay and runs the risk of disparate treatment of end-use customers by separate AEP Texas companies. This underscores the need to address the ISA's service quality provisions in Docket No. 25157 for all AEP Texas companies and not to make isolated determinations in this docket affecting only TCC that may interfere with the ability of the Commission to address service quality issues as they apply to all AEP Texas companies. Accordingly, the Commission should reject those portions of the PFD purporting to calculate TCC's service quality credits under the ISA and requiring TCC to return

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[374] Only a group of cities served by TCC and TNC oppose the agreement.

[375] TCC Exh. 1, Rebuttal Testimony of Randal Roper, at 24, lines 3-12.

[376] *Petition of American Electric Power Company, Inc. for Establishment of Project to Modify Quality of Service Plan and Motion for Interim Stay of Plan Provisions*, Docket No. 25157, Order No. 6 (Oct. 29, 2002), Cities have twice tried and failed to lift the stay in Docket No. 25157.

service quality credits to ratepayers for the years 2001, 2002, and 2003. The Commission should allow Docket No. 25157 to proceed unimpeded and determine the amount of credits owed under the ISA and the method for their return to ratepayers consistent with the unified decisions made in that docket.

Alternatively, the PFD's Calculation of Service Quality Credits is in Error

Although it is AEP's position that Docket No. 28840 should not address or interpret any particular service quality standards in the ISA, in the event that the Commission decides to allow individual standards relating to TCC to be interpreted in this case, the PFD erroneously calculates the amount of service quality credits owing under the ISA. The PFD errs in its calculation of service quality credits under the ISA in two critical respects. First, the PFD misapplies the service quality credits under the ISA to the new service quality standards in the Commission's amended rule. Second, in calculating the service quality credits the PFD fails to account for the effect of significant improvements in outage monitoring and reporting software, referred to in the Commission's rule as "data acquisition" improvements, which give rise, necessarily, to increased SAIDI and SAIFI values.

The PFD incorrectly applies service quality credits to amended distribution feeder standards

To understand the PFD's first error, it is important to understand that the Commission significantly amended its Service Quality Rule after the adoption of the ISA. The amended rule changed the distribution feeder standards from those previously in effect at the time of the ISA. Specifically, instead of a 2% distribution feeder standard, the new rule included a 300% distribution feeder standard, and instead of a 90% standard, the amended rule included a 10% standard. However, as explained in Mr. Roper's testimony,[377] the relationship among the new standards remained the same. Maintaining the same relationship among the old and new standards is important because specific dollar values are attached to a failure to meet each individual standard. For instance, under the old rule, as reflected in the ISA, TCC must credit customers $20 for a failure to meet the 90% distribution feeder standard, but $50 for a failure to meet the 2% distribution standards. Thus, how the Commission determines the relationship between the old standards and the new ones embodied in amended rule § 25.52 has a significant effect on the amount of credits calculated under the ISA.

[377] TCC Exh. 1, Rebuttal Testimony of Randal Roper at 17, lines 16-22, at 18, lines 1-8 and 12-22.

The Commission has already addressed, in two separate proceedings, how the previous standards should be judged in light of changed standards in the amended rule.[378] In Docket No. 21112, the Commission interpreted the new standards in light of a stipulation that pre-dated the amended rule and that was based largely on the ISA. The Commission adopted a stipulation in that docket that applied the $20 credit to a failure to meet the new 10% distribution standard, essentially equating it with the previously effective 90% standard. Similarly, the Commission applied the $50 credit to a failure to meet the new 300% standard, essentially replacing the old 2% standard previously in effect. The Commission followed this same application to the credits associated with the new standards in Docket No. 21190, as explained by Mr. Roper. The non-unanimous stipulation agreed to by AEP and Commission Staff that is the subject of Docket No. 25157 is consistent with the interpretation of the new standards approved by the Commission in these dockets.[379] The calculation of service quality credits in the PFD, however, is not.

The PFD, adopting the recommendation of the Cities, associates the $50 credit with the new 10% standard, and the $20 credit to the new 300% standard. For the reasons set forth in Mr. Roper's testimony, this association is in error and is not consistent with the non-unanimous stipulation in Docket No. 25157 nor with the resolution of this issue in Docket Nos. 21112 and 21190.[380] In the event that the Commission decides to address the calculation of service quality credits in this docket, it should reject the PFD's recommendation as improper and inconsistent with the Commission's previous treatment of the issue.

The PFD fails to give effect to TCC's data acquisition improvements

The PFD's second calculation error concerns its failure to take into account the effect on SAIDI and SAIFI values of data acquisition improvements made by TCC. As discussed by the ALJs, TCC in 1999 implemented a substantially enhanced outage reporting system which results in a greater number of outages being reported than was previously the case.[381] The result is that

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[378] *See Application of Texas-New Mexico Power Company and TNP Enterprises, Inc. Regarding Merger of TNP Enterprises, Inc. and ST Acquisition Corporation*, Docket No. 21112; *Application of Southwestern Public Service Company Regarding Proposed Merger Between New Century Energies, Inc., and Northern States Power Company*, Docket No. 21190.

[379] The orders in Docket Nos. 21112 and 21190 were based on settlements and provide that they are not binding on the Commission for precedential purposes.

[380] TCC Exh. 71, Rebuttal Testimony of Randal Roper, at 17, lines 16-22, at 18, lines 1-8 and 12-22.

[381] *Id.* at 22, lines 17-21.

TCC's SAIDI and SAIFI standards set out in the ISA in 1998 are no longer realistic. AEP's petition in Docket No. 25157 requests that these standards be changed to reflect the effects of the improved outage reporting system, as allowed under P.U.C. SUBST. R. 25.52. As testified by Mr. TCC witness Harry Gordon, TCC began implementation of its new outage data acquisition system in November 1999.[382] Immediately upon implementing that system, TCC's SAIDI and SAIFI value rose significantly for a 12-month period and then substantially leveled off.[383] The reason for this is that SAIDI and SAIFI values are calculated on a rolling 12-month average. TCC Exhibits 70 (HRG-1R and HRG-2R) clearly demonstrate this phenomenon. Unfortunately, although the PFD acknowledges the effect of data acquisition improvements on SAIDI and SAIFI values, it fails to give these improvements any effect in its calculation of service quality credits.

P.U.C. SUBST. R. 25.52(f)(1) specifically provides that reliability standards "may be adjusted by the Commission as appropriate for weather and improvements in data acquisition systems." In the order adopting that rule, the Commission stated, "[t]he commission agrees that weather or improvements in data acquisition systems may affect the utility's ability to comply with P.U.C. SUBST. R. 25.52(f)(2) related to distribution feeder performance." Thus TCC filed its case in 2001 to adjust its reliability standards to account for this new data acquisition system.[384] In addition, more accurate information is essential in developing cost effective asset management programs to improve reliability, as well as allowing accurate quicker restoration of outages.

AEP's petition in Docket No. 25157 requested that new standards be set for the years 2000, 2001, 2002, and 2003, and that the calculation of penalties for that period be based on the new standards rather than the standards established in the ISA. After much discussion and negotiation, the Commission Staff and AEP reached an agreement in Docket No. 25157 to set new performance standards for TCC and TNC to reflect these improvements in data

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[382] TCC Exh. 70, Rebuttal Testimony of Harry R. Gordon, at 11.

[383] *Id.* at 22-23.

[384] As Mr. Gordon testified, the new system not only provides more accurate information, it substantially improves reliability of service by allowing for more accurate predictions of the length of outages and the number of customers affected.

acquisition.[385] The settlement agreement expressly provides that the calculation of credits under the ISA should utilize SAIDI and SAIFI standards as adjusted for data acquisition improvements and abnormal weather for the 2001 reporting year and for the remaining term of the agreement.[386] The only party opposing the stipulation between the Staff and TCC is Cities.

The precise issue of which standards should be used to calculate credits is pending before the Commission in Docket No. 25157. Yet this is the precise issue which the ALJs purport to decide for TCC in this docket. The fundamental unfairness of the ALJs' decision is to calculate credits for the years 2001-2003 on the basis of the current standards established in 1998 under the ISA before the implementation of the new outage data acquisition system. TCC should not be unfairly penalized for implementing this new system. Yet that is exactly what the ALJs' recommendation would do. Failure to give effect to improvements in data acquisition creates a disincentive for companies, such as TCC, to improve their systems. The Commission rules explicitly provide for adjustment of that standard due to new data acquisition, as previously mentioned. The ISA provides for implementation of new standards. There is simply no basis to ignore the fact that TCC's performance relative to the existing standards worsened only because its new system reported outages that would not have been reported before. That issue is pending in Docket No. 25157 and should be litigated there.

TCC urges the Commission to reverse the ALJs and defer any decision on those penalties until Docket No. 25157 is decided.

VIII. Rate Design

A. Load Data

No exceptions filed.

B. Cost of Service Allocations

1. Distribution Field Study

No exceptions filed.

2. Nuclear Decommissioning

No exceptions filed.

[385] The non-unanimous stipulation signed by Commission Staff and AEP does not include adjustments for SWEPCO because improvements in data acquisition had already been fully implemented by the time SAIDI and SAIFI standards were set for SWEPCO.

[386] Docket No. 25157, Motion to Implement Settlement; Exhibit A at 4 (Section 7.B.4) (Nov. 25, 2003).

3. Energy Efficiency Program Costs

No exceptions filed.

4. Debt Reacquisition Costs

No exceptions filed.

5. FERC Account 907 (Supervisions)

No exceptions filed.

6. FERC Account 903 (Customer Service Billing and Record Costs)

No exceptions filed.

7. FERC Account 370 (Meter Installation)

Exception No. 24

> The ALJs erred in recommending the use of Account 370 allocator and meter costs from TCC's UCOS docket instead of TCC's proposed allocator and meter costs to allocate meter costs to customer classes. (FoF 240, 241)

The PFD recommends that TCC use the Account 370 allocator from the UCOS docket instead of the allocator TCC proposes in the current filing to allocate meter costs to customer classes. The allocator proposed by TCC assigns costs based on the installed cost of the meter including additional equipment needed to meter the customer, such as current transformers (CTs) and potential transformers (PTs). TCC developed its allocator based on meter costs approved by the Commission in 2003 during the competitive metering docket for all rate classes except primary and transmission service. The costs for the primary and transmission classes remain the same as the costs in the UCOS docket since the costs of CTs and PTs were not included in the competitive metering docket.[387]

A single meter cost for each unbundled rate class, including the primary and transmission classes, was determined in the competitive metering docket. In contrast, the UCOS allocator used several different meter costs for the old bundled rate classes, such as General Service or Petroleum Service, and mapped them to the new unbundled rate classes as they were defined in the UCOS case. A blended allocator for each unbundled rate class was developed.[388]

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[387] TCC Exh. 84, Rebuttal Testimony of Donald Moncrief, at 27.

[388] *Id.*, at 28.

Since this is the first full rate review since the unbundled rate classes were defined, TCC appropriately developed the Account 370 allocator using one meter cost for each unbundled rate class, just as was done in the competitive metering docket, which is the only other docket relating to TCC's installed meter costs since unbundling, and its methodology should be adopted here.

The PFD suggests that TCC's proposed allocator can lead to skewed results since the meter costs were from two time periods.[389] The PFD proposal should be rejected for two reasons: one pertaining to allocation of cost responsibility among the classes and one pertaining to determination of the actual costs. First, if the allocator proposed in the PFD is adopted, then allocation percentages to each class would be taken directly from the UCOS docket, completely ignoring customer class growth or change in rate class composition since the UCOS case. For example, the transmission class added several customers after the UCOS case. The UCOS allocator proposed in the PFD does not reflect the resulting increased cost responsibility of the transmission class since the UCOS case.[390] Second, TCC appropriately developed meter costs for all classes in the development of its allocator. The PFD presumes that using the metering costs approved in the competitive metering docket for all classes but primary and transmission service will produce skewed results because the transmission and primary class costs were based on the 2001 UCOS docket. TCC disagrees—the metering costs for the transmission and primary classes were approved in 2001 and include *all* costs for meters for those customers, including CTs and PTs, and the costs for the other classes were approved in 2003—this is not a significant time differential from a cost perspective. Consequently, the Account 370 allocator should be approved as proposed by TCC because it accounts for customer class growth and changes in class composition and it reflects comparable cost data approved by the Commission for each rate class.

8. Miscellaneous Rate Design Recommendations from Staff

No exceptions filed.

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[389] PFD at 151.

[390] TCC Exh. 84, Rebuttal Testimony of Donald Moncrief, at 28.

C. Municipal Franchise Fees

1. Allocation of the Fees

Exception No. 25

> The ALJs erred in allocating municipal franchise fees based on kWh sales inside city limits. (FoF 251; CoL 67)

The PFD recommends that municipal franchise fees be allocated to customer classes according to kWh sales made to each class within city limits.[391] TIEC and Staff recommended allocation of the fees based on sales inside city limits rather than on the basis on total kWh sales.

The basis for TIEC's proposed allocation of the fees is that consumption inside the cities is the cause of the municipal franchise fees. That basis is incorrect. The *cause* of the fees is the use of the municipalities' streets and roads for the placement of TCC's facilities. Sales of energy within the cities is merely the methodology chosen by the Legislature for the *calculation* of the fees.

PURA § 33.008(c) specifically recognizes this cost as a reasonable and necessary operating expense, to be collected through a nonbypassable delivery charge.[392] The Commission recognizes the benefit to the system as a whole from the use of cities streets.[393] Moreover, TCC has no other costs that are allocated, or collected, on a geographical basis.

Municipal franchise fees should be allocated on the basis of total kWh sales, which is the same basis on which the ALJs recommend that the costs be collected.

2. Collection of Fees

No exceptions filed.

3. Riders

Exception No. 26

> The ALJs erred in rejecting TCC's proposed Municipal Franchise Fee Adjustment Rider. (FoF 261; CoL 67)

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[391] PFD at 159.

[392] TCC Exh. 84, Rebuttal Testimony of Donald Moncrief, at 14, lines 23-24.

[393] *See Application of Entergy Texas for Approval of its Transition to Competition Plan and the Tariffs Implementing the Plan, and for Authority to Reconcile Fuel Costs, to set Revised Fuel Factors, and to Recover a Surcharge for Under-recovered Fuel Costs*, Docket No. 16705 (Second Order on Rehearing, Oct. 14, 1998).

The PFD states that, "because TCC has agreed to drop its proposal for the municipal franchise fee rider, there would appear to be no basis for having a municipal franchise fee adjustment rider, as TIEC and Staff recommend."[394] The PFD goes on to state that the evidence and argument presented provide no support for adopting such a rider. Contrary to the ALJs' conclusion, the evidence fully supports the approval of the proposed Municipal Franchise Fee Adjustment Rider (MFFA Rider).

The Municipal Franchise Fee Rider (MFF Rider) and the MFFA are two separate riders, address two distinct situations, and present two distinct issues. The MFF Rider is based on the franchise revenue requirement associated with PURA § 33.008(b) (*i.e.*, franchise fee revenue due the municipality for calendar year 1998 divided by total kWh delivered during 1998 equals the charge per kWh).

The proposed MFFA Rider would recover a *change* to the franchise fee revenue requirement that may occur in the future in the event a specific city changes its franchise fee *from that which has been calculated pursuant to PURA § 33.008(b) and is included* in the MFF revenue requirement.[395]

While TCC has agreed to include the municipal franchise fee revenue requirement (MFF Rider) in distribution base rates, TCC continues to support the MFFA Rider.[396] TCC would note that there is no revenue requirement associated with this tariff at this time. The MFFA Rider as proposed is applicable to all Retail Customers within the municipal limits of a city that adjusts its municipal franchise fee factor from that which is included in the monthly municipal franchise fees charged to all Retail Customers. In the event that a city and TCC agree to adjust the city's municipal franchise fee, the Company will develop a factor to collect the difference between the city's municipal franchise fee rate included in the rates of all Retail Customers and the city's new municipal franchise fee rate. This factor will be applicable to the kWh consumption of Retail Customers within the limits of the city making the municipal franchise fee adjustment until the first subsequent rate case.[397] This rider is appropriate because in those cities that retain original jurisdiction over TCC's rates, the city that negotiates a change in franchise fee amounts is also

[394] PFD at 160.

[395] TCC Exh. 90, Rebuttal Testimony of Jennifer Jackson, at 14.

[396] *Id.*, at 19.

[397] TCC Exh. 27, Direct Testimony of Jennifer Jackson, at 65.

the regulator that will have to approve the collection of the additional fee. While the proposed MFFA Rider can be approved on a city-by-city basis as cities with original jurisdiction negotiate changes in their franchise fees, having a Commission-approved tariff is more efficient and reduces the amount of administrative work and costs that each city must bear. This makes it easier for cities to update their franchise agreements and fees.

The Commission previously approved a similar tariff for Southwestern Electric Power Company (SWEPCO).[398] Although SWEPCO is presently a bundled utility while TCC is not, TCC is still required to pay franchise fees to the cities based on the bundled test year of 1998. Therefore, contrary to the ALJs' conclusion, the existence of SWEPCO's Tax Adjustment Rider is relevant and fully supports TCC's proposed Rider MFFA.

D. Rate Case Expenses

Exception No. 27

> The ALJs erred in adopting a three-year amortization of rate case expenses, assuming the ALJs' recommendations regarding initiation of this case and/or achievement of merger savings are adopted by the Commission. (FoF 256)

The PFD cites to TCC's initial request for a three-year amortization of rate case expenses in recommending that rate case expenses be surcharged over a three-year period.[399] The requested three-year amortization was based on TCC's requested rate increase and the expectation that with that level of increase, TCC would not likely file another rate case for three years. If the ALJs' recommendations are adopted by the Commission, TCC will be forced to file a rate case for rates to be effective after the end of the merger sharing period, which expires in 2006, in order to eliminate the double payment of merger savings. Therefore, if those PFD recommendations are adopted, the rate case expenses should be surcharged over a two-year period.

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398 TCC Exh. 90, Rebuttal Testimony of Jennifer Jackson, at 14.

399 PFD at 161-162.

E. Additional Riders

1. Energy Efficiency Cost Recovery Rider

Exception No. 28

> The ALJs erred in rejecting TCC's proposal to recover its energy efficiency costs through a cost recovery rider. (FoF 257, 258, 261; CoL 70)

To recover its energy efficiency (DSM) costs, TCC proposed as its preferred alternative that these costs be recovered through a cost recovery factor. Energy efficiency costs are statutorily-mandated costs—TCC has very limited control over the amount of money expended to meet the statutory requirements. Under its proposal, TCC would recover no more and no less than its costs to meet these goals. True-ups and reconciliations, similar to what occurs under the fuel process for bundled utilities, would ensure no over or under recovery occurs. The PFD rejected this proposal on the grounds that the similar cost recovery factor in effect for SWEPCO is irrelevant and that TCC's proposal is inconsistent with current Commission policy.[400] TCC submits that the PFD's attempt to distinguish the SWEPCO situation is based upon a selective reading of PURA, and that sound policy reasons favor TCC's proposal.

As the PFD correctly notes, SWEPCO's current cost recovery factor was adopted under PURA's integrated resource planning (IRP) provisions, which were repealed in 1999.[401] However, current PURA § 36.204(1) contains the same provision as the IRP provision invoked to authorize SWEPCO's tariff. Section 36.204(1) provides that, "In establishing rates for an electric utility, the commission may: (1) allow *timely recovery* of the reasonable costs of conservation, load management, and purchased power, *notwithstanding* Section 36.201..." (emphasis added). In turn, Section 36.201 directs that, "*Except as permitted by Section 36.204,* the commission may not establish a rate or tariff that authorizes an electric utility to automatically adjust and pass through to the utility's customers a change in the utility's fuel or other costs." (Emphasis added).

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[400] PFD at 164-165.

[401] SWEPCO's tariff also allows for the recovery of renewable energy resources, and TCC and TNC had the same type of tariffs before January 2002. These tariffs are contained in TCC Exh. 88, Rebuttal Testimony of Billy Berny, Exhibits BGB 1R, 2R and 3R. However, TCC and TNC could not have used such tariffs after unbundling occurred because, as transmission and distribution utilities, they could no longer purchase and sell electricity.

Considering PURA §§ 36.201 and 36.204 together, it is obvious that current legislative policy is not to prohibit cost recovery factors of the type TCC proposes here, and that the SWEPCO tariff is statutorily authorized today regardless of the repeal of the IRP regime. The PFD notes that TIEC urges that TCC's proposal would "overturn legislative intent" that these costs be recovered in base rates and that Staff argues that PURA § 36.051 "codifies" the prohibition against piecemeal ratemaking.[402] Yet such arguments either neglect or diminish the legislative policy expressed in PURA § 36.204—that is, cost recovery factors for conservation (energy efficiency) costs *are* permissible under PURA; and PURA would be implemented, not in any way contravened, by adopting such a factor here.

The "current" Commission policy that the PFD relies upon is taken from the March 2000 preamble of the order adopting the energy efficiency rules. Notably, the passage quoted by the PFD begins by saying that a cost recovery factor is not warranted "at this time"—that is, the time when utilities were about to file their UCOS cases. The Commission's concern that a guaranteed recovery of cost increases would eliminate incentives to control costs does not apply to TCC's proposal because TCC's energy efficiency costs would be subject to a reasonableness inquiry. The concern that T&D rates could increase should not be taken to mean that utilities simply should not recover costs which are mandated by PURA § 39.905 and, because of the formula-based method for calculating the budgets to achieve the goal, over which utilities have very little control. Finally, while it is true that TCC's proposal does constitute single cost or issue ratemaking, the fact is that the Legislature has specifically authorized such ratemaking, as discussed above. Denying TCC's proposal because of its intrinsic nature would be tantamount to dismissing PURA § 36.204 because of its intrinsic nature, and would be the same thing as saying a fuel factor and reconciliation process should not be allowed for utilities because it is single issue ratemaking.

Commission policy on this issue should at the least take account of the specific facts of TCC's expenses, which will increase and fluctuate dramatically. As stated earlier, TCC's total energy efficiency expenses are $6.3 million in 2004;. $8.8 million in 2005; $12 million in 2006;

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[402] PFD at 163.

and $8.8 million in 2007.[403] TCC submits that a cost recovery mechanism that captures this varying level of expenses, no more and no less, is the fairest method to both TCC and customers.

2. Nuclear Decommissioning Rider

Exception No. 29

> The ALJs erred in rejecting TCC's proposal to recover its nuclear decommissioning fund costs through a separate rider. (FoF 257, 259, 261; CoL 71)

The ALJs find that TCC, Staff, and TXU did not make a convincing case as to why nuclear decommissioning cost (NDC) should be recovered through a separate rider at this time. TCC disagrees. The evidence shows that a separate NDC Rider will facilitate transparency in the NDC charge to market participants, will allow tracking of the charge, and anticipates the requirements of Project No. 29169.

As stated in the PFD, Staff's position on the NDC Rider is based on Project No. 29169, *Rulemaking on Nuclear Decommissioning Following the Sale or Transfer of Nuclear Generating Plant*,[404] which the Commission instituted for the stated purpose of assuring the continued collection from customers of the costs of decommissioning, protecting the nuclear decommissioning trust funds, and ensuring that nuclear decommissioning funds will be properly collected and administered. The PFD states that the evidence did not adequately explain the reason that the sale of STP (TCC's stake in the South Texas Project) would make a difference in recovering the cost of nuclear decommissioning through a separate rider.[405] The sale of TCC's portion of STP will logically make a difference as to whether nuclear decommissioning costs should be collected through a rider or base rates. With the sale of TCC's portion of STP, TCC will become the collection agent for a non-affiliated entity for a charge that has nothing to do with transmission and distribution service. Section (g)(1) of Staff's straw man rule in Project No. 29169 proposes that a collecting utility that has decommissioning expenses embedded as part of a bundled rate shall apply to have its current level of decommissioning funding removed from its general rates and stated as a separate non-bypassable charge. The basis for breaking out

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[403] TCC Exh.24, Direct Testimony of Billy Berny, Exhibits BGB 5 and 6. These cost calculations exclude the TDHCA payments shown on Exhibit BGB-5.

[404] PFD at 166.

[405] PFD at 168.

the NDC revenue requirement to be collected in a separate rider at this time is so that TCC will not have to come back this year, or in the near future, in another proceeding to separate its decommissioning charges from its base rates. While TIEC points out that this rule has not been finally approved, it is nevertheless an indication as to the direction the rulemaking is going. The rule has been published and is expected to be adopted in August.

As pointed out in the PFD,[406] TCC witness Jackson testified that whether TCC collects the costs through a rider or through base rates, the amount would be the same. This testimony demonstrates that the NDC rider would not be prohibited piecemeal ratemaking because in this docket the rider would be set to recover only the allowed nuclear decommissioning revenue requirement.

Further, as TXU demonstrates, the NDC Rider would also allow market participants to see the amounts charged for nuclear decommissioning required to be collected by TCC because the charges would be easily identified as the NDC Rider on the TDU bill to the REPs. If the cost of nuclear decommissioning is buried in the distribution base rates, no market participant, except those willing to find the work papers associated with this filing or determine the correct charge per distribution class listed in the tariff would know what the NDC charge is. If the NDC charge were in rider format, the charge would be "transparent" on the TDU bill.

The evidence demonstrates that because of the unique circumstances of the cost of nuclear decommissioning funding (*i.e.* TCC will be the collection agent for a charge that has nothing to do with transmission and distribution service), the proposed NDC Rider is appropriate to make the charges transparent to market participants, to allow for better tracking of the charges, and to anticipate the requirements of Project 29169.

3. Catastrophe Reserve Rider

No exceptions filed.

F. Discretionary Service Charges

1. Resolved Disputes

No exceptions filed.

2. Disputes

[406] PFD at 167.

a. **Copy Fee and Special Products/Service Fee**

No exceptions filed.

b. **Special Meter Reading Fee, Connect Fee, and Service Reconnection Fee**

Exception No. 30

The ALJs erred in rejecting TCC's proposed charges for special meter readings, connections and reconnections. (FOF 266, 267, 268)

In this case, TCC updated its cost studies to reflect the current costs of activities associated with performing Discretionary Services.[407] The current fees were approved in TCC's UCOS case.[408] As shown in the rate filing package schedule, the justification of TCC's proposed rates in this case uses the same methodology, *i.e.*, the same employee classifications, vehicles, labor hours, and labor calculations that were approved in the UCOS case.[409] The only change to TCC's current rates is to update the charges to reflect TCC's current costs to provide the services. The PFD rejected TCC's proposed rates for special meter readings, connections, and reconnections and established rates based on rates charged by Oncor or CenterPoint for these services.[410] The Commission has consistently held that Discretionary Service fees are to be set on the basis of the cost of the utility providing the service, and has recognized that each utility has different costs.[411] TCC's proposal ensures that customers requesting these special services pay the costs associated with providing these services. The result of the PFD ruling is to shift cost responsibility away from the customers requesting those specific services to increase the rates paid by all other customers.

The PFD's recommendation is not based on an analysis of TCC's costs, but rather based on a comparison with the rates charged by two TDU's serving customers in densely populated areas as opposed to TCC's less densely populated service area. TCC submits that it is improper to base its Discretionary Service fees on the fees of other utilities. Moreover, the evidence shows that the costs to provide discretionary services by Texas New Mexico Power Company (TNMP)

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[407] TCC Exhibit 26, Moncrief Direct at 23, 25.

[408] PFD at 171-172.

[409] TCC Exh. 2.2, Schedule IV-J-2.

[410] PFD at 171-172.

[411] TCC Exhibit 83, Moncrief Rebuttal at 11.

are higher than TCC's for two of the three services.[412] The PFD finds that TNMP's costs are not material because TNMP serves *more rural customers*.[413] The final Order cited by the PFD in support of this conclusion does not in fact do so. It makes no comparison to TCC's service area and simply finds that TNMP serves rural areas. Further, there is no evidence in this record to support that conclusion. In fact the evidence in the record, which the ALJs cite with approval elsewhere in the PFD, shows that CenterPoint and Oncor serve predominantly large urban territories while TCC serves smaller cities and *a large rural area*,[414] making TCC's service area comparable to that of TNMP. The PFD's conclusion on this issue is unsupported by the record and must be rejected for these reasons.

The PFD's recommendations produce the following rates for these Discretionary Service charges:

	Current Rate	TCC Proposal	PFD Recommendation
Special Meter Read	$15.00	$17.00	$ 8.00
Connect Fee	$25.00	$27.00	$ 8.00
Reconnection Fee	$25.00	$27.00	$10.00

The PFD's recommendations result in the following reductions to TCC's current and proposed rates:

	Reduction to Current Rate	Reduction to Proposed Rate
Special Meter Read	-47%	-53%
Connect Fee	-68%	-70%
Reconnect Fee	-60%	-63%

As discussed above, these significant reductions are not based on TCC's cost, but are based on the rates of two TDUs serving large urban areas. The reduction in these rates causes a shift in cost recovery for these services to the base rates of all customers, including those who do not request, or receive any benefit from, these services.

Further, TCC's tariff for these services has separate pricing provisions for CT meters, priority services, services performed at the pole rather than at the meter, etc. The tariffs for

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412 Tr. 10 at 1984.

413 PFD at 172.

414 *Id.* at 141.

Oncor and CenterPoint do not contain these provisions, and the PFD is silent on how they are to be priced.

For all the reasons stated above, the PFD's recommendation to base TCC's rates on the rates of other utilities is arbitrary and capricious, and should be rejected. TCC's cost-based proposal should be approved, consistent with Commission precedent.

c. Dispatched Order Fee

Exception No. 31

The ALJs erred in rejecting TCC's proposed dispatched order fee. (FOF 269)

Again, the PFD ignores the fact that the proposed rates for this service are based on TCC's actual costs and proposes to reduce the current rates to the level of rates charged by Oncor and CenterPoint. The flaws in the PFD's analysis are discussed in Section VIII.F.2.b, above.

The PFD's recommendations produce the following rates for this Discretionary Service charge:

	Current Rate	TCC Proposal	PFD Recommendation
Dispatched Order Fee			
Routine	$25.00	$23.00	$ 8.00
Priority	$60.00	$29.00	$10.00

The PFD's recommendations produce the following reductions to TCC's current and proposed rates:

	Reduction to Current Rate	Reduction to Proposed Rate
Dispatched Order Fee		
Routine	-68%	-65%
Priority	-83%	-66%

Again, TCC's tariff contains separate pricing provisions for CT meters that are not contained in the CenterPoint and Oncor tariffs and the PFD makes no recommendation regarding the pricing for these services.

For the reasons cited here and in Section VIII.F.2.b, above, the PFD's recommendation should be rejected and TCC's cost-based proposal should be approved, consistent with Commission precedent.

d. Priority Disconnect Fee

No exceptions filed.

G. Lighting (Street and Non-Roadway Lighting)

Exception No. 32

> The ALJs erred in requiring that customers' bills be credited if TCC fails to restore a lamp within three days after official notice of the outage from the customer. (FOF 207)

The ALJs find that pursuant to the intent of the ISA, TCC's lighting tariffs should be amended to state that a credit will be provided to the customer if TCC fails to restore the lamp within three working days after official notice of the outage from the customer.[415] The ALJs' recommendation should be rejected for three reasons. First, the ISA only addresses municipal street lighting; the closed non-roadway lighting is not part of the ISA and therefore there is no basis for the ALJs' recommended tariff change to non-roadway lighting. However, it should be pointed out that in this case TCC amended its non-roadway lighting tariff to voluntarily set a 15 day credit provision that previously did not exist. That proposal was not refuted and should be adopted.

Second, the ISA only sets a target for the Company to replace burned out street lighting bulbs within 72 hours and the parties agreeing to the ISA did not agree to a penalty or credit associated with bulb replacement not occurring within the three day notification period. TCC has proposed a five working day period to restore street-lighting lamps after a reported outage, after which a credit would be applied. The five-day standard has been a long-standing practice of the Company and the proposed rates are based on the five-day replacement standard as shown in the tariff. Even that standard is difficult to meet because, as explained by TCC witness Harry Gordon, the Cities tend to notify TCC of outages in batches, rather than on an as-discovered basis, making it more difficult for TCC to perform repairs within the requisite time period.[416] If the Commission nonetheless requires TCC to modify its tariffs and its operations by shortening the period after which a credit is applied from five working days to three working days, the tariff must be amended to require the cities to notify TCC immediately upon discovery of an outage.

[415] PFD at 175.

[416] TCC Exh.70, Rebuttal Testimony of Harry Gordon, at 35.

Third, this is another instance of the ALJs rewriting the provisions of the ISA to the detriment of TCC.

H. Revenue Allocation

No exceptions filed.

I. Gradualism

Exception No. 33

> The ALJs erred in adopting positions based upon gradualism proposing a constraint of two times the system average increase. (FoF 279-283)

The PFD states that the Commission has traditionally moderated the impact of new rates with gradualism to avoid rate shock. In fact, gradualism was applied in an era of bundled rates, when the TDUs were integrated utilities responsible for sending bills for electric service directly to retail customers. Today the TDUs send bills for T&D service to REPs who decide how to package the bills that go directly to the retail customers. Therefore, retail customers may or may not be able to determine the T&D portion of their bills. More importantly, T&D costs are only a small portion of the retail customer's bill—rate shock is generally not an issue in this environment.

The ALJs state that they are not convinced that gradualism is an abandoned policy. TCC has not proposed that the Commission abandon gradualism constraints in total; in fact TCC does use gradualism in the design of the lighting rates and continues the exceptions to the generic rates for agricultural customers based on the exceptions process of Order No. 40 for headroom concerns. However, TCC's position on setting overall gradualism constraints in this case is that because this case is the first opportunity to design rates on a test year using actual cost and historical data by generic rate class, the rates should be based on the equalized cost-to-serve.

The ALJs question the degree of reliance to be placed on Order No. 40 from the generic proceedings in the UCOS cases. Order No. 40 established that T&D rates are to be based on the generic rate design unless exceptional headroom concerns are shown to exist.[417] There is no evidence that the Commission's rate design orders in the generic UCOS case have been abandoned by the Commission. Following the mandates of Order No. 40, in the current docket, TCC relied on the equalized cost-of-service study class allocations by function to assign a

[417] *See* TCC Exh. 27, Direct Testimony of Jennifer Jackson, JLJ-1 at 5.

revenue requirement to the distribution rate classes for distribution and metering services.[418] Because current rates were set on a forecasted test year, and the proposed rates in this docket are based, for first time since unbundling, on actual cost and historical data available for the generic classes, one would expect some movement in the classes from the cost-of-service study allocations used to set current rates.[419] The rates that result from an equalized cost-of-service based on historic data from the generic rate classes make a better benchmark on which to apply gradualism constraints in subsequent cases, if necessary.

TCC realizes that the ALJs did not adopt the State's position on gradualism by function in its PFD in this case. However, the ALJs nonetheless left the door open for complications in distribution rate design revenue allocation in future rate cases. TCC wants to make it abundantly clear that the State's recommendations on gradualism in this case are based, in part, on a misinterpretation of the proposed rate design data and should not be relied upon for future rate reviews. The ALJs' reliance on the State's gradualism by function example is misguided because it is based on the State's inaccurate assumptions regarding the rate design for the Secondary > 10 kW and the Primary classes. The State's witness alleges that TCC's proposed rate design is particularly severe for Secondary > 10 kW IDR and Primary IDR customers.[420] However, the State's example is based on an improper understanding of the proposed rate design. As shown in the schedules and work papers supporting the proposed rate design, the costs of the IDR and non-IDR customers (for distribution and meter services—the only functions for which the State made changes to the revenue allocation based on gradualism concerns) are included as part of the same class for rate design purposes. The costs for IDR customers are shown separately in the cost-of-service study and in the rate design schedules because IDR customers currently receive a different rate for transmission services and in the proposed rate design, a different rate for the customer charge.[421] It is peculiar that State witness Pevoto would single out Secondary > 10 kW IDR and Primary IDR customers considering the current and proposed distribution and meter charges are the very same as those for customers without IDR meters. Therefore, the percentage change to distribution and meter service charges would be the

[418] TCC Exh. 89, Rebuttal Testimony of Jennifer Jackson, at 21.

[419] *Id.* at 21.

[420] PFD at 179.

[421] Schedule IV-J-6 at 1.

same for IDR and non-IDR customers in the Secondary > 10 kW and Primary classes. Ms. Pevoto bases her conclusions and recommendations regarding gradualism on a rate design that no party has proposed and conclusions drawn from those examples cannot be relied upon.

The PFD states that OPC witness Clarence Johnson was the only expert to oppose the State's proposal on gradualism by function. This is another example of the ALJs' totally ignoring the evidence in the record. TCC wholly opposed the State's gradualism by function proposal. As TCC witness Jackson testified, Ms. Pevoto's adjustment in the allocations to the distribution and metering functions must be rejected because it unnecessarily complicates the revenue allocation process, dilutes the principle of the cost to serve, and causes unnecessary subsidies among the classes.[422]

TCC also asserts that the gradualism cap of two times the system average recommended by the ALJs in this case is not appropriate because, as stated earlier, this case is the first opportunity to base rates on a test year of actual cost and historical data. TCC respectfully requests that the Commission reject the findings of the ALJs on the issue of gradualism and instead continue the process for exceptions to the generic rate design as defined in Order No. 40, which it has previously approved for all TDUs.

IX. Headroom

Exception No. 34

The ALJs erred in their analysis of TCC's headroom calculation.

First, it should be noted that five pages of the PFD are devoted to analysis of this issue that all parties, as well as the ALJs, agree has no revenue impact and is not an issue that must be decided in this rate case. This is more than the number of pages devoted to the issue of who initiated this rate case, which has a $30 million impact.

In the PFD, it is clear that the ALJs completely misunderstand the headroom analysis presented by TCC in its application. The ALJs surmise that the proper headroom analysis should deal with the effect on the current headroom amounts—that is, the impact on headroom under existing T&D rates compared to headroom amounts immediately after new rates are put into effect. That position is summed up on page 184 of the PFD stating, "Using the Commission's formula, an increase in T&D rates would necessarily create a decrease in headroom from that

[422] TCC Exh. 90, Rebuttal Testimony of Jennifer Jackson, at 21.

currently enjoyed by the Intervenors." Of course it is a mathematical truth that, with all other things being equal, if T&D rates increase, headroom decreases.

However, headroom has significantly increased since January 1, 2002, as shown on the table below.

Distribution Class	Usage Level	January 2002 Headroom	Current Headroom	Headroom if TCC's full increase granted
Residential	500 kWh	$0.025450	$0.037748	$0.031941
Residential	1,000 kWh	$0.024650	$0.036987	$0.032229
Sec > 10 kW IDR	35 kW, 15,000 kWh	$0.026230	$0.039460	$0.035085
Sec > 10 kW Non-IDR	35 kW, 15,000 kWh	$0.026780	$0.039643	$0.036613

Even if TCC's proposed full $66.5 million increase was approved, headroom would still be significantly higher since the advent of competition, as shown in the last column.

TCC's point is simply that an increase to TCC's T&D rates will not harm the competitive retail market in Texas. Competition has occurred since January 1, 2002 with headroom levels as low as 2.5 cents/kWh. Headroom levels will be significantly above that—even if TCC's full increase was granted—going forward and competition will not be harmed as a result. While the Commission should be cognizant of the headroom levels, it should not be a factor in setting TCC's T&D rates in this proceeding.

The ALJs also criticized TCC for not utilizing the PCA (capacity auction prices) in the development of its headroom analysis. However, as stated in Mr. Carpenter's and Ms. Jackson's testimony, the results of the most recent capacity auction at the time of the filing—September 2003—were used. TCC did not use the results from a Request for Proposals (RFP) for 10% of the AREP's load in its calculation as contemplated by the Commission's rules since, as a result of selling its AREP to Centrica, AEP no longer has the AREP load for which to issue an RFP. The most recent capacity auction prices were the best proxy of market prices available to TCC to calculate headroom.

Finally, it should be noted that despite their criticisms, no other party presented a headroom calculation.

X. Findings of Fact, Conclusions of Law, and Ordering Paragraphs

A. Findings of Fact

Any exceptions to these are addressed in the section in which the particular subject matter is discussed.

B. Conclusions of Law

Any exceptions to these are addressed in the section in which the particular subject matter is discussed.

C. Ordering Paragraphs

Any exceptions to these are addressed in the section in which the particular subject matter is discussed.

Attachment A to the PFD

TCC's exhibits listed in Attachment A[423] to the PFD are incorrect. Attachment A lists two exhibits as TCC Exhibit No. 47. Thus, the remainder of TCC's exhibits are numbered inaccurately. Additionally, Attachment A does not include TCC Exhibit Nos. 74A or 92. Order No. 16[424] admitted Exhibit Nos. 74A and 92 into the record after completion of the hearing. Attached as Appendix I is a corrected list of TCC's exhibits.

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[423] PFD at n. 10.

[424] Order No. 16 (June 17, 2004).

Respectfully submitted,

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By: John F. Williams

John F. Williams
ATTORNEYS FOR AEP TEXAS CENTRAL COMPANY

CERTIFICATE OF SERVICE

I certify that I have served a copy of AEP Texas Central Company's Exceptions to the Proposal for the Decision upon all parties of record by hand delivery or overnight delivery on this 21st day of July, 2004.

John F. Williams

John F. Williams

AEP Texas Central Company Rate Case
PFD Analysis
Dollars in Millions

Adj. No.	Description	Tran.	Dist.	Total
1	Company Request	(2.3)	68.8	66.5
	Company Agreed Adjustments			
2	Settlement ROE Capital Structure	(8.5)	(15.3)	(23.8)
3	Agreed Refunctionalize Marketing Software	-	(0.2)	(0.2)
4	Agreed Affiliate Reduction	(0.1)	(0.3)	(0.4)
5	Agreed Vehicle Non-Recurring Adjustment	-	(1.0)	(1.0)
6	Agreed Depreciation Reduction	0.2	(0.4)	(0.2)
7	Adjust Materials & Supplies	-	-	-
8	Adjusted Company Request	(10.7)	51.6	40.9
	PFD Adjustments			
	Rate Base Return & Income Tax Impacts			
9	Post Test Year Rate Base Adjustment	-	(0.8)	(0.8)
10	Reduce Cash Working Capital	(0.2)	(1.5)	(1.7)
11	Remove Debt Reacquisition Costs	-	(1.2)	(1.2)
12	Remove Portion of Coleto Creek-Pawnee	(0.3)	-	(0.3)
13 A	Consolidated Tax Adjustment (Low End)	(0.1)	(0.3)	(0.4)
13 B	Consolidated Tax Adjustment (High End)	(1.9)	(8.0)	(9.9)
	Merger Savings and Expenses			
14	Revenue Requirement Credit	-	(7.5)	(7.5)
15	Merger Expense Add Back	-	(16.3)	(16.3)
16	Merger Expense Cost to Achieve	-	(6.2)	(6.2)
	Other Expenses			
17	Factoring Expense	0.2	0.8	1.0
18	Affiliate Expenses	(1.6)	(8.3)	(9.9)
19	TCOS City of San Antonio	-	(1.3)	(1.3)
20	TCOS TCC	-	(1.3)	(1.3)
21	Vechicle Adjustment	(0.1)	(0.9)	(1.0)
22	Salary Adjustments	(0.1)	(0.8)	(0.9)
23	Employee Incentive Compensation	(0.3)	(2.6)	(2.9)
24	Pension Expenses	(0.9)	(5.9)	(6.8)
25	DSM Expenses	-	(2.0)	(2.0)
26	Group Insurance / OPEBs	(0.1)	(1.2)	(1.3)
27	Catastrophe Reserve Request	(0.2)	(1.9)	(2.1)
28	Remove Debt Reacquisition Amort.	-	(0.9)	(0.9)
29	Depreciation Expense	(3.2)	(5.6)	(8.8)
30	Rate Case Expense	(0.5)	(0.9)	(1.4)
31	Decomissioning Expenses	-	(0.6)	(0.6)
32	Misc. Other Taxes	(0.1)	(0.1)	(0.2)
	Revenue Impacts			
33	Rate Case Surcharge	-	1.1	1.1
34	3rd Party Margin Sharing	(1.3)	-	(1.3)
35	TCRF Revenues for City of San Antonio	-	1.3	1.3
36	Revenue Impact With $0.4 million CTA (Scenario #1)	(19.5)	(13.3)	(32.8)
37	Revenue Impact With $9.9 million CTA (Scenario #2)	(21.3)	(21.0)	(42.3)

AEP-Texas Central Company

Description of Adjustments Made to Filing Schedules Based on PFD Recommendations

Adjustment Number	Issue	PFD Reference	Description of Change	Schedule Reference	Workpaper Reference
	Accounting				
2	Return on Equity	Page 40	Adjust Return on Equity to 10.125%	II-C-2.1	N/A
2	Capital Structure	Page 40	Adjust Capital Structure to 60% Debt, 40% Equity	II-C-2.1	N/A
2	Weighted Cost of Capital	Page 40	Adjust Weighted Cost of Capital to 7.475%	II-C-2.1	N/A
3	Marketing Software	Page 39	Refunctionalize $916,700 of Marketing Software out of the T&D Rate Base	II-B-1	(model) Attachment II-B-1 Plant
4 & 18	Affiliate Costs	Page 72	Remove Affiliate Costs of $10,319,991	II-D-1 & II-D-2	WP II-D-2-12
5 & 21	Distribution O & M (Vehicle Adjustment)	Page 107	Reduced Vehicle Related Distribution O & M by $2,000,000.	II-D-1	WP II-D-1-11
6 & 29	Depreciation Expense	Page 111	Adjusted Depreciation Rates to Reflect the PFD. Synchronized with Plant in Service.	II-E-1	WP II-E-1
7	Materials & Supplies Inventories	Page 30	Reduce Materials & Supplies Included in Rate Base by $301,270	II-B-8	WP 11-B-8
9	Post Test Year Rate Base Adjustment	Page 29	Remove $8,228,567 of 6/30/2003 CWIP from Rate Base	II-B-1	WP II-B-1-1
10	Cash Working Capital	Page 38	Adjust Revenue Lag Days of Lead/Lag Study to Match Ms. Hargus' Alternative Recommendation - Synchronized with the Final Expenses	II-B-9	WP II-B-9
11 & 28	Debt Reacquisition Costs	Page 75	Reduced Rate Base by $12,457,136 and Reduced Amortization Expense by $861,712	II-B-12 & II-E-1	WP II-B-12 & WP II-E-1-3
12	Coleto Creek Substation Investment	Page 33	Reduce Transmission Plant in Service by $3,016,482	II-B-1	(model) Attachment II-B-1 Plant
13A & 13B	Consolidated Tax Savings	Page 104	Included $403,906 of Consolidated Tax Savings in Scenario 1 and $9,878,000 in Scenario 2	II-E-3	(model) II-E-3 FIT
14	Revenue Requirement Credit	Page 25	Include an A&G Expense Reduction of $7,496,000 in Cost of Service	II-D-2	WP II-D-2-14
15 & 16	Merger Expense Add-Back and Merger Expense Cost to Achieve	Page 19	Remove $16,337,000 of A&G Expense & $6,176,000 of Amortization Expense from Cost of Service	II-D-2 & II-E-1	WP II-D-2-14
17	Factoring Expense	Page 38	Adjust Factoring Expense to Match Ms. Hargus' Alternative Recommendation - Synchronized with the Final Revenue Requirement	II-D-1	(model) Factoring Exp Calc

AEP-Texas Central Company

Description of Adjustments Made to Filing Schedules Based on PFD Recommendations

Adjustment Number	Issue	PFD Reference	Description of Change	Schedule Reference	Workpaper Reference
19 & 35	Transmission Cost of Service	Page 151	Adjust City Public Service of San Antonio TCOS Rate to $.935/KW.	II-D-1	WP II-D-1-5-1
20	Transmission Cost of Service	N/A	Synchronize TCC's Transmission Rate to be Included in Distribution Cost of Service. Results in a Distribution Cost of Service Reduction of Approximately $1.3 Million.	II-D-1	WP II-D-1-5
22	Salary Adjustments	Page 77	Changed Salary Adjustment to $170,583.	II-D-1 & II-D-2	WP II-D-1-6 & WP II-D-2-5
23	Incentive Compensation	Page 81	Removed $2,908,542 of Incentive Compensation.	II-D-1 & II-D-2	WP II-D-1-6 & WP II-D-2-6
24	Pension Expense	Page 84	Pension Funding set at $0. An Adjustment to the Company's Filing of $6,796,778	II-D-2	WP II-D-2-1
25	DSM Costs	Page 93	Adjusted DSM Costs to Test Year Level of $6,082,450.	II-D-1	WP II-D-1-2
26	OPEB Expense	Page 86	OPEB Expense set at Test Year Level. An Adjustment to the Company's Filing of $365,086.	II-D-2	WP II-D-2-9
26	Group Insurance Expense	Page 87	Group Insurance Expense set at Test Year Level. An Adjustment to the Company's Filing of $908,833.	II-D-2	WP II-D-2-10
27	Catastrophe Reserve	Page 90	Adjusted Catastrophe Reserve Amortization Expense to $630,360.	II-E-1	WP II-E-1-3-1
30 & 33	Rate Case Expense	Page 122	Removed Rate Case Expense of $1,330,334 from Company's Filing. Actual Rate Case Expense will be Surcharged.	II-E-1 & II-E-4.5	WP II-E-1-3-1
31	Decommissioning Expense	Page 115	Reduced Decommissioning Expense to $7,580,000.	I-A	(model) II-E-4
32	Other Taxes	N/A	Synchronization of Other Taxes with Final Revenue Requirement	II-E-2	As Needed
34	Third Party Margin Sharing	Page 120	Included Additional Third Party Margins of $1,324,133.	II-E-5	WP/Schedule II-E-5

AEP-Texas Central Company
Description of Adjustments Made to Filing Schedules Based on PFD Recommendations

Adjustment Number	Issue	PFD Reference	Description of Change	Schedule Reference	Workpaper Reference
	Cost of Service				
	Energy Efficiency Allocation	Page 147	Changed EE allocation to a 50/50 Demand/Energy allocation to all retail classes.	II-I-1	
	FERC Account 370 Meter Installation	Page 150	Changed allocator to Docket 22352 forecasted test year allocator based on UCOS cost and customer data.	II-I-1	WP II-I-1.4
	Taxable Income Allocator	Page 152	Changed per PFD and Staff recommendation.	II-I-1	
	FERC Account 565	Page 154	Changed composite labor allocator 561-566, total O&M allocator, and account 565 to reflect removal of TCOS.	II-I-1	WP II-D-1-5
	Municipal Franchise Fee Allocation	Page 155	Changed allocator of MFF to reflect class kWh within city limits.	II-I-1	WP MFF Alloc
	Discretionary Fees	Page 171	Changed the Special Meter Read, Connect, Dispatched Order, Inaccessible Meter Fee and Reconnect discretionary fees to reflect the PFD.	IV-J-2	WP Misc Rev
	Miscellaneous Revenue Adjustment	Page 171	Changed miscellaneous revenue adjustment to reflect discretionary fee changes per PFD.	II-E-5	WP II-E-5
	3rd Party Contract Margin Sharing	Page 115	Adjusted Miscellaneous Revenues to credit $2,648,266 ABD construction revenues	II-E-5	WP II-E-5
	Consolidated Tax Savings	Page 104	Allocated consolidated tax savings on taxable income.	II-I-1	

Appendix B

SOAH Docket No. 473-04-1033
Docket No. 28840
Exhibit DGC-11R

MEMORANDUM

TO: **Mark McDaniel, City of Corpus Christi**
Larry Dovalina, City of Laredo
Brendan Hall, City of Harlingen
Denny Arnold, City of Victoria
Jim Darling, City of McAllen

FROM: **Jim Darling, Chairman, STAP Board of Directors**

DATE:

RE: **Review Of CPL's Transmission And Distribution Rates**

On June 6, 2003, the South Texas Aggregation Project ("STAP") Board of Directors unanimously voted to implement procedures to evaluate CPL's transmission and distribution rates for reasonableness. The Public Utility Commission (PUC) established the current rates of CPL, now called AEP Texas Central, approximately 18 months ago. These rates were based upon the utility's projected costs (a future test year with crystal ball estimates) and a rate of return that does not reflect the current cost of capital. Actual cost data now exists. In the deregulation statute, the legislature left in place Cities' original jurisdiction over transmission and distribution rates of AEP Texas Central.

The transmission and distribution rates are considered non-bypassable charges which represent a significant component (40% to 60%) of a City's power bill. This rate review is considered by the STAP Board of Directors to be a prudent action in our ongoing efforts to hold down electric utility costs. Attached is a model resolution which the Board encourages your City to adopt. The resolution requires AEP Texas Central to provide certain cost information to be reviewed by our consultants. The resolution provides that a public hearing will be held and a rate ordinance adopted. The reasonable cost of rate review before Cities or the PUC is reimbursable by AEP Texas Central Company. Consequently, there is no cost to your city.

The Cities named above represent the five largest Cities participating in STAP. If CPL's rates are determined to be excessive and a rate ordinance enacted, it is anticipated that other STAP members and Cities Served by CPL will be advised to intervene in any CPL appeal to the PUC.

The Board recommends that the proposed resolution be placed on the agenda at your City's next meeting. If you have any procedural or substantive questions on this matter, please contact Steve Porter at (512) 322-5876 or sporter@lglawfirm.com or Geoffrey Gay (512) 322-5875 or ggay@lglawfirm.com.

Jim Darling
City Attorney, McAllen
Chairman, STAP Board of Directors

Appendix C

RESOLUTION NO. 2003-22

RESOLUTION OF THE BOARD OF COMMISSIONERS OF THE CITY OF McALLEN DIRECTING AEP TEXAS CENTRAL COMPANY TO FILE CERTAIN INFORMATION ("RATE FILING PACKAGE") WITH THE CITY OF McALLEN; SETTING A PROCEDURAL SCHEDULE FOR THE GATHERING AND REVIEW OF NECESSARY INFORMATION IN CONNECTION THEREWITH; SETTING DATES FOR THE FILING OF THE CITY'S ANALYSIS OF THE COMPANY'S FILING AND THE COMPANY'S REBUTTAL TO SUCH ANALYSIS; AUTHORIZING THE HIRING OF LEGAL COUNSEL AND CONSULTANTS; REQUIRING THE REIMBURSEMENT OF THE CITY OF McALLEN'S RATE CASE EXPENSES; SETTING A PUBLIC HEARING FOR THE PURPOSES OF DETERMINING IF THE EXISTING RATES OF AEP TEXAS CENTRAL COMPANY ARE UNREASONABLE OR IN ANY WAY IN VIOLATION OF ANY PROVISION OF LAW AND THE DETERMINATION BY THE CITY OF McALLEN OF JUST AND REASONABLE RATES TO BE CHARGED BY AEP TEXAS CENTRAL COMPANY.

STATE OF TEXAS §
COUNTY OF HIDALGO §
CITY OF McALLEN §

WHEREAS, the City of McAllen, is a regulatory authority under the Public Utility Regulatory Act (PURA) and has exclusive original jurisdiction over the rates and services of AEP Texas Central Company (AEP) to determine if such rates are just and reasonable; and

WHEREAS, Sections 36.003 and 36.151 of PURA empowers a regulatory authority, on its own motion or on a complaint by an affected person, to determine whether the existing rates of any public utility for any service are unreasonable or in any way in violation of any provision of law, and upon such determination, to determine the just and reasonable rates;

WHEREAS, the City of McAllen has reason to believe that AEP Texas Central Company is overearning and its rates are excessive; and

WHEREAS, the City Commission of the City of McAllen desires, on its own motion, to exercise its authority under Sections 36.003 and 36.151 of PURA; and

WHEREAS, a procedural schedule should be established for the filing of a rate filing package by AEP Texas Central Company, procedures to be followed to obtain and review information from AEP Texas Central Company, the filing of an analysis of such information by the City's staff and consultants, the filing of rebuttal information from AEP Texas Central Company, and a public hearing at which time the City shall make a determination whether the existing rates of AEP Texas Central Company are unreasonable or are in any way in violation of any provision of law and if such rates should be revised and just and reasonable rates determined for AEP Texas Central Company.

NOW, THEREFORE, BE IT RESOLVED BY THE BOARD OF COMMISSIONERS OF THE CITY OF McALLEN, TEXAS, THAT:

Section 1. This resolution constitutes notice of the City's intent to proceed with an inquiry into the transmission and distribution rates charged by AEP Texas Central Company. On or before twenty-one (21) days after the effective date of this resolution, AEP Texas Central Company shall file with the City of McAllen, information that demonstrates good cause for showing that AEP Texas Central Company's transmission and distribution rates should not be reduced. Specifically, AEP Texas Central Company shall file with the City of McAllen information for the calendar year ending December 31, 2002, regarding AEP Texas Central Company's cost of service elements as detailed by the table included as "Attachment A" to this resolution, along with all associated work papers. The last two Annual Reports of AEP and the memorandum (whether written or financial), reports, studies and evaluations, of AEP Texas Central Company's financial performance that may have been considered by AEP management and AEP's consultants or attorneys in preparing these annual reports; the most recent 10-K and 10-Q filings at the Securities and Exchange Commission, and all operation and financial reports of AEP Texas Central Company provided to AEP Texas Central Company management or its parent company's management in 2002. Testimony need not be prepared, but a narrative description shall be provided sufficient to describe the information. In addition, AEP Texas Central Company shall file with the City of McAllen revenues and expenses associated with the provision of streetlighting service within the municipal limits during 2000, 2001 and 2002.

Section 2. City's designated representatives shall have the right to obtain additional information from AEP Texas Central Company through the filing of requests for information, which shall be responded to within seven (7) days from the receipt of such request for information.

Section 3. City's designated representatives shall file their analysis of AEP Texas Central Company's filing and information on or before forty (40) days from the effective date of this resolution.

Section 4. AEP Texas Central Company shall file any rebuttal to the analysis of City's representatives on or before fifty (50) days from the effective date of this resolution. With its rebuttal, AEP Texas Central Company may present whatever additional information it desires to defend its current rates.

Section 5. A public hearing shall be conducted by the City Commission for the City of McAllen on August 25, 2003 during the regular commission meeting scheduled to commence at 6:00 p.m. At such hearing a representative of AEP Texas Central Company will be allowed to address the City Commission to summarize previously filed reports for no more than 15 minutes. The City Commission will also consider any written request or recommendation of Cities' consultants. If possible, the City will coordinate its review with other Cities taking similar action, including the holding of a jointly sponsored rate hearing. Based upon such hearing(s), a determination of the reasonableness of the existing rates of AEP Texas Central Company shall be made by the City Commission and, if necessary, just and reasonable rates shall be determined to be thereafter observed and enforced for all services of AEP Texas Central Company within the City of McAllen, Texas.

Section 6. The City Commission may, from time to time, amend this procedural schedule and enter additional orders as may be necessary in the public interest and to enforce the provisions hereof.

Section 7 Subject to the right to terminate employment at any time, the City of McAllen hereby authorizes Geoffrey Gay and Steve Porter of the law firm of Lloyd, Gosselink, Blevins, Rochelle, Baldwin & Townsend, P.C. and other qualified consultants to review AEP Texas Central Company's existing rates and to assist the City of McAllen in its ratemaking and to prosecute any appeals to the Texas Public Utility Commission or court.

Section 8. AEP Texas Central Company shall reimburse the City for the reasonable costs of attorneys and consultants upon presentation of invoices by the City.

CONSIDERED, PASSED, APPROVED and SIGNED this 23rd day of June, 2003, at a regular called meeting of the Board of Commissioners of the City of McAllen at which a quorum was present and which was held in accordance with the provisions of Chapter 551, Texas Government Code.

Resolution

CITY OF McALLEN

By: ______________________
Leo Montalvo, Mayor

ATTEST:

____
Leticia M. Vacek, City Secretary

APPROVED AS TO FORM:

____
James E. Darling, City Attorney

ATTACHMENT A

	2002 Actual Test Year Revenue Requirement
Operations & Maintenance	
Depreciation and Amortization Expense	
Taxes Other Than Income Taxes	
Federal Income Tax	
Return on Invested Capital	
Total Revenue Requirement	

	2002 Actual Test Year Transmission Invested Capital
Plant In Service	
Accumulated Depreciation	
Net Plant In Service	
Total Invested Capital	
Rate of Return	
Return on Invested Capital	

	2002 Actual Test Year Distribution Invested Capital
Plant In Service	
Accumulated Depreciation	
Net Plant In Service	
Total Invested Capital	
Rate of Return	
Return on Invested Capital	

City of McAllen

CERTIFICATION

STATE OF TEXAS
COUNTY OF HIDALGO
CITY OF MCALLEN

I, Leticia M. Vacek, City Secretary of the City of McAllen, do hereby certify that the following is a true and correct copy of Resolution 2003-22 as approved by the McAllen Board of Commissioners at their Regular Meeting held June 23, 2003.

IN WITNESS WHEREOF, I have hereunto subscribed my signature and impressed the official seal of the City of McAllen, Texas, this 25th day of June, 2003.

CITY OF McALLEN SEAL McALLEN, TEXAS

Leticia M. Vacek

Leticia M. Vacek
City Secretary

STIPULATION AND AGREEMENT

On July 14, 2003, AEP Texas Central Company and the Cities of McAllen, Victoria and Laredo (the Cities) entered into the following agreement regarding the rate review proceedings initiated by each of the Cities in their capacities as regulatory authorities.

I. Background

On June 23, 2003; July 1, 2003; and July 7, 2003 the Cities of McAllen, Victoria and Laredo, respectively, adopted resolutions which initiated rate review proceedings of the transmission and distribution rates of AEP Texas Central Company. Each resolution was adopted pursuant to Sections 36.003 and 36.151 of the Public Utility Regulatory Act (PURA), which empower regulatory authorities to review the existing rates of a public utility and to set new rates if the regulatory authority determines that existing rates are not just and reasonable.

Each resolution states that the regulatory authority "has reason to believe that AEP Texas Central Company is overearning and its rates are excessive." The resolutions further require AEP Texas Central Company to file certain information regarding its rates on or before 21 days after the effective date of the resolution, utilizing a test year ending December 31, 2002. Hearings are scheduled for August 25, 2003 in McAllen, September 2, 2003 in Victoria, and July 7, 2003 in Laredo.

After discussion and agreement, AEP Texas Central Company and the Cities agree that it is reasonable and appropriate to alter the schedule established in the resolutions and to alter other aspects of the resolutions as follows:

II. Rate Filing Package

The parties agree that AEP Texas Central Company will file a rate filing package in the form required by the Public Utility Commission of Texas (PUC) with each of the Cities in response to the resolutions in lieu of the filing requirements contained in the resolutions. Such filings will be made with the Cities on November 3, 2003. A public hearing will be held by each of the Cities at a date to be set later.

Because of the Cities' desire to initiate any rate change as soon as possible and the likelihood of an appeal to the PUC of any ordinance that reduces any of AEP Texas Central Company's rates, the parties agree that AEP Texas Central Company will file its rate filing package with the PUC on the same date it is filed with each of the Cities in order to initiate the PUC's review of AEP Texas Central Company's rates. The parties further agree that nothing in this agreement shall be construed to prevent AEP Texas Central Company from requesting a rate increase in the rate filing package to be filed with the Cities and the PUC.

III. Test Year

The parties agree that AEP Texas Central Company shall have the right to utilize in its rate filing package a test year which encompasses the most recent 12 months for which operating data is available, as provided for in Section 17.003(20) of PURA.

IV. Jurisdiction

The parties agree that nothing in this Stipulation shall preclude AEP Texas Central Company from contesting the jurisdiction of the Cities to set any portion of AEP Texas Central Company's transmission and distribution rates.

V. Appeals of City Rate Ordinances

The parties agree that if AEP Texas Central Company appeals to the PUC an ordinance of any City which sets new rates for AEP Texas Central Company prior to the entry of a final order by the PUC in its proceeding involving the AEP Texas Central Company rate filing, the Cities shall not oppose a request by AEP Texas Central Company that the effect of the city ordinance be stayed by the PUC until the PUC enters a final order on such appeal.

VI. Rate Case Expenses

The parties agree that AEP Texas Central Company will not contest the right of the Cities to recover reasonable rate case expenses incurred in these proceedings. AEP Texas Central Company further agrees that such expenses shall be reimbursed on a monthly basis. However, such monthly reimbursement shall not be considered to be agreement as to the reasonableness of the amount paid, and AEP Texas Central Company shall have the right to contest the reasonableness of the amount of rate case expenses claimed by Cities at any point in these proceedings.

VII. Limited Purpose of Stipulation

The parties agree that this Stipulation represents a compromise in an attempt to facilitate these proceedings, and the parties, in approving, accepting and agreeing to this Stipulation, shall not be deemed to have approved, accepted, agreed to or consented to any principle of law or regulatory policy. An agreement to this Stipulation shall not be deemed in any respect to constitute an admission by any party that an allegation or contention made or contained in these proceedings is true or valid or untrue or invalid. The parties agree that the provisions of this

Stipulation are the result of negotiations and that the terms and conditions of this Stipulation are interdependent. A party's support for this Stipulation may differ from its position or testimony in other proceedings. To the extent that there is a difference, the parties are not waiving their positions in other proceedings. Because this is a stipulated agreement, the parties are under no obligation to take the same positions as set out in this Stipulation in other proceedings or dockets, whether those proceedings or dockets represent the same or a different set of circumstances.

AEP TEXAS CENTRAL COMPANY

By ______________________
Philip E. Ricketts, Attorney

CITY OF McALLEN

By ______________________
Geoffrey M. Gay, Attorney

CITY OF VICTORIA

By ______________________
Geoffrey M. Gay, Attorney

CITY OF LAREDO

By ______________________
Geoffrey M. Gay, Attorney

CERTIFICATE

THE STATE OF TEXAS §

COUNTY OF NUECES §

I, the undersigned City Secretary of the City of Corpus Christi, Texas, so certify that the following is a true and correct copy of Ordinance No.025371 passed and approved by the City Council on July 22, 2003 same appears in the Official Records of the City of Corpus Christi, Texas, of which the City Secretary's Office is the lawful custodian.

WITNESSETH MY HAND and the Official Seal of the City of Corpus Christi, Texas, this 12th day of September, 2003.

Armando Chapa/rh

Armando Chapa
City Secretary
Corpus Christi, Texas

(S E A L)

RESOLUTION

DIRECTING AEP TEXAS CENTRAL COMPANY TO FILE CERTAIN INFORMATION ("RATE FILING PACKAGE") WITH THE CITY OF CORPUS CHRISTI; SETTING A DATE FOR THE FILING OF THE COMPANY'S ANALYSIS OF WHY EXISTING RATES SHOULD NOT BE REDUCED; AUTHORIZING THE HIRING OF LEGAL COUNSEL AND CONSULTANTS; REQUIRING THE REIMBURSEMENT OF THE CITY OF CORPUS CHRISTI'S RATE CASE EXPENSES.

WHEREAS, the City of Corpus Christi is a regulatory authority under the Public Utility Regulatory Act (PURA) and has original jurisdiction over the rates of AEP Texas Central Company (AEP) to determine if such rates are just and reasonable; and

WHEREAS, Sections 36.003 and 36.151 of PURA empower a regulatory authority, on its own motion or on a complaint by any affected person, to determine whether the existing rates of any public utility for any service are unreasonable or in any way in violation of any provision of law, and upon such determination, to determine the just and reasonable rates; and

WHEREAS, the City of Corpus Christi has reason to believe that AEP Texas Central Company is over earning and its rates are excessive; and

WHEREAS, the City Council of the City of Corpus Christi desires, on its own motion, to exercise its authority under Sections 36.003 and 36.151 of PURA; and

WHEREAS, a procedural schedule should be established for the filing of a rate filing package by AEP Texas Central Company, procedures to be followed to obtain and review information from AEP Texas Central Company, the filing of an analysis of such information by the City's staff and consultants, the filing of rebuttal information from AEP Texas Central Company, and a public hearing at which time the City shall make a determination whether the existing rates of AEP Texas Central Company are unreasonable or are in any way in violation of any provision of law and if such rates should be revised and just and reasonable rates determined for AEP Texas Central Company; and

WHEREAS, legal counsel for the City of Corpus Christi and other South Texas Cities have recently negotiated a date for AEP to make a complete rate case filing with the City and the Public Utility Commission of Texas ("PUC").

NOW, THEREFORE, BE IT RESOLVED BY THE CITY COUNCIL OF THE CITY OF CORPUS CHRISTI, TEXAS:

SECTION 1. This resolution constitutes notice of the City's intent to proceed with an inquiry into the transmission and distribution rates charged by AEP Texas Central Company. On or before November 3, 2003, AEP Texas Central Company shall file with the City of Corpus Christi and the PUC, information that demonstrates good cause for showing that AEP Texas Central Company's transmission and distribution rates should not be reduced. Specifically, AEP Texas Central Company shall file with the City of Corpus Christi a complete system-wide rate case prepared according to the filing requirements of the PUC, along with all associated work papers. In addition, AEP Texas Central Company shall file with the City of Corpus Christi revenues and expenses associated with the provision of street lighting service within the municipal limits during 2000, 2001, and 2002.

SECTION 2. Cities designated representatives are authorized to intervene the City of Corpus Christi in any proceeding at the PUC that arises out of or is associated with this resolution.

SECTION 3. Subject to the right to terminate employment at any time, the City of Corpus Christi hereby authorizes Geoffrey Gay and Steven Porter with the law firm of Lloyd, Gosselink, Blevins, Rochelle, Baldwin & Townsend and other qualified consultants approved by the City Manager to review AEP Texas Central Company's rate filing and to assist the City of Corpus Christi in its ratemaking and to prosecute any appeals to the Texas Public Utility Commission or court.

SECTION 4. AEP Texas Central Company shall reimburse the City for the reasonable costs of attorneys and consultants upon presentation of invoices by the City.

ATTEST:

Armando Chapa
City Secretary

THE CITY OF CORPUS CHRISTI

Samuel L. Neal, Jr.
Mayor

APPROVED: 21st day of July, 2003.

R. Jay Reining
Acting City Attorney

R38605A1 doc

Corpus Christi, Texas
22nd day of July, 2003

The above resolution was passed by the following vote:

Samuel L. Neal, Jr.	aye
Brent Chesney	aye
Javier D. Colmenero	aye
Melody Cooper	absent
Henry Garrett	aye
Rex A. Kinnison	aye
Bill Kelly	aye
Jessie Noyola	aye
Mark Scott	aye

R38605A1.doc

AEP/CSW Merger
Example of Application of Rate Treatment of Merger Savings and Expense
Central Power and Light Company

Rate Case Initiated By The Company

Year	Net Merger Savings Rate Rider (Attach. A) (1)	Achieved Savings (a) (2)	Net Merger Savings Expense Adj. (Attach. B) (3)	Amortization of Costs to Achieve (Attach. C) (4)	Revenue Requirements Impact: Net Revenue Requirements (2)-(3)-(4) (5)	Revenue Requirements Credit (Attach. E) (6)	Net Base Rate Impact (5)-(6) (7)	Rate Reduction Rider (Table H-1) (8)	Rate Reduction Rider (Table H-2) (9)	Total Rate Impact (1)+(7)+(8)+(9) (10)
Year 1	$ (3,663)							$ (15,337)	$ (4,807)	$ (23,807)
Year 2	(6,999)	Not applicable due to rate cap unless a force majeure proceeding is initiated under Sec. 3. F.						(12,001)	(4,807)	(23,807)
Year 3	(8,841)							(10,159)	(4,807)	(23,807)
Year 4	(10,212)	(25,256)	19,080	6,176	-	2,554	(2,554)	-	(4,807)	(17,573)
Year 5	(11,180)	(27,193)	21,016	6,176	-	3,038	(3,038)	-	(4,807)	(19,025)
Year 6	(11,827)	(28,486)	22,309	6,176	-	3,361	(3,361)	-	(4,807)	(19,995)
Total	$ (52,722)	$ (80,934)	$ 62,405	$ 18,529	$ -	$ 8,952	$ (8,952)	$ (37,497)	$ (28,842)	$ (128,014)

Rate Case Initiated By A Signatory Other Than The Company

Year	Merger Savings Rate Rider (Attach. A) (1)	Achieved Savings (a) (2)	Net Merger Savings Expense Adj. (Attach. B) (3)	Amortization of Costs to Achieve (Attach. C) (4)	Revenue Requirements Impact: Net Revenue Requirements (2)-(3)-(4) (5)	Revenue Requirements Credit (Attach. E) (6)	Net Base Rate Impact (5)-(6) (7)	Rate Reduction Rider (Table H-1) (8)	Rate Reduction Rider (Table H-2) (9)	Total Rate Impact (1)+(7)+(8)+(9) (10)
Year 1	$ (3,663)							$ (15,337)	$ (4,807)	$ (23,807)
Year 2	(6,999)	Not applicable due to rate freeze.						(12,001)	(4,807)	(23,807)
Year 3	(8,841)	(22,514)	16,337	6,176	-	-	-	(10,159)	(4,807)	(23,807)
Year 4	(10,212)	(25,256)	19,080	6,176	-	-	-	(8,788)	(4,807)	(23,807)
Year 5	(11,180)	(27,193)	21,016	6,176	-	-	-	(7,820)	(4,807)	(23,807)
Year 6	(11,827)	(28,486)	22,309	6,176	-	-	-	(7,173)	(4,807)	(23,807)
Total	$ (52,722)	$ (103,448)	$ 78,742	$ 24,705	$ -	$ -	$ -	$ (61,278)	$ (28,842)	$ (142,842)

Note (a) Achieved savings are the reduction in cost of service from gross merger savings as shown in Roberson Exhibit MDR-1.

Transmission

Mr. Mark Bailey, Vice President – Transmission Asset Management for AEPSC, sponsored testimony supporting approximately $3.8 million in affiliate costs related to transmission service. Mr. Bailey described the organization of AEP's transmission group, which is largely centralized in order to provide services to both TCC and TNC on a cost effective basis. He discussed how most transmission planning employees are AEPSC employees as a result of this organization. He noted that this type of organization avoids redundancy, gains economies of scale, and provides cost savings from the organization's ability to leverage the knowledge and experience gained from 11 operating companies for the benefit of each individual operating company such as TCC. He pointed out that over half of TCC's transmission costs were allocated to TCC and TNC because both are part of ERCOT, are closely related functionally and geographically and have numerous employees who perform work for both companies.

He described the primary allocation factor for transmission service charges to TCC, which is based upon the number of transmission pole miles. He further described the primary transmission activities performed for TCC and discussed why a pole mile allocator is reasonable.[1]

[1] TCC Exh. 9, Direct Testimony of Mark Bailey, at 28, line 6 through 33, line 2.

Distribution Costs

Mr. Harry Gordon, the Vice President of Distribution Operations for the Corpus Christi region, testified about affiliate costs related to distribution. These affiliate costs amounted to approximately $5.1 million in the test year. This accounts for approximately 10 percent of TCC's total distribution costs. The affiliate costs largely fall into two classes of categories. One involves support activities for distribution operations. This class accounts for approximately $3.0 million in affiliate costs. Most of these costs relate to the actual operation of the distribution functions' facilities. Other activities include obtaining, evaluating, and implementing distribution equipment and materials; managing joint use facilities; updating distribution maps; testing, maintaining, and repairing distribution equipment and meters; coordinating outage restoration activities; investigating power quality issues raised by customers; and managing TCC's demand side programs. The other primary activity relates to TCC's distribution engineering function.

Approximately $1.5 million in distribution affiliate costs are billed to TCC by AEPSC employees for planning, designing, and engineering TCC's distribution overhead, underground, and network facilities. All of these costs, while provided by AEPSC employees, are direct billed to TCC. Another activity provided in this category involves the construction of facilities. Approximately $500,000 falls within this category. Mr. Gordon explained that this function involves support activities for designing and engineering system backboard facilities and for securing rights-of-way and permits for certain construction projects.

As discussed above, while these affiliate costs are charged by AEPSC employees, the vast majority of those employees are located in Texas and serve TCC and TNC. Only for this reason are the costs by these employees considered affiliate costs.

Mr. Gordon described and justified the allocation factors for these costs.

He also described a benchmarking study for TCC's overall O&M costs based on 2002 FERC Form 1 data. That benchmarking test showed that TCC ranked 36 of 60 electric utilities in O&M dollars per end-use customer. Mr. Gordon pointed out that such a ranking indicates that TCC is neither overspending nor underspending on its customers but that a comparison of this nature alone cannot prove that a utility's costs are reasonable due to the different circumstances each company faces. Further, it logically follows that if TCC's total O&M costs are reasonable, it is quite likely that its affiliate O&M costs are reasonable. As Mr. Gordon pointed out in rebuttal testimony, it would be nearly impossible to perform a benchmark with respect to affiliate costs only by the utilities since most utilities are organized very separately with respect to whether services are provided by an affiliate or within the operating company.[1]

[1] TCC Exh. 8, Direct Testimony of Harry Gordon, at 16, line 18 through 20, line 10; TCC Exh. 70, Rebuttal Testimony of Harry Gordon, at 43, lines 4-5.

Customer Operations Costs

Mr. David Hooper, Manager of Customer Services for the Corpus Christi Region, sponsored testimony supporting $5.7 million in affiliate costs to TCC for customer operations. Mr. Hooper described at great length the organization and functions of the customer operations department of TCC. His testimony made very clear that TCC customers benefit significantly from the centralized services provided by AEPSC in this area. The functions include customer billing and support, resolving customer problems, managing customer relationships, maintaining call centers, and participating in ERCOT activities, among numerous other functions. Mr. Hooper also noted that the AEP customer information system significantly benefits TCC's customers and that the development and maintenance cost study system are supported throughout the AEP system.

He also described how AEPSC costs are allocated and how they are direct billed. Approximately $2.8 million of these costs are related to the call center located in Corpus Christi.[1]

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[1] TCC Exh. 10, Direct Testimony of David Hooper, at 21, line 3 through 25, line 14.