Final Order file

9/21/84

Public Utility Commission of Texas
7800 Shoal Creek Boulevard · Suites 400-450N
Austin, Texas 78757 · 512/458-0100

Philip F. Ricketts
Chairman
Peggy Rosson
Commissioner
Dennis L. Thomas
Commissioner

September 21, 1984

TO ALL PARTIES OF RECORD

RE: Docket No. 5640--Application of Texas Utilities Electric Company for a Rate Increase

Docket No. 5661--Petition for Review of Texas Utilities Electric Company From Final Decision and Action of the City of Lindale, et al.

Dear Sir or Madam:

Enclosed is a copy of the Examiners' Report and proposed final Order in the above-referenced consolidated dockets. This docket will be considered at the Commission Final Order Meeting on Tuesday, October 9, 1984, at the Commission offices, 7800 Shoal Creek Boulevard, Austin, Texas, beginning at 9:00 a.m. Exceptions, if any, to the Examiners' Report must be filed by noon, Monday, October 1, 1984, and replies, if any, to those exceptions must be filed by noon, Friday, October 5, 1984.

Pursuant to Commission Procedural Rule 21.143, requests for oral argument must be made in writing, filed with the Commission and served on all parties by 5:00 p.m. the fourth scheduled working day preceding the Final Order Meeting, in this case, Tuesday, October 2, 1984. If all parties are present at the Final Order Meeting, however, this requirement can be waived and oral argument heard at the Commissions' discretion.

You are not required to attend the Final Order Meeting, but you are welcome to attend if you wish. A copy of the signed Order will be mailed to you shortly after the Final Order Meeting. Please contact either of us if you have any questions.

Sincerely,

Phillip Holder
Phillip Holder
Adminstrative Law Judge

Mary Ross McDonald
Mary Ross McDonald
Hearings Examiner

xc: General Counsel

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Examiners' Report Errata

1. Pages 90 and 91 have been switched and mislabeled. Page 91 should follow page 89; after page 91 comes page 90; and page 92 follows page 90 in text.

2. There is no page 166. The text after page 165 resumes on page 167.

9/21/84

DOCKET NOS. 5640 and 5661

APPLICATION OF TEXAS UTILITES ELECTRIC COMPANY FOR A RATE INCREASE	§	PUBLIC UTILITY COMMISSION
PETITION FOR REVIEW OF TEXAS UTILITIES COMPANY FROM THE FINAL DECISION AND ACTION OF THE CITY OF LINDALE, ET AL.	§	OF TEXAS

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DOCKET NOS. 5640 AND 5661

APPLICATION OF TEXAS UTILITIES ELECTRIC COMPANY FOR A RATE INCREASE PETITION FOR REVIEW OF TEXAS UTILITIES COMPANY FROM THE FINAL DECISION AND ACTION OF THE CITY OF LINDALE, ET AL.	§	PUBLIC UTILITY COMMISSION OF TEXAS

EXAMINERS' REPORT

I. Procedural History

On March 9, 1984, Texas Utilities Electric Company (TUEC) filed a statement of intent to increase its rates within the unincorporated areas served by it. This application would result in a systemwide annual revenue increase of approximately $304.2 million or 7.98 percent over adjusted test year operating revenues recoverable under the existing rate schedules. At the end of the test year, September 30, 1983, TUEC served approximately 1,761,411 Texas retail customers. All Texas customers and classes of customers are affected by the application. The docket was assigned to Administrative Law Judge Angela Marie Demerle and Hearings Examiner Mary Ross McDonald.

The Commission has jurisdiction over the consolidated dockets pursuant to Sections17(e), 37, 26(a), 42 and 43 of the Public Utility Regulatory Act, Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon's Supp. 1984). The application filed by TUEC indicates that applications for rate increases were contemporaneously filed with all regulatory authorities excercising original rate jurisdiction.

TUEC gave published notice in accordance with Section 43(a) of the PURA and P.U.C. PROC. R. 21.22(b)(1), and gave notice of the proposed rate change to all affected utility customers in accordance with Section 43(a) of the PURA and P.U.C. PROC. R. 21.22(b)(2).

The initial prehearing conference was convened on March 26, 1984. The following motions to intervene were granted: Tex-La Electric Cooperative, Inc.; Texas-New Mexico Power Company; St. Regis Paper Corporation; Southwestern Electric Service Company; Citizens Association for Sound Energy (CASE); Texas Retailers Association (TRA); Cap Rock Electric Cooperative, Inc., Lone Wolf Electric Cooperative, Inc., Lyntegar Electric Cooperative, Inc., Midwest Electric Cooperative, Inc., Taylor Electric Cooperative, Inc., and Rayburn Country Electric Cooperative, Inc., (Coops); City of Bowie; Texas Industrial Energy Counsumers (TIEC); Texas Municipal League (TML or Cities); United States Air Force; Office of

Public Utility Counsel (OPC); Brazos Electric Power Cooperative, Inc.; City of Sherman; Department of the Army; City of Irving; City of Odessa; Texas ACORN; City of Waco; Chapparal Steel Company; General Services Administration; City of Grand Prairie; and International Brotherhood of Electrical Workers. At the initial prehearing conference, the stated effective date of April 13, 1984, was suspended for the statutory suspension period of 150 days until September 10, 1984, or until further order of the Commission. A hearing date and procedural schedule were also established at the prehearing conference. In a written order, a revised procedural schedule and guidelines for participation were established. The OPC appealed this order to the Commission, but it was not heard and was denied by operation of law.

At a Final Order Meeting on April 6, 1984, the Commission expressed its intention to "consider" TUEC's fuel factor as an issue in this docket. Although TUEC apparently decided not to pursue a revised consolidated fuel factor in this docket, the staff voiced its intent to consider fuel in this docket, apparently in a "reconciliation" fashion under the new Fuel Rule. However, since TUEC filed its rate case, the Commission set a consolidated fuel factor which was implemented in May, 1984. See, Docket No. 5294, Application of Texas Electric Service Company, et al., 9 P.U.C. BULL. 532 (April 13, 1984). Because of the somewhat confused nature of the TUEC fuel situation, and because the examiners desired to be in the best possible position to set reasonable base rates and, if necessary, fuel factors, in this docket, a prehearing conference was held on April 23, 1984, in order to discuss procedures which might be implemented in this docket in order to arrive at a result consistent with the Fuel Rule and to allow the fullest examination of the fuel issue (if the parties desire that it be examined) in the time remaining in this docket. The parties were allowed to make full oral presentations at the prehearing conference. After consideration of all parties' comments, the examiners determined that neither the PURA nor the Commission's Procedural and Substantive Rules evidence either an intent or a requirement that fuel costs must be determined in every general rate case, only that all fuel costs shall be reviewed in the general rate case. P.U.C. SUBST. R. 23.23(b)(2)(A). Absent an express, unequivocal requirement in the statute or the rules, TUEC cannot be ordered to file a fuel case with a suspension of its effective date until such a filing is made. The alternative-ordering TUEC to file a fuel case without such a suspension of the effective date and consequent time limits-would involve the parties in an issue not required to be in the case, and would be extremely burdensome on the staff and the intervening parties. The examiners therefore ordered TUEC to provide full and complete answers to the specific requests of the Utility Evaluation Division in the General Counsel's third request for information.

On March 22, 1984, the General Counsel of the Public Utility Commission, the OPC and CASE filed motions to dismiss this docket. Motions in support of dismissal and TUEC's response to the motions to dismiss were filed on April 6, 1984. Replies to the applicant's response were filed on April 13, 1984. The three motions to dismiss contained several and varied grounds for dismissal; however, after carefully reading and considering the various arguments on the question of dismissal, the examiners concluded that dismissal was not supported by the pleadings because no legal grounds were alleged which would mandate that this Commission dismiss the case, and because this Commission has no authority to dismiss the case based on the various equitable arguments presented by movants; even if such authority existed, the facts of this case did not support such a harsh remedy. Both OPC and the General Counsel appealed this ruling to the Commission. The appeals were not heard and were denied by operation of law.

Pursuant to Sections 10 and 43(c) of the Act and P.U.C. PROC. R. 21.101, regional hearings were held in three cities in TUEC's service area for the purpose of hearing protests and comments from members of the public. On May 2, 1984, a regional hearing was held in Tyler; two persons appeared and made comments. At the regional hearing in University Park on May 3, 1984, three persons made comments. One person made comment at the regional hearing held in Odessa on May 4, 1984.

On May 29, 1984, a prehearing conference was held for the purpose of hearing argument and ruling on discovery disputes which the parties were unable to resolve through negotiation. One of the disputes brought forward for resolution by the examiners involved the General Counsel's objections to the applicant's first request for information, principally on the ground that the General Counsel and the Commission staff are not subject to discovery because they are not a party to the proceeding. That objection was overruled, and the Commission staff was ordered to respond to the applicant's RFIs. The General Counsel appealed the ruling to the Commission; however, the Commission declined to hear the appeal, and it was denied by operation of law. Rulings were also made on objections filed by CASE and by intervenors Tex-La and the Cooperatives. The parties were able to reach an agreement on all other matters in dispute, including TUEC's providing of class coincident peak demands for each of the twelve months of the test year for the proposed rate classes, as well as each existing wholesale class. TUEC also agreed to provide load research data used or studied in making estimates, and the load research data for the wholesale customers. TUEC agreed that the estimated class coincident peak demand data would be based upon its professional judgment and the best available data; however, TUEC reserved the right to contest at the hearing the appropriateness of using any cost allocation methodology based upon class coincident peak demands and the appropriateness of any other cost allocation methodology inconsistent with that proposed by the company, provided that TUEC agreed not to contest or challenge the class coincident peak demands themselves actually produced by the company. At this prehearing conference, it was further agreed that the hearing on the merits in this docket would be bifurcated into two separate parts, one on revenue requirement and the other on cost allocation and rate design. Filing dates for testimony concerning cost allocation and rate design were advanced in order for the intervenors to be able to utilize the class coincident peak demand data to be provided by TUEC.

By way of written orders, the motions to intervene of the following entities were granted: City of Dallas; City of Fort Worth; Nucor Steel Corporation, Jewett Division; Air Products and Chemicals, Inc.; and Union Carbide Corporation.

Prior to the commencement of the hearing on the merits, TUEC appealed to the Commission from the final ratemaking action of 75 cities served by it, and requested that the appeals be consolidated with the pending rate case. That consolidation was granted, and the cities so consolidated were made parties to Docket No. 5640 for all intents and purposes. The cities made parties are as follows: City of Lindale; City of Howe; City of Nolanville; City of Hutchins; City of Bellevue; City of Glenn Heights; City of McLendon-Chisholm; City of Sweetwater; Town of Haslet; City of Westworth Village; City of Breckenridge; City of O'Donnell; City of Duncanville; City of Euless; City of Chandler; City of Huntington; City of Lacy Lakeview; City of Mansfield; City of Aledo; City of Sansom Park; Town of Holliday; City of Coahoma; City of Stanton; City of Roscoe; City of Hillsboro; City of Balch Springs; City of Seagoville; City of Wilmer; City of Southlake; City of Roanoke; City of Blue Mound; City of Azle; City of Fate; City of DeSoto; City of Colleyville; Town of Pleasant Valley; City of Electra; City of Rockwall; City of Denison; City of Harker Heights; Town of Boyd; City of DeLeon; City of Grapevine; City of Annetta North; City of Saginaw; City of Iowa Park; Town of Ackerly; City of Northcrest; City of Gorman; Town of Lakeside; City of Van; City of Runaway Bay; City of Bedford; City of Heath; City of Robinson; City of Beverly Hills; City of Stephenville; City of Witchita Falls; City of Lakeside City; City of Lamesa; City of Benbrook; City of Watauga; City of Henrietta; City of Archer City; City of Snyder; City of Murphy; City of Noonday; City of Burkburnett; City of Seymour; City of Kennedale; Town of Annetta South; City of Forsan; City of Graham; City of River Oaks; City of Ft. Worth.

Because of the departure from Commission employment of Judge Demerle, Hearings Examiner Phillip Holder was assigned to this docket prior to the commencement of the hearing on the merits.

On June 18, 1984, a settlement prehearing conference was convened for the purpose of the parties' discussing the possibility of entering into stipulations, settlements or agreements concerning facts or issues in this docket. On June 19, 1984, a final prehearing conference was convened in this docket for the purpose of presenting exhibits to be offered in parties' direct cases to the court reporter for marking, the consideration of timely filed pending motions, objections to prefiled evidence, and requests to take a witnesss on voir dire examination, and the scheduling of witnesses and establishing an order of proceeding and cross-examination.

On June 20, 1984, the hearing on the merits in this docket commenced. Examiner Holder presided over the revenue deficiency portion of the hearing. On July 16, 1984, the revenue deficiency portion of the hearing concluded. Briefs on revenue deficiency were filed on July 26, 1984, and reply briefs were filed on July 31, 1984.

On July 17, 1984, a settlement prehearing conference for the cost allocation and rate design portion of the hearing was convened for the purpose of the parties' discussing the possibility of entering into stipulations, settlements or agreement concerning facts or issues in this portion of the docket, and for taking up all other procedural matters. The hearing on the merits in the rate design portion of this docket was convened on July 18, 1984, with Hearings Examiner Mary Ross McDonald presiding and was adjourned on August 6, 1984. Initial briefs on rate design were filed on August 16, 1984, and reply briefs were filed on August 21, 1984.

The hearing on the merits took a total of 32 days, therefore, by written order, pursuant to Section 43(d) of the PURA, the suspension period was extended 34 days past the otherwise effective date of September 10, 1984, until October 14, 1984.

V. Invested Capital

TUEC's Schedule B states a total value of invested capital of $6,196,594,858, a total comprising the following amounts and categories of capital items:

Plant in Service	$5,559,859,832
Less Accumulated Depreciation	1,627,069,537
Net Plant in Service	$3,932,790,295
Electric Plant Held for Future Use	5,969,712
Construction Work in Progress	2,400,000,000
Nuclear Fuel in Process	156,128,052
Plant Materials and Operating Supplies	81,114,619
Fuel Inventory	96,581,903
Prepayments	19,477,977
Cash Working Capital	36,458,066
Accumulated Deferred Federal Income Taxes	(440,513,993)
Reserve for Insurance and Casualties	(11,926,092)
Customer Deposits and Advances	(34,929,566)
Other Cost Free Capital	(44,556,115)
Total Invested Capital	$6,196,594,858

A. Plant in Service

The applicant's plant in service figure as of test year end was adjusted by TUEC's manager of regulatory accounting, Marc D. Moseley. Mr. Moseley's adjustment concerns the company's Sandow Unit No. 4. That unit, placed into commercial operation in 1981, is a 545 megawatt lignite fired generating unit. A portion (450mw) of that unit's generating capability is dedicated to serving Alcoa; Mr. Moseley therefore eliminated 82.569 percent of that unit's total cost from the plant in service portion of rate-base, consistent with the Commission's treatment of this issue in prior rate cases. Applicant's Exhibit 1B, Moseley at 3,10. No witnesses challenged that adjustment, and it should be adopted by the Commission. [Many of the parties in this matter presented witnesses who did not do a complete cost of service analysis. For example, Cooperatives witness Carl Stover, Jr.--who is Vice President of C. H. Guernsey and Company--testified that the Cooperatives have not attempted to analyze any of the adjustments proposed by the Company to the test year numbers and that the Coops therefore did not take a position regarding the reasonableness of such adjustments. Coops Exhibit 1 at 4. Any adjustments to test year data made by the applicant which were not challenged by witness testimony or cogent legal arguments of counsel will be recommended for adoption by the Commission as reasonable.] The subtraction of $205,215,722 from plant in service, as proposed by TUEC, is reflected in this report's recommended invested capital figure.

Both the Cities and the Commission staff recommended further adjustment to TUEC's plant in service proposal. Cities witness Constance T. Cannady, a senior consultant in the management consulting division of Touche Ross and Company, decreased plant in service by $7,074,000 to reflect the January 1, 1984, retirement of Permian Basin units 1-4. She testified that the adjustment is not a consideration of events which occurred subsequent to the test year, but that it represents a determination that the plants were not used during the test year. She pointed out that the units' capacity factors from 1983 through the test year end were 0. Since the units were not used during the test year, Ms. Cannady removed them from plant in service, and removed an equal amount from accumulated depreciation, so that the final effect of these two adjustments would be no change to the applicant's net plant in service. Cities Exhibit 3 at 8.

Staff witness Randy M. Allen also removed the Permian Basin units from the utility's plant in service figure, on the grounds that they were retired as of January 1, 1984, and that they should be taken into consideration as known and measurable changes to the utility's invested capital which have occurred subsequent to the test year. Mr. Allen made a number of other adjustments in observation of this principle.

Counsel for the Cities argues that the Permian Basin adjustment is by no means based upon a known and measurable standard. The Cities in effect argued that, because the units in question generated no electricity during the test year, they are not used and useful·in providing electric service to TUEC's customers. It was pointed out that Ms. cannady left in plant in service numerous units which were in reserve status, and that she excluded only those units which were retired after the test year end and which were not used during the test period. Interestingly, Tex-La supports the adjustment, but concedes that while those units were not used in the test year, they were "useful by virtue of their availability." Tex-La would have the Commission exclude the Permian Basin units because the retirement date of those units was a known and measurable change.

The OPC supported Ms. Cannady's version of the adjustment, and refused to concede that the generating units were even useful. The OPC went further than just the decrease to the plant in service on account of the Permian Basin units, urging the Commission to order TUEC to undertake a study of the possible retirement or other methods of reducing operation and maintenance expense for those gas units which were scheduled for retirement but which are kept in service as workable peakers. OPC Initial Brief at 30. TUEC's Schedule I-6.2 demonstrates that there are fifteen gas units in service which are over thirty years of age. Some of them receive little use. The OPC cites Mr. Tanner's testimony that the retirement of any of those plants would require the building of additional gas fired generation, likely at a higher capital cost, but doubts the efficiency of postponing the retirement of those plants.

TUEC responds to these suggestions by pointing out that, although the Permian Basin units were not called upon to generate power during the test year, they were available as reserve. TUEC Initial Brief at 29 and citations therein. The applicant asserts furthermore that none of the adjustments to plant in service proposed by Ms. Cannady or Mr. Allen (Mr. Allen made a number of other adjustments to invested capital because he felt that they reflected known and measurable changes to the company's net plant in service total) should be allowed unless all known and measurable post year additions are included in plant in service. The applicant argues that the purpose of the test year is in part to determine a level of investment and expenses that is representative of that level which will occur during the prospective period that the rates will be in effect. Id. The applicant therefore insists that it would be improper to exclude post test year retirements without including post test year additions. The record demonstrates that since the end of the test year, TUEC has made additions to plant in service of over $200,000,000. Transcript at 1613 and 3220. The staff accountant conceded that the post test year additions are just as known and measurable as post test year retirements (Transcript at 3224-3225); Mr. Allen did not make the changes for the known additions because he believes them to be a violation of Commission policy (presumably against reclassifying construction work in progress closed to plant in service after test year end). TUEC argues that decreasing test year invested capital for known and measurable changes and making no changes--though known and measurable--for additions to plant in service after test year end "transcends all notions of fairness". Applicant's Initial Brief at 30. Regarding the OPC's requested order that TUEC present a study in its next rate case to justify the decisions to keep certain plants on line beyond thirty years, the utility insists that such an endeavor could achieve a little more than expounding upon the obvious. The expected reserves for the next few years testified to by Mr. Tanner in his prefiled testimony at page 13 are cited--together with the likelihood that retirement of existing units would mean their replacement with more expensive units--as demonstration for the need for that capacity and the efficient allocation of resources to meet that need.

The first issue to be resolved in the Permian Basin dispute is whether the fact that a capital item was not used during the test year requires its deletion from rate base. That result is counter-intuitive. Surely no one would point to the fire extinguishers in a utility's office building and insist that because there were no fires during the test year and because the extinguishers were not actually used, that they should be disposed of, or--if the utility insisted upon such a luxury--that the cost be carried by the stockholders. Innumerable entertaining examples can be selected, can be conjured up by anyone with the time and inclination, though they need not be far fetched. TUEC maintains materials and supplies, fuel inventories, and other capital items, as well as makes payments for insurance, which may not be pairable with test year events requiring their use. Nevertheless, the costs associated with such items are included in revenue requirement to the extent that they represent prudent management incurence of costs necessary to the provision of service. While no detractions to the skill and judgment of the accountants and the attorneys is meant, the examiners are persuaded that the decisions to keep these units available during the test year was a prudent one, and that they were "used and useful" during the test year period. Their availibility (despite lack of actual use) in the test year does not warrant disallowance.

The second issue to be dealt with is whether known and measurable changes should be made to the utility's invested capital total. This Commission has allowed known and measurable changes to operating expenses when they are reasonable, necessary, and fair both to consumers and utility. Application of Houston Lighting and Power Company, Docket No. 2248, 4 P.U.C. BULL. 1647 (May 31, 1979). This treatment is tied to the matching principle, whereby the utility's costs in providing service are established for a time period that is adequately matched to the timing of discerning customer consumption (billing determinants). The Commission, however, has in several recent cases declined to update the utility's invested capital when projects carried as construction work in progress as of test year end were completed and put into service prior to the filing. This treatment is in part due to the dictate of PURA Section 41(a), which ties any construction work in progress figure, and most likely the total original cost of property used by and useful to the utility, to the cost "as recorded on the books of the utility." While the Act does not specify that the end of the test year is the crucial focus in deciding whether construction work is included in rate base or not, the Commission has made that decision as a matter of policy. (See Application of Gulf States Utilities, Docket No. 5560, July 13, 1984). That policy cannot stem from the financial integrity test, since it is known that a project closed to plant in service before the filing of the rate package, for example, is being used by the utility, as it is known by what dollar amount the company's invested capital has increased as a result of that project's completion and going into service. Thus the granting of a return on construction work in progress, treatment which represents an exception to the principle that a utility is entitled to a return only on those capital items used and useful in providing service to its customers, is granted only when necessary to the financial integrity of the utility. Application of the financial integrity test then, to expenditures for plant which have already gone into service, would then be an unnecessary exercise. The real rationale behind disallowance of any reclassification of construction projects already closed to plant in service after test year end must be that known and measurable changes should not result in adjustments to invested capital for ratemaking purposes. It is respectfully submitted that the reasoning behind the Neches 7 disallowance in Docket No. 5560 cannot apply here. To the extent that the "matching principle" (meant to pair expense levels with consumption levels) focuses on growth, it has little to do with consistency in the timing of ganging plant in service. Use of the same temporal point to ascertain components of plant in service is the more important matching. Furthermore, the presence of insurance (a factor in the treatment of the untimely test year explosion at Neches 7) distinguishes the instant dispute from the treatment of post-test year retirement of generating plant in the GSU case.

The principle generally precluding known and measurable changes to test year end plant in service should not be reversed merely because the opportunity for a negative adjustment presents itself. TUEC's argument--that the purpose of the test year is in part to determine a level of investment and expenses that is expected to occur during the prospective period that the rates will be in effect--is correct. Disallowance of the Permian Basin units, without inclusion of the post test period additions to plant in service of over $200,000,000--smacks of a double standard. The cost of service proposed by this report therefore includes a return on an invested capital total reflective of the test year end level.

Regarding the OPC's requested order that the company develop and present in its next rate case a study justifying the decision to keep certain gas plants on line beyond thirty years, the testimony of Mr. Tanner tending to impugn such a request should be credited. He stated that the TUEC system has experienced significant growth, averaging a 4.8 percent annual growth in peak demand over the 1975-1983 time period. The current estimated annual growth rate of 4.0 percent for the next ten years, coupled with long lead times for, and other uncertainties in, the construction of new units, requires that decisions be made well in advance of the anticipated need. Mr. Tanner testified that the company's reserve capacity is currently projected to be 30.0 percent, 24.2 percent, and 19.6 percent in 1986, 1987, and 1988 respectively. (He figures those reserves at 16.2 percent, 11.0 percent, and 6.9 percent without the Comanche Peak units in service.) Cross-examining counsel may choose not to subscribe to the management decisions in which Mr. Tanner has participated, but there is not ground therein for requiring the study requested by the OPC, especially in the absence of competent witness testimony bringing the decisions regarding these gas fired units into question. It may offer a sense of accomplishment to order studies, as it is within the Commission's power to do, but the true need and the costs (to be borne by ratepayers) should also be taken into account. The proposed order recommends no such study.

Staff witness Allen also proposed to make other adjustments to the test year ended invested capital to account for known and measurable changes. The first of those adjustments was to reflect the transfer of production and general plant from TUMCO and TUSI on January 1, 1984. Those adjustments result in an addition to invested capital of $4,268,323. Mr. Allen also recommended removing certain parcels of land which were included in electric plant in service at test year end. He testified that the parcels were surplus land not being used in rendering service to the public. The company put on no rebuttal witness to address this, and one may well infer that those parcels of land were truly "surplus," and were not used in providing service or even necessary to have on hand in the task of providing service (as were, for example, the Permian Basin units). The proposed final Order therefore omits as an item of invested capital the surplus lands adjusted out by Mr. Allen, a decrease in invested capital of $469,496. It should be noted further that Mr. Allen recommended deletion of other post test year retirements, in his efforts to update the company's invested capital total for known and measurable changes. The total staff adjustment (including the Permian Basin retirement) was a decrease of $21,182,061. While Commmission policy which would allow--indeed require--the updating of rate base for <u>all</u> known and measurable post year additions and deletions would be supportable, it would appear arbitrary to recognize only decreases to rate base. It is not suggested that this is Mr. Allen's rationale, however; he did make a positive adjustment to account for post year transfers, as discussed above, in the amount of $4,268,323. Nevertheless, departure on the route of recognizing changes in invested capital, except only for those which have been carried as construction work in progress as of test year and then transferred to the plant in service account, is an ill advised journey. TUEC's plant in service should therefore be set at $5,559,390,336, the test year end amount minus the cost of the land not used and useful.

-continued-

C. Construction Work in Progress ("CWIP")

The Commission has previously authorized partial inclusion in rate base of construction work in progress on the books of the three operating companies which comprise the applicant. TP&L was allowed in Docket No. 4321 to earn a return on rate base which included 60 percent of its CWIP, an amount of $484,992,000; in Docket No. 5200, TESCO was allowed to include 55 percent of its booked CWIP as of test year end in rate base, in the amount of $582,743,000; and DP&L was permitted to include 80 percent of its test year end CWIP in rate base to earn a return, an amount of $406,526,000. These amounts total $1,474,261,000 of CWIP in rate base, currently earning a return. The discussion below addresses the testimony and arguments presented by the parties, and recommends that TUEC be allowed no additional CWIP in rate base in this case.

1. Testimony

a. Applicant (Kelch, Scotto, and Spence)

David E. Kelch is a Vice President and Treasurer of TUEC; his responsibilities include maintenance of the company's financial integrity, management of cash flow, and administration of the obligations associated with outstanding securities and debt. He testified to the consumer benefits of a financially healthy electric utility, pointing out that the company's obligation to provide reliable electric service at the lowest reasonable price over the long run is best met if the company is financially healthy, health being inferrable in part from the utility's bond ratings. This witness testified that customers of electric utilities with higher bond ratings have traditionally had, and now presently have, lower electric costs. He stated that the construction program entered upon by this utility was in part made possible by its high bond ratings, and will result in lower fuel costs for TUEC's customers. The treasurer asserted that the Public Utility Commission of Texas has historically granted lower returns on common equity to higher bond rated electric utilities, and voiced his belief that a deterioration in TUEC's financial integrity would increase the cost of capital and would eventually result in higher electric rates to the applicant's customers.

Mr. Kelch addressed the topic of construction work in progress, recommending that 2.4 billion dollars of CWIP be included in TUEC's rate base, an increase of approximately one billion over the amount now included. He felt that such inclusion was necessary "to restore and maintain our financial integrity." Applicant Exhibit 1A, Kelch at 7. According to Mr. Kelch, 2.97 billion dollars was the booked amount of CWIP at test year end, and that amount is some 41 percent of the company's net plant at test year end. This witness stated that CWIP has become an increasingly larger portion of the utility's net plant in the recent past, and that a substantial portion of that is not in the rate base and therefore earns no cash return. According to Mr. Kelch, CWIP will increase at about thirty-six million dollars per month through the end of 1984, on the average, at the end of which period the amount booked will have grown to approximately $3.5 billion dollars. He declared that even if TUEC were granted its request to include $2.4 billion dollars in rate base, there would still be $1.1 billion dollars of CWIP not in rate base at the end of 1984. He compared the company's CWIP to the amount of common equity investment as of September 30, 1983, finding that ratio to be 101 percent. In Mr. Kelch's opinion, having an amount of CWIP which is approximately equal to the common equity of the company is a truly exceptional circumstance, and a topic of great concern for investors. He found disheartening the effects of excluding CWIP from rate base, and salutory the effects of including it.

Mr. Kelch defined financial integrity of the utility as "the sound and unimpaired financial condition for the Company that maintains the exchange value of invested capital." Applicant Exhibit 1A, Kelch at 16. He saw any loss in TUEC's financial integrity as devolving primarily on customers . Seeing a connection between rate of return on equity and CWIP inclusion in invested capital, Mr. Kelch indicated that the company must be granted its requested return on common equity <u>and</u> rate base inclusion in CWIP "if it is going to attain and maintain the appropriate level of financial integrity." <u>Id.</u> at 18.

Referring to recent downgrades of TUEC bonds by some of the rating agencies that rate electric utility debt, Mr. Kelch extolled the virtues of a high credit rating, which he perceived as giving the company the ability to finance advantageously in all types of money markets. Concommitantly, he found numerous and grave the problems of short term financing of long term assets which lower rated companies may be forced into, in times of tight money or high interest rates. Mr. Kelch disagreed with the proposition that utilities with lower rated bonds, even though of investment grade, have only a few problems in issuing capital, and he illustrated such problems.

Believing that supplemental pretax interest coverages are more important as financial indicators for this utility than primary coverages, Mr. Kelch explained the financial obligations of the company related to Texas Utilities Fuel Company (TUFCO) and Texas Utilities Mining Company (TUMCO).

TUEC also presented the testimony of Daniel Scotto, Vice President in the fixed income group of L. F. Rothschild, Unterberg, Towbin, members of the New York Stock Exchange. Mr. Scotto is responsible for evaluation of the credit standing of over one hundred electric companies in the country, and writes reports about the industry on a regular basis that are received by more than two thousand members of the financial investment community. Mr. Scotto pointed out that competition for funds within the fixed income market has become intense since the early 70's, and investors--dissatisfied with the utility sector, which has been characterized by downgrades of credit standings of nearly fifty percent of the industry since 1975--are becoming reluctant to invest in the utility sector and are turning elsewhere. It was the witness's view that a high bond rating allows an electric utility greater access to the fixed income market, given that many institutional investors may be precluded by policy or law from investing in securities rated lower than AA. The quality of electric utility debt, according to Mr. Scotto, depends mainly upon the utility's current ability to service all of its fixed obligations, and the strength and probable duration of that ability. Gauging that quality includes consideration of such factors as interest coverage (with and without AFUDC), the level of internal cash generation, and capitalization ratios. Mr. Scotto was of the view that the financial stability of a company is quite important, but that the financial stability of a company depends upon more than quantifiable financial measures. He believes, for example, that the high quality of TUEC management focuses more investor attention (in the quest for financial stability) on the quality of regulation over that utility.

It was Mr. Scotto's testimony that the most important criteria for judging the risks associated with a given utility are those that the utility will realize prospectively. He stated that each financial ratio is given a different degree of emphasis depending on the circumstances, and that such qualitative factors as vitality of the service territory, diversification of the industrial base, revenue dependence on or independence of any single customer or class of customers, and operating characteristics of the utility are also important in the determination of an electric utility's financial integrity and creditworthiness. According to this witness, the credit rating assigned to a given electric utility depends in significant part upon the amount of faith that investors and the rating agencies have in the regulation of that utility. Specifically, investors are concerned with Commission sensitivity to the dollar disparity between rate base and capitalization. Mr. Scotto described investors as recognizing that capitalization must be served with cash, not AFUDC or earnings, and that CWIP in the rate base is the answer to this concern. Investors might also look at the level of authorized rates of return, the potential to earn those rates of return as well as the competitiveness of the levels, proper recognition of expenses and rate base, recovery of capital costs, regulatory lag, the timely and complete recovery of fuel costs, the consistency of regulatory policies and practices, and "the degree of intervention in the regulatory process by restrictive legislation." Applicant's Exhibit 1A, Scotto at 7.

Mr. Scotto testified that inclusion of CWIP in rate base for a cash return is interpreted by investors as a clear sign that a regulatory agency is willing to support major construction endeavors needed to fulfill the service obligation of the utility, without harm to its credit standing. He felt that failure to include an appropriate amount of CWIP in rate base would cause utilities to be at a competitive disadvantage in the marketplace for funds.

The inquiry into a utility's credit health is most perceptively achieved, according to Mr. Scotto, by scrutiny of the company's supplemental interest coverage. He described it as a statistic given considerable weight by the rating agencies, and found TUEC's pretax supplemental interest coverages for 1983 implicitly disappointing. He also stated that because AFUDC represents a substantial portion of earnings, the tendency of analysts, investors, and rating agencies is to focus more on cash interest coverage and cash earnings positions, statistics excluding AFUDC. He found that currently, interest coverage excluding AFUDC is the coverage statistic most often examined.

In support of his assertion that supplemental coverages were more important than primary ones, Mr. Scotto cited the misleading conclusions that might be drawn from straight income statements or balance sheet analyses, and stated that in the industrial area, rating downgrades due to substantial debt obligations not on the balance sheet are not unusual. After citing examples of same, he pointed out that during the years in which he was directly responsible for analyzing the three TU companies at Standard & Poors, supplemental interest was a key statistic in judging the three companies' ability to meet all fixed income obligations. Therefore, the debt obligations of the service companies, TUFCO and TUGCO, were considered fully as part of the utility's subsidiary income statements, thereby requiring appropriate coverage protection levels stronger than those applicable to the income statements and balance sheets of the utility's fuel affiliates alone.

Finally, Mr. Scotto testified that a lost credit rating is followed by a real danger of further downgrade. He pointed out that such a slide, once set in motion, is difficult to stop, and even harder and more costly to reverse. In illustration, he traced the downhill skid marks of eight electric utilities rated Aaa by Moody's and five rated AAA by Standard & Poor's in 1974. Mr. Scotto evaluated TUEC's current credit position as being significantly below what it should be, and recommended that an increased cash return on assets be furnished in order to support a high quality credit rating, and to protect the applicant against further downgradings.

Michael D. Spence, President of Texas Utilities Generating Company (TUGCO), a division of TUEC, has general management reponsibility for the construction and operation of Comanche Peak Steam Electric Station. He submitted prefiled testimony in this docket describing the Comanche Peak Station, updating the construction status of the nuclear plant, reporting on the prudence of the management of the construction, relating the status of fueling of the plant, evaluating the costs and benefits of the project, and documenting the company's claim that the project has been managed efficiently and prudently. According to Mr. Spence, Unit 1 of the plant is nearing completion and is scheduled for operation in 1984, and full service in early 1985. Nuclear fuel has been delivered to the plant and is in storage. The utility has sufficient amounts of nuclear fuel under contract to supply Comanche Peak for seventeen years of operation.

Mr. Spence testified that safety is a primary concern in all company operations, including the construction and operation of a safe nuclear power plant. He stated, with documentation, that the decision to build Comanche Peak was a good decision. According to Mr. Spence, factors like inflation, interest rates, and regulatory requirements have affected the cost and schedule of the plant, but Comanche Peak compares favorably with plants using fossil fuels due to the higher costs of those fossil fuels. It was Mr. Spence's testimony that despite the fact that the expected completion cost of the project has increased measurably since the original estimate in 1972, Comanche Peak is still among the lowest cost facilities of its type in the nation, at $1640 per KW (as compared to the average of $2300 per KW). Applicant's Exhibit 1A, Spence at 9. He concluded that the project will provide significant economic benefits to the applicant's customers.

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b. Tex-La (Ewert)

Dr. David C. Ewert is a Professor of Finance and Director of the Executive MBA Program at Georgia State University. He testified, on behalf of Tex-La, that all CWIP should be taken out of TUEC's rate base.

Dr. Ewert summarized financial integrity as meaning "the ability to attract capital at reasonable costs," indicating that the "company must be able to earn reasonable rates of return to pay the investors their required interest payments, dividend payments, or to obtain sufficient earnings to provide capital gains." Tex-La Exhibit 4 at 7. He felt that it was in the best interest of both investors in and customers of utilities that such utilities issue bonds. The witness pointed out that while an electric utility can have too high a bond rating, it was necessary to have one of investment grade, meaning of a rating of Baa or higher. However, the Tex-La witness stated that bond ratings should not be an issue in this proceeding, since no recommendation of any witness to this proceeding would reduce TUEC's bond rating to below investment grade and thus affect its financial integrity. He disagreed with Mr. Kelch that lower interest rates (attributable to high credit ratings) mean lower costs to the customers. He found that for this applicant the higher coverages necessary for it to regain a AAA bond rating would be more costly to the customers than the savings gained with the lower interest rates associated with AAA bonds.

Dr. Ewert took issue with TUEC witnesses Kelch and Scotto as to the necessity of using supplemental coverage ratios for ratemaking purposes, reasoning that the Commission allowed TUEC to include those interest payments to the fuel affiliates in the fuel factor, and that the Commission allows for a reconciliation of over or under collection of fuel costs. He pointed out that supplemental coverage is not mentioned as an issue by rating agencies who recently lowered the bond ratings for the operating companies, and that the Commission has persistently found that these utilities have failed to show their financial integrity significantly linked to the earnings necessary to achieve good supplemental coverage. Id. at 17. The Tex-La witness doubted the applicability of Mr. Scotto's Minnesota Power and Light example, in which the obligation related to Square Butte was considered significant by rating agencies. Dr. Ewert points out that the Square Butte obligation represented 29.3 percent of the capital structure of Minnesota Power and Light, while for TUEC, the debt of the fuel affiliates represents only 7.04 percent of adjusted long-term capitalization. Id. at 18.

Dr. Ewert stated that in his opinion the company's bonds are not in danger of "further immediate downgradings." He pointed out that rating agencies have recently characterized the TU systems as "financially strong." Id. at 19. The

Tex-La witness identified the reasons for the recent downgrades as the company's construction program, its involvement in nuclear power, and change in the regulatory environment. He doubted that those areas were of such concern as to cause another downgrade in the near future. Dr. Ewert explained that the company, by its own admisssion, has a certain amount of flexibility in its construction program, that Comanche Peak may well be on line soon, and that "the Texas Public Utility Commission is still one of the most highly regarded Commissions in the country." Id. at 22.

Mr. Kelch had stated that TUEC needs rates to meet several requirements on an ongoing basis, including a pretax supplemental interest coverage of 4.0x (including AFUDC), and 3.5x (excluding AFUDC), pretax primary interest coverage of 4.5x (including AFUDC) and 4.0x (excluding AFUDC), 25 percent or less AFUDC (as a percent of earning available to common shareholders), and 50 percent or more of construction expenditures being furnished by internal cash generation. Dr. Ewert pointed out that during the eleven year period 1973 through 1983, these requirements have never been met concurrently, and that the company has simply never met Mr. Kelch's minimum requirements for supplemental coverage with or without AFUDC.

Dr. Ewert observed that CWIP is under the PURA an "extraordinary form of rate relief", meaning that CWIP should be included in rate base "only when a utility is clearly shown to be in exceptionally weak financial condition." Id. at 25. It was Dr. Ewert's opinion that zero percent CWIP in rate base still alowed the utility interest coverages which compare favorably with other utilities rated AA by bond rating agencies. Conceding that the interest coverage without AFUDC under his recommendation would be in the 2.8x range, that the internal cash generation as a percent of construction expenditures would be around 24 percent, and that the AFUDC as a percent available for shareholders would be at approximately 61 percent, Dr. Ewert cautioned against placing undue emphasis on those indicators, since--according to the witness--the "problems they appear to portray will be self-correcting, when Comanche Peak Unit 1 commences commercial service." Id. at 29.

Dr. Ewert performed an analysis of selected financial indicators for the company, associated with Tex-La's (prefiled but increased by Dr. Taylor at the time of the hearing) return on equity of 15 percent and zero CWIP in rate base, concluding that "TUEC will maintain a reasonable level of financial integrity relative to the performance of other investment grade bonds." Id. at 30.

As an alternative to including CWIP in rate base, Tex-La urged through the testimony of this witness that TUEC engage in more joint ownership ventures with certain wholesale customers, especially Tex-La. Tex-La is currently a co-owner of the Comanche Peak nuclear project with TUEC and other parties, and has contributed approximately $109 million in construction costs. Id. at 32. Such joint ownerships decrease the capital requirements to TUEC, according to Dr. Ewert. Specifically, Tex-La has attempted to discuss with TUEC the possibility of its participation in the purchase of Alcoa's 30 percent ownership interest in the Twin Oak lignite unit now under construction by the applicant. Tex-La finds TUEC's lack of interest in such discussions annoying, in light of the purported potential public benefits.

c. Staff (Johnson and Skinner)

Dr. Ben Johnson, a consulting economist testifying on behalf of the staff, recommended inclusion of $1,425,000,000 of CWIP in the company's rate base. He discussed the notion that a cash return on CWIP would be a necessity only in exceptional circumstances, and pointed out that a competitive firm would have to wait until such projects are completed before the new facilities can contribute to that firm's earnings. He found it necessary for the economic incentives operational in a competitive context to be preserved in a regulatory context also. Dr. Johnson found several general problems with the company's proposal to include $2.4 billion of CWIP in rate base, including the difficult regulatory problems associated with failure to accrue AFUDC were the construction projects considered to be cancelled or otherwise never become operational, the virtual impossibility of matching costs and benefits as among current and future ratepayers, the necessity of smoothing the impact on customer rates which will occur when massive amounts of plant are transferred to plant in service from CWIP, and the fact that current customers are providing cash flow support even for the portion of CWIP not included in rate base, due to the company's use of a net of tax AFUDC rate. Among the factors the Commission should consider in resolving TUEC's proposal for CWIP inclusion are the appropriate regulatory policy (focusing mainly on the matching concept), applicable statutory provisions (requiring CWIP inclusion to be an exceptional situation), and utility's financial stability and strength, according to the staff witness.

Dr. Johnson disagreed with the company on several points in this area. To endorse the applicant's assumption that the financial integrity issue is to be evaluated by way of projected financial ratios consistent with a AAA rated utility is to ignore the requirements of the PURA, Dr. Johnson stated. Staff Exhibit 5 at 13. He also explained that Mr. Kelch's insistance that a high level of financial strength necessarily means lower electric rates is not necessarily true. Id. at 14.

Analyzing the approaches used by the Commission staff previously to inquire into a utility's financial integrity, Dr. Johnson suggested that placing too much emphasis on the utility's projected information and formulating specific target ratios was in error. Dr. Johnson's analysis of TUEC's financial integrity was made in accord with several guidelines, including the evaluation of both historical and projected information, use of historical information to compare the utility's performance to the industry as a whole and to formulate trends of the indicators over time, evaluation of the historic and projected financial data relative to target ranges rather than to point estimates, establishment of target ranges "less ambitious" than previously established staff targets, and uncoupling the analysis of the financial ratios previously linked to the other ratemaking adjustments at controversy in the docket. Id. at 18-20.

Dr. Johnson began his discussion of TUEC by noting that the trend in its financial indicators has generally been upward, that its achieved return on average equity has been substantially higher than the utility average (and has been stable or trending upward since 1976) and that the applicant's cash flow to construction ratio has also been higher than industry average and has continued to rise in the face of larger increases in the applicant's construction spending. Id. at 20-21.

Dr. Johnson examined data showing the effects of the level of CWIP allowed in rate base on the company's financial indicators of cash flow to construction expenditures, AFUDC to net income, pretax interest coverage, and earned return on average equity. He concluded that these ratios are significantly affected with different CWIP amounts included in rate base. Id. at 22-23, Schedule 2. Dr. Johnson developed certain target ranges for financial ratios to be used in determining the amount of CWIP to be included in the company's rate base, suggesting that the cash flow to construction ratios be targeted at 20 to 40 percent, that the AFUDC to net income ratio range from 30 to 60 percent,that pretax interest coverage in the range of 2.5 to 3.5x be obtained (primary with AFUDC), and that achieved return on average equity be in the range of 12 to 16 percent. Given these rather broad target ranges, he concluded that there was not good reason shown for increasing the CWIP in rate base beyond the amount previously allowed by the Commission:

> It is my conclusion that the Company's financial position has been, and will continue to be, secure enough that a dramatic increase in the level of CWIP in the Company rate base is unwarranted. In other words, the Company's request to increase the level of CWIP in rate base from approximatley $1.4 billion to $2.4 billion should be rejected.
>
> Nevertheless, it would not be wise to move to the other extreme and precipitously remove all CWIP from the Company's rate base after so many years of inclusion. The Company's current strong financial position is partly due to past policy of consistently including large amounts of CWIP in rate base. The Company's financial integrity can be maintained while the amount of CWIP in rate base is gradually reduced; however, if the Commission decides to move in this direction, it should do so cautiously. Sudden or precipitous reversal of past policies can have an adverse effect on investor attitudes which go beyond the direct impact on the Company's financial performance.

Id. at 26.

Dr. Johnson conceded that the company's financial indicators can be expected to decline for the next few years absent "substantially increased amounts of CWIP in rate base," but that the commercial operation of Comanche Peak will improve this situation. Id. at 26-27.

While Dr. Johnson did not undertake to assess the details of the company's construction program, staff engineer Sam F. Skinner discussed various cost and schedule changes in the construction of Comanche Peak, in light of the PURA's requirement that management of construction work in progress projects be prudent, and he discussed the current status of the project in light of the fuel loading and the ultimate placement of Comanche Peak in rate base. Mr. Skinner pointed out that P.U.C. SUBST. R. 23.21(d)(ii) requires that "construction work in progress shall not be allowed for any portion of a major project which the utility has failed to prove was efficiently and prudently planned and managed." Mr. Skinner therefore addressed the staff's responsibility to make a prudence recommendation, prior to the financial integrity test.

Mr. Skinner's recommendation was that a ceiling of $1.8 billion of CWIP be set for inclusion in rate base, based upon "a very general order-of magnitude estimate of the costs associated with the redesign, rework, construction delays and delays in final acceptance by both NRC Region IV and the Atomic Safety and Licensing Board (ASLB)." Staff Exhibit 6 at 5. Mr. Skinner simply stated that in his opinion, about one-third of the total $3 billion increase in the estimated cost of Comanche Peak stems from key decisions made by the utility, and that TUEC has not yet demonstrated to his satisfaction that those decisions meet the "prudently planned and managed" test. Mr. Skinner reviewed various cost increases related to seven major forecasts occurring from the original estimate in August 1972 up to the latest budget estimate of December 1983. The fact that the cost per kilowatt is below average for similar nuclear plants of a similar size and schedule was in Mr. Skinner's opinion not sufficient demonstration to satisfy the Act and the Rules. He therefore reviewed the amounts of change in the major components of the cost estimates, concluding that indirect costs increased to a greater extent than direct costs, consistent with increases traceable to project delays. The staff witness stated that "these higher than average increases could be the result of the decision of TUEC to postpone many of the quality control inspections often done in progress until the after the construction was essentially complete." (emphasis added) Id. at 6. He cited the latest construction progress report (dated April 30, 1984) as showing that 65 percent of the systems were "transferred" to operations, but a mere 8 percent were accepted. Mr. Skinner conceded that many of the problems could be related to the numerous changes in design resulting from the Three Mile Island accident, and cited a 1980 NARUC estimate that such changes resulted in a cost increase of some $500 million in a "typical" nuclear plant. There are also current changes in quality assurance and quality control documentation required by the NRC, which mitigate, but the staff witness infers a hesitancy on the part of the applicant to react to those types of regulatory changes. The recording of significant deficiencies and deviations on punch lists and inspection reports, rather than tne "official" NonConformance report form, as well as the responses made by TUEC to various allegations by CASE, are--according to Mr. Skinner--points of contention between TUEC and the NRC which have still not been resolved. Also pending is an assessment of the propriety of contacts between CYGNA (which investigated these allegations) and TUEC which allegedly violated the independence of the CYGNA investigation. Id. at 7.

Mr. Skinner found in a decision by TUEC early in the project, to file for their construction permit in 1974 based on an ASME code that was in the process of revision at the time, another contributor to the delay. Another factor was the firing of three quality control inspectors by Brown & Root, TUEC's general contractor. The Department of Labor has ruled against Brown & Root in those three firings, and Brown & Root's appeal of the ruling, and generally the pendency of those matters has led to the NRC's reopening investigations concerning inspector intimidation and harassment. The ASLB also required TUEC to prove that the design and construction of Comanche Peak is in accord with federal safety standards, and there is an operative ASLB presumption that reporting of nonconforming conditions was discouraged. Mr. Skinner found a number of items still being considered by the ASLB, in the matter of compliance with federal standards. All of this has led to an April 1985 schedule for conclusion of the ASLB hhearings, as Mr. Skinner cites ASLB Chairman Peter Block. Id at 8-9.

Mr. Skinner made an attempt to quantify the cost of any questionable TUEC decisions that could have contributed to the cost increases at Comanche Peak, but he characterized them as "not very successful." Nevertheless, Mr. Skinner concluded that "the key decisions made by TUEC related to the above causes of delay could have contributed as much as one half to the cost increases" not directly related to the increased regulatory requirements after the Three Mile Island incident. Id. at 9-10.

Mr. Skinner also provided an update on the status of construction at Comanche peak, testifying that as of April 30, Unit 1 was 97 percent complete and Unit 2 was 65 percent complete. The projected fuel load date at the time of hearing was September 1984, but Mr. Skinner doubted that the ASLB hearings would be completed by that time, and there was another unresolved problem in the De Laval emergency diesel generator. Mr. Skinner stated that NRC has informed the applicant that it will not let a nuclear plant start with this piece of equipment, without first fully verifying the design and manufacture of the generator. Assuming a timely September 1984 fuel load would allow TUEC to file a rate case including Comanche Peak in rate base in summer of 1985, although Mr. Skinner was doubtful about the absence of futher delays. He finally clarified that in such a rate case, he would reassess the prudence of management and recommend no rate base disallowance based on that criterion, given sufficient evidence by TUEC that their decisions were prudent.

d. OPC (Effron & Szerszen)

Consulting accountant David J. Effron testified on behalf of OPC that he had considered the relevant financial indicators for various assumptions regarding the CWIP level allowed a return, and that he recommended limiting that level to the present amount earning a return pursuant to Commission order, $1.474 billion. That amount would represent a denial of TUEC's request to increase the amount of CWIP already in rate base. According to Mr. Effron, "the level of CWIP includable in rate base should be the minimum CWIP balance necessary to maintain the financial integrity of the company." OPC Exhibit 1 at 10. He considered certain financial indicators as relevant to the determination of TUEC's financial integrity, including primary coverage excluding AFUDC, primary coverage including AFUDC, internal cash generation, and AFUDC as a percentage of earnings available for common. Mr. Effron calculated the financial indicators, which include consideration of the OPC recommended return on common equity as well as other cost of service issues, under three different assumptions. The first would limit the level of CWIP to that currently earning a cash return; the second limited CWIP to the level of investment in Comanche Peak Unit 1 as of test year end ($1.699 billion); the third represents a composite weighted average of the percentage of CWIP as of test year end on which the three operating divisions were granted returns by prior Commission cases (resulting in $1.873 billion). Mr. Effron assumed that the Commission would accept all of his recommendations regarding revenue deficiency in his calculation of those indicators, and he accepted certain of the company's assumptions in that calculation, although he doubted the value of the sum of the company's projections of its September 30, 1985, indicators, since TUEC has notified the Commission that it could seek additional rate relief with Comanche Peak in rate base in early 1985. He finally stated that he had included a $1.474 billion figure of CWIP in rate base, based on the assessment that the annual revenue requirements associated with the in service date of Comanche Peak Unit 1 will appromimately equal the fuel savings from nuclear generation from Comanche Peak Unit 1, assuming a capacity factor of 67 percent. Id. at 16.

OPC Economist Dr. Carol Szerszen addressed the issue of financial integrity. She found Mr. Kelch's required standards of finaancial integrity, a 4x supplemental coverage including AFUDC, a 3.5x supplemental excluding AFUDC, 25 percent of earnings available to common stockholders comprising AFUDC, and 50 percent internal cash generation, to be arbitrary and unjustified. According to the OPC witness, these healthy indicators are not likely to confer any real benefits on customers, inclusion of no additional CWIP will not perceived by investors as increasing the company's risk, and there are no exceptional circumstances warranting the inclusion of additional CWIP in rate base in this case. OPC Exhibit 2 at 30-31. Dr. Szerszen listed the average values of six financial ratios for AA rated electric utilities and AA rated electric utilities with nuclear plants under construction, listed the minimum and maximum values for each indicator in the AA rated utility groups, and presented those results on her Schedule 8. She concluded that the indicators for September 30, 1984, and for 1985, assuming no rate relief whatsoever, were consistent with maintenance of a AA bond rating. On this point, Dr. Szerszen concentrated more on coverage ratios than on internal cash generation and AFUDC as a percent of earnings available to common, reasoning that the latter were generally not important variables in the bond rating process. She observed more variation in those variables within entities with a given bond rating than between groups with different ratings. Id. Dr. Szerszen discounted reliance on projected coverage ratios as an indication of TUEC's financial integrity, and observed that bond ratings often involve subjective evaluations. Finally, looking at the earned return on average common equity, assuming no rate relief, for September 30, 1984, and for 1985, Dr. Szerszen used the company's projected financial statements to predict that the company will earn a return on average common equity at year ending September 30, 1984, of 16.24 percent, and 15.23 percent in 1985. She doubted that the company will have to borrow money to pay dividends, as had been asserted by Mr. Kelch, and found unlikely the prospect that investors would perceive the company's financial position as jeopardized. Id. at 36, 37.

The OPC witness also undertook to refute Mr. Kelch's assertion that increased risks perceived by investors would ultimately mean higher electric rates for the customers. She found no reason that investors should perceive additional risks if TUEC is given no CWIP return in addition to that already allowed by Commission orders, found no showing by Mr. Kelch that there is necessarily a relationship between bond ratings and revenue per kilowatt hour, and disputed Mr. Kelch's assertion that the Commission has historically granted lower returns on common equity to electric utilities with higher bond ratings. Referring to her Schedule 11, Dr. Szerszen concluded that improved bond ratings may not necessarily result in interest cost savings, but that even if such interest cost savings did occur, the costs of maintaining the ratings might well outweigh the benefits, from the customers' point of view. She found it "more likely that a BB or BBB company will experience significant savings in interest costs if its rating is improved to a double A than will an A rated company that is upgraded to a double A." Id. at 44.

The OPC witness also differed with Mr. Kelch's conclusion that lower credit ratings lead to shorter term maturities and high refinancing rates on debt, based upon her examination of utility bond issuances between July 1982 and June 1983 and her observation that AA as well as BBB rated companies issued debt maturing in a shorter period than thirty years during that period. She concluded that one may not safely presume that "low bond ratings" decrease financing flexibility. Id. at 48-49.

Dr. Szerszen summarized Mr. Kelch's testimony as demonstrating merely that in tight money markets, utilities are likely to face financing difficulties across the board. She found that it did not automatically follow that the applicant is currently unable to maintain financing flexibility and attract adequate capital with its current bond rating; accordingly, the OPC has recommended that TUEC be allowed no additional CWIP in rate base.

e. Coops (Murry)

Coops witness Dr. Donald A. Murry, an Economist with C.H. Guernsey & Company and Professor of Economics at the University of Oklahoma in Norman, recommended inclusion of 50 percent of TUEC's CWIP as of test year end, a recommendation he presented in tandem with his return on equity recommendation. Dr. Murry relied upon the information generated by several complementary approaches, and considered the resulting financial indicators under various scenarios to determine the necessity for a given return level for TUEC. According to the Coops witness, the size of the CWIP request in this proceeding mandates an analysis of rate of return on equity and inclusion of CWIP in rate base together, rather than separately. After performing his complementary analyses, (which are discussed in more length in Section VI. B. 3. of the report below), Dr. Murry concluded that a 15 percent return on equity and a $1.5 billion inclusion of CWIP in rate base was sufficient to ensure TUEC's financial integrity. His Schedules 4.1, 4.2, 4.3, and 4.4 demonstrate that his recommendation would likely result in a 4.4x interest coverage including AFUDC, a 3.82x interest coverage excluding AFUDC, an AFUDC as a percentage of earnings available to common ratio of 30.2 percent, and an interal cash generation of construction expenditures level of 50.6 percent. He concluded that those levels, commensurate with a 15 percent return on equity and inclusion of 50 percent of test year CWIP in rate base, are "most adequate to insure the financial integrity of TUEC." Coops Exhibit 2 at 26.

f. TML (Lattner)

Douglas J. Lattner testified on behalf of the TML that 55 percent of the applicant's test year end CWIP book amount should be allowed a return. To indicate the financial integrity of the utility, Mr. Lattner considered several financial ratios, including internal cash generation as a percentage of construction, pretax interest coverage, AFUDC as a percent of income available for common, and return on common equity. He pointed out that the results of one measure should not individually be used to reach a conclusion as to financial integrity, but that they should be looked at as a group. Based upon the TML's overall recommended requirement in the case, Mr. Lattner concluded that estimated internally generated funds as a percentage of construction expenditures would be approximatley 46.22 percent, that TUEC would have a pretax interest coverage including AFUDC of 4.39x and 3.87x excluding AFUDC, that of the income available for common equity 26.16 percent would represent AFUDC, and that the estimated actual return on book equity would be 17.1 percent. Mr. Lattner therefore recommended inclusion of $1,634,488,000 of CWIP, an increase of $160,227,000 over the amounts already earning a return pursuant to Commission order. TML Exhibit 2, Schedule 37.

g. CASE

CASE did not put on any direct witnesses, although it did introduce numerous exhibits and engage in extensive cross-examination in order to make its points. CASE asserted that the applicant need not maintain its current AA bond rating in order to preserve its financial integrity, and that the real causes of recent downgrades in the company's bond ratings relate to the company's untimely filing of rate cases and to problems at Comanche Peak. CASE concluded that since there had been widespread downgrading of utilities involved in nuclear construction, that "these credit rating drops are directly related to mismanagement of these projects by their respective utilities," (CASE Initial Brief at 8) and concluded ultimately that all CWIP related to Comanche Peak must be disallowed from rate base. CASE points out that the PURA allows inclusion of CWIP in rate base only as an exceptional form of rate relief and argues that the company has made no showing that such relief is merited. Quite the contrary, CASE argues: the fact that the Comanche Peak project is now approximatley five times over budget from an original estimate of $779,000,000 to the current estimate of $3.89 billion constitutes strong evidence of mismanagement, and justifies total disallowance.

Dr. Boltz urged in brief that the utility must first show that the projects sought for inclusion have been efficiently and prudently managed, and declared that TUEC has not--and indeed cannot--make that showing. With numerous references to the evidence, CASE points out that Comanche Peak is far behind its original schedule, that there are evidently no comprehensive historical files so as to assess properly the reasons behind the delays, and that in that context any assumption that the scheduling was prudently or efficiently achieved "becomes a leap of faith." Id. at 17. CASE also doubts that the current estimates of fuel load dates and in service dates are reliable. CASE argues that the company's deferring of its lignite plant construction for Comanche Peak was a poor management decision.

CASE points to the fact that Comanche Peak is over budget, that the project cost has been increased six separate times since the original 1972 estimate, and asserts that the current estimate of $3.89 billion is itself questionable. CASE impugns the use of a 70 percent capacity factor by company witness Nye in his projection of revenue requirement, and urges that 60 percent is by far a more realistic goal. CASE urges the Commmission to consider establishing nuclear capacity operating standards for Comanche Peak containing provisions for penalties and rewards in light of a utility's performance against the standard.

CASE doubts the company's projected cost per kilowatt of $1,640 as part and parcel of the utility's demonstrably inaccurate cost estimation.

CASE took issue with the company's assertions that regulatory change has played a large part in the cost escalation and scheduling delays experienced at Comanche Peak, asserting that a large part of the costs of schedule changes are related to terms of contracts, change orders, and supplements to contracts, as well as a long series of redesign, rework, modifications, retests, and reinspections attributable to the imprudence of the management of the project. This intervenor sought to demonstrate that the company has exercised inadequate control over contracts and contractors by failing to invoke penalty provisions in the contract when the work and or supplies were clearly substandard. CASE was more than suspicious of the fact that the costs of rework were not documented and tracked in a way that could be reviewed by the parties to this proceeding, and urged that without such an accounting system in place there is simply no incentive to guarantee the quality of work or the reasonability of costs. CASE points out that there were dramatic increases in the amount paid to contractors, as opposed to those amounts originally budgeted, as well as amounts paid for construction materials.

CASE took up the TUEC decision to postpone final verification QA/QC (quality assurance/quality control) inspections, arguing that the company has not even met its own deadlines for documentation of such inspections. CASE explored the ASLB licensing proceedings similarly, demonstrating more purported instances of imprudent management, and "negligence" as against the ratepayers. Id. at 46. CASE urges that even though the issues litigated before the ASLB and in the appeal from the Department of Labor rulings are not yet finally resolved, the mere existance of those rulings and litigation demonstrates the company's lack of prudence in management at Comanche Peak. According to CASE, it is the Commission's responsibility to issue in this docket a ruling on the prudence or imprudence of TUEC in managing Comanche Peak, and that pending allegations call into question not only the quality of the company's management, but its integrity and competence. Id. at 52.

CASE requests Commission exclusion of all CWIP related to Comanche Peak, pending the company's full documentation of the costs associated with rework, redesign modifications, reinspections, retests, repairs, etc., and the causes of those costs. CASE closes by pointing out the need for the development of a capacity factor incentive for nuclear plants, and urges the Commission to consider the necessity of a uniform decommissioning standard for Texas nuclear power plants that would insure the sufficiency and equitability of ratepayer contribution to decommissioning costs. Id. at 54-55.

2. Other Arguements

There was considerable attention paid to the issue of CWIP by the parties in closing briefs. Counsel for many parties evidently decided that the testimony of their own witnesses should be abandoned in favor of the recommendations of another witness. The CWIP arguments in the briefs constitute a woof of threads largely already present in the testimony of the witnesses, but woven in new patterns. The discussion below does not summarize in detail the arguments made by the parties in brief, although it does attempt to depict the salient features of those arguments.

TUEC reurged the points made by its witnesses, citing the fact that CWIP is 41 percent of test year end plant and that at test year end CWIP was 101 percent of common equity, and calling these "exceptional circumstances". The applicant insists upon inclusion of substantially more CWIP than is currently in rate base. TUEC Initial Brief at 22-23. The applicant reurged the necessity of scrutinizing supplemental coverages as significant financial indicators, and insisted that indicators must be calculated on a prospective basis. Such prospective calculations should take into account that Unit 1 of Comanche Peak would not be in commercial operation until late summer of 1985. Id. at 25. The utility criticized the recommendations of other parties, and declared that "if there is not a substantial increase in the current level of CWIP included, a downgrading is inevitable, not only for the Company but for other utilities in Texas as well..." Id. at 26. TUEC addresses the suggestion of CASE that an accounting system to track reworks is essential by pointing out that such a system would simply not be efficient, and by citing Docket No. 5256 for the point that reworks do not imply negligence or imprudence. Id. at 27. The utility refutes the assertion of the Coops that the lignite plants are in some sense alternatives to Comanche Peak, and explores the testimony of Mr. Skinner, pointing out that he did not find imprudence in management, that he was not urging that the Commission apply 20/20 hindsight to the Comanche Peak experience, but that--in many ways--the attacks made by various parties on the management of Comanche Peak are superficial. Id. at 27-28. After numerous citations to the record, the applicant's brief submits that the speculative suggestions proffered by the other parties to the proceeding do not overcome the probative effect of TUEC's evidence that the nuclear project is prudently and efficiently planned and managed. Id. at 29.

The TRA urges that "the Commission is now affirmatively mandated to examine a major construction project such as Comanche Peak to determine whether that construction has been prudently or efficiently managed." TRA Initial Brief at 5. This intervenor did not discuss the financial integrity test, but did urge that the company's failure to provide information satisfactory to the intervenors documenting the reasons and costs of rework, design changes, and other overruns and delays constitutes a failure by the company to carry its burden of proof. TRA suggests that the extent to which the company's current strength is a result of concerns over Comanche Peak and possible mismanagement is not clear. TRA suspects that TUEC's assertion that it does not keep records of defects and rework is a deception. Id. at 16. Even if the burden of proof is on parties wanting to show imprudence, the company's failure to keep adequate records and refusal to provide information to parties has effectively cut off the parties' ability to carry that burden, according to TRA. The proper remedy is, among other things, to require the company to begin keeping records of "the costs of and the reasons for each design, engineering, construction or equipment (including machinery, equipment, hardware, protective coatings, etc.) defect which requires remedial efforts of either the company or the company's vendors/suppliers/or contractors." Id. at 19.

The Coops in brief bypassed the recommendation of Dr. Murry, concluding that the utility provided "no evidence which will support the inclusion of any additional construction work in progress in its rate base." Coops Brief at 3. Counsel for the Coops points out that inclusion of CWIP in rate base is an exception to the "used and useful standard" usually applied in determining rate base, and that there is simply no basis in this record demonstrating TUEC's entitlement to such "exceptional relief of inclusion of additional construction work in progress in rate base to preserve financial integrity of the utility." Id. at 6, 7. The point that construction work in progress represents an exception to the used and useful standard normally applicable to the determination of rate base was also made by the TML. TML Initial Brief at 16. TML urged the Commission to note that the utility is still quite financially strong, that it has consistently earned more than authorized, that the effect on its financial indicators of the TESCO and DP&L increases has not even been seen but that the indicators have not significantly deteriorated recently, that the going on line of Comanche Peak will solve many of the company's worries, and (citing OPC Exhibit 11) that the applicant had intentions of filing two rate requests in 1985. Id. at 20, 21, 22, 24, 25. The Cities cite evidence to the effect that TUEC will have projected financial indicators within the range of those experienced by AAA and AA rated companies even without a rate increase in 1984 or 1985. Id.

Tex-La spends some space in its brief exploring the recent revisions to the PURA, and concludes that inclusion of CWIP in rate base is to be the exception, not the rule; according to Tex-La inclusion of CWIP is to be "an infrequent and unusual event," and "exceptional" is synonymous with "rare." Tex-La Initital Brief at 8. Interestingly, Tex-La argues that the final Order in the Gulf States rate request, Docket No. 5560, incorporated the TML's 50 percent CWIP recommendation which was not based on any stated objective, and which constituted no alteration in the TML witness's analysis of CWIP on account of the changes to the PURA effective September 1, 1983. Id. at 15-16. Tex-La notes that Gulf States Utilities did demonstrate an exceptional circumstance allowing this unusual form of rate relief, through the fact that its bonds are rated BBB, GSU being the only utility in the state to enjoy such a status. Id. Tex-La urges the adoption of Dr. Ewert's testimony, pointing out that his financial indicators result from the use of historic test year numbers, and that the use of any projections in calculating indicators must include the commercial operation of Comanche Peak. This intervenor again asserts that a happy alternative is available to the increasing levels of CWIP of TUEC, namely the willingness of Tex-La to directly invest in the construction. Id. at 20.

The OPC also urges that the 1983 amendments to the PURA indicate that a stricter standard is appropriate both to the question of whether CWIP should be allowed, and the question of how much CWIP should be included in rate base. The Public Counsel points out that the New York Public Service Commission reached findings and conclusions after hearing that the benefits of maintaining a rating above A were outweighed by the costs. OPC Initial Brief at 17. The OPC attacks the credibility of the company's presentation on this issue, and argues that the applicant failed to rebut a great amount of evidence in the record suggesting that the Comanche Peak delay and cost overruns are associated with imprudent management. The Public Counsel explores the NRC documents in the record, concluding that the costs and construction standards of Comanche Peak have been without the full and prudent control of the utility. In light of the questions of prudence, the OPC finds it "unreasonable for ratepayers to pay a return on any further CWIP associated with Comanche Peak." Id. at 26. The brief goes further, reurging the recommendations of OPC witnesses Effron and Szerszen that no additional CWIP be allowed in rate base in order to maintain the company's financial integrity. Finally, the brief adds that if the Commission finds an overall revenue requirement differing substantially from the OPC's recommendation of a rate reduction in the range of $80 to $100 million, the CWIP level should be reduced below its current level since preservation of the utility's financial integrity can be achieved with less than the currently allowed CWIP in rate base.

The General Counsel found that there were exceptional circumstances justifying the inclusion of some CWIP in rate base, in this instance the size of the construction work in progress in relation to the utility's net plant. Pointing out that such a ratio is similar to Mr. Kelch's CWIP to common equity ratio, the General

Counsel cites the testimony of staff witness Herbig (who generally provided background information relied upon by Dr. Johnson) that TU's CWIP to net plant ratio was 70.5 percent in 1983, and TUEC's ratio was 75.6 percent. The fact that such ratios are "considerably higher than the industry average" (Staff Exhibit 4 at 6) constitutes an exceptional condition warranting return on some CWIP, according to the General counsel. General Counsel Initial Brief at 10.

The staff's position is that there should be a movement toward specific criteria for financial integrity, and that Dr. Johnson's range of indicators represents a step in that direction. The General Counsel also agreed with the TRA that the company did not meet its burden of proof regarding efficiency and prudence of management of Comanche Peak. Specifically, the General Cousnel suggests that company witness Spence did not know enough details to allow for a cogent Commission exploration of this issue. The General Counsel cites <u>RE Detroit Edison Company</u>, 24 PUR 417, 362 (Mich. PSC, 1978) for the proposition that the utility has the responsibility to monitor costs and to attempt to keep them within reason, all going to the point that TUEC has not put an adequate tracking system in place to monitor the costs of rework. <u>Id.</u> at 15. The General Counsel also makes a persuasive suggestion that the parties should begin negotiation on the issues which will inevitably occur in the next rate case for this utility. Given the timing of the next case, after Comanche Peak goes into commercial operation, and the need for emergency relief likely to be perceived by the utility, a fierce conflict is likely to occur, absent planning and negotiation ahead of time.

The General Counsel also presented some thoughtful considerations in its reply brief of the statutory standard for CWIP, concluding that "investment grade" is the proper dividing line between utilities with financial integrity and those without. Given that there is more involved in assigning bond ratings than cold mechanical calculations, the General counsel advises against drastic Commission action which conceivably would drop TUEC's ratings below investment grade, thus entitling it to CWIP inclusion, leading to the inefficiency observable in an air conditioning system in which the thermostat is set so finely that minute changes in temperature cause the system to cut on or off. In the General Counsel's mind, CWIP is akin to heroin and "cold turkey" could prove fatal for this patient. The General Counsel restates the necessity of using historical data to compute financial indicators, concluding that the Act uses financial intesgrity as a short term measure. Particularly in this case, there are weaknesses in the projected data methodology, especially given the uncertainty of Comanche Peak's in service date. The General Counsel concludes by joining with counsel for TML, Coops, and OPC in endorsing Dr. Szerszen's CWIP level of $1,474,261,000, in the alternative to Dr. Johnson's approach.

3. CWIP Recommendation

The PURA provides for inclusion of construction work in progress in rate base only in certain instances. The following guideline is provided by Section 41(a):

> The inclusion of construction work in progress is an exceptional form of rate relief to be granted only upon the demonstration by the utility that such inclusion is necessary to the financial integrity of the utility. Construction work in progress shall not be included in the rate base for major projects under construction to the extent that such projects have been inefficiently or imprudently planned or managed.

Many words have been written and spoken concerning the meaning of this passage, especially upon the import of the word "exceptional." The most obvious meaning of the term is that suggested by counsel for the TML and for the Coops, that allowing a return on CWIP is an exception to the normal regulatory principle which allows the utility a fair return on the capital assets presently "used and useful" by the utility in providing service to the public. Although there are good arguments that this language is meant to be precatory and is not particularly useful as an analytical tool, it is clear that the term was given major significance by the Legislature. One might inquire as to the extent of the field to which inclusion of CWIP in rate base is the exception. Does this term present the opportunity of declaring that an emergency exists, as deliberative bodies routinely do to carry out their daily functions? Might a party attempt to demonstrate that these are generally exceptional times, that the particular company before the Commission is an exceptional one when viewed against the array of all business concerns over all time? Probably not. At the least, the use of the term "exceptional" suggests that the Legislature wished to notify the agency that stricter standards should be used in the evaluation of a utility's request for CWIP in rate base.

P.U.C. SUBST. R. 23.21(c)(2)(D) is in keeping with this conclusion. That rule provides:

> The inclusion of construction work in progress is an exceptional form of rate relief. Under ordinary circumstances the rate base shall consist only of those items which are used and useful in providing service to the public. Under exceptional circumstnaces, the commission will include construction work in progress in rate base to the extent that the utilty has proven that:
>
> (i) the inclusion is necessary to the financial integrity; and (ii) major projects under construction have been efficiently and prudently planned and managed. However, construction work in progress shall not be allowed for any portion of a major project which the utility has failed to prove was efficiently and prudently planned and managed.

The rule makes clear that two ceilings are to be put on CWIP inclusion in rate base, that the utility may recover a return on that level equal to the lower of the two ceilings. Practically, it is the lower ceiling that must be delineated precisely. And of course, before the financial integrity and prudence of management tests are applied, there must first be a showing that there are exceptional circumstances present.

There is one general point wanting exploration before the particular analysis at hand commences. Many of the parties suggested that it is necessary to define financial integrity, and that such definition would not necessarily be peculiar to this case. Notable was the suggestion of Tex-La , which was joined in by the General Counsel, that financial integrity should be equated with the quality of the utility's bonds, and that a utility with investment grade bonds should be considered to have financial integrity. The General Counsel also forwarded the notion that financial integrity was necessarily a short term assessment. The Commission should not so conclude. It is possible that financial integrity could in some circumstances mean maintenance of a utility's current bond rating; such a definition might depend upon the rating of that utility and the possible consequences of downgrade ensuing upon disallowance of CWIP. The Commission should reaffirm its prior conclusions that the relevant facets of the financial integrity test are subject to factual inquiry on a case by case basis. <u>See</u> Docket No. 5560, Finding of Fact no. 13. The difficulty of course with this endeavor is that the preservation of the Commission's flexibility by the Legislature mean that it is still allowed broad discretion in this determination, but that it must also endure the discussion of this issue in subjective terms. Beneath the various mathematical calculations of the witnesses and their supposedly pinpointed conclusions, lie the individual judgments and predictions of the witnesses, tangled within a skein of words so as not to disclose as much as they purport to.

Application of the standard in the Act and the Rules first requires consideration whether there are exceptional circumstances present. TUEC presented through cross-examination the thesis that these have been exceptional times, when many companies were required to convert their generation facilities from gas to other fuels, at a time when interest rates were abnormally high. Staff witness Johnson disagreed with this view, but the staff attorney points out that TUEC's abnormally high ratios of CWIP to net plant satisfies the threshold test set by the Commission's Rules. To the extent that such is necessary in order to preserve TUEC's current dollar level of CWIP in rate base, this report agrees. However, agreement with the General Counsel's point that the threshhold test should be accomplished by factors independent of the utility's financial integrity should be not be inferred.

CASE spearheaded the theory that there has been mismanagement and imprudence in Comanche Peak, that the project is tainted by these defects, and that--absent a showing by the utility of prudence--the first ceiling should be set at floor level. Many of the arguments advance by CASE were also propounded in Docket No. 5256 and there rejected by the Commission. CASE offers the Commission in this docket many jigsaw pieces meant to demonstrate error by the utility in the Comanche Peak project. The task presented to the Commission on this record is as difficult as concluding that a defendant was negligent without knowing the appropriate standard of care. Staff witness Skinner testified that errors do not necessarily spell mismanagement although Dr. Boltz suggested that the Commission can see from the particular instances documented in evidence that the project was mismanaged. While the company's "better than average" assertion (that Comanche Peak will produce kilowatts at a lower cost by far than the average for comparable nuclear projects) does tend to deflate CASE's thesis that redesigns, reworks, etc. mean mismanagement per se, that is not enough to demonstrate prudence conclusively. However, absent a context in which to fit these jigsaw pieces, a context which must depend on factual matters and expertise, it is virtually impossible to conclude that the errors constitute imprudence or mismanagement. If a conclusion of mismanagement is to be reached in this docket in good conscience, there must be convincing expert testimony, subject to cross-examination, or the mismanagement must be apparent to the lay eye. CASE'S depiction of Comanche Peak as a sinking ship, furthermore, is inconsistent with Tex-La's repeated assertions that there is indeed more room available in steerage. A conclusion of mismanagement at this point and on this record could well mean exclusion of portions of the project from rate base even when the project becomes operational, and it is neither wise nor necessary--in light of the recommendation below--to reach such a conclusion. CASE'S taint approach is, moreover, not appropriate, and not necessary, since all the various instances and circumstances questioned by Dr. Boltz were implicitly included in the recommendation of staff witness Skinner. Transcript at 2697-2698.

Of the $2.4 billion request made by TUEC, Mr. Skinner suggested that the ceiling might be as low as $1.8 billion. Mr. Skinner was careful not to insist that the lowering was due conclusively to the presence mismanagement and imprudence, but that simply there could theoretically have been as much as $.6 billion of unneeded attributable to management decisions. A number of flaws in Mr. Skinner's analysis were pointed out by the company and were acknowleged by the staff witness. Clearly, before the staff has completed the analysis required by the final Order in Docket No. 5256, it will be very difficult to tell what costs might be due to a punishable lapse of prudence and what costs would not. This report adopts the prudence ceiling set by Mr. Skinner. The Commission thereby conscientiously can discharge its duty, ensuring that no return will be allowed on any CWIP which was imprudently or inefficiently planned or managed. Again, this is not a finding of mismanagement or lack of prudence; it is the setting of the higher of the two ceilings, and is not the crucial determination in this analysis.

The setting of the CWIP level necessary for the utility's financial integrity must, however, be precise. Its current level is $1.474 billion, and--for the reasons to follow--the important inquiry is whether any party or witness has shown that that amount should be changed. TUEC's current level of financial strength is based in part upon rates set previously by this Commission, rates which included return on construction work in progress. While TP&L's last rate case was well over two years ago, the rates for the other two operating companies were set by the Commission in mid-December, 1983 and mid-January, 1984. It is true that the PURA without the "exceptional" language was technically in force at that time; however, the "flavor" of the new PURA was mentioned often by the Commissioners at Final Order Meetings during that time, and the current CWIP dollar amounts may well largely reflect the Commission's use of a stricter CWIP approach, although the "exceptional circumstances" and two ceilings were not yet applied. It might also be noted that the dollar amounts of CWIP in rate base may have remained the same since those cases, but the percentages have not, since TUEC has continued to spend tens of millions of dollars every month on its construction program. For reasons well explained by the staff attorney in brief, the issue of CWIP inclusion is best addressed by three positions advanced at the hearing: the company's request for somewhat above 80 percent, the OPC's insistance that the CWIP dollar amount be left where it is (a position joined in by counsel for the TML, Coops, and--in the alternative--by the staff), and Tex-La's recommendation of zero CWIP, joined in by CASE.

There are difficulties with all these positions, but the report recommends adoption of the OPC's approach. The company's suggestion that it wished to improve its position only to the average for AA rated electric utilities was contested by the other parties as a veiled attempt to regain a AAA bond rating. Without becoming immersed in the unenlighting mire of that dispute, the Commission should recognize that TUEC's target indicators are simply too high. See TML Reply Brief at 7-8. It is arguably good for the Commission to aim high in steering to prevent a well managed company from sliding toward the bottom of the investment grade spectrum, but the relief requested by the company is not consistent with a strict reading of financial integrity. On the other hand, the urgings of Tex-La, that no CWIP should be given to a utility until it reaches a Baa bond rating, is too harsh and short-sighted a position to be taken by the Commission.

This report recommends no change from the dollar level of CWIP presently allowed a return under previous Commission rate orders, and there are many points in favor of that position. The staff's warning that dramatic slashes to CWIP inclusion is one that is well taken. Such action could have a very dangerous effect on the utility's financial integrity, given the importance of investor perceptions of the regulatory climate in Texas. [This is not to say that the investment community's perceptions are free of hysteria; at times it appears that the certainty of bad news is so preferable to uncertainty that those hasty to downgrade must strain mightily to hear the bad tidings that may not even be there.] Moreover, the ultimate rate shock to customers when a project the size of Comanche Peak does go into service would be greatly worsened by decreasing the amount of CWIP in rate base and increasing the accrual of AFUDC, followed by putting that invested capital (including AFUDC) into rate base in one fell swoop.

Investor perception of the Commission need not center alone on CWIP. Company witness Scotto testified that rate of return is one of the factors that will be considered by investors; the failure of the Commission to give an increase in the amount of CWIP does not necessarily mean further downgrades. The CWIP recommendation of this report, together with the overall rate of return on invested capital, is sufficient to ensure this applicant's financial integrity (which, incidentally, should not be measured by reliance on supplemental coverages, for reasons well explained by Dr. Ewert). Reference to Dr. Murry's Schedule 4.1, 4.2, 4.3, and 4.4 and cross-interpolation of the amounts shown on those tables suggest that the overall recommendation of this report would lead to the following financial indicators: interest coverage with AFUDC of 4.45x, interest coverage excluding AFUDC of 3.8x, AFUDC as a percentage of earnings available for common of 30 percent, and internal cash generation of construction expenditures of 50 percent. Dr. Murry did use test year numbers for these calculations, and did not take into account the additions to CWIP that will be made monthly by the applicant. Reference to Mr. Effron's Schedule RB-3A of OPC Exhibit 1A suggests that the recommendations of this report will produce indicators for the twelve months ending September 30, 1985, of somewhat better than the following: interest coverage with AFUDC of 3.8x, interest coverage without AFUDC of 3.2x, internal cash generation as a percent of construction expenditures of 41.3 percent, and AFUDC as a percentage of earnings available to common of 37.7 percent. These indicators were calculated assuming that the OPC rate decrease was adopted by the Commission, including $1.474 billion of CWIP in rate base and allowing a return on equity of 15.5 percent. Similarly, reference to Dr. Johnson's sensitivity analysis suggests that the September 30, 1985, indicators resulting from this CWIP level and 15.7 percent return on equity will be: approximately 41 percent of construction expenditures fundable from internal cash, 35 percent AFUDC as a percentage of earnings available to common, 4.1x pretax interest coverage, and an earned return above 16 percent. Staff Exhibit 5, Schedule 2. These conclusions assume 100 percent inclusion of nuclear fuel in process in rate base. Id., Fn. 1.

Application of the recommended return on equity and CWIP proposal of this report to Dr. Ewert's Schedules DCE-10 and DCE-12 suggests an internal cash generation percentage of 40 percent, AFUDC as a percentage of earnings available to common of 32 percent, interest coverage with AFUDC of 4.1x and interest coverage without AFUDC of 3.4x. TML witness Lattner's schedules suggest the following indicators, based on the TML's overall recommendation: internal cash generation in the 45-46 percent range through 1985, pretax interest coverage of 4.39x with AFUDC and 3.87x without, 26.16 percent AFUDC as a percentage of income available to common, and 17.1 percent estimated earned return on equity. It is true that there was disagreement over the proper methodology for calculating the indicators, and it is likely that the indicators will be characterized by the applicant as puny and inadequate, but it must be acknowledged that TUEC's construction program is a massive one, and that other utilities with nuclear construction programs sport similar indicators. Solomon Brothers reported on April 2, 1984, that such companies generated internally 49 percent of the funds necessary for construction, that they had a median pretax interest coverage with AFUDC of 2.9x as of December 1983, and that they have a median primary pretax interest coverage with AFUDC as of December 1983 of 3.2x. TUEC Exhibit 12. Pretax interest coverages (including AFUDC) for AA companies is gauged by Standard & Poors as 3.25-4.25x. Nucor Exhibit 5. The evidence does not persuade the examiner that TUEC is entitled to, or in need of, any additional CWIP in rate base.

Regarding other suggestions and requests for relief made by the parties, two of them are best dealt with outside the context of this case. One is the setting of a capacity factor incentive for utilities in Texas with nuclear generating plant; the issue was not fully enough explored in this docket that this Commission can confidently set such an incentive requirement on TUEC regarding Comanche Peak. Certainly a capacity factor target should not be set for all utilities in Texas in this docket. Staff witness Skinner agreed that such an incentive would be a good idea, and it is this report's suggestion that the staff request a rulemaking proceeding with a specific proposal on this topic if desired. In a similar vein, it is clear that a uniform decommissioning policy is needed. It is clear that this issue must be addressed cogently, but this docket and this evidence do not provide the fitting context for such a formulation. Actions by other regulatory authorities, and by legislative bodies and should also be taken into account.

As to the request that the Commission order TUEC to begin keeping records of the costs of rework and begin more fully documenting the construction at Comanche Peak with an eye to determining the prudence and efficiency of the project, the proposed Order attached does not provide such a requirement. However, the applicant should note that it has the burden of persuasion in such an inquiry, and that the evidence it presented in this case to answer the allegations of CASE and others did not convince the trier of fact that Comanche Peak is free of the taint of mismanagement or imprudence in construction. The staff's inquiry into this matter will helpfully resolve the points at issue, but the utility should not assume that its mere cooperation with the staff will suffice to discharge its obligation to demonstrate prudence in the cases to come.

4. Specific Identification of CWIP

Applicant's witness Moseley proposed an accounting change for the calculation of AFUDC. He testified that under the company's present method of calculating AFUDC, the monthly AFUDC base is figured by subtracting the CWIP amount included in rate base from the previous month's balance of CWIP. Then the resultant accrual base is multiplied by the monthly AFUDC accrual rate to reach the AFUDC amount for that month. Mr. Moseley stated that under the present method of AFUDC calculation, the amount of CWIP in rate base subtracted each month remains constant. According to the company's accounting witness, the applicant wishes to begin using the "specific identification method" of accruing AFUDC at the time the rates set in this proceeding become effective. The methodology is appropriate, according to Mr. Moseley, in order to moderate the volatile effect on earnings when large construction projects are placed in service. The current method allows the level of AFUDC to drop drastically whenever a power plant is closed to plant in service, because the CWIP balance is reduced although the amount of CWIP in rate base used to calculate AFUDC remains constant, with an understated AFUDC accrual base being the result. Absent the use of a specific identification method, the situation can only be remedied by the company's perfect scheduling of a rate case and the Commission's authorization of new rates which precisely coincide with the in-service date of the power plant in question. Applicant's Exhibit 1B, Moseley at 13.

TNP witness Albert Schuman testified that such a provision is prohibited by the Act and the Substantive Rules. He recommended that if the Commission were to allow such a treatment, that other utilities similarly situated also be permitted to accrue AFUDC in the manner suggested by TUEC. TNP Exhibit 1 at 5.

Staff witness Randy Allen discussed the company's proposed method of calculating AFUDC and agreed that there should be some type of a specific identification, but did not support the methodology advanced by the applicant.

Mr. Allen testified that the staff has traditionally recommended an allowance factor of CWIP to be included for a return in rate base, and that that factor is meant--unless otherwise stated--to be applied on a pro rata basis to all qualifying CWIP projects. He recommended that the CWIP dollar amount be applied not first to Comanche Peak Unit 1 and then Unit 2 as Mr. Moseley had recommended, but rather that the CWIP amount in the case be spread to all plants under construction on a pro rata basis. Staff Exhibit 1 at 9-10.

The parties, witnesses, and examiner found this topic to be immensely entertaining, and a great number of hypothetical situations were posited and explored by the parties during cross-examination of witnesses and in brief. Those examples generally demonstrate that the closing to plant of Comanche Peak Unit 1 unfairly reduces the AFUDC accrual base, and may well cause the utility to file a rate case in order to have the Commission redetermine its plant in service and CWIP, so as to permit AFUDC accrual to the then current accrual base. The dollar amounts of the AFUDC accruals can become quite large, especially for a utility with a construction program like TUEC's. Mr. Moseley's Exhibit MDM-1 was based on a CWIP total balance at the time of closing of Comanche Peak Unit 1 to plant in service of $3.5 billion, inclusion in rate base of $2.4 billion, Commission identification of the CWIP as going first to Comanche Peak Unit 1 (and the balance of dollars going to Unit 2), and an annual AFUDC rate of 9.5 percent; that exhibit demonstrates that the utility would be accruing AFUDC at approximately $106 million annually before the closing of Comanche Peak Unit 1 to plant in service, but there would be no AFUDC income (the number is actually negative) after Comanche Peak Unit 1 goes on line. The company's proposed methodology would result in AFUDC accrual annually of $74,287,143 after Comanche Peak Unit 1 closed to plant in service, thus saving it the trauma of a rate case meant in part to have the Commission redetermine that portion of CWIP which is not included in rate base and given a return. It is clear that the current approach functions as though the Commission had specifically identified the CWIP items granted a return beginning with the most remote (furthest from completion) project and ending with the project closest to completion. The applicant is correct that the tacit assumption in the "pot" approach is unfair, and may well cause utilities with large construction projects to file rate cases in order to preserve their right to put carrying charges (on these portions construction projects not allowed a return by the Commission) into rate base, to earn a return when the projects are completed and put in service.

Commission adoption of the company's accounting methodology in this matter would mean that the CWIP inclusion of $1.,474 billion would apply only to Comanche Peak Unit 1. Logic and law, together with the other recommendations of this

Report, militate against this result. As has been discussed in the immediately preceding sections, the Commission cannot make the findings necessary to apply the full amount of CWIP inclusion to Comanche Peak Unit 1. The applicant has not discharged its burden of proof to show that the construction at Unit 1 is free of mismanagement or imprudence. It is clear that the utility has this burden under the PURA for the reasons that follow: Section 41(a) prohibits the inclusion in rate base of CWIP to the extent that the projects were inefficiently or imprudently planned or managed. The Commission is not required to make a finding of imprudence or mismanagement, and should not do so in this case. Whenever the Commission is required to make a specific finding, the Act indicates same; for example, see Section 41(c)(1), which requires specific findings by the Commission in the area of payments to affiliated interests. PURA Section 40 provides generally that in any proceeding involving a rate change, the burden of proof to show that the change is just and reasonable rests with the public utility. It is therefore quite doubtful that the changes to Section 41(a) effective September 1, 1983, were meant to place the burden of production and pursuasion on parties attempting to demonstrate imprudence or mismanagement in a major construction project. It makes much more sense to place the burden upon the entity in possession of the information sufficient to make the showing (if such showing can indeed be made), and the Legislature has so provided. This interpretation of PURA Section 41 is supported by the Commission's Substantive Rule dealing with construction work in progress, which explicitly places the burden of proof in this area on the utility.

The Commission should, as a matter of policy, be disinclined to accept the company's proposed accounting treatment. It is likely that a utility with a large construction project, such as the applicant, will be filing a rate case quite quickly upon the closing to plant in service of one of its major projects, unless its financial integrity has required, and the Commission has allowed, substantial amounts of CWIP to be included in rate base. In fact, even if the latter were the case, a rate case might still be filed so that the increased operational expenses and depreciation could be recovered through rates. Given the operation of the twin ceilings contemplated in the CWIP inquiry, it may well be that that rate case will also be characterized by a fair amount of dispute over the prudence and efficiency of planning and management of those major projects now included in plant in service. The Commission should not prejudge such issues by sanctioning, through approval of accounting treatment of those portions of a major project, that which it could not sanction on the basis of the evidence in the CWIP analysis proper. It might possible to seek a percentage level between the pro rata level of CWIP inclusion and the exclusion percentage ceiling in the prudence portion of the CWIP analysis, but this approach was not explored by the parties, and may itself be subject to the same dangers of prejudgment noted above. Accordingly, this report recommends that Mr. Allen's recommendation be accepted, and that the CWIP percentage (in this case 49.6 percent) be applied prorata to the applicant's plants under construction as of test year end. The applicant has pointed out that its $2.4 billion CWIP figure to earn a return is the amount of test year end booked CWIP in the two Comanche Peak Units, and the $1.474 billion recommendation of this report should be spread ratably to those two units based upon the CWIP inclusion factor and the test year end CWIP amounts attributable to each unit.

D. Plant Held For Future Use

TUEC's total electric plant held for future use (PHFU) was $6,243,581 as of test year end. The applicant adjusted that figure downwards by $273,869 for the value of potential trade land, leaving a requested rate base amount of $5,969,712. OPC witness David J. Effron, a consultant specializing in utility regulation, recommended the removal of all PHFU from rate base except for two of the twelve items requested by TUEC, for two future substation sites which are scheduled to go into service in 1984 and 1985. An identical recommendation was made by TML witness Cannady. TNP witness Albert H. Schuman, senior analyst in the Contract and Regulation Department of Texas-New Mexico Power Company, also recommended disallowing from plant held for future use all requested items except but the two future substation sites. However, Texas-New Mexico Power Company urged in brief that Mr. Schuman's original proposal for inclusion of $341,276 be increased to $3,059,599, based on the testimony of TUEC witness Tanner that several of the items considered as property held for future use in Schedule C-5 of the rate filing package were as of the time of the hearing dedicated to plant. TNP Brief at 5. Staff witness Randy Allen eliminated land associated with the Mill Creek Generating Unit, land designated as "Possum Kingdom Lake," and potential expansion land in Hood County associated with the De Cordova Unit. Mr. Allen also added to the plant held for future use requested by the company some some $322,554 associated with the Sylvania Operating Center in east Fort Worth. He added as well the Lake Fork water rights which staff witness Poole disallowed as an expense. (See Section VII. A.1.g. of the report below for a discussion of this adjustment.)

The company's response to these proposals was one of dismay, and it characterized the ten year rule used by the witnesses as "rigid" and "mechanical." The company argued that a mechanical application of the ten year, in service rule is not workable because of the lead time necessary for site acquisition, permitting, engineering, and construction of solid fuel plants. This Commission has recently reaffirmed the requirement that, for plant held for future use to be included in rate base and given a return, the utility must have a specific plan that would put the item in service within ten years, and the utility should show that the plan is a reasonable one. See, Docket No. 5560, Supra at 37. TUEC insists that "a longer ten-year commitment rule is necessary." Applicant's Initial Brief at 32. The company maintains that certain of the lignite under lignite leases shown on Schedule C-5 will be used at the certified Twin Oak and Oak Knoll plants presently under construction, that certain water rights relate to a future coal plant in far west Texas, that other land holdings are either good sites for future plant or are planned to be in service by 1995, that--given the unique requirements of generating plant sites--certain of the land holdings represent very prudent investments, that some of the land will be transfered to plant in service in the near future, and that some of the lignite will be used at an existing plant in its later years of operation. TUEC points out that no witness has challenged the prudence of the acquisition of any of those items, and notes that exclusion of them from the rate base would discourage such prudent acquisitions made in the customers' interest, since TUEC--or for that matter any other utility--would lose its carrying cost due to the impermissibility of recording AFDUC on plant held for future use. Id. at 32.

Plant held for future use normally refers to resources that are not man-made (for example, water, land, lignite, minerals, or coal). Such assets may be viewed as akin to construction work in progress, or to inventory of smaller, man-made items . These water rights, land, and lignite leases are assets in which the company has invested, but they are less close to usefulness than capital items in construction work in progress. They are also further removed from usefulness than inventory items, which are on hand because of their likely need in the near future. They further differ from inventory in that they are discrete items with original cost that will probably eventually go into rate base, while inventory (prior to going into service) is reflected in rate base as some sort of average balance. The goals of the Commission in dealing with plant held for future use should include the encouragement of prudent planning by the utility, as well as observance of the conviction that today's ratepayers are not paying for a return on capital assets whose benefit to them is masked by the mists of the future. Considering the stringent approach that the Legislature has required in dealing with construction work in progress, expansion of the allegedly Procrustean ten year standard would be incongruous. The facts of this case offer little in support of such an expansion. The company's proposed standard--which would allow plant held for future use in rate base if the resource were "committed" within a ten year period--allows precisely the type of rethinking which the parties decry in this case. An expectation that a plan will be developed within the next ten years for use of these assets is cold comfort to today's ratepayers being saddled with the carrying costs. Counsel for the TRA demonstrates via brief (with appropriate citations to the evidence) that the commitment-within-ten-year principle simply allows too much slippage in the projected dates for use of these assets. The TRA concludes persuasively that, "[i]t is neither outrageous nor unreasonable to require a definite plan for plant held for future use within a ten year time frame." TRA Initial Brief at 33.

There is nothing in the record to warrant the conclusion that the rights and assets sought to be included in the rate base by the company were imprudently purchased or are in any manner wasteful, or that any slippage originates in deception. However, the absence of specific reasonable plans for use of the assets within ten years militates their exclusion from rate base. Even the lignite coal leases in Limestone and Robertson Counties, which were related by TUEC witness Tanner to the Twin Oak and Oak Knoll Generating Units which are under construction, do not satisfy the ten year rule. As the OPC points out, Twin Oak is approximately ten percent complet and Oak Knoll is approximately one percent complete. Transcript at 1323. Given Mr. Tanner's concession that the construction completion could well slide depending on many factors and may not be used within ten years (Transcript at 1370-1371), and the company's asserted flexibility in its lignite construction program, those leases do not satisfy the standard.

Mr. Allen added to PHFU some $2,933,399 for water rights associated with future generating stations at Mill Creek, Possum Kingdom Lake, and Milam County, reasoning that those rights represented scarce resources. Transcript at 3183-3185. These water rights payments were disallowed as expenses by staff accountant Judy Poole, pending the water's use in a power plant. Staff Exhibit 8 at 12. Strict adherence to the ten year standard also requires disallowance of these water rights as capitalized items at this time, since the land associated with them was also disallowed for TUEC's lack of a specific & definite plan for their use within ten years. Scarceness at the resource alone is not sufficient. Application of GSU, Docket No. 5560.

Regarding the staff's addition of $322,554 to plant held for future use for the Sylvania Operating Center, adoption of the report's recommendations against making known and measurable changes to test year ended invested capital would logically prevent adoption of this recommendation, and the company's omission to join in the request and present an explanation of this item in the rate application would make it an unsolicited lagniappe. In summary, the recommendations of witnesses Effron and Cannady should be adopted by the Commission, and $341,276 of plant held for future use should be included in rate base. This amount represents land to be used for the same two substations included in TESCO's plant held for future use in Docket No. 5200.

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I. Other Cost Free Capital

The applicant deducted some $44,556,115 from rate base to account for other cost free capital. Staff witness Allen adjusted this amount, decreasing it by $3,994,583, an adjustment to reflect the effect of staff accountant Judy Poole's adjustment to federal income tax relating to the amortization of lignite depletion prior accruals. Ms. Poole's recommendation was based upon her determination of the proper amount that should have been booked during the test year, and no party contested this adjustment. TUEC points out that the adjustment is proper and that it does not represent changes in invested capital due to events occurring after the test year period, but instead reflects what should have been booked during the test year. The staff proposal should be adopted, and TUEC's other cost free capital, used as an offset to positive items of rate base to calculate total invested capital, should be set at $40,561,532.

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VII. Cost of Service

TUEC proposed a Commission finding that its total cost of service is $4,117,791,332 and that its base rate revenue requirement is $4,077,292,816, comprising the following elements:

	Test Year Per Books	Company Adjustments	Company Test Year
Fuel	$1,503,166,305	$352,239,755	$1,855,406,060
Operations and Maintenance	645,101,305	(19,759,299)	625,342,501
Depreciation	187,919,341	(10,239,358)	177,679,983
Other Taxes	194,321,033	46,203,403	240,524,436
Interest on Customers Deposits	0	2,109,878	2,109,878
Federal INcome Taxes	232,829,411	183,918,667	416,748,078
Return	593,753,109	206,227,287	799,980,396
Revenue Requirement	$3,357,090,999	$760,700,333	$4,117,791,332
Less			
Other Revenue	$44,275,842	$(3,777,326)	$40,498,516
Base Rate Revenue	$3,312,815,157	$764,477,659	$4,077,292,816

Several items in the cost of service total were challenged by other parties. Where the components of revenue requirement were contested, they are discussed below; absent the contesting of any line item by parties and discussion in the report, that item is recommended for approval by the Commission. The text to follow deals first with accounting adjustments other than those relating to the setting of fuel factors, and then with the issues surrounding fuel.

A. Nonfuel Accounting Adjustments

1. Operations and Maintenance

a. Payroll

TUEC witness Moseley increased the test year payroll figure charged to expense by $14,640,066, in order to reflect changes in salary and employee numbers "occurring before the proposed rates are to go into effect." Applicant's Exhibit

1B, Moseley at 4; Schedule A, page 6. The adjustment resulted from the application of a 5.4 percent salary increase to test year end employees, based upon a union contract currently in force. The other parties criticize the application of a 5.4 percent increase to non-union and part-time employees, and two witnesses proposed adjustments to the payroll proposal of TUEC.

TML witness Wilson decreased the total payroll amount by $2,406,000. He annualized the September base payroll for DP&L in a manner different from the company's and annualized only the payroll expense as of test year end, based on salary and wage levels at that time. The witness prorated some of the salary increases which had occurred after the test year end, using September 30, 1984, as a cut-off date. Mr. Wilson also declined to apply the increase to non-union and part-time employees, reasoning that the company has seen a decrease in part-time salary expense since test year end. TML Exhibit 1 at 10-11.

Staff witness Judy Poole recommended a total decrease in payroll expense of $1,633,791, in accord with four discrete adjustments. First, she redetermined the level of temporary and part-time payroll, quantifying the decrease in the use of temporary and part-time employees after the merger at 26.12 percent (comparing numbers of employees during the first four months of 1983 and the first four months of 1984), and applied that rate to the test year level of temporary and part-time employees, concluding that costs should be $320,978 less than test year levels. Ms. Poole also chose not to apply the 5.4 percent increase to all employees, having determined that the hourly employees at TESCO were given only a 4 percent increase. She used that amount to calculate a pro forma increase for TESCO hourly employees. Third, the staff witness proposed a correction to the calculated overtime rate for TP&L, removing amounts for other pay (which could include items like moving expenses, termination pay, and accrued vacation pay) to calculate the overtime rate. The company agreed with this correction. Finally, Ms. Poole used an expense factor different from the company's test year rate of payroll charges to operation and maintenance expense, preferring instead the use of a three year average as a more representative level of expensed payroll. Staff Exhibit 8 at 5-7.

The company responds to TML's proposal by pointing out that temporary and part-time employees receive pay increases in accordance with the company's salary guidelines for non-exempt employees and that the level of temporary and part-time employees has increased since the end of the test year. Applicant's Initial Brief at 44-45 and citations. TUEC criticizes Mr. Wilson for annualizing increases pro rata, providing the example that, if an increase occurred in December, 1983, the TML proposal would allow only 75 percent of the increase. Id. The applicant concludes that Mr. Wilson's payroll level understates the applicant's known and measurable payroll expense, since the full amount of the 5.4 percent increase will have been in effect for a year during the time that the rates set in this docket are in effect.

The utility opposes three of the four staff proposed adjustments to payroll, first pointing out that Ms. Poole's perceived decrease in the use of temporary and part-time employees after the merger was based upon incomplete information provided during the discovery process. TUEC cites evidence to the effect that temporary and part-time expenses did actually increase after the test year end and after the merger. TUEC Initial Brief at 44. The difficulty with the numbers provided to the staff during the discovery process was that the 1984 number did not include the employees of the present TUGCO division who were previously employed by DP&L, TP&L, and TESCO. Transcript at 1619. The company also opposed Ms. Poole's pro forma salary increase for TESCO of 4 percent, urging that the actual increase on the system is above 6 percent, demonstrating that Mr. Moseley's use of 5.4 percent across the board is conservative. Id. Finally, TUEC challenged the use the expensing factor computed by Ms. Poole (a three year average instead of test year), pointing out that the information originally furnished to Ms. Poole was unfortunately incorrect. Id.

The recommendations of Mr. Wilson were successfully impugned by the applicant, there being no good reason shown why a known and measurable change to such an operation and maintenance expense as payroll should be prorated solely because of its incurrence outside the test year. The applicant's argument that the staff recommendations are in part based upon incorrect information is, however, not very persuasive. The staff attorney points out in his reply brief at page 16 that Ms. Poole had made corrections to adjustments when she discovered that she was in error, and that--the recommendations of all three witnesses being flawed--the staff's are the most credible. The General Counsel points out that the staff accountant did change her testimony in accord with information supplied to her late, when she could determine that she had truly been in error.

The Commission must decide which of the proposals is most reliable. The general counsel and staff of the Commission are charged with protection of the public interest, including the consumers and the utilities. PURA Sections 2 and 8(c). The applicant in a rate proceeding should not be heard to argue that the entity charged with protecting the public interest has presented evidence and recommendations which are based on misinformation, when such was supplied by the utility. There are flaws in the recommendations of each of the witnesses, and the report credits the testimony of Ms. Poole, since the principles expressed by her in reaching the total adjustment are reasonable ones, and since the "incorrect" information provided by TUEC colors only two of the four adjustments comprising her total decrease. It is not possible on the record to sort among the adjustments to payroll made by the staff, and her total adjustment should be recognized by the Commission as the most reliable.

b. Payroll related expenses

TUEC proposed to decrease its payroll related expenses by $2,776,149, a proposal with which TML witness Wilson took no issue. Staff accountant Poole recommended decreasing the amounts still further by an additional $885,714. Staff Exhibit 8A, Schedule II. Her recommendation resulted from use of an expense factor different from the one proposed by the company (discussed above), a calculation of savings in employee benefits which should be achieved as a result of the corporate reorganization, and a further reduction to reflect TP&L's experience rating refund and deficit for group life insurance and medical insurance. She pointed out that the annual costs reflected in a rate package included such refunds and deficits for DP&L and TESCO, but had excluded those items for TP&L. Staff Exhibit 8 at 7-9. TUEC challenges these adjustments, restating its point that the expensing percentage was not appropriately determined, characterizing as a "double-dip" the merger savings which the company contends is reflected in the total dollar level of Mr. Moseley's adjustment to other O&M to reflect merger savings, and by characterizing the reduction to reflect TP&L's experience rating refund and deficit for group life and medical insurance as a nonrecurring item. Again, although the applicant should not be allowed to benefit from mistakes resulting when it provides incorrect information through the discovery process, the effects of the expensing factor are again not extractable from Ms. Poole's total adjustment; however, the company's point regarding the merger savings is a telling one. This report therefore recommends that the adjustment relating to the experience rated insurance be made in the amount of $93,478, resulting in an adjustment to test year payroll related expense of $2,869,647. That amount concededly includes the use of Ms. Poole's expensing factor, but is the only number available to make this adjustment in the record, and TUEC's cost of service is more accurately determined by making the adjustment than not making it.

c. Retirement plan costs

The company decreased its test year retirement plan costs by $4,073,774, a proposal which only the staff contested. Ms. Poole decreased the retirement plan cost component of other operation and maintenance expense by another $136,584, to reflect her expense factor, which was determined by reference to the incorrect historical data supplied by the company. This problem has now been reduced to its essence, there being no other adjustments mixed with this one so that a weighing of credibility can be tempered with notice that information supplied during the discovery process should be good information. Although feelings were observably ruffled by the fact that incorrect information was supplied, there was no real showing that the company willfully misled the staff. The Commission could conceivably rule that TUEC is estopped to controvert information which it has previously supplied, or that the controverting itself is not credible, but this report does not recommend so in this instance. Of the two recommendations presented to the Commission, Mr. Moseley's is probably the more accurate. The company's adjustment to retirement costs should therefore be accepted.

d. Uncollectible expense

There was not a bona fide dispute over the method of calculating uncollectible expense. The company proposed a factor of .003, which the staff reviewed and which Ms. Poole recommended be used by the Commission. The uncollectible expense component of operation and maintenance recommended by this report is therefore calculated by use of this factor.

e. Research, dues, fees, and contributions

The parties placed in issue numerous of the company's expenditures in this area. Schedule A of the rate filing package included a company proposal to increase the test year Electric Power Research Institute (EPRI) dues by $1,541,916. TML witness Wilson decreased this amount by $391,000, reflecting his determination that the costs for the EPRI research subscription should be that incurred in the twelve month period following test year end. TML Exhibit 1 at 12. TUEC points out that this adjustment has the effect of failing to account fully for the increase in the rate charged by EPRI (which is based upon 1982 kilowatt hour sales). The payment is made quarterly, and each quarterly payment is in the same amount. The applicant argues that Mr. Wilson's use of nine months at the 1984 rate and three months at the 1983 rate will understate the actual level of the expense. For that matter, even the company's adjustment will understate the level of the expense since the 1985 rate will be based upon the higher 1983 kilowatt hour sales, according to TUEC. Applicant's Initial Brief at 46. The company's proposed adjustment may arguably be related to growth, but it is growth between the years 1982 and 1983. On the basis of the evidence adduced and the arguments presented, the Commission should find the company's adjustment to recognize a known and measurable change to the EPRI research subscription and include the adjustment in the cost of service calculation.

Staff witness Judy Poole recommended disallowance of $4,405 in contributions which she considered to be of a recreational or political nature. Those items excluded were contribtutions to the Colonial Country Club ($350), Senator Grant

Jones-Governor for a Day ($500), and the purchase of Texas Ranger tickets ($3,555). This recommendation was not contested and should be incorporated in the Commission order. The staff accountant also reviewed the Edison Electric Institute (EEI) dues applicable to political activities, finding that in the test year TUEC paid dues of $392,747 to support the EEI and $219,809 to support the Media Communications Program. TUEC had excluded 1.68 percent of the EEI dues as related to expenditures for legislative advocacy as defined by the Federal Regulation of Lobbying Act, and 7.69 percent of the Media Communications Program (which percentage was deemed to be devoted to grass roots lobbying). Ms. Poole reviewed the "Preliminary Report on the Expendtitures of the EEI", a document drafted by the NARUC Staff Subcommittee on Accounts. Because the report indicated that the Subcommittee had experienced difficulties in segregating costs related to political activities from total expenditures (in part becasue of EEI's lack of cooperation), and the Subcommittee's determination that approximately 25 to 33 percent of EEI dues should be borne by the shareholders, Ms. Poole questioned the small percentage excluded by the company's adjustment. However, she was not content to rely upon the judgment of the Subcommittee, because of lack of supporting documentation. She therefore recommended disallowance of all dues payments to EEI and to the Media Communications Programs, removing $589,055 from cost of service because of the company's arguable failure to provide support for the reasonableness of those costs. Staff Exhibit 8 at 10-11.

TUEC presented the testimony of rebuttal witness Douglas C. Bauer, EEI senior Vice President-Economics and Finance, in support of the company's EEI expenses. He testified that EEI is involved in a great number and variety of activities which are beneficial to both companies and ratepayers. Those activities, according to Mr. Bauer, are those typical of a normal trade association, and "include collecting, developing, analyzing, and disseminating information on virtually every phase of the generation, sale, distribution, and use of electricity." Applicant's Exhibit 28 at 2. EEI serves the goals of facilitating information exchange among personnel of its member companies, and analyzing proposed rules of federal agencies (and developing industry responses when appropriate). Mr. Bauer testifed that 2 percent of EEI's 1983 expenditures were devoted to direct lobbying (1.68 percent) and 18 percent to the nonlobbying aspects (or broad support) of legislative activities. TUEC argues that such activities are not lobbying, but reflect expenditures that must be made when there are "congressional requests for facts, data and information upon which informed public policy may or may not be made." Applicant's Intitial Brief at 47. TUEC argues that the NARUC Subcommittee report referred to by Ms. Poole is only preliminary in form, that it has not been acted on by the NARUC Executive Committee, and that it has received no official NARUC sanction. <u>Id.</u> and citations. The company argues in the alternative that even were the preliminary report used as a guide, the largest reasonable decrease to EEI dues would be $129,607, representing a decrease of 33 percent of the amount paid during the test year.

The other parties respond to the applicant's rebuttal position by noting the difference between the federal definitions of lobbying and the stricture in the PURA prohibiting "legislative advocacy expenses, whether made directly or indirectly, including but not limited to legislative advocacy expenses included in trade association dues..." PURA Section 41(c)(3)(A). The TML, OPC, and General Counsel urge that the broad based information gathering function performed for legislators by EEI is indirect lobbying. The TML points out that the Commission ultimately refused to include any EEI dues in GSU's cost of service because of lack of convincing evidence (TML Initial Brief at 46), but the company argues that the evidence in this case is more thorough. Applicant's Reply Brief at 27.

The OPC argues that all EEI dues should be excluded, because the company did not with certainty show that some of the remainder would be used to influence legislative and executive action, that EEI might help fund an organization which engages in political activities, that some of the remaining expenses include trying to influence such entities as the Financial Accounting Standards Board and participating in a law suit not in the State of Texas, that EEI should not charge dues to its members because it is already well funded, and that there may be other legislative oriented and issue oriented advertisements not fully adjusted out of the company's cost of service. OPC Initial Brief at 50-52.

The parties who argue that the 18 percent identified as being spent on broad legislative support by EEI constitutes dollars spent for lobbying, at least indirectly, make a point that becomes stronger because of Mr. Bauer's testimony than it was without it. Those whose occupations include the task of persuading others probably do not spend 100 percent of their time in the presence of those they must persuade, urging their points on a crucial issue. The 1.68 percent cannot be so easily disentangled from the other 18 percent of EEI dues. The proposed order attached therefore includes 80 percent of the EEI dues in operation and maintenance expense, or an amount of $314,198. The amount excluded is therefore $78,549. These recommendations are quite sufficiently documented by reference to the testimony of Mr. Bauer, and represent a more balanced and probably accurate cost of service inclusion than application of the 25 to 33 percent range in the NARUC Subcommittee report; they also reflected a willingness to recognize the validity of trade association dues, which the PURA itself implicitly does. The company rightly points out that any past "dispute" with NARUC may be probative in this matter, but it is ultimately this Commission that the applicant must satisfy. The quality of the evidence demonstrates that the 20 percent exclusion probably captures well the amount of dues expended toward direct and indirect lobbying, and the OPC's attempt to pick at the remainder as being less than perfect information is not persuasive.

The Media Communications Program, to which the applicant paid $219,809, includes amounts expended for legisative advocacy. The applicant determined that 7.69 percent of that amount, or $16,903, should for that reason be excluded from cost of service, and made that adjustment. As for the rest of the program, Mr. Bauer testified that it was not devoted to "grass roots lobbying," but was used to advertise methods of conserving electricity and electricity cost control measures for customers. TUEC Exhibit 28 at 7. Other parties argued that that amount includes funds "promoting increased consumption of electricity" in violation of P.U.C. SUBST. R. 23.21(b)(2)(F). The EEI has paid for a series of ads promoting electricity, "the power of choice", as well as for the promotion of construction of a coal slurry pipeline and a public television panel show meant to present discussion on issues interesting to the body politic generally. Notably, the General Counsel argues that the Media Communications supports EEI's perception of the national interest, and that to require the ratepayers (particularly those who intensely disagree with the development of nuclear power) to pay for the promotion of nuclear power is simply unfair. The OPC adds to this that the media fund payments should be excluded because the rate filing package does not clearly demonstrate that legislative oriented and issue oriented ads were fully adjusted out of the company's cost of service. OPC Initial Brief at 52.

TUEC points out that the 7.69 percent does include such items as the coal slurry pipeline advertisements, and notes that the argument that there must be some benefit to all of the applicant's customers before an advertising expense can be allowed was expressly rejected in Conclusion of Law No. 19 in the final order in Docket No. 5256. It also notes that the applicable Substantive Rule, Rule 23.21(b)(1)(E), allows a utility to include up to .3 percent of its gross receipts for ordinary advertising, contributions, and donations, and that no requirement of consensus can be found in the rule. This point is well taken. Under the General Counsel's argument, Dr. Boltz should not have to fund advertisements for nuclear power. The irony is poignant, but under that rationale, the utility should not be allowed to include any rate case expenses in its cost of service, since presumably at least some customers violently disagree with the request to increase rates. It is an inescapable reality that utilities must function in a political environment, and--if they are to survive-- face the task of persuading the arbiters of public policy with fact and argument. To insist that ratepayers, or for that matter taxpayers, must agree with the way that their dollars are being spent would generally incapacitate government, and would specifically prevent the Commission, its General Counsel, the Office of the Public Utility Counsel, and the TML from advocating and adopting positions unless those positions are unopposed by ratepayers funding that advocacy. The company has shown by preponderence of the credible evidence that its adjustment to the Media Communications Program puts the requested amount within the Commission's rules, and $202,906 should be included in cost of service for that program.

Although OPC accountant Effron made no such recommendation, the OPC challenged a number of entries in Account No. 930 proposed for inclusion by TUEC. Of the various membership dues and fees, and contributions in that account, the OPC recommended disallowance of dues for the Atomic Industrial Forum, an organization that assists utilities in the TMI recovery process, breeder reactor technology, fusion technology, and international nuclear policy. It recommended that dues to the Texas Research League, an organization that performs research on tax matters, be excluded from cost of service, as should membership dues for the National Association of Manufacturers, a group that develops and advocates sound industrial practices and the importance of a competitive market system. The OPC also concludes that the Texas Association of Business dues paid by TUEC should be excluded for the same reason. According to the Public Counsel, dues to the American Nuclear Energy Council should be disallowed since that body is involved in lobbying for the nuclear power industry. The OPC also urged the Commission to exclude TUEC's payment of Chamber of Commerce dues, there being no evidence indicating that membership in that body is necessary or beneficial to ratepayers. OPC Initial Brief at 45-46. This line of recommendations was developed by OPC counsel during cross-examination of company witness Scarth, whose characterization of these organizations and dues are repeated above, except that he did not agree that these expenses were of no benefit to ratepayers. The factual finding that the expenses are not necessary is one that the OPC urges the Commission to make based on reasonable inferences from the evidence. Reasonable inference from the evidence and common sense, however, indicate otherwise. Except for the American Nuclear Energy Counsel's lobbying efforts, the disallowances recommended by the OPC in brief should not be adopted by the Commission. Accordingly, $6,922, dues associated with the American Nuclear Energy Council, should be disallowed from cost of service as direct and indirect lobbying expenses.

OPC suggests in brief, although its accounting witness did not do so, that an amount of $171,764 in Account 930 for research and development should be disallowed, since it went to the Texas Atomic Energy Research Foundation for fusion research. Noting that company witness Scarth conceded that the company does not currently have plans for nuclear fusion generation, and that no commercial plants operate on that power source, the Public Counsel opposed inclusion of that amount. The applicant responds that few innovative projects are embarked upon without the performance of research, and that there never will be nuclear fusion generation if there is no research done. Regardless of one's feelings about nuclear power generally, or fusion generally, the applicant's arguments are persuasive, and the proposed disallowance should not be made.

The OPC seeks disallowance of $23,499 in a miscellaneous category of Account 930 because the amount involved the providing of lunches at plant tours at Big Brown and Comanche Peak. Transcript at 1556. That amount comprises $4,535 for plant tours, $7,082 for Chamber of Commerce tours, and $11,883 to Coburn's Catering for lunches for plant tours. OPC Exhibit 3. There are many possible inferences that can be drawn in this dispute, but in the absence of a cogent company response, the Public Counsel's recommendation of disallowance of this amount should be adopted by the Commission.

The Public Counsel recommended exclusion of $124,113 of Account 930 contributions and donations associated with Chambers of Commerce, Committee on Economic Development, North Texas Commission, Temple Industrial Foundation, Texas Rangers, and Texas Research League. Some of these amounts were given toward the goal of helping to control surplus capacity in a manner that equates to promotion of electricity consumption, according to the OPC. OPC Initial Brief at 47. Company witness Scarth testified that these expenditures generally were made in order to improve the economic environment in which the company serves, to provide jobs for people who live the area, and generally to assist the company in serving the areas, and having load to serve (prevention of idle capacity). Again, the company suggests that the OPC recommendations in this area generally constitute an OPC directive that "the company tuck its head into its shell and not involve itself with the world around it." Applicant's Reply Brief at 26-27. The report adopts the recommendation of the OPC; the issue is a close one, and it is arguable that the utility should serve those in its service area and not--with ratepayer money--attempt to entice more customers into the area. There would appear to be a number of good arguments on both sides of this policy issue, but in the absence of a further development of the evidence and the arguments on this point, the company has not shown by a preponderence that these amounts should be included. The company's operation and maintenance expense should be decreased by $124,113.

The OPC recommended disallowing $1,901,214 included in general advertising in Account 930, "because it is self-serving, corporate and institutional advertising not intended for the benefit of ratepayers." OPC Initial Brief at 47-48. The report does not recommend adoption of this approach, the factual conclusion suggested by the OPC being based upon an inference being drawn from one advertisement. Id.

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f. Rate case expenses

The applicant requested a total of $941,428 in rate case expenses, of which $231,428 was attributable to the unamortized rate case expenses of prior cases, and $710,000 is attributable to the estimated expenses for preparation and presentation of the instant application. Applicant's Exhibit 1C, Schedule A, page 13. TML witness Wilson decreased the company's request by $310,000, a result attributable to two alterations he made to the computation. First, he added $90,000 to the proposed rate case expense for this docket; second, he amortized the $800,000 result over a two year period and added one year's share to the previously unamortized rate case expenses. TML Exhibit 1 at 12. Evidently, the addition that the TML witness made to the company's estimate was attributable to the Cities' rate case expenses. Mr. Wilson testified that the cost of legal and consulting fees for the Cities is based upon billing rates comparable to those charged by firms doing similar work, although he did not present any details other than that legal costs are included at a rate of $75 per hour. The company indicates that it agrees with the reasonableness of the Cities' estimated expenses. Applicant's Initial Brief at 46. The utility points out that rate case expenses should be included in the cost of service based upon the anticipated period of time the rates will be in effect. Mr. Wilson conceded that the rates set in this docket would not be in effect for two years. Transcript at 2354-2355. Given the great length of discussion about, not whether TUEC would file a rate case in 1985, but whether it would file more than one, there is little to commend the TML witness's amortization recommendation. The rate case expenses, as determined below, should be amortized over a one year period.

Like the accounting witness for the Cities, OPC witness Effron did not challenge the rate case expense estimated for this docket. OPC Exhibit 1 at 48. Nevertheless, both the OPC and the TML suggest in brief that their witnesses' recommendations should not be adopted by the Commission in this regard. The TML argues that the company's estimation of rate case expenses greatly exceeds prior actual rate case expenses of the three operating companies, and that lower expenses in this area should be expected due to the corporate merger. The Cities point out that DP&L's most recent case included in cost of service $186,000 of rate case expenses, that TESCO's most recent case included $350,000 of rate case expense, and that TP&L's last case included $427,000 in rate case expenses. TML Initial Brief at 47-48. In light of the fact that these total $963,000, that the one hearing for all three companies in the instant docket lasted thirty-two days, and that the number of parties--as well as the record they created--is staggering, TML's argument is not convincing. The OPC revealed in its Initial Brief at page 45 that it opposed recovery of the rate case expenses for this case, since the amount is not known and measurable, since the filing in the case is unreasonable (a fact one is to infer from the rate reduction recommendations of intervenors and staff), and since the filing was premised on higher profits for shareholders rather than recovery of necessary expenses for certain ratepayers. It may be arguable that the expenses were not necessary to increase the company's revenue requirement by the amount it sought, but the ratepayers have benefited by the redetermination of the unified company's cost of service and the setting of systemwide rates. The OPC's arguments, running across the grain of its own witness's testimony, are no more persuasive than the TML's.

OPC witness Effron did adjust rate case expenses, reducing them by $231,000 to reflect his determination that the unamortized portions of rate case expenses associated with prior rate cases should be eliminated. He pointed out in prefiled testimony that the purpose of allowing an amount for rate case expense is not to guarantee the recovery of those amounts actually expended, but rather is to gauge the level of rate case expense on an annual basis that the company can reasonably expect to incur. He points out that allowing rate case expenses greater than the expense associated with a given rate case is appropriate only if one assumes that the company will be filing rate cases more often than once a year. He doubted that such is the case. OPC Exhibit 1 at 48-49. According to TUEC, this recommendation catches the utility in a double bind; amortization of rate case expenses presumes that another rate case will not occur until those expenses have been recovered through rates. The regulatory authority's failure to permit the full recovery of expenses which it required to be amortized over a given period conflicts with simple notions of integrity, argues the applicant. Applicant's Initial Brief at 46.

Staff witness Poole reviewed and examined the company's rate filing package and supporting information provided by the company, and determined not to adjust the proposed rate case expense figure. For the reasons given by the company in its reply brief, and in accord with the opinion of Ms. Poole, Mr. Effron's disallowance of unamortized rate case expenses from prior dockets should not be adopted by the Commission.

One issue remaining concerning rate case expenses involves the City of Bowie and its participation in this docket. Bowie sought a finding that its legal and consulting fees associated with participation in this docket (which, incidentally were better documented than any other party recovering rate case expenses herein) were reasonable under PURA Section 24(a). Bowie made a similar argument in Docket

No. 5200, but the Commission concluded that the language of the PURA then in force precluded the City of Bowie from recovering its rate case expenses. As reenacted and effective September 1, 1983, the PURA does not preclude the City of Bowie from being reimbursed its reasonable rate case expenses. It is a "governing body" of a "municipality participating in" a "ratemaking proceeding," within the meaning of Section 24(a).

The Coops showed unusual interest in this topic, arguing that the City was not present in the case in its governmental capacity as a regulator, but entered the case in order to "enhance its proprietary status at the expense of the Cooperatives." Coops Rate Design Reply Brief at 6. According to counsel for the Coops, the Legislature intended that one set of customers not be favored over another, especially through the exercise of governmental powers. The Coops argue, without merit, that it is "simply unconscionable" that Coops as customers be required to pay any of the costs incurred by the City of Bowie in this docket.

It cannot be gainsaid that ratepayers as a whole have funded or will fund a large part of the massive expenditures made in litigating this docket. Commission employees are paid ultimately through the gross receipts assessment, whereby a percentage of utilities' revenues are turned over to the state, which in turn operates the Commission. The Texas Municipal League Cities participating in the case are entitled under Section 24(a) to receive their reasonable rate case expenses, which go into the utility's cost of service and will be funded by TUEC ratepayers across-the-board. Participation of other parties in the case is also funded by ratepayer money, through that and separate routes, including the Coops themselves. The Coops' philippic against the City of Bowie in the matter of rate case expenses should be disregarded by the Commission. TUEC's final rate case expense should be increased by $112,900 a result of the company's $710,000 expense, the unamortized rate case expenses, the increase to the Cities' rate case expenses proposed by Mr. Wilson, and the expenses of the City of Bowie.

g. Water rights

Various witnesses proposed exclusion of expenses during the test year representing TUEC's payments to retain water rights in Account 557, associated with possible future generating stations. The amounts are included in the company's proposed cost of service, although they are not presently associated with plant now in service. Transcript at 1610-1611. Witnesses for the staff, the OPC, and the TML recommended removal of these amounts from cost of service. $726,000 is associated with the options retained by TUEC for Lake Fork water rights when they were sold to the City of Dallas. $2,310,000 in expense is associated with water rights payments to various entitites, reflected on Mr. Wilson's Schedule 9. $27,500 related to an agreement for water in the future which has since been terminated, and was treated by the staff accountant as a nonrecurring expense to be excluded from cost of service. Staff Exhibit 8 at 12. These amounts total $3,063,500, which should be deleted from cost of service, since the water is not currently being used for, nor is it even dedicated to, a specific generating plant.

h. Property reserve

TUEC witness Kelch urged Commission approval of annual accruals to a self insurance reserve, which is part of a three point plan to provide protection for TUEC's assets. The other two points of the plan are the purchasing of external insurance coverage for high dollar level catastrophic losses and the charging of relatively low level dollar losses ($500,000 or less) to current year expenses. Applicant's Exhibit 1A, Kelch at 35. Mr. Kelch testified that such a combination of methods provides the lowest cost to customers and the most efficient coverage for losses to the company. Self insurance is, according to the company witness, the most effective method to provide protection in those areas of uninsured loss where insurance cannot economically be had and to assure that the large deductibles required in the external insurance program will be covered. Mr. Kelch described the primary advantage of a self insurance reserve as the provision of lower costs to customers. He pointed out that, if the company wanted to purchase the additional external insurance and reduce deductibles to achieve the same results as that available under the insurance reserve, the annual premium cost would increase by almost $10 million per year. He asserts that a provision to the reserve of $2,160,000 annually will achieve the same results and avoid the additional premium costs.

Mr. Kelch testified that annual accruals would mean a balance of $18,400,000 within three years, assuming that there are no further losses during that time period. Mr. Kelch conceded that the monthly accruals would not be set aside in a special insurance fund if the self insurance reserve accruals were approved by the Commission, noting that none of the company's other reserves are segregated (and citing accruals to the depreciation reserve as not being set aside to replace assets as they go out of service). Witness Kelch found the post-amortization of a property loss not to be a reasonable method for dealing with that loss in cost of service, because of three problems: that there is no assurance that future regulators will allow the amortization of the loss, that amortization cannot begin until the company files for and is granted a rate increase, and carrying costs on the funds--possibly in substantial amounts--would not necessarily be accrued for recovery by the regulatory authority. (There would be no carrying costs under the insurance reserve method.) Id. at 37-38. Cities witness Wilson, staff witness Poole, and OPC witness Effron all recommended elimination of the $2,160,000 annual accrual to the reserve. Tex-La joins in this argument, pointing out that the Commission has already issued a ruling on this matter in Docket No. 5200, in which the accounting treatment recommended by Mr. McEuen was ordered implemented by the Commission. The arguments offered by the parties' witnesses do not add to the pros and cons regarding the reserve accruals as advanced in TESCO's most recent rate case, Docket No. 5200. It is clear that the current balance of the insurance reserve, some $11,926,000, represents 3.7 years of such charges. OPC Exhibit at 45-46. There is likewise no controversy over the fact that the funds are not segregated, and that the target set forth by TUEC represents some three times the amount of likely casualties in a given year. The nature of this proposal has been described as one proposing the advance recovery of expenses which are not known and measurable changes to test year events, although there is a strong policy argument that the insurance reserve approach sought by the applicant is much more efficient (for utility and ratepayer) than the alternatives. This report adopts the recommendation of staff accountant Poole in removing the $2,160,000 accrual to the property insurance reserve from operation and maintenance expense, finding insufficient reason to depart from the Commission's ordered treatment in Docket No. 5200. However, the staff and parties should be encouraged to explore the issue of insurance reserves in more depth in future cases.

i. Other O and M merger savings and expenses, corporate expenses

Erle A. Nye, Executive Vice President of TU, President of Texas Utilities Service, Inc. (TUSI) and Executive Vice President of TUEC, prefiled testimony which described the current functions of the various companies within the TU system. He described the company's service area, and presented testimony on the benefits resulting from the new organizational structure effective January 1, 1984. Mr. Nye pointed out that it would be impractical if not impossible to quantify fully every change resulting from that reorganization, but he did present examples in support of his thesis that the changes will result in hundreds of millions of dollars to be saved over the next decade as a result of the merger. According to this witness, the vast majority of those benefits stem from reducing duplication of effort.

Exemplary of such reduced duplication of effort is the topic of economic dispatch. Before the merger, each operating company independently selected the generating units that would be scheduled to function to meet the daily generation requirement. Each company independently allocated the instantaneous load requirement to its own generating units in a way calculated to reduce the total production costs for the operating company. After the merger, the scheduling of units to be on line each day is done on the basis of a single company operation, whereby the dispatcher selects from the total pool of generators available on the TUEC system a more efficient combination of units to meet the TUEC system load than could be achieved by individual operating companies meeting their individual loads. Mr. Nye described TUEC's construction of a new control center ("TUSOC") to be completed sometime in 1985, after which full automated economic dispatch of all of the applicant's generating units on a joint basis will be possible. Mr. Nye saw that project as spelling potential fuel cost savings in 1986 (the first full year of the economic dispatch system) of thirty-six million to fourty-five million dollars.

Mr. Nye provided another example of reduced duplication of effort, in the area of personnel. TUEC will be providing the same service, to even more customers (the applicant is adding new customers at the rate of approximately 70,000 per year) with fewer employees. Mr. Nye testified that there has been a reduction of 342 employees since October 1, 1982, and based upon past trends, there are approximately 1,268 fewer employees necessary under the merged companies than would be necessary in the premerger setup. He approximated the savings to be in the neighborhood of $28,000,000, based upon the average payroll and payroll related expenses associated with the reduction, and declared that the savings are reflected in the company's test year cost of service, since that cost of service is based upon the test year end number of employees.

Mr. Nye described the reorganization resulting in TUEC as creating a much more streamlineddecision making process, for example in the area of data processing. According to Mr. Nye, the prior organizational structure led to independent approaches to common problems, but centralization will--after a two year transitional period--result in the savings of both hardware and software requirements by an annual amount eventually of $2,290,000.

Mr. Nye recounted the costs associated with reorganization at $611,011 in the test year and the total cost to TUEC through the end of 1983 at approximately $634,000. Those costs include the preparation of legal documents, preferred shareholders' meetings, obtaining necessary rulings from the Internal Revenue Service, payment of registration fees for securities, and audit fees.

Mr. Nye summed up his view of the merger, noting that cost reductions will in large part be passed onto the customers, since they are embedded in the unadjusted test year data, and that such benefits will be reflected in future costs of service calculated by the company in future rate cases. He stated that the full benefit of all savings would be reflected in rates charged for electric service by the applicant.

TUEC witness Moseley sponsored a reduction to other operation and maintenance expense in the amount of $7,222,994, due to economies attributable to the reorganization of the three operating companies into TUEC. That adjustment was made to reflect reduced duplication of effort achieved by that reorganization, and was based upon a determination by the witness that during the test year the company reduced the number of employees by 342, an overall decrease of approximately 2.5 percent from the test year beginning level. He pointed out that the reduction percentage was applied to all other operation and maintenance expense items which were not individually adjusted, since individual adjustments are not feasible to the many other operation and expense items. Such a report on savings attributable to merger was required by the Commission's final Order in Docket No. 4713.

Staff witness Poole testified that the dollar level proposed by the company represents a reasonable measure of savings related to the corporate reorganization, although she did not necessarily endorse the methodology employed by the company. Staff Exhibit 8 at 13. She also testifed that she had started with the testimony of Mr. Nye, had spent quite a bit of time with company accountant Moseley trying to determine what other types of savings could be achieved, and trying generally to quantify other savings which she could identify as compared to Mr. Moseley's suggested adjustment. Although her calculations resulted in numbers smaller than those proposed by Mr. Moseley, she suspected that there <u>were</u> other savings that she was not able to identify or quantify, so she accepted his number as reasonable. Transcript at 3339. No other witness chose to challenge the company's adjustment although TML witness Wilson did inquire into the adjustment to satisfy himself that it was a reasonable estimate. The company itself suggested that the adjustment did not represent a truly known and measurable change. Applicant's Initial Brief at 51.

Tex-La and TRA argued that the company has evaded the Commission's order in Docket No. 4713, which required TUEC in its first rate case to " prepare testimony which will demonstrate any actual savings or increased expense which may have resulted from the consolidation of the applicant companies into TUEC." 8 P.U.C. BULL. 250, 255. Tex-La agreed that the merger would result in substantial cost savings, but the benefits of the merger were in danger of being "appropriated" by the utility if the Commission were to fail to order the applicant to file studies quantifying the actual savings or increased expenses resulting from the merger during the test period supporting its next rate case. Tex-La Initial Brief at 47. TRA urged the Commission to order a management audit of TUEC to discern the actual costs, savings, and efficiency of the reorganization. TRA Initial Brief at 27.

The OPC joined in grudging acceptance of the company's merger benefit estimate. OPC Initial Brief at 54. However, the Public Counsel argues, reduced operation and maintenance expense is merely the beginning point, and the OPC urged a reduction of $382,556 for legal work "which ought to be reduced by merger," a reduction in 1983 donation and membership expenses by 5 percent owing to the company's 5 percent goal of reducing such expenses in its 1984 ocst reduction program, a similar reduction to advertising and information expenses due to the 1984 cost reduction attempts of the utility, a decrease to employee benefit insurance and administrative costs by $1,440,000, a lowering of advertising agency expense by $123,000, a downward adjustment to customer opinion survey expense of $27,000, and a reduction to external reporting expense by $123,000. Id. at 55-56. The OPC characterizes TUEC's approach to the merger as "cavalier." Id. at 57.

TUEC points out in its reply brief that the "number of allegedly quantifiable adjustments for merger savings" set forth by the OPC are already included in Mr. Moseley's adjustment to O&M expense, and would constitute a double-dip. Applicant's Reply Brief at 27. Reference to the cross-examination of Mr. Nye, as well as the direct testimony of Mr. Moseley, indicates that the company is correct. Transcript at 680-681; Applicant's Exhibit 1B, Moseley at 7.

No party demonstrated that the company's requested merger savings adjustment was definitely awry, although it must be conceded that quantification of the savings is subject to different approaches. The report recommends adoption of Mr. Moseley's reduction to other O&M expense as the best available estimate of merger savings on the record, and one that was made in good faith by the applicant. As to the request that the Commission "order" a management audit, it is doubted that such a decision should be made in this instance in a contested case context. PURA Section 16(h) has evidently been read by the Commission as giving the agency a fair amount of investigatorial discretion, and decisions to audit certain phases of utilities' operations have been made on criteria including factors other than those appearing in the instant merger savings dispute. The Commission is clearly free to take the course urged by the TRA, but this report declines to suggest particuar steps in the Commission's plans to satisfy the requirements of PURA Section 16(h).

There was also a dispute over the corporate reorganization expenses incurred by the company during the test year. The company included $517,000 associated with reorganization in its cost of service; OPC witness Effron recommended exclusion of that amount from cost of service, reasoning that the company will not be reorganizing again soon and that the $517,000 represents a nonrecurring expense. Tex-La joined in this contention, in a sense, although there was some confusion over the precise amount of the expenses attributable to reorganization. See Tex-La Initial Brief at 46-47; Applicant's Reply Brief at 30-31. If the company is correct in asserting that the expenses associated with the merger are ongoing and will continue to incurred, the same inference can be made about the emergence of further savings due to the merger. The Commission could have ordered a study, as Tex-La would have it, but it is likely that the company's next test year will adequately capture further savings. The most balanced approach is to adopt the recommendation of Mr. Effron in tandem with Mr. Moseley's recommended merger savings adjustment. Therefore, the company's cost of service should be decreased by $517,000.

Finally, in the area of corporate expenses, the OPC recommended disallowance of $327,403 in corporate expenses included as an adjustment to Account 930. The OPC pursued a line of cross-examination with Mr. Moseley, and Mr. Moseley testified that they were costs associated with TUEC that had been deferred and charged to expense in September 1983. There was not a showing of the time that the expenses had been incurred. Until a final disposition of the expenses was made, they were held in a suspense account, because--at the time the costs were incurred--the company was not sure whether they should be expensed or capitalized. Mr. Moseley did not know what the costs were related to, could not even give a broad description of them, could not help Mr. Gay locate those costs in the rate filing package, and generally did not recall anything about the amount other than that it had been deferred and charged to expense. The OPC correctly argues that the company failed to meet its burden of proof to explain and justify that amount. The $327,403 "corporate expense" should be deducted from operation and maintenance expense.

j. Other O&M-econometric adjustment

Art Ekholm, Manager-Economic Research of Texas Utilities Electric Company, presented testimony in support of the company's econometric adjustment to other operation and maintenance expense. That adjustment was made to reflect price levels esisting at the end of the test year, and consisted of an increase of

$4,238,503. Dr. Ekholm testified that monthly other O&M levels were individually adjusted to test year end by the ratio of the year end implicit price deflator for gross national product (GNP) divided by the quarterly value of the deflator for each month. It was his opinion that the adjustment was appropriate because a wide range of expenses is included in other O&M, making it prohibitive to achieve specific adjustments to each individual type cost in that category. He felt that a reasonable measure of increases in such a collection of expenses is provided by the implicit price deflator for GNP. Applicant's Exhibit 1B, Ekholm at 7-8. It should be clarified that the company's adjustment is not an attempt to increase other O&M expenses included in cost of service to account for inflation occuring <u>after</u> the test year. The increase is proposed to adjust the booked other O&M expenses to account for inflation which occurred during the test year; it is in essence an annualization of the effects of test year inflation.

The use of the implicit price deflator was challenged by TML witness Dr. John Livingstone, because that deflator is based on preliminary estimates of the gross national product which are later revised. He pointed out that the deflator is not a currently reliable price index due to these retroactive corrections, and found no evidence that the other O&M expenses actually do or should move in accordance with the GNP deflator. Believing that the grant of such an adjustment would give the utility no incentive to control and minimize this type of expense, Dr. Livingstone concluded that the adjustment should not be allowed. He examined the trend of other O&M expense over the test year, and concluded that the trend was generally downwards rather than upwards. TML Exhibit 4 at 3-4.

Staff witness Louis W. Pompi also presented testimony challenging the company's adjustment. Dr. Pompi noted that past attempts to adjust other O&M expenses for changes in the number of customers have been rejected, because the relationship between customers and expenses could not be defined accurately enough to satisfy the known and measurable test. The staff witness described the GNP implicit price deflator as "perhaps the most comprehensive measure of inflation available." Staff Exhibit 9 at 17. He pointed out that the many commodities included in the estimation of the deflator consis of many items not included in the other O&M category, and the GNP is a national index which may not be an accurate measure of regional price changes. Dr. Pompi concluded that the company procedure did not provide a very accurate measure of the effect of test year price changes on other O&M expenses and--conceding that there may well have been an increase in other O&M expenses during the test year--recommended that the company's proposal be rejected by the Commission, due to its questionable accuracy.

TRA witness Raymond J. Stanley, President of R. J. Stanley & Associates, Inc., also disagreed with the adjustment to other O&M. He pointed out that a similar adjustment was proposed in DP&L's last rate case, Docket No. 5256, and that the

Commission refused to conclude that a high degree of statistical correlation alone (in that instance a correlation between number of customers and other O&M expenses) necessarily indicated a causal relationship. Mr. Stanley presented his Exhibit RJS-4, showing the monthly balances in several O&M accounts and the GNP price deflator on a monthly basis during the test year, and he pointed out that visual inspection of that exhibit demonstrates little correlation between those two; he also recommended that the adjustment be rejected by the Commission.

The parties argued in brief still other reasons why the econometric adjustment should not be made. TRA points out that Dr. Ekholm did not specifically examine either the other O&M accounts, or the items contained in those accounts, to discern whether the items or accounts varied in correspondence to the price deflator, that the items used by the Department of Commerce to construct that deflator may well include items not normally contained in the other O&M accounts, and that the price deflator also considered demand for products as well as price increases. TRA Initial Brief at 2-3. The General Counsel points out that Dr. Ekholm was not certain which specific items were included in the company's other O&M account, and that the analysis failed to consider the various price discounts the company's representatives can obtain when purchasing goods and services. General Counsel Initial Brief at 52-53. The TML provided perhaps the most thorough catalog of flaws in the adjustment, demonstrating that a major category of the deflator is private domestic investment in durable equipment, including things like machinery, automobiles, barges, ships, and railroad equipment; that the deflator includes residential structures, the value of which increased 60.98 percent during the test year; that the deflator included as a category government spending, which includes national defense expenditures on such items as military equipment and ammunition (the Cities doubt that items like tanks and aircraft carriers are included in TUEC's other O&M expenses). TML Initial Brief at 50-51. OPC witness Effron and OPC counsel urged that the company has simply failed to carry its burden of proof in this matter. OPC Initial Brief at 42, and citations therein. Tex-La joins tersely with these parties to oppose the adjustment, in its brief at 60.

The applicant suggests that Dr. Ekholm's adjustment must be considered in tandem with Mr. Moseley's adjustment to other operation and maintenance expense for merger savings, and that "both parts of the adjustment are consistent in methodology." Applicant's Initial Brief at 51. Despite the company's assertion that a double standard is being applied, Dr. Ekholm's econometric adjustment should not be approved by the Commission. It comes nowhere near reflecting a known and measurable change to the specific operating expenses of the company. Furthermore, there is no inconsistency in accepting the company's merger savings proposal, and rejecting its use of the price deflator; the methodologies have little in common.

k. Energy conservation expense

Staff witness Judy Poole recommended a decrease in other operation and maintenance expense in the amount of $735,242, to reflect discontinuance of one of the company's many conservation programs. That program provided incentive payments for customers switching to higher efficiency fluorescent lamps. Staff Exhibit 8 at 14. The staff accountant reasoned that this particular program represented an expense which is nonrecurring. The OPC joins in this recommendation in its Initial Brief at 45, arguing that the company's 1983 cost reduction program called upon employees to eliminate such programs which did not effectively and economically help achieve the goal of system load management. OPC also argued that load management and conservation efforts impermissibly promote consumption of energy in off peak periods.

The applicant points out that during corss-examination the staff accountant acknowledged that she would not logically make the adjustment if the evidence showed that the discontinued program was replaced by another ongoing one. Applicant's Initial Brief at 55. The company points out further that it began in 1984 to make incentive payments to builders for participation in the E-OK Program, and that the staff's own witness Dr. Monts suggested that the company continually evaluate its programs and redirect funds toward alternative programs once one is deleted. In light of the company's actions meant to do precisely that, disallowance of the amount in question is a disincentive to the very goals that staff witness Monts sought to encourage in this docket. The General Counsel recanted the staff's position on this issue, and believes it appropriate that the Commission send a strong signal encouraging energy conservation expenditures. The General Counsel therefore recommended that Ms. Poole's adjustment not be made and that the test year level of expenses for conservation efforts not be decreased. This report recommends no adjustment to energy conservation expense, agreeing with the arguments of the applicant and the General Counsel, and finding the arguments of the OPC curious.

l. Purchasing expense

Staff witness Poole recommended a decrease in variable purchasing costs expense of $52,544, based upon the testimony of staff witness Jones. This result was achieved by application of Mr. Jones' reduction factor of .997 to the test year level of purchasing costs. The company points out that Mr. Jones' recommendations generally were discredited, and that his methodology regarding purchase order processing time is arbitrary and insupportable. TUEC Exhibit 33 at 8-9. Mr. Tanner testified during rebuttal that witness Jones' failure to make allowances for the purchases of safety related items at Comanche Peak and to make offsetting positive allowances for the Martin Lake plant, and to round the adjustment factor consistently with his other roundings, are the only reasons that the factor was not 1.0. Id. at 9; Transcript at 3109-3110.

The General Counsel points out that Ms. Poole's adjustment follows logically from the testimony of Mr. Jones. This is correct; the adjustment should not be made. The numerous flaws in the staff's approach to material and supplies inventory precludes confident decrease to purchasing expense on this record.

m. O&M adjustments - summary

TUEC booked $625,342,501 in other O&M expenses during the test year, and proposed increases to various items in that category totalling $19,759,299. The recommendations above amount to a disallowance of $13,524,364 of the company's adjusted test year total, resulting in a figure of $611,818,137 for other operations and maintenance to be included in the applicant's cost of service. A two page summary of these adjustments, titled "Operation and Maintenance Expense," is attached to this report and incorporated herein by reference.

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2. Depreciation

Dwight L. Cole, a TUGCO employee who is currently responsible for developing depreciation studies and rates for TUEC, testified in support of the company's proposed depreciation expense. That expense is based upon distribution of the cost of tangible capital assets over the estimated useful lives of those assets in a systematic manner. Mr. Cole used the remaining life methodology to determine functional depreciation rates, which method takes the undepreciated remainder of the depreciable investment in facilities, adjusted for net salvage, and divides that remainder into equal annual depreciation accruals over the estimated remaining life of the facilities. Mr. Cole stated that the depreciation rates being proposed for TUEC were based upon the same functional grouping of property previously used for the operating companies and that the annual functional depreciation rate for gas and oil facilities was 3.49 percent, while it was 3.55 percent for lignite facilities. Mr. Cole testified to changes in the gas and oil unit retirements schedule, reflecting the extension of service life of five gas and oil units from one to five years each and reduction of the service life of two units by one year each. He testified to other depreciation rates proposed by the applicant which are not disputed by the parties. The weighted composite depreciation rate proposed by the applicant was 3.37 percent. Applicant's Exhibit 1B, Cole at 8.

Three types of adjustments were proposed to depreciation expense. First, TML witness Wilson and staff witness Poole proposed decreases in that expense to account for the deletion from invested capital by witnesses Cannady and Allen, respectively, of the Permian Basin Units 1-4. The adjustment, based upon reduction of depreciable property because of post test year retirements, should not be approved by the Commission if the recommendations in Section V of the report are adopted, concerning adjustments to invested capital for out of period events. Adoption of the TML's and staff's position regarding the Permian Basin Units would require an adjustment to depreciation expense. (Depreciation expense may simply be computed by applying the composite depreciation rate as a multiplier to the plant in service amount approved by the Commission.)

Staff engineer Tom Sweatman recommended certain changes to the company's proposed depreciation rates. He noted that the company has conceded a need for revising previous estimates of service lives of gas and oil fired generating units. Natural gas prices have, according to Mr. Sweatman, not increased commensurate with companies' previous estimates, and the estimated in-service dates of other new units (e.g. lignite) have been extended. He pointed out that in the three most recent rate cases of the TUEC operating companies, the service lives of several gas and oil units had been revised upward by the companies. Staff Exhibit 3 at 6. The staff witness questioned whether accurate predictions of retirement dates for such units can be made over the next twenty years when rapidly changing conditions can easily alter such estimates in either direction, and he therefore had doubts about the accuracy of the company's predictions. Believing it possible to predict witn reasonable accuracy the retirement dates of generation units occurring within the next few years, he accepted the company's predictions of retirement dates for units through the year 1991. However, he recommended that an average service life of thirty-five years be assigned to all oil and gas units in operation beyond 1991. According to Mr. Sweatman, thiry-five years is quite a reasonable estimate of the service life of such a generating unit, and--indeed--it is possible with proper operation and maintenance for the units to continue in service for longer than fifty years. He notes that the company proposes a service life of fifty-one years for one of its gas/oil units. Id. at 7. Use of these guidelines produces an average weighted remaining life of 19.17 years for all units to be retired after 1991, and a new depreciation rate of 2.74 percent for the gas/oil production account. Mr. Sweatman's recommendation results in a reduction to depreciation expense of $7,645,640. He investigated the other proposed depreciation rates of the applicant and determined that they are reasonable.

The TML joins with the staff in this recommendation, urging that the utility had provided no reasonable argument to rebut Mr. Sweatman's recommendation. TUEC did oppose Mr. Sweatman's approach, arguing that there was no justification shown for the use of an average thirty-five year life for all of the units, particularly for mature units with known performance characteristics. It argued that his approach is demonstrably fallacious, because of Mr. Sweatman's estimated negative two year life for Mountain Creek Unit 2, as shown on his Exhibit 1, page 1. The utility currently expects to retire that unit in 1996. Schedule I-6.2, page 1. The unit was placed in service in 1945. Id. However, the company's use of a unit that will be in service for fifty-one years, by the company's current estimate, to demonstrate that an average service life for such units should be deemed thirty years rather than thirty-five years, is not convincing. Mr. Sweatman's use of a negative remaining life for that plant must be taken in the context of other plants; it is not flatly stated by the staff engineer that each plant will be in service for precisely thirty-five years, but that thirty-five years is a good workable average. The company did not successfully rebut this recommendation and it should be adopted by the Commission.

Finally, staff accountant Poole recommended an adjustment to depreciation expense in the amount of $134,548, to reflect the amount of depreciation for power operated equipment and vehicles which should be capitalized. Before calendar 1984

DP&L did not capitalize any depreciation on power operated equipment or vehicles, according to Ms. Poole. The applicant did propose an adjustment to reflect the amount to be capitalized, and the only change made by the staff accountant was to reflect an allocation percentage based on DP&L's actual experience after January 1, 1984, rather than the rate used by the company. The utility argues that the staff has not sufficiently explained why its approach is better than the company's. It also points out that the proposed methodology was that used by the Commission--with the staff's approval--in Docket No. 5256. Departure from a methodology approved by the Commission for one of the operating companies of TUEC in its last rate case should be accomplished upon the demonstration of good reasons therefor. The matter was simply not explored at the hearing sufficiently to justify this recommended decrease.

In accord with the discussion above, the applicant's depreciation expense should be decreased by $7,645,640, and its depreciation and amortization expense set--for ratemaking purposes--at $170,034,343.

3. Other Taxes

The applicant requested some $240,524,436 in other taxes. That amount includes property taxes of $48,707,352, an adjustment of $10,113,818 over the property taxes charged to operating expenses during the test year (excluding Sandow Unit No. 4) of $38,593,534. Applicant's Exhibit 1C, Schedule A, page 23. According to company witness Moseley, the applicant makes an estimate of ad valorem taxes during the first part of the year and then adjusts its accruals to reflect the actual assessments when they become known. Transcript at 1626. The effective tax rates used to calculate the company's adjustment were those for 1983. Applicant's Exhibit 1B, Moseley at 9.

TML witness Wilson removed the test year ad valorem taxes relating to Permian Basin Units 1-4, based upon the determination that they should not be included in rate base. TML Exhibit 13 at 16-17. Again, such an adjustment is appropriate only if the units are removed from rate base, which this report does not recommend.

OPC witness Effron recommended an adjustment to the property tax amount based on his determination that property taxes charged to operating expense during calendar 1983 included an adjustment for prior years. He therefore recommended a reduction to property tax expense by $1,027,000. That adjustment would be logical if the company <u>had</u> underaccrued ad valorem taxes in 1982 and added the remainder to 1983 taxes. The applicant demonstrated that it actually overaccrued ad valorem taxes in 1982 (Transcript at 1626), and that if Mr. Effron's theory were to be implemented, it would result in a positive rather than a negative adjustment. The applicant is correct; Mr. Effron's adjustment should not be adopted by the Commission.

Finally, staff accountant Poole decreased ad valorem taxes by $4,951,798. Noting that accurals often do not reflect actual expenditures, she testified that she had attempted to verify the accuracy of the company's accruals. She pointed out that property taxes charged to operating expense in 1983 were $48,125,077, and that "to date, actual 1983 tax payments expensed or expected to be expensed were $44,324,301." Staff Exhibit 8 at 16. Ms. Poole suggested that the company may well have accrued more than it will actually pay, and therefore she used the actual 1983 tax payments and plant in service as of January 1, 1983, to derive an effective rate for the property tax. She then applied that rate to the recommended plant in service at test year end to determine a proforma level of expense. That amount was $43,755,554. Staff Exhibit 8A, Schedule III.

The applicant's response to this proposal is that TUEC adjusts its estimated accruals to reflect actual assessments when known, and that the effective tax rates for 1983 were used in the company's adjustment. Applicant's Initial Brief at 54. These observations do not demonstrate that the company's proposal is more accurate than the staff accountant's treatment; on the contrary, Ms. Poole's methodology should be credited by the Commission, and the effective rate (calculable from the staff's proposed property tax expense and its proposed plant in service) should be applied to the plant in service total recommended by this report.

The company recorded $15,158,507 in payroll taxes during the test year, a figure which it adjusted downward by $13,295. Both staff witness Poole and TML witness Wilson proposed adjustments to that expense, using the 1984 FICA base of $37,800, instead of the $35,700 wage base used by the company. The applicant agreed that the methodology behind these adjustments was correct, although it continued to press its disagreement with the payroll levels to which the payroll tax factors were applied. Because this report recommends adoption of the staff's adjustment in the matter of payroll expense, the staff's adjustment to payroll taxes is also appropriate and should be adopted by the Commission.

Staff witness Poole recalculated the effective tax rate for the state gross receipts tax, making that calculation on an accrual basis by dividing the tax annually assessed on test year revenue by the amount of test year revenue. She reached an effective tax rate of .0138, rather than the company's rate of .0136.

Staff Exhibit 8 at 17. This methodology is reasonable, was not effectively opposed by the company, and should be adopted by the Commission. The state gross receipts total recommended by this report is a result of that effective tax rate and the revenue requirement proposed herein.

Likewise, the staff accountant proposed a reduction to the company's state franchise taxes, employing the same methodology used by the company, namely applying the statutory rate to the capital structure, test year accumulated investment tax credits and level of property insurance reserve. Mr. Wilson, witness for the TML, had a more far-reaching adjustment to propose. He testified that the capital structure upon which the tax payment is calculated is that which existed at December 31st of the prior year. He explained that the company pays the state franchise tax in June, based upon the capital structure of the previous December, that it will amortize the June payment for the period beginning May of the year of payment and through April of the next year. His adjustment is meant to reflect the amortization of the expense expected to be recorded by the applicant through September 30, 1984. His expense, a decrease of $1,259,000 from the company's request, reflects the amortization of seven months for the capital structure at year end 1982 and five months for the capital structure existing at the end of 1983. TML Exhibit 1 at 17. The TML argues in support of Mr. Wilson's adjustment that he was "the only witness to calculate state franchise fee based on the December capital structure upon which the actual fee is based and on the company's method of amortization of the expense." TML Initial Brief at 44. The Cities assert that consideration of the company's expense beyond September 1984 would require an adjustment to reflect kilowatt hour sales and customer levels after that time. The applicant responds to the Cities' position by urging that Mr. Wilson's twelve month cut-off methodology is as inappropriate in this instance as it is in other areas. The company takes the TML witness to task for failing to consider the known and measurable March 31, 1984, issue of common stock properly included in TML witness Lattner's capital structure. Applicant's Initial Brief at 54. The issue in this matter is whether the change is a known and measurable one that should, in fairness to the utility and customers, be made. TML suggests that the adjustment violates the matching principle, but such is not the case. The franchise tax is not based upon revenues, but is based upon the recommended capital structure, accumulated investment tax credits, and property insurance reserve. Application of the staff witness's methodology does not violate the matching principle, and the franchise tax amount (included in "other taxes" on attached Schedule III) is calculated in accord with the staff methodology, using the other pertinent recommendations of this report.

4. Federal Income Tax Expense

Federal income tax expense was calculated by various witnesses who presented cost of service recommendations. The most thorough discussion of methodology is to found in the testimony of staff witness Judy Poole. Ms. Poole began her calculation of federal income tax expense with the return (overall weighted cost of capital times total invested capital), which is an after income tax amount. From return is subtracted an amount for interest expense, as well as other items which are deductible for federal income tax purposes. The resultant figure, taxable income after taxes, must then be "grossed up" to arrive at net taxable income before income taxes. That number is then multiplied by the marginal federal income tax rate of 46 percent, and reduced by tax credits and other tax savings, to result in the income tax amount includable in cost of service. The staff accountant testified that those computations result in full normalization of timing differences, so that it would be inappropriate to include any amounts in the calculation representing timing differences, as the company had done. Although she disagreed with the company's methodology, she recommended no adjustment to those items since there would evidently be no dollar effect to them.

Ms. Poole calculated interest expense by multiplying the staff's weighted cost of debt by the level of invested capital recommended by staff witness Allen. That procedure is meant to ensure that only the interest incurred allocable to utility plant would be deducted from taxable income. She also adjusted the amount of amortization of investment tax credits, because the company did not in her opinion use the correct amount of gross ITC's for DP&L and TESCO, and because of the staff's recalculated composite depreciation rate (used to compute annual amortization). Ms. Poole proposed an increase to the company's calculated depletion adjustment, added $15,601,203 in additional depreciation which is being recorded on the company's books but is not depreciated for tax purposes, and adjusted prior years tax accruals relating to the depletion allowance, owing to the company's treatment of this accrual as cost free capital until the amounts are reversed upon completion of IRS audits. Other witnesses proposed federal income tax expense amounts, but through processes not so clearly explained as Ms. Poole's and with results based upon their own recommendations in the case. The applicant took no issue with the methodology to be followed in computing federal income tax, except for the OPC's recommended "interest synchronization."

Public Utility Counsel witness Effron noted that the interest deduction for income taxes was reached by the company by multiplying the cost of debt included in its capital structure by the proposed rate base. He points out that the capital structure utilized to calculate the weighted debt component includes Job Development Investment Tax Credits (ITC's), and that inclusion of the ITC's in the capital structure has no effect on the overall cost of capital, but that it does effect the weighted cost of debt. Inclusion of ITC's in the capital structure reduces the weighted cost of debt, which makes a smaller interest figure used to calculate interest deduction in the income tax calculation. The bottom line of this process is that the federal income tax expense is higher when investment tax credits are included in the capital structure than when they are not. It was Mr. Effron's recommendation that investment tax credits not be included in the capital structure for the purpose of determining interest deduction in the income tax calculation. He found no logic to including ITC's in the capital structure for that purpose, and concluded that the company's methodology results in the ITC's earning a higher effective rate of return than the rate base supported by the company's other capital. OPC Exhibit 1 at 53. It is the OPC's position that TUEC's shareholders will receive the great majority of the benefits of ITC's, regardless of the method chosen to calculate interest expense, but that the company's proposed methodology does not properly share the benefit derived from ITC's between ratepayers and shareholders. OPC Initial Brief at 59. According to Mr. Effron, use of ITC's in calculating the interest deduction may theoretically actually cost customers more than if ITC's had not been available to the applicant at all. OPC Exhibit 1 at 54. The Public Counsel argues that Congress intended the benefits of these credits to be shared between ratepayers and customers, and that the use of ITC's in the capital structure to calculate interest could possibly result in no sharing. OPC Initial Brief at 61.

The company presented the rebuttal testimony of Mr. Umbaugh, who testified that the OPC's procedure in essence imputed a non-existent tax deduction in the calculation of income taxes. Applicant's Exhibit 37 at 11. The witness was of the opinion that the OPC's method would endanger the company's claim to ITC's, and actually resulted in de-synchronizing the interest expenses. Mr. Umbaugh illustrated convincingly that the imputed interest method produces more interest expense than is actually available from the debt capital used to support the rate base. See Applicant's Exhibit 37 at 12. Mr. Umbaugh challenges the conclusion of Mr. Effron that the OPC's recommended approach will not jeopardize the company's eligibility for investment tax credits. Conceding that the approach had not been directly disallowed by the IRS, the company's rebuttal witness noted that there are pending requests for rulings by the IRS on that subject, and that, in a private letter ruling dealing with a case before the Florida Public Service Commission, the IRS indicated that the failure to recognize the taxable earnings characteristics of the ITC benefits would violate the limitations imposed by the Internal Revenue Code, constituting an indirect reduction to cost of service on account of the ITC's, and a treatment of the credits as capital provided by someone other than common shareholders.

Mr. Umbaugh pointed out that the capital provided by ITC's is treated as coming partially from debt securities under the OPC's approach, and that the imputing of an interest deduction resulted in a rate of return assigned to ITC's actually less than the authorized rate of return. Id. at 14. The company adds to this that there have been cases in which courts have upheld a regulator's decision to apply interest synchronization, but that those cases were not tax cases involving the IRS. Applicant's Initial Brief at 52 and citations therein. Likewise, there have been nontax cases in which courts have upheld a regulator's decision to reject the synchronization. While Mr. Umbaugh would not advise his clients that interest synchronization would not jeopardize the continued availability of ITC's, the company was not able to demonstrate conclusively that it would be disqualified from the credits by the OPC's suggested treatment. However, there are pending requests for ruling by the IRS on this very issue, and the company submits to the Commission that this is an area in which caution should be excercised until a formal pronouncement by the IRS, so that the benefits of ITC's both to company and customers are not jeopardized.

The Commission has previously rejected the approach suggested by the OPC. TML's witness Jansen advocated use of this methodology in Docket No. 5568, the Application of Texas-New Mexico Power Company, (July 18, 1984). It rejected the suggestion of TML witness Johnson to take that same approach in Texas-New Mexico Power Company's previous rate case, Docket No. 4985. In these circumstances, it must be concluded that the likelihood of the applicant's losing the credits as a result of the OPC's recommended methodology is not precisely ascertainable, but it is nevertheless present. The applicant's supplication that caution be excercised in this area should be heeded; the federal income tax expense on attached Schedule IV therefore adopts the staff methodology and uses components recommended by this report, where they differ from the numbers shown on Schedule IV of Staff Exhibit 8A.

5. Interest on Customer Deposits

TUEC requested inclusion in cost of service of some $2,109,878 to account for the provision of 6 percent interest on customer deposits; such interest is required to be paid by the Commission's Substantive Rules and the request was not contested by any of the other parties. That expense should be included in the company's total revenue requirement.

6. Return

As explained above, the applicant's overall weighted cost of capital is 12.44 percent. Application of that percentage to the utility's invested capital recommended by this report produces an annual return amount of $650,649,506.

7. Other Revenues

During the test year, the applicant had other revenues of $44,275,842, a figure which it adjusted downwards by $3,777,326. TML witness Wilson recommended an adjustment to the company's revenues to include income from temporary cash investments, a proposal made consistent with TML witness Cannady's proposal to include temporary cash investments in her analysis of working cash. Given that the working cash requirements of the applicant have not been determined in this report by adoption of the TML's position, the other revenues of the applicant should not be adjusted on this account.

The utility points out in its Initial Brief at 56-57 that revenues (e.g. rentals) derived from plant held for future use which is excluded from rate base by the Commission should be adjusted out of test year revenues. TML witness Wilson had recommended such a downward adjustment of $42,000 for revenues attributable to the company's property rights in Culberson County and at Possum Kingdom Lake, as well as the lignite properties and potential trade land, consistent with his exclusion of these items from rate base. TML Exhibit 1 at 19. The applicant does not suggest precise dollar amounts associated with the particular items of plant held for future use that were challenged, and makes no reference to its rate filing package and the location of such information. It is clear from Mr. Wilson's Schedule 17 that the $42,000 adjustment was calculated from information provided by TUEC in response to an RFI. Given the recommendations in Section V.D. of the report, Mr. Wilson's $42,000 adjustment to other revenues should be made.

Mr. Wilson also proposed an adjustment concerning the gain from the sale of the Lake Fork water rights. He determined that of the interest income to be remitted by the City of Dallas to the company for the opportunity cost of money lost while funds were expended on the Lake Fork project, 25 percent of that should be used as an offset to other revenues to account for the 25 percent ratepayer contribution to the Lake Fork project. TML Exhibit 1 at 20. However, during cross-examination, Mr. Wilson conceded that the calculation would be in error if the only payments for Lake Fork expenses included in rates were those prior to October 1, 1981. Transcript at 2362. Mr. Moseley testified that such was indeed the case

(Transcript at 1606-1607) and the company points out in its Initial Brief at 57 that its Schedule A page 17 demonstrates that those amounts were already taken into account in the base rate revenue request. Mr. Wilson's Lake Fork adjustment to miscellaneous revenues should therefore not be made.

In accord with the recommendations above, the applicant's other revenue figure should be set at $40,456,516.

8. Revenue Requirement Summary

The total electric revenue requirement of the applicant, determined in accord with the recommendations of this report, including the recommended treatment of fuel below, is $3,662,401,067. TUEC's base rate revenue requirement is $3,621,944,551, and the establishment of that figure as the applicant's cost of service for which rates will be designed is consistent with a finding that the utility has a revenue deficiency of $7,041,461, rather than the $304,196,722 asserted by the company. Rates should be designed to allow the company to recover that additional amount (which was calculated in accord with the overall recommendations of this report, including recommendations immediately following for fuel and the adjustments to test year consumption discussed in Section VIII below.) The revenue requirement meets the criteria established by PURA Section 39(a) and P.U.C. SUBST. R. 23.21(b). Appendix I to this report shows the requested and recommended revenue requirements by category.

B. Fuel

1. Procedural Background and Testimony

TUEC filed this rate case prior to the entry of a final Order in Docket No. 5294, which set the fuel factors currently in effect for the company. TUEC's filing in this rate case requested that the fuel costs and factors approved in Docket No. 5294 be used in this case, and not be determined anew. Thus the company's initial fuel request was identical to the amount it sought following the Order of Remand in Docket No. 5294. The final Order of the Commission in that docket set recoverable fuel costs at a level somewhat below what TUEC had argued for, but the company has held to its position that the fuel costs approved of in Docket No. 5294 should be used in this docket and need not be redetermined. TUEC's argument is based upon a literal reading of the Fuel Rule, which provides that while fuel costs must be reviewed during each general rate case, they need not be redetermined during that rate case.

Several parties took issue with TUEC's views concerning the requirements of the Fuel Rule. A prehearing conference was held on April 23, 1984, to clarify the requirements of the Fuel Rule and the PURA, and to determine the procedures necessary to meet those requirements. As reflected in the Examiner's Eighth Order, the examiners were unable to read into the PURA or the Commission's substantive or procedural rules either a requirement or an intent that fuel costs must be redetermined in every general rate case. P.U.C. SUBST. R. §23.23(b)(2)(A) requires only that fuel costs be reviewed in the general rate case. Based upon this ruling, the examiners did not require TUEC to file a fuel case, but did order the company to provide full and complete answers to requests for information concerning its fuel costs and revenues.

Of the numerous parties to this docket, only four (including the staff) presented witnesses who testified concerning fuel in any depth. Coops witness Stover identified four reasons for the need to redetermine fuel costs, one of which was the belief that the Commission's rules require a company to file fuel data as a part of its rate filing package; he recommended that fuel costs be based solely upon the actual value as reported for the test year.

Mr. Stover also made several recommendations concerning the issue of whether certain fuel cost components should be unreconcilable in nature. First, he suggested that all fuel costs be rolled into the base rates. Coops Exhibit 1 at 10. He then recommended that those costs over which the company has some control, those associated with affiliate transactions, be deemed unreconcilable in nature. Of the $1,508,507,942 actual total test year fuel expense figure, Mr. Stover calculated that some $412,977,666 in fuel costs, or over 27 percent of the total amount, fit that description and thus should not be reconcilable. Id., Schedule A-1.0.

Like Mr. Stover, TML witness Stephen Wilson began with actual test year fuel expenses, but he made a number of adjustments to that base figure in order to reflect known and reasonably predictable changes. First, he increased fuel cost by $2,593,000 to reflect the increase in gas prices put into effect by Lone Star Gas Company. The increase is based upon the minimum take-or-pay volumes specified in the contracts with Lone Star. The next three adjustments proposed by Mr. Wilson--to account for year end customer and weather adjustments, to replace the power purchased from Alcoa, and to replace the gas purchased under the now expired Exxon contract--were each determined by multiplying the additional gas kwh generation associated with the adjustment times the cost of incremental gas. Mr. Wilson utilized an incremental gas cost figure of $3.40 per MMBtu. TML Exhibit 1 at 25. He testified that this figure was basically the average spot market gas price encountered during the test year, although somewhat above an estimated range of $3.20 to $3.27 per MMBtu for the 1984-1985 period. As can be seen by the magnitude of the adjustments ($64,743,000 for the customer/weather adjustment; $3,947,000 to replace the Alcoa purchases; and $38,182,000 to replace the Exxon contract), the level at which the cost of incremental gas is set has a major effect on adjusted fuel costs. The fifth adjustment, an increase of $6,104,000, reflects Mr. Wilson's recommended 5.4 percent wage increase for TUMCO employees. The witness also made three adjustments to eliminate nonrecurring costs and recoveries. These adjustments include an increase of $1,845,000 to compensate for expenses relating to the Old Ocean Fuel Company, an increase of $23,000 to compensate for a payment received by the company associated with a blowout in one of its drilling areas, and a decrease of $2,292,000 reflecting certain nonrecurring expenses at the Big Brown lignite mine.

The next four adjustments proposed by Mr. Wilson were designed to reconcile under and overbillings made by the company and its affiliates. The first of these adjustments was a decrease of $1,407,000, to offset overbillings made by TUMCO during the test year. The second such adjustment, to compensate for test year underbillings made by TUFCO, increases fuel costs by $5,048,000. The third adjustment in effect reconciles the $8,080,000 cumulative underrecovery sustained by TUEC while the interim fuel factors were in effect, through March 31, 1984. The last reconciliation adjustment, increasing fuel costs by $628,000, reflects the interest expense associated with the various monthly over and underrecoveries experienced by TUEC through March of 1984, calculated by use of the company's overall cost of capital during the time periods involved.

The total effect of the twelve adjustments described above is to increase test year fuel costs by $127,494,000 to $1,630,660,000. Id., Schedule 3. Mr. Wilson then made an adjustment decreasing fuel costs by $1,391,000, equal to the test year carrying cost on the lignite inventory charged to TUEC by TUMCO. This adjustment was made in accordance with TML witness Cannady's inclusion of the lignite inventory in the value of invested capital. The amount of interest was calculated by multiplying the level of lignite inventory included as invested capital by the average outstanding cost of debt to TUEC during the test year. By using TUEC's cost of debt, Mr. Wilson assumed that the carrying costs were financed through short term borrowings, rather than by senior notes retained by TUMCO.

Mr. Wilson's final adjustment was to transfer to operations and maintenance expense all labor, depreciation and interest costs charged to TUEC by TUMCO and TUFCO. Mr. Wilson explained that these costs were primarily fixed expenses, not unlike any other plant operating expenses currently included in base rates, and he felt that these expenses should not be subject to reconciliation as recoverable fuel costs, but simply be treated as any other non-fuel base rate expense. Mr. Wilson determined that test year labor, depreciation and interest relating to fuel equalled some $175,746,000, and after deducting this from his adjusted recoverable fuel cost figure, recommended that recoverable fuel costs be set at $1,453,523,000. Based upon the kwh sales figures proposed by TML's witness Dr. Livingstone, Mr. Wilson recommended the following fuel factors:

	Summer	Winter
Secondary	$.027127	$.022865
Primary	.026557	.022385
Transmission	.025871	.021806

OPC witness Effron recommended that recoverable fuel costs be set at $1,657,152,000. OPC Exhibit 1 at 41. He derived this figure by assuming that the level of fuel expenses found reasonable in Docket No. 5294 ($1,653,959,000) would be a reasonable estimate of the test year fuel expense that would be produced if the rates authorized in Docket No. 5294 were applied to TUEC's test year billing factors. Mr. Effron then made an upward adjustment of $3,193,000 to reflect the adjustment to test year kwh sales urged by the OPC, producing the final figure noted above. Mr. Effron made no other adjustments, and made no recommendations concerning the issue of unreconcilable fuel costs.

Ms. Marilyn Neff testified on behalf of the Commission staff. She stated that the staff had taken the fuel cost information received in response to its RFI's and analyzed it using the same methods and procedures as would be used if TUEC had in fact requested a redetermination of its fuel costs. Based upon that review, Ms. Neff testified that the fuel factors adopted in Docket No. 5294 will not create an overrecovery of fuel costs by TUEC, and should in the absence of a request to increase the factors be continued. Staff Exhibit 7 at 3. Based upon the adjusted sales figures presented by staff witness Pompi, Ms. Neff determined that the amount of fuel revenue to be collected if the current factors are not altered will be $1,697,294,521, which is $43,336,002 greater than the reasonably predicted fuel expense figure adopted in Docket No. 5294. Ms. Neff explained that this additional amount of revenue is due to the 1,509,586,985 kwh increase in adjusted sales presented in this docket vis-a-vis the sales figure adopted in Docket No. 5294. Ms. Neff has assumed, as did the company, that the cost of generation will equal the additional revenues collected, thus eliminating the prospect that additional sales might cause an overrecovery.

Concerning reconciliation and unreconcilable costs, Ms. Neff testified that the review she had done was not a reconciliation. She did, however, note that those costs which can be considered fixed or semi-variable in nature would not be subject to reconciliation if an underrecovery had occurred. Since Ms. Neff did not view this proceeding as a reconciliation proceeding, she did not analyze the company's fuel cost components to determine their nature, based upon the view that such an analysis is obligatory if a redetermination of the fuel factors is required, but unnecessary if fuel factors are only being reviewed. She stated that the proper occasion for compensating for past over or underrecoveries would be a fuel cost redetermination, wherein the fuel cost figure would be adjusted as required. According to Ms. Neff a separate billing factor, used only to refund or collect past over or underrecoveries, would be economically inefficient. She pointed out that such a separate billing factor, necessarily based upon estimated sales, would almost inevitably create a continuing over or underrecovery of the amount to be refunded or collected. For these reasons, she found unduly cumbersome the task of adjusting a fuel factor solely to rectify past revenue discrepencies.

It should be noted that staff rate design witness John W. Kepner recommended that the summer fuel factor be in effect for a four month period, instead of a three month period, so as to coincide with his recommended four month base rate summer season. In order to expand the summer season to include four months without increasing total fuel revenues, he recalculated the summer and winter fuel factors, but did so in such a manner as to keep the ratio between the seasonal factors constant. Kepner, Schedule JWK-13. There are two reasons why Mr. Kepner's proposal must be rejected. First, in determining kwh usage for the summer season, Schedule JWK-13 lists the summer season as being the months of June and July. The correct four month period is from June through September. Whether the figures used actually include only June and July kwh sales or whether the heading is simply mistakenly labeled is unclear. Second, the Order in Docket No. 5294 explicitly specified a four billing month summer season for purposes of determining and billing the summer fuel factor. The tariff sheet itself specifies the period for which consumption can be billed at the summer rate, and that period is from May 27th through October 3rd, which is a four month billing cycle. There are two possibilities with regard to this facet of Mr. Kepner's testimony: the approved factors were not correctly calculated and his adjustments are proper; or the approved factors were correctly calculated based upon a four month summer season, and Mr. Kepner misconstrued their calculation. Absent any evidence in the record that the factors were not correctly calculated, the approved tariff provision should be presumed to be correct and proper, and Mr. Kepner's substitute factors should be rejected.

As was noted earlier, the company believes that the fuel factors set in Docket No. 5294 should not be redetermined, and it fully supports Ms. Neff's recommended fuel "cost" figure of $1,697,294,521.

2. *The Fuel Rule: Reviews, Redeterminations and Reconciliations*

The ultimate recommendation put forth below is that the fuel factors set in Docket No. 5294 should be maintained, but because this docket represents the first case to be filed under the Fuel Rule where the utility already has a fixed (not interim) fuel factor in place, it raises a number of conceptual issues regarding the implementation of the Fuel Rule. As previously noted, the Fuel Rule differentiates between a review and a redetermination of fuel costs. A review of fuel costs is mandatory, but a redetermination is not. The Fuel Rule is, however, silent as to what distinguishes a redetermination from a review, as to when a redetermination should or need be made, and as to what the utility must prove in each of the two types of proceedings. All of these conceptual issues require a closer examination.

The first matter requiring address is the distinction of a review of fuel costs from a redetermination. Despite some extended discussion by the Commission at the January 13, 1984 Rules Hearing, the exact meanings of these terms remain veiled. The discussion and resolution that follows is an attempt to interpret the

Fuel Rule in a manner consistent with the concerns of the Commissioners, taking into account the desire for flexibility in dealing with fuel. Based upon the comments of the Commissioners, a review appears at first glance to be a broad look at fuel costs. Commissioner Rosson wanted to avoid defining a review as a species of passive spectator occupation akin to a review of a parade. Transcript, January 13, 1984 Rules Hearing, p. 176. Although his approach was not adopted, Chairman Erwin suggested clarifying the word "review" to mean "to look at it in any context." Transcript, January 13, 1984 Rules Hearing, p. 177. These comments suggest a review should consist of the full development of a new, adjusted test year fuel cost figure. But the Commission also apprehended a hard and fast requirement that fuel costs be determined regardless of need. Transcript, January 13, 1984 Rules Hearing, pp. 176-178. There are two possible sets of circumstances in which there would be no need to redetermine fuel costs. The first would be when a full recalculation is done and the adjusted test year fuel cost figure, when combined with the adjusted test year kwh sales figure, produces fuel factors identical to the factors then in effect. The likelihood of this happening is so small that it cannot be the rationale for the Commission's actions. The second possible instance would occur when the review shows the utility to be unlikely to overrecover under the current factors. But if a review does consist of producing a new test year fuel cost figure, as adjusted for known and reasonably predictable changes, a redetermination should always be done, because calculation of a new adjusted test year figure will require the parties to put on full, no doubt mutually controverting, fuel cases. The correct adjusted test year fuel cost and kwh sales figures will only be known when the Commission itself actually decides the case. At that point, even if the utility is going to underrecover, a full fuel case will have already been done, and there would be no logical reason not to go ahead and redetermine the fuel factors, because all the necessary figures will already be in the record. Not to redetermine the factors at that point would in fact be inconsistent with the Commission's goal of having accurate factors. Thus, if a review consists of the development of full adjusted test year fuel cost and kwh sales figures, any discernable rationale for including the term "redetermination" in the Fuel Rule, and making it a permissive action, is chimerical.

It is therefore submitted that a review must involve some type of analysis or audit that involves less scrutiny than a redetermination. However, a review cannot reasonably be simply a mini-redetermination. To determine just certain costs would be improper and likely lead to an incorrect result. In any event, drawing the line between costs to be redetermined and those not poses a very difficult question. A review could be just an inspection of actual fuel costs, to ensure that they are reasonable, but that is already required under §§23.23(b)(2)(D) and (E), and those sections do not indicate that such an investigation is the same as a review under §23.23(b)(2)(A). It would appear that the focus of a "review" is different from that of a redetermination. Whereas a redetermination focuses on setting a fuel costs figure equal to reasonable test year expenses as adjusted for known and reasonably predictable changes, a review should focus only on actual fuel costs and revenues incurred since the fuel factor was last set. If there has been no overrecovery to date, and it is predicted--as is the case in this proceeding--that the increase in kwh sales will not cause overrecoveries in the future, there is no need (absent a supportable plea to increase the factors) to do anything more. An examination of the reasonableness of the actual costs must be done under §§23.23 (b)(2)(D) and (E) in any event, and the utility will also have to meet various burdens at such time as a reconciliation is performed. It would be a waste of resources to force the company to put on an entire fuel case when it is not overrecovering its costs and is unlikely to do so in the future.

The second issue raised is: at what point should a redetermination become mandatory? A redetermination should be mandatory when a utility has a cumulative fuel revenue overrecovery as of the date the rate case is filed. If, however, the utility has a cumulative underrecovery, it may either request a redetermination or simply submit to a review of its fuel costs. It should be noted that a certain leeway might be advisable, instead of a strict underrecovery/overrecovery dichotomy. This is especially true since an underrecovery at the time of filing does not preclude the emergence of an overrecovery by the hearing date. A one percent overrecovery (of total allowable fuel costs as set in the previous docket) as of the hearing date might be an acceptable limit: it takes into account the fact that fuel factors are no more than a best estimate, and recognizes the monthly variations in costs and revenues that a utility experiences, but it keeps any overrecovery to a minimal amount. If the utility does not desire a redetermination of its fuel costs, each party to the case can then conduct its own fuel cost review and present testimony as to what its review indicates. If, in the unlikely event that all the parties doing a fuel review agree that the existing fuel factors will not result in an overrecovery, then the review portion of the fuel case is complete without gunplay. If a party's review indicates an overrecovery will occur, the issue is then joined and evidence will be taken at the hearing as with any other issue. If the Commission finds that an overrecovery will occur, fuel costs and fuel factors will be redetermined. If the Commission finds that an overrecovery will not occur, the fuel factors will not be modified. In other words, if the utility can prove it will continue to underrecover its fuel costs, but it does not want affirmative relief, the Commission should not force a redetermination of fuel costs on the utility, anymore than the Commission forces a utility to file a non-fuel rate case when the utility's revenues are inadequate. The choice should remain with the utility.

It should be noted that resolution of this issue also answers the question of whether a utility must present a full fuel rate case as a part of its general rate case; the utility only need do so if it has overrecovered its costs or will do so in the future. While at first glance it might appear to be advantageous to mandate full fuel cost redetermination at the same time as the general rate case, it is possible to envision future scenarios where none of the parties would want to redetermine fuel during the general rate case. For example, suppose that nine months after a utility has put into effect fuel factors approved of in a general rate case, the utility has a sizeable overrecovery, and the General Counsel initiates a reconciliation proceeding. Five months later fuel costs are redetermined and new factors are put into effect. Three months later the utility files a general rate case, at which time the utility is slightly underrecovering its fuel costs. Therefore, the utility requests only a limited fuel cost review. As of the hearing date there is still a cumulative underrecovery. In such circumstances, it is submitted that nothing would be gained by having a full redetermination of fuel costs in the rate case, and that the only results of a full fuel hearing would be to increase rate case expenses and unduly divert attention away from other issues. It may therefore be justifiably concluded that neither the language of the Fuel Rule, nor the intent behind it, imply that a full fuel cost redetermination must be made during each general rate case.

One other point needs to be made at this time. Several parties have expressed the fear that if TUEC is not forced to submit to a full fuel cost redetermination in this docket, it will continue to file "incomplete" rate cases, with only fuel costs in one docket, non-fuel costs in the next, and so on. These fears are not unfounded; neither Section 43(g) of the PURA nor P.U.C. SUBST. R. §23.23(b) prevent a utility from doing so. The Legislature specifically provided that a fuel proceeding "shall not be considered a rate case under Section 43 of this Act," PURA Section 43(g)(2)(C), most likely to provide this Commission with the widest latitude permissible in dealing with fuel costs. And while the Commission in adopting the Fuel Rule may have intended that a utility must file a fuel case as a part of its general rate case, neither the Rule itself, nor the comments of all the Commissioners at the public hearings during which the Rule was considered, clearly express that intent. If that was, and is, the Commission's intent, it is recommended that the Fuel Rule be amended so that such a requirement is clearly expressed in the rule. As was developed earlier, it is believed that the most efficient method of handling fuel cases would not require the utility to file for a fuel cost redetermination as part of its general rate case if it is underrecovering its costs. But a utility should also not be allowed to file for a redetermination at any other time, except for a fuel reconciliation proceeding or emergency request (as the Rule currently provides). The choice would be with the utility either to file for a redetermination now, or forgo the opportunity to do so until the next rate case (or until such other time as the Rule currently allows).

The third conceptual issue raised in this docket concerns the burden of proof. What the company must prove should logically vary with the type of fuel proceeding being conducted. If the utility has a cumulative underrecovery and simply desires a review of its costs, but not a redetermination, it will need to show the following:

1. That from the time its current fuel factor went into effect until the filing of the rate increase, its actual fuel costs have exceeded its actual fuel revenues;

2. The amount of the additional revenue to be gained based upon the new, adjusted test year kwh sales figure and the current fuel factors;

3. The amount of additional generation costs to be incurred based upon the new, adjusted kwh sales figure, and the heat rate, system loss ratio, and cost of incremental gas found to be reasonable in the docket in which the current fuel factors were set; and

4. That the amount of additional revenue due to increased kwh sales will be less than the sum of the additional costs plus the amount of the underrecovery.

The elements above, if proven up, show that at the fuel factor levels then currently in effect, the underrecovery will not be fully alleviated by the increase in kwh sales. Furthermore, the calculations necessary to meet the burden imposed are quite simple, and except for the new test year adjusted kwh sales figure, are already in existence. Moreover, adjusted kwh sales figures have to be determined in a general rate case in any event. Thus the procedure to be used for a utility that is underrecovering its fuel costs, but which does not wish to change its fuel factor, is as it should be: short, simple, and fairly easy to verify. If a redetermination of fuel costs is either mandatory at the time of filing, is requested by the utility, or is necessary based upon the evidence at the hearing (evidence showing that an overrecovery will result unless a redetermination is made), then the utility has the normal burden of proof to show the propriety of its test year costs and any known and reasonably predictable adjustments.

However, the Fuel Rule requires more than just a review or redetermination of fuel costs and fuel factors. Under P.U.C. SUBST. §23.23(b)(2)(D), the utility must show, for nonaffiliated fuel contracts, that its contract negotiations have produced the lowest reasonable cost of fuel to ratepayers, and failure to do so requires disallowance of any portion of fuel costs not found to be reasonable. P.U.C. SUBST. R. §23.23(b)(2)(E) puts a similar burden on the utility with regard to fuel provided by an affiliate, but expands the review to include all fuel-related affiliate expenses. Due to these provisions, a review requires an analysis of certain fuel costs that would otherwise only be done during a fuel cost redetermination. In other words, a review becomes in effect a partial redetermination, but only insofar as the reasonableness of actual costs is determined; no adjustments are considered. The Fuel Rule is silent, however, as to how to proceed when a review indicates that there will be no overrecovery of costs in the future and thus no need to change the fuel factors, but the circumstances are such that the utility has failed to show that all of its fuel costs have met the standards of reasonableness imposed by the Rule. The most rational method of proceeding, it is suggested, would be simply to deduct the unreasonable fuel costs from the actual fuel costs, and then compare the resulting figure with the actual fuel revenues. If an underrecovery still exists, then the review process should be adhered to. If what was an underrecovery becomes an overrecovery, then a full redetermination becomes mandatory.

There is yet another provision of the Fuel Rule that must be considered and integrated into the procedure to be used when dealing with fuel costs. That provision is P.U.C. SUBST. R. §23.23(b)(2)(I), covering reconciliation proceedings. It begins:

> No less than twelve months after implementing a change in its base rates, a utility shall request reconciliation of any overrecovery of fuel cost revenues and may request an opportunity to reconcile any underrecovery of such fuel costs. (Emphasis added.)

Quite clearly, if a utility has underrecovered its fuel costs, it need not request a reconciliation. If it has overrecovered its fuel costs, it must file for a reconciliation "no less than twelve months" after a base rate change. * If a reconciliation is requested (or required), the utility has yet another burden of proof that it must meet: that it has operated its plant and generated electricity efficiently, and that it has maintained effective cost controls. If the proceeding is to reconcile an underrecovery, the utility is allowed to reconcile only those fuel costs increased by conditions or events beyond its control, and it must show that such events or conditions could not have been predicted or forseen at the time

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* The meaning of the phrase in quotes is unclear. The plain meaning of the words is "after 12 months have elapsed." If this meaning is what the Commission intended, it must be pointed out that it is rather unusal to require a utility to take an act after a certain period of time has elapsed, but not include an outer time limit in which the utility must act. If this is the correct interpretation, a utility need never come in for a reconciliation, as all that is required is that it not come in for one within 12 months. If however, the Commission meant the words to mean "Within 12 months" or "at the end of 12 months," then the intent of the rule is clear, although the language used is not. Luckily, TUEC has not recovered, and the examiners need not decide as between the conflicting interpretations presented. But no matter which meaning of the phrase was intended, it is recommended that the Rule be amended to more clearly express the desired intent.

the rates were established. Thus yet another, and distinct, showing must be made by the utility. If the utility does request a reconciliation at the time of its rate case, such a reconciliation will be combined with either a review of fuel costs or a redetermination of fuel costs. The Fuel Rule does not indicate whether a reconciliation may be combined with both, or just with a redetermination. Under the reading of the Fuel Rule espoused herein, a utility that has overrecovered at the time of reconciliation must have its fuel costs redetermined, regardless of any other reconciliation request or requirement. Thus there will be a combination reconciliation/redetermination. The question is, if the utility has underrecovered its costs and requested a reconciliation, but not requested a redetermination of fuel costs (a possible though perhaps unlikely situation), should the fact that a reconciliation has been requested force a redetermination upon the utility? The answer should be yes, for the sake of efficiency. A reconciliation involves a full review of all fuel costs incurred since the previous reconciliation, and the resetting of the fuel factors. There is no logical reason not to redetermine all fuel costs and reset the fuel factors, especially since the reconciliation proceeding itself indicates that the fuel factors are inaccurate.

In sum, there are three different types of fuel proceedings possible: a review of fuel costs, a redetermination of fuel costs, and a reconciliation (which includes a redetermination). As the Fuel Rule is currently written, either a review or redetermination of fuel costs is required in each major rate case of a generating electric utility. As detailed earlier, there is a different standard of review for each. The Fuel Rule does not currently require a reconciliation of fuel costs during the rate case, but if a reconciliation is made, the standards contained in P.U.C. SUBST. R. §§23.23(b)(2)(I) come into play. Finally, §§23.23 (b)(D) and (E) contain two more standards, similar but not identical, that are to be applied in all rate cases, regardless of the type of fuel proceeding.

The foregoing rather extensive tour around and through the Fuel Rule is perhaps beyond the scope of this docket. Yet to do otherwise is to survive (hopefully) a harrowing journey and leave insufficiently helpful notes for the next sojourn among these puzzling landmarks. No doubt the other travelers on this expedition have come away with differing impressions of the scenery. Should the Commission take a view different from the one expressed herein, it is recommended that the Rule be amended to clarify its implementation. That way those who follow will know what to expect when traversing this territory, and costly meandering will not be repeated.

3. Application of the Fuel Rule

Turning now to the evidence in this docket, it is necessary first to determine whether TUEC had a cumulative underrecovery as of the filing date. If so, a simple review of fuel costs is all that is required, as that is all that the company requested. It would be almost worthless, however, to do a review in this case. One could review the costs and revenues produced while the interim fuel factor was in effect, but that would do no good, for the interim fuel factor was superseded by the Order in Docket No. 5294. A review which shows that TUEC underrecovered its fuel costs under the interim factor will be meaningless because that interim factor will not be the factor that will continue in effect if no redetermination is made in this docket. Similarly, a review of the factors approved of in Docket No. 5294 is almost meaningless. At the time of the hearing, they had been in effect for approximately one month (Transcript at 1247-1248), hardly sufficient time in which to determine whether they are accurate or not. Indeed, the record does not disclose whether that first month produced an underrecovery or overrecovery of costs. The record does show that the company went from an $8,080,000 underrecovery at the end of March, 1984 (Wilson, Testimony, p. 27), to an underrecovery of $38,942,688 by the end of May, 1984 (Transcript at 1248). But it is impossible to ascertain *how much* of this additional underrecovery occurred in April under the interim factor and how much occurred during May under the Docket No. 5294 factors. Even if the full amount of the additional underrecovery occurred in April, and TUEC actually overrecovered in May, it would be a difficult task to find that one month of overrecoveries indicates that the Docket No. 5294 factors are inaccurate.

While it is fruitless to undertake that portion of a review which inquires whether an underrecovery or overrecovery has occurred under the current fuel factors, it is possible to look to whether the increase in kwh sales will produce an overrecovery in the future, assuming Docket No. 5294 factors are not altered and taking into account the present underrecovery. Ms. Neff has testified that an overrecovery will not occur. However, her conclusion is based upon an analysis different from the method that was outlined earlier. Ms. Neff stated that her review was exactly the same *type* that *would* have been done had a redetermination been requested. Such an analysis is not necessary, and in fact negates one of the reasons for differentiating between reviews and redeterminations: minimizing the effort and expenses incurred by all the parties to the case. Ms. Neff's testimony also shows the other defect in using a redetermination type of analysis to predict whether an overrecovery will occur in the future under existing factors: the witness makes a broad conclusion, but does not include the easily available underlying data. The adjudicator thus cannot check the figures used, and cannot determine if they are reasonable. Yet if Ms. Neff had included the underlying data, the figures she used would be open to attack on cross-examination, leading to just the type of proceeding that a review is meant to avoid. The hearing on fuel would revolve around the accuracy of the various redetermination analyses presented by the parties, when those analyses are being used only to show whether or not an overrecovery will occur in the future. That showing is part of a review process that is ostensibly designed to eliminate the very need to take evidence concerning any redetermination analyses.

The proper method of determining whether an overrecovery will occur is to base the review on the heat rate, marginal gas costs and system loss ratio as set in the docket in which the current factors were approved, then use the adjusted test year kwh sales figure as determined in the current docket to recompute projected costs and revenues. The method used by Ms. Neff, while it ultimately produces an answer to the inquiry, should not be encouraged in the future, since it provides the opportunity to turn a simple fuel cost review into a full blown fuel cost redetermination. Luckily, that did not occur in this docket, and the conclusion drawn by Ms. Neff that an overrecovery will not occur in the future is sound. But if the interpretation of the Fuel Rule set forth herein is adopted, it is imperative that the method utilized by Ms. Neff not be allowed in any future fuel cost reviews, only in fuel cost redeterminations.

Since the review described above might be seen as having limited value, it would appear at first glance that a redetermination of fuel costs might be necessary. But a more thorough examination of the circumstances surrounding this docket indicates that that is not so. The question of how to deal with fuel in this case was the subject of extensive discussion by the Commission at the April 6, 1984 Final Order Meeting at which Docket No. 5294 was decided. There was some disagreement among the Commissioners as to how to proceed (Transcript, April 6, 1984 Final Order Meeting, pp. 74-84). Ultimately two decisions were made. The first was to direct the staff to pursue the reconciliation of second and third quarter (1983) affiliate fuel under and overrecoveries in this docket. The second was to allow the examiners in this case to decide whether TUEC was required by the Fuel Rule to file a full fuel case as a part of its general rate case. The examiners requested comments from the parties to this docket on the latter issue, and also held a prehearing conference to hear oral discussion on the matter. The examiners ultimately ruled that the Fuel Rule did not require TUEC to make a full adjusted test year fuel filing. However, TUEC was ordered to answer the General Counsel's RFI's dealing with fuel, some of which in essence requested that the Company specify what its adjusted test year fuel filing would have been if one had been required. Neff, Testimony, pp.2-3.

Since a full fuel filing was not required, this docket now envinces a similarity to Docket No. 5294. The company did not file an adjusted test year fuel filing, either in its direct testimony or on rebuttal, based upon the ruling of the examiners. While several of the intervenors did present evidence as to an appropriate adjusted test year fuel cost figure, those recommendations are unworthy of adoption, as will be seen below. Thus a full and correct redetermination of fuel costs cannot be made based upon the evidence in the record at this time. Several parties to this docket have argued that if a redetermination is required and if the testimony of their witnesses is found to be unacceptable, the only alternative is to use the unadjusted test year fuel cost figure and base the fuel factors upon that. Such an argument should be strongly rebuffed. The company has followed the order of the examiners in this docket, an order which was not appealed to the Commission by any party to these proceedings. The Examiner's Order effectively determined what it was that the company had to prove. Should the Commission now decide that the burden which the company bears is in excess of that which the examiners determined--i.e., the full burden which a fuel redetermination places upon an applicant--the company should be allowed an opportunity to present such a fuel case. It would be of arguable legality, and questionable fairness, to penalize an entity for failing to do that which it was told with authority it need not do.

The discussion of the Commissioners at the April 6, 1984, Final Order Meeting also lends support to the decision not to redetermine TUEC's fuel factors. The question of whether the Fuel Rule requires a utility to file a fuel case with its general rate case, and thus the need for TUEC to file supplemental testimony in this docket, was deferred until it could be raised as a part of this case. Transcript, April 6, 1984 Final Order Meeting, pp. 82-83. The Commission also felt that it would be desirable to have an "interim period" in which to assess the accuracy of the current fuel factors. Transcript, April 6, 1984 Final Order Meeting, p. 77. While that interim period is longer than four days, one month (as of the hearing date) is hardly a long enough period of time by which to judge the accuracy of a fuel factor. To require that new fuel factors be set, before the accuracy of the ones set in Docket No. 5294 can be determined, would appear to destroy the rationale for even reaching a decision in Docket No. 5294.

It is submitted that, in general, once fuel factors are set, it is reasonable to let the utility collect under those factors until such time as it is determined, based upon actual costs and revenues, that those factors are inaccurate. At such time as it can be deemed that the factors are inaccurate, if the company is overrecovering, a reconciliation proceeding can always be filed by the General Counsel. This Commission is never without recourse in the event that an overrecovery has occurred. If the company is underrecovering, however, it must wait twelve months from the date the most recent base rates were approved, and it should be noted that the twelve month period runs from the date of the most recent change in <u>base</u> rates, whether fuel was redetermined at that time or not. In effect, the company will have gambled and lost. It will be unable at that point to file for reconciliation, unless it can prove that an emergency exists.

Some parties may argue that due to the procedural difficulties encountered in Docket No. 5294, the factors currently in effect are suspect. The reply to such an assertion is two-fold. First, it is only surmise that the current fuel factors are "inaccurate." Only the passage of time will indicate their true reliability. Second, an order setting fuel factors in this case at this time, without a remand of the case in order to reopen the hearings, would itself result in suspect factors. Neither the company nor the staff presented any evidence as to an adjusted test year fuel cost figure. Cross-examination discredited the intervenors' witnesses who testified as to adjusted test year fuel costs. To use an unadjusted test year figure would, in the view of some, give the company its just deserts, but it is highly unlikely that the use of that figure will produce accurate fuel factors, which should remain the ultimate goal of this Commission.

Having several times noted that the testimony of the witnesses who did testify as to test year fuel costs is less than persuasive, it is appropriate at this point to examine the testimony of those witnesses in some detail. Coops witness Stover simply utilized the unadjusted test year cost per kwh. Coop Exhibit 1 at 7. He did this for two reasons, because of information that fuel costs are going down, and because TUEC failed to file a reconciliation proceeding. As to the first reason, Mr. Stover did not present any data to indicate costs were in fact going down. He did include two schedules showing the company's fuel costs for the period from October 1983 through March of 1984 (Id., Schedules B-1.0 and E-1.0), but those data alone do not indicate a decrease in fuel costs. Indeed, those schedules show wide fluctuations in cost (ranging from 19.88 mills/kwh in February to 31.52 mills/kwh in December), and an average cost of fuel higher in March of 1984 than it was in October of 1983. During cross-examination Mr. Stover conceded that he had made no analysis of the comparability between the first quarter of 1984 and the last quarter of 1983, or of any other time period. Transcript at 1865 and 1867. He admitted, however, that a change in fuel mix would affect fuel costs (Transcript at 1866), and that average fuel costs normally would be lower in off-peak periods such as October through March. Transcript at 1854-1855. Without an analysis as to comparability and fuel mix, it is difficult to see how unadjusted cost figures prove that prices are decreasing, especially when the raw data are not necessarily consistent with that conclusion.

Mr. Stover's second reason for utilizing unadjusted test year data was because he felt that a reconciliation proceeding was necessary in this docket. On cross-examination, he indicated that what was actually needed was a redetermination of fuel costs (Transcript at 1859) and a decision as to what costs will and will not be reconcilable under the Fuel Rule. Transcript at 1857-1858. Mr. Stover believes that a reconciliation is necessary so that the company will know when it needs to file another rate case, based upon its financial indicators. The issue of reconciliation will be discussed later in this section of the report. As to whether a redetermination is in fact required by the Fuel Rule, Mr. Stover simply disagrees with the Examiners' Eighth Order (Transcript at 1860), and the final decision is one that will ultimately be made by the Commission itself in this docket.

In general, Mr. Stover's conclusion that the test year fuel cost of 25.46 mills/kwh is a reasonable fuel cost for the company (Transcript at 1862) is without merit. Mr. Stover admitted he was not an expert in the fields of energy or the market prices for gas, and that he had made no study of the market prices of gas that might be available to TUEC in the near future. Transcript at 1863. He made no adjustments for the loss of low priced gas contracts. Transcript at 1863. Indeed, he made no adjustments at all, either increases or decreases. While Mr. Stover was not obliged to prove the company's case (assuming for the sake of argument that a redetermination of fuel costs is required), he did need to prove up his own recommendation of that level of fuel costs which is reasonable, utilizing the known and reasonably predictable standard set forth by the Commission in Docket No. 5294. This he failed to do, and thus his 25.46 mills/kwh recommendation is without merit. Finally, it should be noted that, had Mr. Stover known of the magnitude of the cumulative underrecovery as of the end of May, 1984, he admittedly would have changed his testimony. Transcript at 1864. This admission casts a pall over his entire fuel testimony.

TML witness Wilson did recognize the need to make adjustments to the test year data. Mr. Wilson's downfall, however, is the overly low price he utilized as the cost of incremental gas: $3.40 per MMBtu. That price level corresponds to the average test year price for spot term gas. The difficulty with Mr. Wilson's testimony is his use of that price for all of his adjustments, including the replacement of expired low cost contracts and the acquisition of additional gas necessary to meet load growth, even though he could not recall any month during 1984 that the average cost of gas had reached as low as $3.40 per MMBtu. Transcript at 1373. He would not testify that all expiring gas contracts could be replaced by gas priced at $3.40 per MMBtu (Transcript at 2342, 2374 and 2381), and could not testify as to knowing of any substantial quantities of gas that have been purchased in the immediate past at that price. Transcript at 2379. Further, unlike Mr. Stover, Mr. Wilson would not declare that the cost of gas is going down. Transcript at 2378. As Mr. Wilson admitted, the $3.40 per MMBtu price is a "target" (Transcript at 2342), "an incentive for the company to try to obtain the contracts at the lowest cost possible." Transcript at 2381. While there is no theoretical difficulty with setting gas prices at a level low enough to serve as an incentive to the company to hold down its fuel costs, it is preferable that such price levels serve as attainable goals. Without a doubt, TUEC can meet some of its needs in the spot market. Mr. Tanner testified that the company plans to purchase some 30 billion cubic feet (bcf) of gas in the spot market in 1984, up from 11.8 bcf during the test year. Applicant's Exhibit 32 at 2. But that 30 bcf of spot gas represents only about eight percent of TUEC's projected gas requirements for 1984. Id. For an electric utility with an expanding customer base, it simply is not reasonable to believe that all required marginal gas can be obtained in the spot market. Spot market gas contracts tend to be for only a year or two in length, without any guarantees as to deliverability, and often are cancellable on 24 hour notice. Transcript at 1245, 3428. Further, purchases of spot market gas can be limited by an inabilty to get the gas to the proper generating unit, as well as a decreased need for the gas during periods of low demand. Mr. Wilson made no study as to these limitations (Transcript at 2380), and made no study as to what sources of gas would likely be used to replace expired contracts. Transcript at 2343. He also did not consider the current long term market for fuel supplies. Without such studies, it is impossible to set a reasonable "incentive" price for additional purchases of gas. It is found, however, that Mr. Wilson's $3.40 per MMBtu cost of marginal gas is unreasonable, and thus his recommendations are unacceptable.

OPC witness Effron took a different tack, accepting the cost figure and fuel factors adopted in Docket No. 5294 as reasonable. He made only one adjustment, to reflect the adjustment to kwh sales he was recommending. OPC attorney Gay stated he could not fully support Mr. Effron's adjustment to sales (Transcript at 3550), and in its brief, the OPC totally abandoned Mr. Effron, preferring the testimony of Mr. Stover over that of its own witness.

It should be noted that once Mr. Effron's adjustment is rejected, his underlying recommendation is to keep the fuel factors as approved in Docket No. 5294. Thus there is some evidence in the record that the fuel operating expense figure found reasonable in Docket No. 5294 is also a reasonable estimate of test year fuel expense. But this evidence is shaky at best; it is based solely upon an assumption as to reasonableness, with no rationale given that would support the assumption. OPC Exhibit 1 at 41. The evidence is not sufficient, should a redetermination be required, to support any findings of fact concerning test year fuel costs.

In sum, a review would normally be the proper method by which to examine fuel. It is inappropriate here only because of the change from an interim fuel factor to a permanent fuel factor during the pendency of this docket. Such circumstances are unlikely to occur again in the future. Further, there is no advantage to be gained by conducting a redetermination in this case at this time. The current factors have not been in effect for a sufficient period of time in which to show their inaccuracy. Should new factors be required by the Commission, it is recommended, albeit reluctantly, that additional evidence be taken in order to determine the correct adjusted test year fuel cost figure. The testimony in the record at this time dealing with the setting of new factors simply is not credible, for the reasons outlined above.

Before leaving the area of reviews and redeterminations, it is necessary to make such findings as are required by §23.23(b)(2)(E), relating to the reasonableness of all costs incurred by the utility's affiliates. Normally, an examination of the reasonableness of fuel costs would be the first step taken in reviewing a utility's fuel case. However, since this is a case somewhat different from the hypothetical norm, it is not improper to have waited until this point to make such inquiry.

Of the three burdens imposed on TUEC by §§23.23(b)(2)(E) and (E)(i), two were not seriously disputed by any of the parties to this case. Mr. Tanner testified that the price charged to TUEC is no higher than prices charged by the supplying affiliates (TUFCO and TUMCO) to its other affiliates or divisions or to unaffiliated persons or corporations for the same item or class of items. Applicant's Exhibit 1B, Tanner at 42. There is no reason to disbelieve that testimony. Mr. Tanner also testified that the affiliate fuel price was "at cost," with no return on equity or equity profit being included in the affiliate fuel price. Id. at 41-42. Once again, the record does not disclose any reason to doubt the veracity of this testimony.

As to the third burden placed upon the company, that of showing that all fuel and fuel-related affiliate expenses were reasonable, there is conflicting testimony. Mr. Tanner testified that the prices the company has paid and are paying are reasonable and necessary. Id. at 40. Ms. Neff agreed that the prices were reasonable, based upon the standard fuel cost analysis done by the staff in this case. Transcript at 2621.

TML led the assault on the company's fuel costs, arguing that: (1) the recent prices for short term contracts were in the range of \$3.20 to \$3.27 per MMBtu (TML Exhibit 1 at 25); (2) TUEC has recently negotiated gas contracts which are firm for one year and renewable for a second year, for prices ranging from \$3.20 to \$3.70per MMBtu (Transcript at 3428, 3446); (3) wellhead production exclusive of Section 107 gas is priced well below \$3.41 per MMBtu (Transcript at 3444-3445); (4) the weighted average price of gas for electric utilities in TUEC's region during 1983 was $2.99 per MMBtu, and is predicted to rise to only $3.06 per MMBtu for 1984 (Cities Exhibits 10 and 11); (5) Gulf States Utilities projects that it will be able to purchase gas during the last half of 1984 at a weighted average cost of $1.35 per MMBtu, or $3.59 per MMBtu excluding cheap Exxon gas (calculated from Cities Exhibit 12c, p. 7); (6) pipeline companies purchase and sell cheap gas through affiliates, thus keeping the weighted average cost of gas they charge customers such as TUFCO high (Transcript at 3453-3456); and (7) the company has been able to negotiate a reduced take-or-pay amount with Lone Star, a high priced supplier, facilitating the purchase of cheaper gas in the spot market (Transcript at 3424-3425). A closer look at these arguments will show, however, that they do not support a finding that TUEC has been paying unreasonable prices.

The TML is correct in its assertion that short term gas is available in the $3.20 to $3.27 per MMBtu price range. However, there is a limited ability to get firm contracts (for one year) at that price. Mr. Tanner testified that of the ten spot market/short-term TUFCO contracts entered into since early 1983, only half of those were firm for one year. The rest are cancellable, some of them on 24 hour notice. According to Mr. Tanner, these opportunities are "all that's out there." Transcript at 3428. It should also be noted that the original prices under those ten contracts in fact ranged from $3.20 per MMBtu to $3.75 per MMBtu. Transcript at 3446. As for the $3.20 per MMBtu gas, Mr. Tanner stated that "it's not available everyday and you can't depend on it. We are using it to the extent that it's available on the days we can use it." Transcript at 3429. This testimony shows that the company is taking advantage of the soft gas market to an extent consistent with its need for reliability and deliverability. As was noted earlier, for 1984 the company plans to virtually triple its purchases of spot market gas, to the point where such purchases will account for eight percent of its requirements.

Turning to the TML's next argument, concerning wellhead gas, the testimony is just as supportive of the company as it is of the TML. There is wellhead gas (which is not curtailable) being taken at below $3.41 per MMBtu. But some of the wellhead gas is Section 107 gas, which ranges in price from $5.00 to $5.25 per MMBtu. The company has been able to freeze the price for Section 107 gas at those levels, and is taking only the minimal take-or-pay requirements. Transcript at 3441-3442. Section 102 wellhead gas was $3.56 per MMBtu, and Mr. Tanner testified that TUFCO was unable to get those producers to freeze their price or reduce the take-or-pay volumes. Transcript at 3423. TUEC obtains approximately 35 percent of its gas from wellhead production (Transcript at 3444), and of that 35 percent roughly 7 percent is Section 107 gas. Transcript at 3441. The average price of wellhead gas for the test year was $3.41 per MMBtu (Transcript at 3445), so obviously some wellhead gas is priced below that figure. But it is not necessarily unreasonable for the company to have long term, noncurtailable contracts with Section 107 producers, especially in light of the fact that wellhead gas production declines roughly 17 percent per year and new contracts must constantly be entered into.

Transcript at 3444. That the average price of wellhead gas is at least $1.50 per MMBtu lower than the Section 107 gas prices indicates the company has been successful in its efforts to obtain other wellhead gas at low prices. The average wellhead gas price of $3.41 per MMBtu should be found by the Commission to be reasonable.

The various comparisons between TUEC's cost of gas and the cost of gas to other utilities can fairly be characterized as underwhelming. There is no such thing as a single national market, or generally even regional markets, for gas. A utility's geographical location will determine what pipeline companies and suppliers it can deal with, and thus what gas it can get delivered to its various plants. Gas markets vary within Texas, and they are not necessarily comparable to out of state gas markets, particularly in light of federal price controls on interstate gas. Within Texas, a simple comparison of the gas costs between two utilities, such as TUEC and GSU, proves nothing. The utilities are in different geographical areas, have different suppliers, and have a different number of suppliers. Transcript at 2620. The amount of gas required by an electric utility is of course a major variable. The existence of long term, low priced contracts is another. GSU has an extremely low priced contract with Exxon in effect, and base loads most of the units supplied by Exxon gas. Transcript at 2621. It is not unreasonable to assume that a utility with such a large, low cost gas contract will be able to purchase its additional requirements at a low price. Such a utility would not require as large a volume of gas as does TUEC, and it would also be less concerned with reliability, deliverability, and the need for long term contracts. It is thus clear that a simple look at average test year gas prices is unproductive, and may in fact be misleading. Only after an analysis of the various factors involved can any comparisons be drawn. The TML did not attempt to present such an analysis. The staff, however, did do one in this case, using the same methodology as was used in the GSU case. The staff concluded that TUEC's gas prices were reasonable, as had been GSU's in its rate case, even though the utilities had different gas costs. Transcript at 2621. In sum, the fact that TUEC's gas prices may be higher than those of other utilities within the state by no means indicates that TUEC's prices are unreasonable.

Regarding the issues concerning gas purchased from Lone Star and Valero, and the use of affiliates by such companies to market lower cost gas, the company's witness was not as personally knowledgeable as might be expected, but nonetheless provided satisfactory answers. As to the weighted average cost of gas of Lone Star and Valero, Mr. Tanner testified that in the past full audits were done on an annual basis, with spot audits being done quarterly or monthly, and he presumed that that is the current practice. Transcript at 3452. While not familiar with all the subsidiaries of the gas pipelines with which TUFCO deals, Mr. Tanner was aware of the fact that major gas pipeline companies use subsidiaries to market cheaper gas. He also indicated that he was sure that some of the spot market purchases TUFCO had made were from such subsidiaries, and that TUFCO personnel have been checking into the utility of such contracts. Transcript at 3454. As to the reduction in the take-or-pay amount negotiated with Lone Star (Transcript at 3424 and 3450), this is simply one indication that the company is attempting to control its costs and maintain its flexibility by renegotiating its contracts whenever possible. Finally, because Lone Star and Valero have the highest prices of any supplier/producer (excepting Section 107 gas), the company is minimizing the amount of gas purchased from those companies. Transcript at 3441-3443.

It appears that the gist of the TML's argument is that the company entered into some unfortunate long term, high priced contracts with Valero and Lone Star, and that it is not doing enough to get lower priced gas. It seems as if 20/20 hindsight is distorting the TML's view of the gas market. The Lone Star contract was a twenty year contract, due to expire in 1979. It was renegotiated once in 1974, and then was extended for ten years in 1978, before the Natural Gas Policy Act of 1978 went into effect. The extension was made in order to forestall any possible problems that that Act might have caused relating to contract extensions. Transcript at 3451-3452. The contract provides for renegotiation, and Lone Star has the right to increase the weighted average price up to a certain amount each year, while the company has the offsetting right to reduce its take-or-pay volume. Since 1970 the gas market in Texas, as well as throughout the nation, has been less than stable. It was not possible in 1978 to forsee that the gas markets in Texas would be soft in 1983 and 1984. Had events turned out differently, it is possible that market prices would be much higher than they are now, and long term contracts such as the Lone Star contract would be viewed with affection. Such may yet be the case in a year or two's time. One only has to look to the price of gas in TUEC's recently expired Exxon contract to see the advantages that long term contracts can sometimes provide. Long term contracts with large pipeline companies, although higher in price, also provide greater reliability, more delivery points, and increased flexibility. For example, should a base loaded lignite unit unexpectedly trip off line, and the lost generation be made up by a gas fired unit, only a large pipeline company could supply the additional gas required. It would not be possible to purchase the quantities needed on the spot market. Transcript at 3424-3425 and 3457.

In sum, the evidence does not show that the company's current long term contracts are unreasonable, even though the current short term market price is below the prices contained in those long term contracts. Likewise, it appears that the company is taking such reasonable steps as are possible to avail itself of the soft market for gas, consistent with its current constraints and requirements. The Commission should find the company's fuel and fuel related affiliate expenses to be necessary and reasonable for the purposes of this docket, which finding would not prevent or restrict the scope of inquiry in any future reconciliation proceeding.

4. Reconciliation

The parties have presented a number of views concerning the proper method of handling the reconciliation of fuel expense. Some parties have recommended that certain accounts be rolled into the non-fuel portion of base rates. The staff has indicated that only variable costs should be reconcilable, but did not address the issue of rolling fixed and semi-variable costs into the nonfuel portion of base rates. The manner in which a refund or a surcharge should be recovered is also undetermined at this point.

Contrary to the wishes of some of the parties, in this instance it is preferable to *put off until tomorrow what need not be done today.* This is done not because of any reticence about doing further exploratory surgery with the Fuel Rule, but rather because the patient (TUEC) has not yet requested that it be done. Based upon the decision that a reconciliation is required only if one is requested, or if a redetermination is done, a reconciliation is simply not required in this docket. An argument can be made, and has been made (Transcript at 1857-1858), that it is either advisable or necessary to determine in this docket what fuel costs are reconcilable and what fuel costs are not, or else the company will not know the degree to which it might be underrecovering nonreconcilable expenses, or the degree to which it might be overrecovering reconcilable expenses. It is true that if the company incorrectly interprets the Fuel Rule reconciliation provisions, it will not know what its true financial status is. However, if the company is willing to take that risk, it should be allowed to do so. For example, assume that the company underrecovers its fuel expenses but does not file a reconciliation proceeding as soon as it is possible to do so, based upon a belief that the underrecovery will be fully reconcilable. If, when the reconciliation proceeding is finally held, only a portion of the underrecovery is reconcilable, it will be the company and its shareholders who will absorb the loss, not the ratepayers. If TUEC's management is willing to take that risk, that is their decision, and the Commission should let it stand. A second reason why reconciliation is better put off until later consists of the expectation that the Commission will incorporate into the Fuel Rule further guidelines as to what accounts, if any, should not be subject to reconciliation. The type of fuel expenses incurred do not vary significantly from utility to utility, and a rulemaking proceeding is most likely the best forum in which to make what is in essence a policy decision applicable to all generating electric utilities. To interpret the Fuel Rule on a case by case, piecemeal basis will only lead to a waste of resources and possibly inconsistent application of the Rule. While no doubt there will always be a plethora of issues raised in a reconciliation proceeding, a more explicit Fuel Rule would provide a firmer base for decision, and hopefully keep the number of issues to a minimum.

There remains one last reconciliation issue to be discussed. In its Order in Docket No. 5294, the Commission directed the staff to pursue the reconciliation of affiliated fuel costs incurred by TP&L, DP&L and TESCO from April 1, 1983, to July 31, 1983 in this docket. Ms. Neff did not directly discuss reconciliation of those affiliate fuel cost under or overrecoveries. She did testify that since the company had not requested a redetermination of fuel costs in this docket, it would be cumbersome and unnecessary to adjust the fuel factors for reconciliation purposes. Staff Exhibit 7 at 10. At this point there is no choice but to follow Ms. Neff's recommendation, since the record does not contain any reliable under or overrecovery figures. Mr. Wilson testified as to the need to reverse $1,407,000 in overbilling by TUMCO and $5,048,000 in underbilling by TUFCO, but he did not specify the time period to which those under and overbillings relate. TML Exhibit 1 at 25, Schedule 3. It would be questionable to rely on these figures without further explanation. In any event, in light of the recommended dispostion of the fuel issues in this docket, Ms. Neff's recommendation that the fuel factors not be altered solely to accommodate such past discrepencies is a sound one. If, however, the Commission decides that a redetermination of fuel costs is required, and that new evidence should be taken, those under and overrecoveries should be dealt with at that time. Absent such a decision, the staff's ultimate fuel calculations -- incorporated in the revenue requirement attached to this report -- should be adopted by the Commission.

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VIII. Adjustments to Test Year Kwh Sales and Revenue Associated with Year End Customers and Weather

A. TUEC Proposal

Through the testimony of its witness Charles F. Johnston, TUEC proposed adjustments to kwh sales and revenue based on number of customers and weather. Mr. Johnston testified that kwh sales for rates other than transmission service, street and guard lights, and resale service were adjusted to year end by multiplying the actual kwh sales in each month by the ratio of year end customers to customers during the month. For transmission service and street and guard light rates, kwh sales were adjusted to year end by assuming that customers in service in the last month of the test year were in service for all months of the test year. Resale kwh sales were adjusted for customer growth by assuming the same growth rate experienced by the company. TUEC Exhibit 1B, Johnston at 2.

Revenue was adjusted for the change in numbers of customers during the year by rebilling for their electric usage customers who received service for the entire year using the present rates. Base rate revenue for each rate was then determined based on kwh sales adjusted to test year end. Fuel cost revenue was determined on the basis of the base rate fuel components requested in the company's brief following remand in Docket No. 5294. In this docket, the company is requesting that the base rate fuel components as ultimately determined in Docket No. 5294 be used in calculating the revenue-related taxes in the final Order of this case.

Finally, Mr. Johnston used Dr. Art Ekholm's multiple regression analysis of several years of weather and kwh sales data from the company's records to determine the effect of weather on kwh sales. This analysis produced coefficients for each weather-sensitive rate. The coefficients were applied to test year data to normalize kwh sales and revenue for weather. Resale kwh sales were adjusted for weather by assuming the same effect determined for retail kwh sales of the company. TUEC Exhibit 1B, Johnston at 2-3.

Through the testimony of Dr. Ekholm, TUEC presented a detailed description of the weather adjustment which was made in this case. TUEC Exhibit 1B, Ekholm at 4-7. It was Dr. Ekholm's testimony that common sense, observation and experience, and econometric provide solid evidence that kwh sales in the TUEC service area are heavily influenced by fluctuations in the weather. This is the result of a large amount of weather sensitive equipment, for example, air conditioning. Dr. Ekholm testified that if a test year has a cooler than normal summer and a warmer than normal winter-a mild year-the kwh sales are unusually small. Likewise, a harsh test year-a warmer than normal summer and a cooler than normal winter-would record an unusually large amount of kwh sales. In Dr. Ekholm's opinion, unbiased ratemaking requires the adjustment of test year kwh sales to those sales which would occur with average or normal weather conditions. TUEC Brief 1B, Ekholm at 4.

Dr. Ekholm described in detail how weather was measured by collecting from the National Oceanic and Atmospheric Administration weather stations in the TUEC service area the cooling degree days and heating degree days, adjusted for billing cycles; these were averaged together with the customer weights for service areas corresponding to the weather stations. Dr. Ekholm explained that cooling degree days for a day are the number of degrees by which the average of the high and low temperatures for that day exceeds 65 degrees. Heating degree days for a day are the number of degrees by which the average of the high and low temperatures for that day is less than 65 degrees. TUEC Exhibit 1B, Ekholm at 4-5. The coefficients relating changes in kwh sales to changes in cooling and heating degree days were determined with econometric models for four groups: Residential; General Service Secondary, Schools and Municipals; General Service Primary and High Voltage; and Water Pumping. For each billing cycle adjusted month of the test year, deviations of actual degree days from the thirty year average degree days were used with the econometric coefficients to calculate the adjustment in kwh sales which would bring rate class sales to those which would be expected under normal/weather conditions. TUEC Exhibit 1B, Ekholm at 5. Dr. Ekholm further testified that proper adjustments require the measurement of the influence of those factors which affect the consumption of electricity, thus requiring use of econometric models to ensure proper weather adjustments. Econometric models of kwh consumption combine economic theory and professional judgment with a statistical technique referred to as mutiple regression analysis, which is used by social and physical scientists and engineers to measure the independent influence of each of several positive factors on a particular result during a sample period in which all the influences have been operative. TUEC Exhibit 1B, Ekholm at 5. The econometric models for TUEC customers are based on the partial adjustment theory of demand for electricity, which Dr. Ekholm views as a widely used specification. The four econometric models are presented along with measures of their statistical performance in TUEC Exhibit 1B, Ekholm, Exhibit AE-1, and the definitions and data for the variables included in the model are presented in TUEC Exhibit 1B, Ekholm, Exhibit AE-2. Dr. Ekholm testified that he reviewed these measures of statistical performance for the models used and found them to be statistically sound. TUEC Exhibit 1B, Ekholm at 6.

B. Cities Proposal

The Cities agreed with TUEC's proposed adjustment for year-end customers, but disagreed with the specific weather adjustment proposed by Dr. Ekholm. The Cities witness on this issue, Dr. Livingstone, agreed with the basic premise of a weather adjustment, that is, that it is fair to set rates based on normal, weather but stated that such an adjustment is fair only if it is unbiased. Cities Exhibit 4 at 6. Dr. Livingstone testified that to insure an unbiased weather adjustment, such an adjustment should be applied consistently based on exactly the same method each time. When there is no consistency in the methodology, Dr. Livingstone believes that the adjustment becomes biased and unfair. Dr. Livingstone stated that the proposed weather adjustment in this docket continues a well-establisned pattern of inconsistencies set by TUEC. TML Exhibit 4 at 6. As a result, Dr. Livingstone charged, the inconsistency creates bias in the weather adjustment and the company's proposed weather adjustment lacks credibility. TML Exhibit 4 at 6. Dr. Livingstone compared the weather adjustment methodology used in Docket No. 5640 with that used in Docket No. 5200 and concludes that the difference in the methodologies is very significant and a striking example of the effect of inconsistency and resulting bias. Although the bias was in favor of the customers rather than the company, Dr. Livingstone concludes that bias is unfair per se and that it should not be allowed to persist. TML Exhibit 4 at 7-8.

Dr. Livingstone had specific criticisms of the variables used by TUEC in its regressions which were rejected by the Commission in Docket No. 5200, that is, price elasticity and economic activity. He recommends that these variables again be removed for the same reasons the Commission rejected them in Docket No. 5200. TML Exhibit 4 at 8. The effect of removing these variables from the regressions is to change the coefficients of the remaining variables. Since these changes affect the weather adjustment variables, they also alter the weather adjustments themselves. TML Exhibit 4 at 9. Dr. Livingstone's ultimate recommendation on the regression models was that only the weather variables and the lag variable should be retained. The resulting revised coefficients are, in Dr. Livingstone's opinion, better suited for making a weather adjustment. TML Exhibit 4 at 11. His recommendation was that the weather adjustment should be made only for degree days that fall outside the 90 percent confidence interval around the mean, in other words, the adjustments should only take into account the extreme portion of fluctuations in degree days. TML Exhibit 4 at 12. Dr. Livingstone justifies this approach on the basis that because it is usual for the weather to fluctuate it is seldom exactly on the average and thus, fluctuation in and of itself does not make the weather abnormal. In addition, if the goal is to adjust for abnormal weather, this means adopting a range of normal or expected fluctuation, which leads to a confidence interval approach. Dr. Livingstone considers this practical and sensible. Finally, Dr. Livingstone considers the approach to be adequately supported in a 1981 Commission publication entitled "A Review of Econometric Adjustments in Electric Utility Rate Proceedings" by Laura J. Owen.

In brief, the Cities argue that although they have hisitorically opposed weather adjustments and will no doubt continue to do so in the future, especially where such proposed adjustments are based on faulty econometric models, the Cities' opposition in the last TESCO case was unsuccessful to the detriment of TESCO's customers. Thus, the Cities argue, it is only fair that TESCO's customers now receive the benefit of this small company proposed weather adjustment in their favor in this case. The Cities agree that Dr. Livingstone's recommendation that the adjustment be made only to the 90 percent confidence level has the effect of reducing the customer favorable weather adjustment. The Cities argue that if the Commission permits weather adjustments, a policy of adjusting to a confidence interval is desirable, in that it takes into account that weather normally fluctuates and that there is a range of normal fluctuation. The Cities urge adoption of this adjustment only if the Commission adopts the confidence interval approach as policy to be followed in future cases, when the confidence interval approach favors customers. Cities Brief on revenue requirement at 52.

In its brief on revenue requirement, TUEC points out that its proposed weather adjustment was accepted by all parties except the Cities. TUEC Brief on revenue requirement at 57.

C. OPC Proposal

OPC did not oppose the company's proposed calculation of the year end number of customers, but through the testimony of its witness David J. Effron, OPC proposed detailed adjustments to the kilowatt hour sales and revenues based on the year end number of customers as calculated by TUEC. OPC Exhibit 1 at 36-40. In rebuttal testimony, Charles F. Johnston summarized his objections to Mr. Effron's adjustments. TUEC Exhibit 31 at 3. Mr. Johnston's primary concern was that Mr. Effron made adjustments in three cases for existing customers who changed rates during the test year, but did not make corresponding adjustments to the kwh of the rates from which the customers changed. In another adjustment, Mr. Effron separated two rates which are identical. In Mr. Johnston's view, the result of these adjustments is to inflate kwh sales in excess of what they should be. TUEC Exhibit 31 at 3. OPC counsel abandoned the recommendations of Dr. Effron. Transcript at 3550. In its brief on revenue requirement, OPC state that its original recommendations were based upon misrepresentations by the company. Transcript at 2907; OPC Brief on revenue requirement at 52. OPC charges, however, that even if the customers at issue were customers who changed schedules rather than new customers, TUEC could have made manual adjustments for the handful of large scale customers at issue rather than being satisified with what Mr. Johnston perceives as a "reasonable balance." TUEC 31A at 3. OPC argues that it is absurd for Mr. Johnston to contend that it is possible to manually adjust for 300 wholesale customers, but not for one steel mill customer. Transcript at 3562; OPC Brief on revenue requirement at 53. OPC asserts that the recalculation of average GPSC consumption with the addition of the four months of consumption for the one customer that left the class during the test year would add approximately 450 kwh a month per customer. OPC Exhibit 53; Transcript at 3562-3563; OPC Brief on revenue requirement at 53. OPC pleads that it did not have the time since the close of the hearing to pursue and recommend specific dollar adjustments, but urges that the company be required to make specific manual adjustments in the future for large commercial and industrial customers who change rate classifications during the course of the test year. OPC Brief on revenue requirement at 53.

D. Staff Proposal

Dr. Louis W. Pompi presented the staff recommendations regarding weather and customer growth adjustments to test period kwh sales and revenue.

Dr. Pompi recommended adoption of the company's proposed adjustments for customer growth. These adjustments total 1,107,834,571 kilowatt hours. Staff Exhibit 9 at 4. Although Dr. Pompi was not able to perform a comprehensive analysis of the company's procedures and calculations in making the customer adjustment, he did spot-check the calculations to verify the arithmetic. He also reviewed the computer printout provided by TUEC to check that the appropriate method was used for the different customer classes. In his opinion, the discrepancies he found were adequately explained by the company. Dr. Pompi stated that it is important to note that there are several methods or procedures which can be used for customer adjustments. In his opinion, none of these alternatives enjoys the status of conventional wisdom, thus the choice is purely a matter of judgment. Dr. Pompi believes that the company's methods reflect reasonable choices which were consistently applied. Any errors which might exist are small in comparison with the total adjustment being made and he recommended adoption of the company's adjustments. Staff Exhibit 9 at 14-15.

Dr. Pompi testified that he had reviewed the proposed weather adjustments reflected in the prefiled testimony of Dr. Art Ekholm, and that he is in general agreement with Dr. Ekholm regarding his overall procedure, units of weather measurement, and definition of normal weather. Dr. Pompi thus concentrated his analysis on the models used to estimate the weather effect. Staff Exhibit 9 at 5-6. Dr. Pompi reviewed each model for conformance with common sense, experience and economic theory. Dr. Pompi basically agreed with the models; however, he did not agree with the company's treatment of autocorrelation in the water pumping model. Staff Exhibit 9 at 7-9. Because Dr. Ekholm applied the Cochrane-Orcutt technique, Dr. Pompi assumed he attributed the autocorrelation problem to the prolonged influence of random distrubances. Although this is possible, Dr. Pompi believes the autocorrelation is the result of misspecification in the form of an excluded relevant variable, making the Cochrane-Orcutt correction inappropriate. Staff Exhibit 9 at 10. Dr. Pompi's opinion is that the electricity consumed by the water pumping class may be influenced by precipitation. Dr. Pompi's investigation revealed a low correspondence between precipitation and degree days, suggesting that inclusion of the precipitation variable would improve the pumping model. Staff Exhibit 9 at 11. Dr. Pompi decided to estimate the water pumping model using a standard ordinary least squares technique. His proposed weather adjustment reflects the coefficients which resulted from this estimation procedure. Staff Exhibit 1 at 11. It was Dr. Pompi's opinion that the model which he used in calculating the weather adjustment for the water pumping class was more appropriate than making no adjustment at all. Staff Exhibit 9 at 12. The proposed company adjustment for the water pumping class is 15,340,564 kilowatt hours, while Dr. Pompi's recommended adjustment is 13,134,668 kilowatt hours. Staff Exhibit 9 at 4. Thus Dr. Pompi's recommended adjustment for weather totals 620,885,717 kilowatt hours, as opposed to the company's proposed adjustment of 623,091,613 kilowatt hours.

In its brief on revenue requirement the General Counsel points out that not only did Dr. Ekholm agree with Dr. Pompi that if precipitation were deemed to be an explanatory variable, a misspecification of the model would occur (Transcript at 1810-1812), but further agreed that a Cochrane-Orcutt adjustment would not correct this misspecification. Transcript at 1813. Dr. Pompi conducted a limited test to determine whether rainfall was correlated to degree days and fofnd only a slight correlation. Staff Exhibit 9 at 11. Dr. Ekholm testified that he conducted no studies for the current docket to determine whether any correlation existed between water pumping customers' usage and precipitation, or between rainfall or the other variables in the model. Transcript at 1811-1812. General Counsel argues that the company does not know whether a correlation exists between rainfall and the other variables in the water pumping model nor does it know the true cause for the autocorrelation in the model. General Counsel argues that the company has not provided any evidence to prove that autocorrelation was the result of disturbances and not misspecification of the model as tested and supported by Dr. Pompi. General Counsel Brief on revenue requirement at 56.

E. Recommendation

TUEC's proposed customer adjustment was not challenged; therefore it is recommended that the company's adjustment to the number of test-year-end customers be accepted.

TUEC's proposed weather adjustment was challenged only by Cities witness Livingstone and staff witness Pompi. The Cities argument that its recommendation should be adopted only if the Commission adopts the confidence interval approach as a policy to be followed in future cases when the confidence interval approach favors customers (Cities Brief on revenue requirement at 52), appears to conflict with the testimony of its own witness that bias is unfair per se and should not be allowed to persist. Cities Exhibit 4 at 8. The better evidence is the case supports the weather adjustment recommended by the staff, and it should be adopted herein.

TUEC's proposed kwh adjustment was challenged only by OPC witness Effron; however, OPC Counsel stated that OPC could no longer support the adjustments to kwh sales recommended in Dr. Effron's testimony. Transcript at 3550. The staff supported the company's adjustment to kwh with the exception of its weather adjustment. It is therefore recommended that the staff adjustment to kwh be adopted.

COMPANY PROPOSED R&E

IX. Cost Allocation Methodology

A. TUEC's Proposal

Through the testimony of its witness Charles F. Johnston, the company proposed an average and excess allocation methodology. TUEC argues that excess demand allocation methodologies do not vary greatly (Transcript at 4317), and that the proposed average and excess methodology best achieves the goal of demand allocation for four reasons. First, it provides a sharing of the benefits of diversity; second, it is clear and understandable; third, it does not require an unreasonable amount of data; and fourth, it provides a reasonable degree of stability from year to year. TUEC Exhibit 1B, Johnston at 6. According to the company, its methodology also considers the relative amount of capacity being utilized during the year, as well as peak period usage during peak months. TUEC Exhibit 1B, Johnston at 6. The company further argues that its methodology is not susceptible to shifts in cost responsibility from year to year, and therefore it provides more stable results than other methods. TUEC Exhibit 1B, Johnston at 6; TUEC Brief on rate design at 2.

TUEC argues that its method does in fact take into account instantaneous demand and usage or average demand of each customer class throughout the year. In the company's opinion, the significance of this point is that the average demand is considered in determining the total demand allocation; thus, all capacity costs are correctly reflected as demand related, as opposed to what TUEC considers to be the erroneous classification of some capacity costs as energy related. Transcript at 5727-5729; TUEC Brief on rate design at 2.

Although there was a great deal of discussion concerning the reliability of the coincident peak data provided by TUEC, the accuracy of the non-coincident peak data is firm. TUEC Exhibit 1B, Johnston at 7; Coops Exhibit 24 at 9-10; TUEC Brief on rate design at 2. TUEC asserts that the year to year stability of results provided by its average and excess methodology (Transcript at 4158) was not disputed and that Dr. Andersen, OPC's witness, admitted that one would tend to see more stability in noncoincident peak data. Transcript at 6430. Dr. Andersen also testified that one would see more stability in a non-coincident peak allocation than in a single coincident peak allocation. Transcript at 6431; TUEC Brief on rate design at 2.

In further support of its use of the average and excess allocation methodology, the company argued that the advantages of its method had been proven and well recognized by virtue of its having been accepted in the last five TESCO rate cases (Transcript at 4260, 5180), and that the TP&L and DP&L divisions had utilized similar methodologies which were approved by the Commission in past cases. Transcript at 4260-4261; TUEC Brief on rate design at 3. TUEC found additional support for its methodology in the testimony offered by other parties in this proceeding. Mr. Neidlinger, witness for the Army, urged adoption of his four coincident peak allocation proposal (Army Exhibit 1 at 5; Transcript at 4664); however, he conceded that if his proposal was not adopted, the company's average and excess methodology should be used. Transcript at 4672. Although Coops witness Carl Stover had concerns with the coincident peak data, he elected to use the company's average and excess methodology. Transcript at 4975-4976. Coops witness Michael Moore also stated that it would be wise to use the non-coincident class peak demands. Coops Exhibit 24 at 12. Mr. Moore additionally testified that since the non-coincident peak average and excess methodology had been used in prior cases for the TUEC operating divisions, it would not be prudent to use coincident peak data of questionable accuracy to derive allocation factors which could result in a substantial shift of cost responsibilities between classes (Coops Exhibit 24 at 12-13. TML witness Larry Patterson agreed with the company's average and excess demand allocation methodology for this rate proceeding because, in his opinion, it insures that all customers are allocated a portion of the demand related costs. Cities Exhibit 15 at 3-4. TIEC witness Jeffry Pollock also recommended use of the company's proposed average and excess methodology. TIEC Exhibit 2 at 9-10; TUEC Brief on rate design at 3. TNP also agrees with the cost allocation methodology proposed by TUEC in this case. TNP Brief on rate design at 21-22. Although Nucor Steel did not present direct testimony advocating adoption of any particular demand allocation methodology, and its witness Dr. Wilson did indicate agreement with the theoretical principles underlying the proposals of the staff and OPC (Transcript at 5316-5317, nevertheless, Dr. Wilson did not agree with the results of either methodology. (Dr. Wilson's specific disagreements with these methodologies will be discussed in connection with the discussion of the staff and OPC proposals in Parts C and D below.) Nucor Steel ultimately recommended adoption of the company's proposed modified average and excess demand methodology as the more prudent course, because it has the benefit of stability and certainty of result compared to other alternatives which have not been tested and could lead to uncertain results. Nucor Steel Brief on rate design at 36. Finally, although Tex-La took the position that a demand allocation methodology that considers coincident peaks, such as the proposed average for summer month coincident peak method, is preferable to an average and excess methodology, because a company constructs its power supply facilities to meet its system peak demands, not class non-coincident peak demands, Tex-La nevertheless conceded that since accurate coincident peak data is unavailable at this time, the company's average and excess methodology should be used in this case. Tex-La Exhibit 21 at 30; Tex-La Brief on rate design at 46.

B. St. Regis Corporation Proposal

St. Regis witness Kenneth Eisdorfer recommended use of a four coincident peak methodology as best suited for the allocation to customer classes of TUEC's production and transmission plant costs. St. Regis Brief on rate design at 9. The coincident peak methodology utilizes class demands coincident with a system peak. Transcript at 5312. There was virtual agreement among all parties that TUEC is a summer peaking utility, experiencing its greatest peaks during the four summer months of June, July, August, and September, from 1977 through 1983, and that the TUEC system is expected to continue to peak in this manner from 1984 through 1988 as forecasted by the company. St. Regis Exhibit 2, Schedules 1 and 2. A composite of St. Regis Exhibit 2, Schedules 3 and 4, shows that annual system peaks exceed the average of the twelve monthly peaks by at least 21.7 percent, and by as much as 41.4 percent. Based on the data presented in St. Regis Exhibit 2, Schedules 1 through 4, Mr. Eisdorfer determined that the four coincident peak methodology is the most appropriate method for allocating the TUEC production and transmission plant costs. In addition, Mr. Eisdorfer performed a cost of service study for the TUEC system using the four coincident peak methodology. It is the position of St. Regis Corporation that the summer months are responsible for the magnitude of TUEC's production and transmission demand related costs because of the extreme weather sensitive nature of TUEC's load. St. Regis Brief on rate design at 9.

Despite the considerable controversy surrounding the validity of the class coincident peak data provided by TUEC, Mr. Eisdorfer had no opinion regarding the accuracy of this data. However, Mr. Eisdorfer offered an alternative revenue distribution proposal based on the company's non-coincident peak demand average and excess methodology for the allocation of bulk power costs. Transcript at 5273-5274. It is Mr. Eisdorfer's opinion that in the absence of valid class coincident peak data, the company's cost allocation methodology is the most appropriate for this proceeding. Transcript at 5273; St. Regis Brief on rate design at 26. Finally, Mr. Eisdorfer testified that if the Commission cannot rely on the accuracy of either the coincident peak or the non-coincident peak data, then any base rate revenue change resulting from this proceeding should be allocated to classes on their proportionate share of current base revenues. Transcript at 5273; St. Regis Brief on rate design at 26. It is the position of St. Regis Corporation that in the absence of reliable cost of service data, an across-the-board distribution of base rate revenues would be the only logical way to distribute a base rate revenue increase or decrease resulting from this case. St. Regis Corporation Brief on rate design at 26.

C. Office of Public Utility Counsel Proposal

Through the testimony of Dr. Stephen Andersen (OPC Exhibit 55), OPC proposed a production cost allocation methodology referred to as "capital substitution." The initial premise of the OPC proposal is that because TUEC's construction program has been undertaken for the purpose of providing cheaper energy, energy considerations remain a critical component in TUEC's planning process for production cost incurrence. OPC Brief on rate design at 3. The planning process begins with projection of both demand and energy requirements (TUEC Exhibit 1B, Tanner at 4); once the system planner decides that new generation facilities should be built, the planner then evaluates the most economical method to provide that capability by considering the capital, O&M and fuel costs of various alternatives. TUEC Exhibit 1B, Tanner at 6. Fuel is a critical input in the evaluation and selection of the type of generating facilities to be added. TUEC Exhibit 1B, Tanner at 6. According to the OPC, during the early and mid 1970's, TUEC system planners chose to construct large base load units not to meet demand but in order to realize fuel savings. OPC Brief on rate design at 3. Mr. Tanner tesified that the fuel savings from lignite generation between 1975 and 1983 were $2.8 billion and the fuel savings from that construction program were $721 million in 1983. TUEC Exhibit 1B, Tanner at 14; Transcript at 1440. Mr. Tanner indicated that he expects the fuel cost savings for Comanche Peak to be similar to those of the lignite units. Transcript at 1329-1330. OPC argues that the fuel savings from lignite were so significant that they more than offset the higher capacity and O&M costs associated with base load lignite plants as opposed to intermediate and peaking capacity. Mr. Tanner testified that lignite units are more complex and inherently less reliable than other alternatives. TUEC Exhibit 1B, Tanner at 13; Transcript at 1330; OPC Brief on rate design at 3-4. Lignite units have higher forced outages than other production plant. Transcript at 1330. The company now has a 20 percent reserve margin requirement as a result of the diminished reliability of generation plant attributable to the lignite units, in comparison to a 15 percent reserve margin at time of system peak when the company was predominantly dependent upon natural gas. TUEC Exhibit 1B, Tanner at 12-13; Transcript at 1329-1330. To the extent that there are costs associated with a higher reliability requirement, they too have been more than offset by fuel savings according to Mr. Tanner. Transcript at 1330A; OPC Brief on rate design at 4.

OPC characterizes as archaic and anachronistic the notion that all fixed costs are demand costs and that all production related costs must be classified as demand. OPC Brief on rate design at 4. OPC argues that such a notion may have been appropriate when the electric utility industry was a declining cost industry only concerned about adding capacity in order to meet peak demand requirements. In OPC's view, the events of the 1970's changed the economic realities for electric companies as incremental costs began to exceed average costs and natural gas prices rose dramatically. As a result, utilities, including TUEC, made production plans not exclusively for meeting peak demand but also for reducing their reliance on natural gas and achieving fuel cost savings. OPC concludes that since production plant on the TUEC system was constructed and is being constructed for the dual purpose of meeting demand or reliability needs and providing cheaper energy, there is no basis in economics or common sense to continue to permit cost classification decisions to be based on the catchy but antiquated definition that fixed production costs equal demand costs (OPC Brief on rate design at 4), and Dr. Andersen appropriately begins his analysis by classifying production costs as both demand and energy. Consistent with the assumption that all generation and plant operation prior to the lignite conversion program was put in place for the purpose of meeting demand, Dr. Andersen allocates 94 percent of oil and gas production plant as demand, and 6 percent of oil and gas generation is classified as energy to reflect that the fuel conversion program has caused TUEC to increase its required reserve margin from 15 percent to 20 percent. TUEC Exhibit 1B, Tanner at 12-13; Transcript at 1329-1330; OPC Exhibit 55 at 19-20; OPC Brief on rate design at 5. In Dr. Andersen's plan, 6 percent of the total gas generation is equivalent to the additional 686 MW of gas reserves necessary to increase the reserve margins from 15 percent to 20 percent in order to realize energy benefits from lignite generation. OPC Brief on rate design at 5. OPC asserts that Dr. Andersen's methodology appropiately reflects both the fact that TUEC substituted capital costs for fuel costs in constructing the lignite units and the dual nature of generation from lignite plants as providing cheaper energy throughout the year and contributing to meeting the peak demands upon the system. OPC Brief on rate design at 6. Recognizing that a portion of the lignite capacity insures reliability at the time of system peak, Dr. Andersen determined that the portion of the cost of such capacity classified as demand should be limited by the least cost alternative which the system had for meeting the reliability needs that are functionally met by lignite capacity. OPC Brief on rate design at 6. Dr. Andersen selected the 1981 replacement cost ($160.89/kw) of the gas-fired Handley units 4 and 5 as the appropriate benchmark for determining the cost of reliability. OPC Exhibit 55 at 19. OPC argues that the Handley units are representative of the most recent peaking capacity actually added to the TUEC system. Dr. Andersen determined that the corresponding replacement cost for recently added lignite capacity was $508.28/kw, based on the cost of Sandow 4. Transcript at 6468; OPC Exhibit 55 at 19. Dr. Andersen divided the replacement cost of the peaker ($160.89/kw) by the replacement cost of lignite ($508.28/kw) to determine that 31.65 percent of lignite costs should be assigned to peak and that 68.35 percent should be classified as energy. OPC Exhibit 55 at 19; OPC Brief on rate design at 7.

OPC urges that in addition to recognizing and reflecting the principle of capital substitution, Dr. Andersen's model reflects the seasonal variation in costs on the TUEC system. OPC Brief on rate design at 7. This result is achieved by insuring that the allocation of fuel costs is internally consistent with the allocation of capacity costs by allocating non-fuel operating expense on the basis of distribution of hours of operation throughout the year for each generating unit, and allocating station maintenance expense to track the variations in station generation throughout the year. OPC Exhibit 55 at 24. OPC argues that the capital substitution model takes fuel costs, energy related costs, non-fuel operating costs and station maintenance costs to months during the test year for each and every TUEC generating unit in order to ensure symmetrical allocation. Transcript at 6503-6506; OPC Brief on rate design at 7.

OPC argues that the capital substitution allocation methodology comes closer to matching the costs and benefits of lignite generation than either the coincident peak or average and excess approaches. To the extent that lignite generation has saved TUEC billions of dollars in fuel costs as compared to the costs of gas generation, OPC argues that those savings are realized through kwh charges associated with fuel factors, and that it is inherently unfair to allocate all lignite capacity costs as demand costs when all fuel savings attributable to lignite capacity are allocated on the basis of energy or kwh consumption. OPC Brief on rate design at 7-8.

Dr. Andersen employs the same allocators to transmission costs as he does to production costs because there is an economic rationale for considering investment in transmission as an extension of and, to some extent, a substitute for investment in generating capacity. OPC Exhibit 55 at 27; OPC Brief on rate design at 8. Dr. Andersen explained that in the absence of transmission investment, production investment would be higher; a portion of transmission plant is put into place to realize energy savings. OPC Exhibit 55 at 25-27. The transmission network ensures reliability; it also permits economy energy sales and purchases by interconnection with other utilities. OPC Brief on rate design at 8. The transmission system permits utilities to take advantage of opportunities to "purchase energy at a cost lower than generating its own energy." TUEC Exhibit 1B, Tanner at 34-35.

OPC argues that it is important that the transmission costs reflect the demand/energy split inherent in the classification of lignite costs because the "economic benefits of lignite diminish when the plant is moved a significant distance from the mine site." TUEC Exhibit 1B, Tanner at 11. Thus, OPC argues, some portion of transmission cost is a substitute for fuel transportation expense which would be rolled into the price of fuel. OPC Brief on rate design at 9. Had TUEC built lignite plants close to load centers and avoided a great deal of transmission investment, lignite fuel would have been more expensive because of transportation charges in getting the lignite from the mine to the generating site. Therefore, OPC argues, transmission investment has been substituted for higher energy charges. Transcript at 4588-4590; OPC Brief on rate design at 9.

OPC contends that its capital substitution proposal is the only cost allocation methodology proposed in this docket which actually reflects TUEC's costs. According to OPC, a number of witnesses recognized the propriety of a capital substitution allocation methodology in reflecting the fact that TUEC made capital investments in order to achieve fuel savings. TUEC witness Johnston testified that system planners engage in capital substitution. Transcript at 4576. TIEC witness Pollock stated he was not in disagreement with the theory of capital substitution, just its application. Transcript at 5527. Nucor Steel witness Dr. Wilson stated he would employ capital substitution in allocating TUEC's costs. Transcript at 5347. Brazos witness Ms. Taylor expressed her view that capital substitution was the most appropriate allocation methodology for TUEC. Transcript at 5119, 5122.

Almost every party in this docket leveled heavy criticism at the proposal of OPC. TUEC characterized the OPC proposal as a radical departure from established rate design principles and methods approved by this Commission. TUEC argues that even Dr. Andersen realizes the dramatic consequences would which result from his adoption of his methodology when he urged the convening of an "Oh my God" proceeding in the event the Commission adopted his recommended cost allocation methodology. Transcript at 6216; TUEC Brief on rate design at 3. TUEC submits that there is no reason to require such a proceeding, particularly in light of the Commission's ruling in Docket No. 3437, a generic hearing on the question of cost allocation methodologies to be utilized in Texas. TUEC proposes that should the Commission contemplate a departure from established cost allocation methodologies, it would be inappropriate to do so without another generic hearing, such as that conducted in Docket No. 3437, where all affected persons would have the opportunity to be heard. TUEC Brief on rate design at 4. TRA concurs with this recommendation. TRA Brief on rate design at 4. TUEC's more specific criticisms of the OPC proposal deal not only with the effects of implementing the capital substitution methodology, but also with the conceptual basis from which the methodology originates.

TUEC's initial argument is that capital substitution bears no relationship to the reality of cost incurrence on the TUEC system, despite Dr. Andersen's concession that the appropriate inquiry for the Commission is the determination of which cost allocation methodology is the most reasonable representation of how and why costs are incurred. Transcript at 6418; TUEC Brief on rate design at 5. TUEC points out that the model used by Dr. Andersen proceeds from the key assumption that the cost of a combustion turbine represents the ceiling on the cost of capacity on TUEC's system. OPC Exhibit 55 at 3. All costs in excess of the assumed hypothetical cost of a combustion turbine for the entire system capacity of the company are allocated on an energy basis. OPC Exhibit 55 at 8-9; TUEC Brief on rate design at 5. TUEC argues that the use of the cost of a combustion turbine for allocating costs is totally unrealistic and without foundation, because TUEC is not building any combustion turbines or gas-fired units at the present time (Transcript at 6416), nor are any such units in the company's future expansion plans. Transcript at 3949, 4371-4373, 6307-6307; TUEC Brief on rate design at 6. Because Dr. Andersen could only speculate that "somewhere in this country, combustion turbine capacity was added," but that he did not know when, where, or by whom (Transcript at 6374-6375), TUEC concludes that the OPC model is useless from the standpoint of planning capacity expansion (Transcript at 6417), just as it is useless for defining the next unit the company should construct. Transcript at 6417; TUEC Brief on rate design at 5. TUEC finds significant Dr. Andersen's admission that the company "has done an excellent job in terms of capacity expansion," (Transcript at 6367); TUEC Brief on rate design at 6, and his further admission that in "the reality of the situation" for minimizing total costs, the company is "better off building coal and lignite and nuclear than they are building peaking capacity." Transcript at 6372. TUEC asserts that such admissions demonstrate that capacity and energy costs are not in fact incurred as the model of Dr. Andersen assumes in order to satisfy a pure economic theory. TUEC Brief on rate design at 6.

TUEC asserts that the critical assumption of capacity costs being classified as energy, based on the cost of a mythical combustion turbine, is clearly erroneous. TUEC Brief on rate design at 6. TUEC refers to the testimony of SWESCO witness Mr. Chick (Transcript at 6184-6185), where he states that it is a gross and misleading assumption to utilize the cost of a combustion turbine in such a fashion. TUEC urges that the company's actual expansion plan should be utilized to measure the marginal cost of capacity on the company's system, not the arbitrary assumption of a combustion turbine. Transcript at 6185; TUEC Brief on rate design at 6. TIEC witness Pollock similarly criticized the OPC proposal for not considering those costs that the utility actually incurs but instead utilizing the cost of what the utility could have built and decided not to, i.e., the combustion turbine. Transcript at 6469. TIEC witness Chalfant also testified that it is "totally arbitrary to select one point on the whole range of capital substitution possibilities and, in fact, to pick an extreme point, and to say 'let's measure everything against that.'" Transcript at 5647; TUEC Brief on rate design at 6. TUEC thus concludes that the cost allocation scheme set forth by OPC is not based on the reality of the way in which costs are incurred on the TUEC system, but rather is based upon the cost associated with the arbitrarily selected combustion turbine. TUEC argues that that selection, which it characterizes as obviously designed to foist costs away from demand and onto energy, has no basis in reality. TUEC therefore suggests that if reality is to be ignored, there is no reason to ignore it in the favor of combustion turbine. It would be equally logical to make the equally unrealistic assumption of the cost of constructing giant windmills or even using oxen power. TUEC submits that such an absurd argument is no less defensible than any cost allocation methodology based on an arbitrary and unrealistic assumption. TUEC Brief on rate design at 6.

A more specific criticism leveled at the OPC proposal by TUEC and other parties has to do with what is termed the problem of symmetrical allocation of fuel costs, i.e., having those classes charged with a disproportionate share of investment in base load plants also receiving a similarly disproportionate share of the lower fuel costs from these plants. TIEC Exhibit 3 at 3-4. TUEC acknowledges that Dr. Andersen attempted to address the fuel symmetry problem by looking at fuel costs on a monthly basis as opposed to an annual basis, but argues that since the major variations in fuel costs occur on a daily basis and not monthly, his method amounts to "killing off all the flies, but not worrying about the black widow spiders." Transcript at 5652-5653, 6236; TUEC Brief on rate design at 7.

The OPC proposal was also criticized by TUEC and other parties as resulting in a double counting of energy consumption, since it is counted in both the average demand component and again as a subset of the coincident peak demand. TIEC Exhibit 2 at 16; TIEC Exhibit 3 at 4; TUEC Brief on rate design at 7. TUEC argues that this obviously results in a double assignment of costs to some customers (Transcript at 4640), and that the double counting results in a "total negation of true cost causation" according to Mr. Eisdorfer. Transcript at 5758-5761; TUEC Exhibit 39. In TUEC's opinion, the explanations offered by proponents of capital substitution do not negate the problem of double counting. Transcript at 5471-5475, 5654-5655; TUEC Brief on rate design at 7.

TUEC enumerated a variety of other problems which it identifies as arising from the OPC cost allocation methodology. In TUEC's view, greater emphasis on recovery of costs through energy leads to substantial earnings instability for a utility. Transcript at 4332, 5713-5714. TUEC also argues that it is impossible to precisely determine and measure marginal costs and this is equally true with electricity (Transcript at 5592-5595), and that marginal costing methodologies invariably overprice to some classes and underprice to others. Transcript at 5644; TUEC Brief on rate design at 7.

TUEC also contends that a higher system load factor is beneficial for all customers on the system. Transcript at 5992. TUEC submits that it has room for a higher load factor and that it would be desirable to obtain a higher load factor. Transcript at 3970-4308. Dr. Andersen, incorrectly in the opinion of TUEC, has determined that load factor is not a proper regulatory objective (Transcript at 6467), and Dr. Andersen's methodology increases costs to those customers with higher load factors. Transcript at 6235. TUEC asserts that it is clear that the OPC proposal will substantially increase costs allocated to the higher load factor classes on the system and therefore substantially increases their costs as compared with generally accepted allocation methodologies. TUEC Exhibit 40; Transcript at 5608, 6198, 6207; TUEC Brief on rate design at 7-8.

TUEC identifies other negative consequences flowing from the classification of capacity costs as energy. One obvious consequence is that energy charges are emphasized and demand charges are de-emphasized, leading to a reduced load factor (Transcript at 4332), a reduction of total kilowatt hour sales, but at the same time an increase in demand. Transcript at 4307. TUEC alleges that such an approach ignores the currently heightened legislative and regulatory concerns for conservation, load management and economic use of resources. TUEC Brief on rate design at 8. TUEC urges that there must be emphasis on demand charges in the recovery of capacity costs, because if there is not, the likely result will be the need for installation of additional capacity (TIEC Exhibit 2 at 30), in TUEC's view, the worst of all possible worlds. TUEC also argues that the results obtained from classifying capacity costs as energy costs are more highly sensitive to the assumptions made than are conventional methodologies. Transcript at 4323, 5580, 5562. Dr. Andersen agreed. Transcript at 6245-6246. Minor modifications to the assumption of generation costs result in dramatically different percentage amounts allocated to energy. Transcript at 5376-5382, 5650. TUEC alleges that choices have been made in this case to deliberately overstate the amount of revenue to be recovered through energy and understate recovery through demand. Transcript at 5324; TUEC Brief on rate design at 8.

Finally, TUEC challenged Dr. Andersen's proposal because he made rate recommendations for only three classes (Transcript at 6352), and in TUEC's opinion, many customers cannot determine without making assumptions outside his testimony and a good deal of effort, something as fundmamental as the rate they will be paying. Transcript at 6354-6359; TUEC Brief on rate design at 9.

TNP criticized the proposal of OPC on both its theoretical underpinnings and its practical results. TNP argues that capital substitution ignores the fact that as a summer peaking utility, TUEC builds production plant to meet the largest demands imposed on its system by all customers. In order for the utility to meet those demands, plant must be constructed and the use of that plant is determined by the customers' usage. In TNP's view, capital substitution does not take into account the fact that plant is built to serve all customers and that all plant is designated for use during the peak time. To single out large users solely because they are large users, in TNP's view, fails to acknowledge the summer peaking characteristics of the TUEC system. TNP Brief on rate design at 23.

A fallacy of the capital substitution methodology, according to TNP, is that its basic premise is faulty: that is, that a utility can add a combustion turbine using petroleum or natural gas to meet its increased load. TNP Brief on rate design at 23. Dr. Andersen testified that one option available to TUEC in meeting peak demand was the building of a combustion turbine peaking unit which would burn petroleum or natural gas. Transcript at 6371-6372. TNP argues that this recommendation ignores the federal law prohibiting the building of such plants. TNP argues that there are several exceptions to the prohibition in the statute, but that Dr. Andersen could not recall which exceptions TUEC might utilize. Transcript at 6524. Dr. Andersen stated that an exemption for a peaking plant could be a possiblity for TUEC, and that he recalled that the law provided such a peaking plant could be used for 3,000 hours during the year. Transcript at 6522. TNP points out in brief that the federal statute provides an exemption for 1,500 hours of operation. TNP calculates that the costs associated with such a peaking plant would have to be recovered even though the plant would be used only 17 percent of the year. According to TNP, this exemption would not allow the peaking unit to be on-line for the entire peak season for TUEC. TNP concludes that the capital substitution methodology fails to take into effect the prohibition in the federal law, and thus is premised on a faulty assumption. TNP Brief on rate design at 24-25.

TNP further argues that the capital substitution methodology is flawed even if the law allowed a petroleum or gas-fired peaking unit to be built. The basis for this argument was testimony from TUEC witness Tanner, who testified that natural gas was not available in sufficiently reliable quantities to justify the expenditure for such a gas-fired plant and that even if it were available in sufficiently reliable quantities, the price for such gas was an unknown and would probably be too expensive. Trancript at 3975-3979. TNP alleges that Dr. Andersen failed to perform a study of the costs and availability of gas as a primary fuel source but instead based his knowledge of the natural gas market upon his intuitive belief that sufficient quantities of reliable low cost gas would be available for the life of the unit. Transcript at 6525; TNP Brief on rate design at 25-26. TNP argues that a utility's obligation to serve its customers is based upon a long term view. Even a low cost fuel which is unavailable in reliable or sufficient quantities is not a realistic or proper alternative for an electric utility. TNP submits that for this reason, basing any allocation methodology upon such a fuel source is unrealistic and improper in setting rates. TNP Brief on rate design at 26.

Finally, TNP argues that the capital substitution methodology is flawed because the exact impact on customer classes is not known. TNP Brief on rate design at 26. TNP's concern is that the impact upon the wholesale class of this cost allocation methodology would be to substantially raise the rates of the wholesale class without giving any consideration to the unique attributes of the members of the class. TNP views the wholesale class as a smaller version of the TUEC system itself, and argues that it is improper ratemaking to ignore the customers which the wholesale customers serve. TNP Brief on rate design at 27. Dr. Andersen testified that he did not propose a rate for the wholesale class at his proposed revenue requirement. OPC Exhibit 55, Schedule SA-18; Trancript at 6354. Dr. Andersen did state that regardless of what revenue decrease TUEC received, the wholesale class rate would not go down; under the three scenarios he proposed in OPC Exhibit 55, Schedule SA-17, the wholesale rates went up even though the other customers received a $40 million decrease. TNP Brief on rate design at 28.

TNP argues that it is improper to approve a cost allocation methodology without specific knowledge of customer impact, especially where the customer impact will be very great upon a class such as a wholesale class which serves other customers. TNP did not find any mitigation in the fact that the OPC proposed a revenue reduction. TNP argues that an inappropriate methodology should not be accepted simply because it will not have a great customer impact. TNP Brief on rate design at 29. Second, TNP takes the position that the capital substitution methodology will have a significant impact on itself and other wholesale class members, even if the OPC's revenue requirement is adopted. Dr. Andersen demonstrated that under the OPC revenue requirement, a $95 million reduction, the residential and small general service customers receive a significant and substantial rate reduction, and that the rates to the wholesale class remain the same. OPC Exhibit 55, Schedule SA-17. TNP argues that for TUEC to have revenues cut by almost $100 million and not have any of the decrease flow through to the wholesale class will indeed be a severe impact on the wholesale class. TNP Brief on rate design at 29.

The City of Bowie noted in brief that it is opposed to the pricing principles put forth by OPC and it supports the position of the intervenors in this docket who oppose its implementation. Bowie Brief on rate design at 10.

Tex-La, advancing arguments similar to those of other parties, urges rejection of the OPC proposal as flawed, unrealistic and biased. Tex-La Brief on rate design at 48-53.

OPC responded to other parties' criticism of its proposal by arguing that those criticisms were unsupported, unreliable and incredible. OPC Brief on rate design at 4. OPC asserts that TUEC witness Johnston admitted that capital substitution is theoretically correct (Transcript at 4537, 4576), and he was unable to demonstrate any misapplication of Dr. Andersen's model of cost incurrence on the TUEC system. OPC Brief on rate design at 14. OPC characterized Mr. Johnston's disagreement with Dr. Andersen's methodology as therefore being without foundation. OPC also argues that Mr. Johnston's negative opinion of the capital substitution methodology was based on his assumption of its similarity to the Coyle methodology which he could neither describe nor define. Transcript at 4545-4546, 4562-4563; OPC Brief on rate design at 4. OPC argues that the Coyle methodology is a variation of average and excess, similar to the average and excess methodology proposed by GSU in Docket No. 5560 and adopted by the Commission. Transcript at 6455. OPC asserts that there is no methodological similarity between Dr. Andersen's capital substitution approach and Dr. Coyle's average and excess methodology. OPC Brief on rate design at 14.

OPC argues that no party disputes the fact that Dr. Andersen has presented an accurate characterization and reflection of the manner in which TUEC concurs costs. OPC Brief on rate design at 14-15. OPC asserts that TUEC and TIEC suggest that Dr. Andersen's capital substitution methodology is indistinguishable from his time of use proposal in the GSU docket and that because the Commission rejected Dr. Andersen's proposal in the GSU case, Dr. Andersen's proposed capital substitution methodology should be rejected here as well. OPC argues that those proposals are not identical, but that even if they were, such an argument is weak and unpersuasive. OPC Brief on rate design at 15.

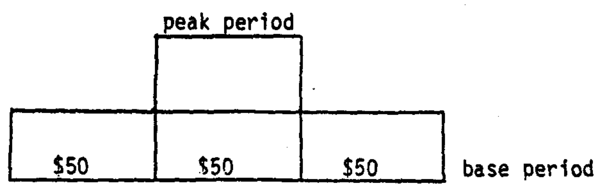
In response to the criticism that capital substitution overcharges high load factor customers, OPC argues that the attempt to demonstrate such a result was dependent upon separate evaluations of capital and fuel costs, and was therefore deceptive and contrary to Mr. Pollock's assertions. TUEC Exhibit 38, TIEC Exhibits 4 and 5, Transcript at 5525-5526, 5529, 6458-6461; OPC Brief on rate design at 16. OPC argues that in using capital substitution, the cost analyst must evaluate costs on a dollars or cents per kwh basis, because system planners decide between construction alternatives on a total cost or an average cost per kwh basis, not on independent evaluations of capital costs and fuel costs. OPC Brief on rate design at 16-17. OPC referred to TUEC witness Tanner's direct testimony as a description of correct cost analysis. TUEC Exhibit 1B, Tanner at 7-9. In that testimony, Mr. Tanner describes the company's decision to build Comanche Peak. OPC argues that TUEC analyzed capital costs and fuel costs, but the decision to construct Comanche Peak was based on an average cost of kwh in comparison to other alternatives. OPC Brief on rate design at 17. OPC argues that the independent evaluation of capital costs and fuel costs is neither meaningful nor appropriate for cost allocation analysis, and that Mr. Pollock's evaluation was designed to distort the impact on high load factor customers. OPC Brief on rate design at 17. OPC asserts that TUEC Exhibit 38 and TIEC Exhibits 4 and 5 are deceptive because they do not focus on the total cost to any particular customer class as compared to other customer classes. Transcript at 6459. OPC argues that Dr. Andersen's methodology produces an energy charge for transmission voltage customers during the winter months which is 95 percent of the charge on residential customers for production and transmission costs and a charge during the summer months which 83 percent of the comparable charges to residential consumers. Transcript at 6460-6461. OPC does not deny that Dr. Andersen's methodology charges high load factor customers more than the company's proposal, but argues that such is the result allocating costs in a manner that reflects cost incurrence. OPC Brief on rate design at 17.

OPC further asserts that it is inappropriate to promote the arbitrary standard of increasing a utility's load factor. OPC cites the testimony of Nucor witness Dr. Wilson as supporting that argument. Transcript at 5345, 6467. According to Dr. Wilson, "the load factor approach is an approximation to a cost principle," and there is no need to rely on an approximation. Transcript at 5346; OPC Brief on rate design at 18. Dr. Andersen testified that "load factor should be the product of choices that consumers make in response to costs." Transcript at 6467. From that premise, OPC concludes that if one follows cost principles, tracks cost incurrence and reflects costs in rates, then high load factor customers will receive appropriate and yet relatively lower charges than other customers. Transcript at 5346; OPC Brief on rate design at 18.

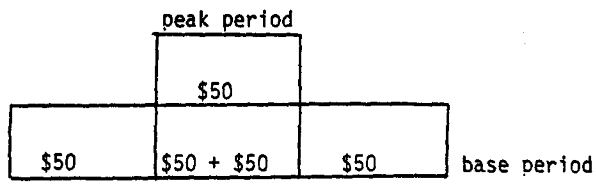
OPC further argues that the selection of an allocation methodology for the arbitrary purpose of promoting load factor by stimulating off- peak consumption would cause TUEC to burn more of its marginal fuel source (gas), thus driving up the average fuel cost factor, thus increasing fuel expense allocated to all customers. Transcript at 1337, 5128-5129, OPC Exhibit 58: OPC Brief on rate design at 18. Furthermore, in OPC's view, promotion of off-peak consumption could cause yet another round of construction of higher cost base load generating plants. OPC Exhibit 55 at 13; OPC Brief on rate design at 18-19. OPC goes on to assert that employment of a capital substitution methodology for allocating costs could improve load factors without arbitrarily focusing on load factor as a goal. Transcript at 5347. Not only does Dr. Andersen's methodology reflect TUEC's incurrence of capital costs to achieve lower fuel costs, it also reflects seasonal variation in costs. OPC Brief on rate design 19. That reflection of variation in cost, according to Dr. Wilson, would increase conservation, particularly during high cost periods. Transcript at 5348. Thus, OPC concludes that load factors may improve because customers will have an incentive to constrain their peak consumption relative to their average consumption. OPC Brief on rate design at 19.

In response to the criticism that energy based allocation methodologies double count energy to customer classes, OPC intially argues that such criticisms are inherently dependent upon the assumption that all fixed costs may only be classified and allocated as demand costs. OPC Brief on rate design at 19-20. If all production costs must be classified to demand irrespective of the utility or the nature of cost incurrence, then OPC argues that allegiance to cost based rates is a gigantic hoax. OPC Brief on rate design at 20. OPC charges that TIEC desires to hold the Commission firmly to the notion that fixed costs, and particularly production costs, can never be allocated as anything other than demand. OPC Brief on rate design at 20.

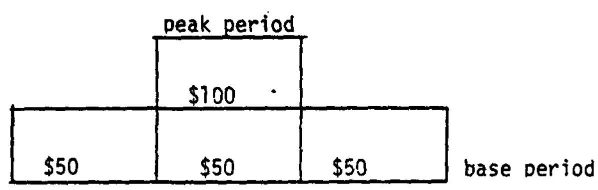
OPC responded specifically to the allegation that the capital substitution methodology "double-dips" on energy by arguing that the methodology reflects the purpose behind lignite costs so as to fairly allocate energy costs. OPC Brief on rate design at 21. Under Dr. Andersen's proposal, the classification and allocation of TUEC's lignite costs should be analogous to the allocation of prepaid fuel costs. Transcript at 6483-6485. OPC argues that lignite costs were incurred to permit access to cheap energy. Thus, it is entirely appropriate, logical, and straightforward to recognize that a portion of the lignite capacity, that portion which exceeds gas costs, is related to energy and is not related to demand. Transcript at 6485; OPC Brief on rate design at 21-22. Therefore, OPC argues that capital substitution works by subtracting the cost of a peaker from the cost of lignite capacity and allocating the residual as energy costs across time periods in proportion to each period's share of annual generation from lignite capacity. Transcript at 6486. Demand or reliability costs are then allocated in equal increments to the usage blocks within the peak period. Transcript at 6487; OPC Brief on rate design at 22. In its brief, OPC goes into great detail to refute the double-dip argument. In describing how capital substitution works when applied to Dr. Wilson's hypothetical "hat" (Transcript at 5353), Dr. Andersen assumed lignite costs of $200 and peaker costs of $50 for total fixed costs of $250. Allocating those fixed costs according to the following diagram would place $150 in the base period with $50 in each time period. Transcript at 6486-6487. The hypothetical would appear thus:



Capital substitution would then allocate the remaining $100 of reliability costs to the peak period in equal increments, such that $50 would be allocated to the base portion of the peak period and $50 to the top of the hat. The cost assignment would then appear thus:



The allocation of $50 of the $100 of reliability costs to the base of the peak period is the source of the allegation of a double-dip. OPC refers to Mr. Pollock's "corrected" version of capital substitution as outrageous. OPC Brief on rate design at 23. Mr. Pollock would correct the capital substitution approach of Dr. Andersen by allocating the entire $100 of reliability costs to the excess (or top of the hat) portion of the peak period. Transcript at 5491. Mr. Pollock's version of capital substitution would appear as follows:



If a peaker designed according to the hypothetical to serve the excess cost only $50, it would be ridiculous to charge consumers in the excess period twice that amount, according to OPC. OPC Brief on rate design at 23. The $100 of reliability cost is attributable to the peak demand, not the excess demand. Transcript at 6486-6487A. OPC submits that Dr. Andersen's cost assignment is consistent with the cost of units. Because the total base period is assigned a total of $200 which coincides with the fact that based load fixed costs are $200, there is no double-dip. Transcript at 6487-6487A; OPC Brief on rate design at 23. OPC further argues that Mr. Pollock's double-dip could not be illustrated unless fuel and capital costs are segregated. Transcipt at 5526. OPC concludes that such a demonstration can be achieved only through manipulation of numbers and assumptions of unrealistic costing considerations. OPC Brief on rate design at 23. He further argues that allegations of a double-dip are designed as a scare tactic to keep intact the "fixed costs equals demand costs" definition and to preserve the alleged mismatch of allocation of lignite costs and benefits, which works as a great and unjustified financial reward to industrials. OPC argues that the only fair way to allocate lignite costs so as to match the fuel cost savings attributable to lignite capacity is to apply capital substitution. Transcript at 5119; OPC Brief on rate design at 23.

To the criticism that alteration of certain assumptions in Dr. Andersen's model would change the results, OPC responded that that notion holds true for almost every aspect of a proceeding before the Commission, including rate of return analysis and accounting adjustments. Transcript at 6476; OPC Brief on rate design at 24. OPC asserts that the most unreasonable assumption in any of the proposals is that made by the proponents of the coincident peak and the average and excess methodologies, that is that TUEC production capacity is a big chunk of homogeneous plant put into place for the sole purpose of meeting peak demands. OPC Brief on rate design at 24. OPC further argues that Dr. Andersen's actual assumptions and their basis went unchallenged, except for allegations during cross-examination that use of a peaker in cost allocation was inappropriate because TUEC has no peakers in its generation plans. OPC Brief on rate design at 24. OPC argues that that line of attack stems from either a misunderstanding of capital substitution or a deliberate attempt to avoid dealing with cost analysis. OPC argues that use of the peaker within the allocation methodology has nothing to do with whether TUEC should or should not build peakers (Transcript at 6481), and that the methodology is simply a reflection of the choices and tradeoffs in contemplation of total costs that system planners make. Transcript at 6481-6482; OPC Brief on rate design at 24. Use of the peaker in capital substitution methodology serves the function of assisting in the appropriate classification of lignite plant costs. OPC Brief on rate design at 24.

OPC urges rejection of arguments based on TUEC's inability to add gas peaking capacity as irrelevant and erroneous. OPC Brief on rate design at 24. OPC refers to TUEC witness Tanner's statement that exemptions under the Fuel Use Act could be "fairly easily achieved" for peaking facilities (Transcript at 3978), and that the approximately 15 gas-fired units on the TUEC system which are over retirement age should not be removed from rate base because those plants should be kept operational as peaking units. If such units were retired, TUEC would construct replacement peakers at a higher cost per kw than the retired units. Transcript at

1331-1332, 1335. TUEC owns and operates relatively inexpensive peaking capacity, a fact that is explicitly recognized in Dr. Andersen's analysis, according to OPC. OPC Exhibit 55 at 11, 19. Finally, OPC argued that Dr. Andersen's choices and assumptions were biased against residential consumers to dispel any notion that capital substitution was designed to minimize cost assignment to residential consumers. Transcript at 6464-6466. OPC Brief on rate design at 25.

OPC took great pains to distinguish Dr. Andersen's methodology from marginal cost approaches, despite the fact that the method reflects the manner of cost incurrence on the TUEC system. OPC Brief on rate design at 26. OPC argues that Dr. Andersen's fuel cost allocations were based on TUEC's actual average fuel costs and the capacity cost allocations were based on embedded capacity costs. Transcript at 6480. Use of a marginal cost without a capital substitution approach as suggested by Nucor witness Dr. Wilson would have charged all customers on a kw basis the cost of a combustion turbine and the incremental cost of fuel within time periods during which they consume. Transcript at 6479. OPC further asserts that a marginal cost analysis would present a revenue reconciliation problem that does not exist in Dr. Andersen's approach. Transcript at 5356-5357, 6480. Dr. Andersen's use of replacement cost estimates for the Handley and Sandow Units was solely for determining the demand/energy split for the classification of capacity costs; however, both the analysis and the rates which Dr. Andersen proposes are based on embedded costs. Transcript at 6480; OPC Brief on rate design at 26.

OPC also argues that to the extent that CWIP is included in rate base, the Commission should follow the classification analysis presented by Dr. Andersen. OPC Brief on rate design at 30. Dr. Andersen used TUEC's proposal for functionalization of CWIP between production, transmission, distribution and general; he then disaggregated production plant as nuclear, coal and other, and applied his capital substitution principle to determine the appropriate demand/energy classification. Consistent with the principles of capital substitution which he espouses, Dr. Andersen allocated to classes on an energy basis the costs of nuclear and coal units in excess of the 1985 cost of combustion turbine capacity ($300 per kilowatt). The balance of production in CWIP was classified as demand related. OPC Exhibit 55 at 31. OPC argues that since Comanche Peak is scheduled to come on-line in 1985, the company's $300 per kw estimate of combustion turbine capacity is a more appropriate value for determining the CWIP production costs to be classified and allocated as energy than the replacement costs of the last peaker actually added to the TUEC system. OPC Brief on rate design at 30. OPC further cites Dr. Andersen's testimony that TUEC's estimate of the 1985 cost of combustion turbine capacity is more relevant to CWIP analysis because "combustion turbines are unambiguously eligible for exemption under the Fuel Use Act." OPC Exhibit 55 at 32; OPC Brief on rate design at 30.

D. Staff Proposal

General Counsel urges that in this case the time is ripe to adopt a new direction in cost allocation and rate design for utilities in Texas. General Counsel Brief on rate design at i. General Counsel urges that the staff's allocation of generation capacity costs is based upon a recognition of the fundamental economics of the capacity planning process. That view holds that because the decision to build an expensive lignite facility is premised upon the recognition of the fuel savings such a unit will realize over the life of the plant, the allocation of capital costs of that unit should be based upon the benefits received from that unit in the form of fuel savings, as well as the benefits of additional capacity. General Counsel Brief on rate design at i-ii. Therefore, a substantial portion of the capital costs of these plants should be allocated upon the basis of energy rather than allocating the costs entirely upon the relative demand characteristics of the various classes. General Counsel further urges that the staff's rate design recognizes the future costs that may be incurred by TUEC if present consumption patterns continue. Arguing that traditional rate design methods have not stressed efficient price signals, General Counsel offers the staff proposal as a gradual introduction of peak load pricing for the largest and most sophisticated consumers within the TUEC service territory as part of the State's comprehensive concern for energy efficiency and conservation. General Counsel Brief on rate design at ii.

General Counsel asserts that the key to understanding the staff's allocation of production plant costs is understanding the system planning process. General Counsel Brief on rate design at 1. This process considers not only the objective of meeting peak load, but also considers how to meet the total load in the least expensive fashion. In using this approach, General Counsel argues, fuel costs as well as capital costs are evaluated in determining the least cost alternative when it is necessary to add additional plants to meet growth and system load. General Counsel references TUEC witness Tanner's testimony that the company looks at fuel costs in determining the least cost to serve (Transcript at 8976-8977), and states that company witness Johnston agreed with the portion of the staff's method that looks at fuel. Transcript at 4576. General Counsel cites two objectives for efficient system planning: insuring system reliability and minimizing energy cost. Transcript at 6306, OPC Exhibit 55 at 9, Staff Exhibit 36 at 40. It is urged that the system planner will balance the capital costs of a plant with any fuel savings. Staff Exhibit 36 at 40, Brazos Exhibit 1 at 21, Transcript at 4577. Because the utility will attempt to maintain the capacity and fuel costs at a minimum after scrutinizing all available alternatives (Brazos Exhibit 1 at 19), General Counsel asserts it would be illogical for the system planner to build a unit more costly than the least capital intensive unit available, unless the basis for that decision rested upon the expected fuel savings. Staff Exhibit 36 at 41; General Counsel Brief on rate design at 1. General Counsel cites as an example of this tradeoff the company's Comanche Peak nuclear units; the $1,600 per kilowatt cost may be justified due to the expected fuel savings. Transcript at 5340, 6406-6407; General Counsel Brief on rate design at 1.

Staff Exhibit 49 arguably demonstrates the conceptual replication of the staff's allocation methodology, and how it reflects system planning. Transcript at 6871; General Counsel Brief on rate design at 2. The graph reflects the total cost of capacity and fuel (Transcript at 6903), with the crossover point exemplifying that point where the buyer is indifferent, i.e, the total capital and fuel costs are equal. Prior to the crossover point, the costs are lower for a peaking unit, and after the crossover point, the costs are lower for a base load unit. The difference between the capital costs of a base load and a peaking unit is that portion classified as energy because of the energy savings realized for the extra capacity costs of that base load unit. General Counsel Brief on rate design at 2. The staff proposes to classify part of the production plant as energy related; that portion of capacity cost classified as energy is considered reflective of the inherent nature of the costs, that is, costs incurred for the benefits of fuel savings. The portion of capacity costs classified as energy is allocated to classes by kwh sales. The remaining portion of the capacity costs is classified as demand related and allocated on the basis of class contribution to the system peak. Staff Exhibit 36 at 41, Transcript at 6746; General Counsel Brief on rate design at 3. The critical assumption in the staff's allocation methodology is that capital costs can be substitutes for fuel costs. Staff Exhibit 36 at 41; General Counsel Brief on rate design at 3.

The staff methodology, presented in the testimony of staff witness John Kepner, considered the fact that capacity related costs in the utility's revenue requirement reflect capacity of different vintages. General Counsel Brief on rate design at 3. Therefore, Mr. Kepner used the 1984 replacement costs for a gas-fired peaking unit and a base load unit in order to obtain a forward-looking approach and to reflect similar dollar values for those plants. General Counsel Brief on rate design at 3. Two critical components of Mr. Kepner's model are: one, the percentage of lignite or gas capacity in the company's current generation mix, and two, the relative costs of the lignite or gas-fired plants. Mr. Kepner based his allocation of production plant on actual figures reflected on the company's books.

General Counsel Brief on rate design at 4. Staff Exhibit 44; Mr. Kepner used $1, 056 per kilowatt for the base load unit, and $300 per kilowatt for the peaking unit (Staff Exhibit 36 at 44), figures obtained from TUEC. Mr. Kepner used $300 per kilowatt for the peaking unit even though the company indicated that the cost ranged between $300 and $500 per kilowatt. Mr. Kepner compared the figures utilized by Gulf States Utilities ($215) and the Houston Lighting and Power Company ($250-295), and concluded that his $300 per kilowatt for the peaking unit was reasonable and within the range of figures supplied by the company. Staff Exhibit 36 at 45. The actual cost of the lignite unit was not used to obtain the figures shown in Staff Exhibit 44; Mr. Kepner used $1,000 per kilowatt instead of the actual $1,056 per kilowatt cost in order to effect his stated policy of gradualism. Staff Exhibit 36 at 5; General Counsel Brief on rate design at 4.

Staff Exhibit 44 demonstrates that approximately 67 percent of the company's capacity was generated by gas or oil plants and 33 percent of its capacity was generated by lignite plants. Mr. Kepner obtained the percentage of lignite plant classified as energy by using the company's supplied figure of $1,056 per kilowatt for a lignite plant and $300 per kilowatt for a gas turbine plant. Conservatively, only 70 percent of a lignite plant was classified as energy with the remaining 30 percent classified as demand in Mr. Kepner's application to the company's plants. Staff Exhibit 44, Appendix B. The 70/30 ratio is reflected in the total demand related costs, i.e., the 30 percent appears as the $300 per kilowatt figure which is applied to all of the company's lignite plants. The actual percentage of generation capacity costs classified as demand for the composite mix of the company's plant is 56.4 percent, and the actual percentage of generation capacity costs classified as energy for the composite plant mix of the company is 43.6 percent. Staff Exhibit 44, Appendix B; General Counsel Brief on rate design at 5.

Staff references the testimony of other parties' witnesses in support of its approach. Brazos Coop witness Ms. Taylor and Nucor Steel witness Dr. Wilson both testified that the approach of the staff was the most accurate depiction of cost causation, that is, the examination for fuel savings. Transcript at 5152, 5303-5304. General Counsel argues that the fuel savings from base load units is the catalyst for the company to incur additional capacity costs, because the company chooses to build a plant not solely to meet its demand. Transcript at 6241, OPC Exhibit 55 at 4, 12, Staff Exhibit 36 at 41; General Counsel Brief on rate design at 6.

The staff's use of a combustion turbine was defended as only an upper bound or ceiling to capacity costs (Transcript at 6577), or merely an analytical tool in Mr. Kepner's model to determine the classification of the energy portion of the capacity costs. General Counsel Brief on rate design at 7. General Counsel argues that Mr. Kepner did not imply or suggest that TUEC should construct gas fired units; the model merely illustrates that the gas units as well as other units are alternatives available to the company. General Counsel argues that Dr. Wilson used the combustion turbine in a similar manner in testifying that he used the combustion turbine to determine the energy portion of the capacity costs. Transcript at 5303-5304; General Counsel Brief on rate design at 7.

General Counsel urged that it is appropriate at this time in Commission's history to adopt the staff's allocation methodology. General Counsel Brief on rate design at 8. Because utilities do consider the fuel savings as well as the capacity costs when constructing generation units, General Counsel argued that it is important to recognize that utilities in Texas continue to undergo fuel diversity and fuel conversion. General Counsel urges that the biggest investor-owned utility should take the lead as as example for other investor-owned utilities in Texas. General Counsel Brief on rate design at 8. General Counsel urged adoption of the staff's position in this docket in view of the company's impending operation of nuclear plants, because the capacity costs classified on an energy basis will be much greater once the nuclear units come into operation. In the view of General Counsel, Commission action in adopting the staff's proposed methodology recognizes that the system planning of utilities plays a role in anticipated fuel savings and that these savings should be classified accordingly to reflect the causal relationship staff espoused. General Counsel Brief on rate design at 8-9.

TUEC leveled at the staff's proposal essentially the same criticisms it had of the OPC proposal. TUEC characterizes the staff's proposal as a radical departure from established rate design principles and methods approved by this Commission. Specifically, TUEC references Mr. Kepner's testimony that adoption of marginal cost pricing in rate design would result in "completely overturning rate design in Texas." Transcript at 6814-6815. TUEC argues that there is no reason to completely overturn rate design in Texas, particularly in view of the generic hearings held by the Commission in Docket No. 3437 on the question of cost allocation methodologies to be utilized in Texas. TUEC Brief on rate design at 4. In the alternative, the company submitted that departure from established cost allocation methodologies would be inappropriate without another generic hearing where all affected persons would have the opportunity to be heard, a suggestion which Mr. Kepner supported and believed to be a good idea. Transcript at 6186; TUEC Brief on rate design at 4.

TUEC did recognize that the actual rate recommendations made by the staff are tempered by what Mr. Kepner referred to as gradualism, and do not reflect a literal application of marginal costing. Transcript at 6812, 6937; TUEC Brief on rate design at 4. The company does fear, however, that Mr. Kepner's view of this case as an opportunity to get a "foot in the door" for marginal costing (Transcript at 6813), inevitably would result in the disappearance of gradualism and the onslaught of the legion of problems which TUEC asserts have been demonstrated by the evidence presented in the hearing. TUEC Brief on rate design at 4. TUEC identifies these problems as arising from not only the effect of implementing the staff's cost allocation methodology but also with the conceptual basis from which the methodology originates. TUEC Brief on rate design at 4-5.

TUEC argues that like Dr. Andersen's model, Mr. Kepner proceeds from a key assumption that the cost of a combustion turbine represents a ceiling on the cost of capacity on the company's system. Staff Exhibit 36 at 13. TUEC asserts that the use of a combustion turbine for allocating costs is unrealistic and without foundation, because TUEC is not building any combustion turbines or gas-fired units at the present time (Transcript at 6416), nor are there any in the company's future expansion plans. Transcript at 3949, 4371-4373, 6307-6307A; TUEC Brief on rate design at 5. Mr. Kepner does not know of any utility in the United States which has built a combustion turbine in the last five years (Transcript at 6636), and, as to whether a utility could even build a combustion turbine if it wanted to do so, Mr. Kepner simply opined that "if push came to shove...they might be able to do that." Transcript at 6782. TUEC asserts that such testimony demonstrates that the model set forth by the staff is useless from the standpoint of planning capacity expansion (Transcript at 6417), just as it useless from the standpoint of defining the next unit the company should construct. Transcript at 6417. TUEC further asserts that capacity and energy costs are not in fact incurred in order to satisfy a pure economic theory as in the model of Mr. Kepner. TUEC Brief on rate design at 5-6.

As with its criticism of the OPC proposal, TUEC characterized as erroneous the critical assumption that capacity costs should be classified as energy based on the cost of a mythical combustion turbine. TUEC identified as a problem with the staff's proposal its failure to symmetrically allocate fuel costs, a criticism also made of the OPC proposal. TUEC Brief on rate design at 7. Similarly, TUEC argues that the staff proposal results in a double counting of energy consumption because it is counted both in the average demand component and again as a subset of coincident peak demand, resulting in a double assignment of costs to some customers. TUEC argued that greater emphasis on recovery of costs through energy charges leads to substantial earnings instability for a utility and that reliance on marginal costing methodologies results in overpricing in some classes and underpricing to others. Transcript at 4332, 5644, 5713-5714; TUEC Brief on rate design at 7. An additional problem TUEC finds with the staff's proposal is that its methodology would substantially increase costs allocated to the higher load factor classes on the system and would therefore substantially increase their costs as compared with generally accepted methodologies. TUEC Exhibit 40, Transcript at 5608, 6918, 6207; TUEC Brief on rate design at 7. TUEC identifies negative consequences stemming from the classification of capacity costs as energy: one would be emphasizing energy charges and de-emphasizing demand charges, leading to a lessened load factor, (Transcript at 4332), a lessening of total kilowatt hour sales but at the same time an increase in demand. Transcript at 4307. An additional result would be the need for installation for additional capacity. TUEC also argues that the results obtained from classifying capacity costs as energy costs are more highly sensitive to the assumptions made than are conventional methodolgies. Transcript at 4323, 5580, 5652; TUEC Brief on rate design at 8. TUEC alleges that this point is not disputed by Mr. Kepner. Transcript at 6612-6613, TIEC Exhibit 8. TUEC Brief on rate design at 8. Minor modifications to the assumptions of generation costs result in dramatically different percentage amounts allocated to energy according to Dr. Wilson and Mr. Chalfant. Transcript at 5376-5382, 5650; TUEC Brief on rate design at 8.

Another problem TUEC finds with the staff's proposed methodology is that Mr. Kepner did not look at the impact of his recommendation until after he had filed his testimony. Transcript at 6662-6663; TUEC Brief on rate design at 8. In addition, TUEC argues that its cross-examination of staff witness Bentley Erdwurm illustrated serious deficiencies with the cost of service study prepared by the staff, making it difficult if not impossible for TUEC to place reliance upon the staff's recommendations. Transcript 6938-6939; TUEC Brief on rate desgin at 8-9. In her reply brief, General Counsel attempts to explain the problems elicited by TUEC counsel in its cross of Mr. Erdwurm. General Counsel Reply Brief on rate design at 12-15. Those explanations are not part of the evidentiary record, however, and Mr. Erdwurm was unable to explain the apparent discrepancies.

TNP also criticized the staff's cost allocation methodology proposed in this case on the grounds similar to its criticism of the OPC proposal. TNP argued that the staff proposal in this case ignores the fact that as a summer peaking utility, TUEC builds production plants to meet the largest demands imposed on its system by all customers. TNP also found fallacious the staff's assumption that TUEC could build a combustion turbine peaking unit which would burn petroleum or natural gas. Transcript at 6873. TNP Brief on rate design at 23. TNP reiterated its argument that the staff's proposal ignores the federal law prohibiting construction of such peaking units. TNP Brief on rate design at 24-25. An additional flaw identified by TNP in the staff's proposal is that Mr. Kepner had not performed a study of the costs and availability of natural gas as a primary fuel source, but simply speculated that sufficient quantities of reliable low cost gas would be available for the life of the unit. TNP Brief on rate design at 25-26. Finally, TNP criticized the staff's proposal because there was no impact analysis on each customer class at various revenue requirement levels. TNP charged that the staff's proposal would have an adverse impact on the wholesale class even if the rate increase ultimately granted in this case is very small, zero or negative. TNP Brief on rate design at 26-27.

The City of Bowie noted in brief its opposition to the staff's cost allocation methodology and its support of the position of those intervenors in this docket opposing its implementation. City of Bowie rate design brief at 10.

The intervenor Cities urged the Commission to excercise extreme care before embarking upon adoption of the proposed staff methodology. Cities Reply Brief on rate design at 2. The Cities argue that the staff's proposal indicates that it would result in obvious inequities for certain customer groups without any gain for ratepayers as a whole. The Cities argued that the staff's belated effort at an impact study came after it had filed its testimony and was so often amended that no one could discern what the staff's proposal would produce in the way of actual rates. Cities Reply Brief on rate design at 2. In addition, the Cities charged that the staff also ignored the efforts of others. Transcript at 6661; Cities Reply Brief on rate design at 2-3. The Cities also expressed concern regarding the additional risk to the utility resulting from adoption of the staff's position. The Cities argue that the staff recommendations cause considerably greater volatility in the company's revenues and, since the company is not guaranteed a recovery of its allowed return and must assume certain risks inherent in its operations and only being entitled to a reasonable opportunity to earn its allowed return, it is inappropriate to <u>create</u> risk rather than shifting risk unless a clearly defined benefit has been demonstrated. Cities Reply Brief on rate design at 3. Thus, the Cities conclude, the uncertainty in effect and volatility of revenues inherent in the staff's case produces added risk with no demonstration of overall benefit to the company's ratepayers as a whole. Finally, the Cities contend that while marginal considerations may be valid in making certain marketing or production decisions, they do not serve well in the allocation of costs among customers who must be served by a utility because the judgments involved are so subjective that they amount to no standard at all. Cities Reply Brief on rate design at 4. The Cities conclude that as a result, such a proposal puts ratepayers at the mercy of an individual's economic and personal whims.

Although Nucor Steel did present rate design proposals, it did not propose or advocate implementation of any particular demand allocation methodologies in this proceeding. Nucor Steel's witness Dr. Wilson indicated during cross-examination his agreement with the theoretical principles underlying the methodology proposed by Mr. Kepner (Transcript at 5316-5317), but also noted that Mr. Kepner's implementation of these principles was incomplete. First, Dr. Wilson noted that Mr. Kepner "did not precisely take those figures-- the marginal costs of energy and capacity on the TUEC system-- and go to a rate design that was reflective of the economic costs that he identified." Transcript at 5317. Dr. Wilson also testified that his problems with "what Dr. Kepner did are in the linkage between the definition of costs and his determination of rates." Transcript at 5318. Finally, Dr. Wilson pointed out that "work needs to be done in going from the cost definitions in Mr. Kepner's analysis to the ultimate rate structure." Transcript at 5318. Nucor Steel also points out that on cross-examination Mr. Kepner acknowledged that he had not fully developed his concepts and carried them through in the development of rates. Transcript at 6636; Nucor Steel Brief on rate design at 33-34. Because of the numerous problems Nucor Steel identifies in implementation and application of Mr. Kepner's proposal, Nucor Steel did not recommend adoption of the staff's proposal in this case, but instead agreed that the company's modified average and excess demand methodology should be used. Nucor argues that because this methodology has been approved in five previous TESCO cases, it is more prudent to rely upon such an accepted allocation methodology which has the benefit of stability and certainty of result when faced with choosing among numerous other alternatives which are untested and could lead to uncertain results. Nucor Steel Brief on rate design at 36.

The Coops also noted their opposition to the staff proposal in their brief on rate design at 12.

Tex-La also opposed the staff's cost allocation methodology, again arguing that it is flawed, unrealistic and biased. Tex-La Brief on rate design at 48-53.

In response to the criticism that TUEC witness Johnston had for the staff's proposed methodology, the staff argues that because Mr. Johnston did not work through the capital substitution model (Transcript at 4551-4564), he does not really understand the principles behind the method and therefore his criticism is without foundation. General Counsel Brief on rate design at 10. General Counsel argues that it is a misconception to infer that the staff's method is a recommendation that TUEC should construct combustion turbines. General Counsel contends that the combustion turbine was used as an analytical tool (Transcript at 6577, 6872-6874), as an upper bound in the staff's methodology for classfying the extra costs associated with lignite plants to the energy savings realized by such a choice. General Counsel Brief on rate design at 10-11.

In response to the allegation that the staff's methodology would place an undue cost burden on high load factor customers, the General Counsel argues that load factor is not an input into the cost allocation process because it is not a costing mechanism. Transcript at 5345-5346, 6394; General Counsel Brief on rate design at 11. In General Counsel's view, load factor is improperly considered as a target or objective; it should be simply a reflection of the decisions made by TUEC customers. Transcript at 6467. In addition, General Counsel asserts that there is no unfair shifting of any costs; its methodology simply assigns the costs where they properly belong. According to the staff proposal, the capital substitution methodology corrects problems inherent with other methodologies proposed in this case which burden low load factor customers. Transcript at 6213, 6236-6237, 6838; General Counsel Brief on rate design at 11. The General Counsel argues that the staff's cost allocation methodology apprises all customers, including high load factor customers, of the costs incurred by the company in relation to their individual usage. Thus, the high load factor customer makes an informed choice regarding the amount and timing of his consumption. Transcript at 6314-6315, 6838. General Counsel agrees that, like the methodology proposed by OPC, the staff's methodology does indeed assign a larger portion to energy costs to high load factor customers, but that these customers also are assigned a comparatively lower per kw cost. Transcript at 6905; General Counsel Brief on rate design at 12. As examples, General Counsel points out that the high voltage customers, the customer class with the highest load factor, in the staff's proposal has the lowest total kwh charge, and the class with the lowest load factor, municipal service, correspondingly has the highest kwh charge. Staff Exhibit 41; General Counsel Brief on rate design at 12.

In response to the double-dip argument, the General Counsel argues that a method which classifies part of the capacity costs first on the basis of energy and then on the basis of demand and which subsequently allocates the demand based on the customer class contribution to system peak and allocates the energy based on the customer class energy consumption is merely recapturing the costs incurred. Transcript at 5185-5186; General Counsel Brief on rate design at 13-14. General Counsel argues that what the critics of the staff methodology fail to recognize is that both energy and capacity are needed to meet system load, that two costs are being incurred and both need to be compensated. Transcript at 5351-5354. According to the General Counsel's argument, the system peak is not consuming energy, it is only responsible for the additional capacity costs associated with peak demand. General Counsel Brief on rate design at 14. General Counsel also asserts that the critics of the staff's proposal fail to understand that the classification of a portion of the capacity costs as energy does not mean that all of the costs of the units that provide service at the time of system peak have been recovered through this allocation of energy costs. Transcript at 6483; General Counsel Brief on rate design at 14. General Counsel used a diagram (Transcript at 6486-6487A), to illustrate what it alleges to be the fallacy of the double-dip argument:

	50 C	
50 E	50 C 50 E	50 E

In this diagram, $200 equals base load unit, $50 equals peaking unit, E equals energy classification, and C equals capacity classification. The entire $200 of the base load unit is not classified as energy, only the difference between the base load unit and the peaking unit, $150. The additional $150 in capacity costs was expended for fuel savings. The $150 of capacity costs classified as energy is thus distributed proportionately to the three time periods. The cost of meeting the system's peak load would require two combustion turbines, one placed in the two blocks needed to meet the system peak demand. The recovery of the capacity cost is on the basis of the class contribution to demand. Transcript at 6487-6487A. In the bottom three blocks of time period, the base load unit was allocated a total cost of $200, although not totally allocated on a demand basis but partially on the energy basis due to the fuel savings. The peaking unit's capacity cost is $50; this figure is reflected as the top portion of the diagram. General Counsel asserts that it would be illogical to allocate the $100 as capacity costs for the peaking unit when this unit only costs $50. To put the $100 at the top block for the peaking unit is simply illogical in the General Counsel's view, and stems from a fundamental misconception of the staff's methodology. General Counsel Brief on rate design at 14-15.

Those who criticized the staff's methdology on the basis that since more capacity costs are assigned to certain classes, they should also receive lower fuel costs (TIEC Exhibit 2 at 19), fail to recognize that they are confusing the classification process with the allocation process in the capital substitution model, according to the General Counsel. General Counsel Brief on rate design at 15. This misconception occurs when capital substitution is viewed as allocating above-average capacity costs. Because of the energy classification of capacity costs there is less demand to allocate to the customer classes' coincident to the peak, argues the General Counsel. Under the capital substitution model, the actual energy charges of this classified energy category is allocated on the basis of the classes' kwh sales; thus, the General Counsel urges that the staff's method does not overcharge capacity costs. General Counsel Brief on rate design at 16. In addition, the General Counsel argues that the mere allocation of more energy costs, due to the fact that fuel savings cause the additional investment, does not logically lead to the assertion that the affected parties deserve lower fuel costs. General Counsel Brief on rate design at 16. The fuel cost is derived from a mix of plant. Transcript at 5142, 5158: General Counsel points out that company witness Tanner agreed that charging customers the blended cost of fuel is appropriate. Transcript at 3956. According to the General Counsel, the customer already benefits from his usage since he receives charges for his consumption based upon the blended fuel mix, and consequently an average cost for fuel; merely because the customer uses more energy does not mean that customer should receive a discount for his consumption. General Counsel urges that the staff's method does not allocate more capacity costs to one class of customers than another since the customers usage determines his kwh charge. General Counsel Brief on rate design at 16.

E. Recommendation

The proper cost allocation methodology to be used for the combined TUEC system was one of the most hotly contested issues in this docket. While not all the parties were in total agreement with the modified average and excess methodology proposed by TUEC, several parties (SWESCO, TNP, City of Bowie, the Cities, TRA, Nucor Steel, and Tex-La) advocated use of the average and excess methodology in this case because it has been approved by the Commission in prior TESCO cases and because it would result in a reasonably predictable and stable assignment of costs to the customer classes. Most of those same parties also sharply criticized the methodologies put forth by OPC and the Commission staff because of their alleged radical shifting of costs among customer classes, and the perceived revenue instability from recovering a greater portion of the revenue requirement on the basis of kwh sales.

Company witness Tanner testified that the company's reserve capacity is declining (TUEC Exhibit 1B, Tanner at 13), and at present, the company's capacity expansion is for the purpose of meeting peak load growth. Transcript at 3946, 4509-4510. While it may have been true that in the past capacity expansion was guided by a desire to utilize cheaper, more reliable sources of fuel, the evidence in this case supports the company's contention that capacity expansion is now for the purpose of meeting increased load. The proposals of the General Counsel and OPC purport to reflect the system planning process and cost causation; however, the fact that the company chooses to construct a lignite plant instead of a gas-fired plant in order to realize fuel savings cannot be the only element of the system planning process on which a cost allocation methodology focuses. Clearly, the decision to expand capacity is based, at least in part, on the necessity of meeting system peak load. Thereafter, the decision regarding what type of plant to construct must take into account all relevant factors, including capital costs and fuel costs.

While it is clear that the use of a combustion turbine as an analytical tool in the methodologies of OPC and the staff do not imply that TUEC could or should construct gas-fired units, it is equally clear from the evidence in this record that these analytical tools rest on too narrow a premise regarding capacity expansion and thus cannot stand. By classifying a greater portion of capacity costs as energy, thus reducing the demand allocated to the customer classes coincident to peak, there is a significant risk of revenue instability and a greater likelihood that customers will receive an incorrect price signal. By lowering the demand charge and increasing the kilowatt hour charge it is likely that there will be an increase in peak demand and a requirement that additional generation capacity be constructed, with a corresponding decrease in kilowatt hour sales, producing a lower system load factor. It is apparent that the OPC and staff methodologies do not address adequately the problem that the cost of generating capacity on the TUEC system does not fluctuate with energy.

Although not without flaws, the company's proposed average and excess allocation methodology has the virtue of consistency, which is particularly important in this consolidation case, and the company's cost of service study shows that under such a methodology, all customer classes are essentially at unity. It is therefore recommended that the company's proposed average and excess allocation methodology should be adopted in this case.

X. Customer Classes
A. Divisional Rates

1. TUEC Proposal

In this docket, TUEC has proposed the setting of rates which will apply systemwide, regardless of which division of TUEC serves a particular customer. TUEC asserts that this is in compliance with the Commission's final Order in Docket No. 4713. Systemwide fuel charges were established for TUEC in Docket No. 5294, and the company views the consolidation of non-fuel base rates as the final step in consolidating all of the company's rates.

2. Army Proposal

Through the testimony of Dan L. Neidlinger the Department of Army proposed that the rates of TUEC not be combined without the benefit of current load research information on the combined utility, information which, according to Mr. Neidlinger, will not be available until mid- 1985. Army Exhibit 1 at 3-4. He further testified that any increase in the revenue requirement ordered by the Commission should be spread on an across-the-board basis to all current rate schedules. Army Exhibit 1 at 4. TUEC challenged Mr. Neidlinger's proposal by noting that Fort Hood is a TP&L customer (Transcript at 4685), and since TP&L has not received a rate increase as recently as the other two divisions (Staff Exhibit 36 at 7, Trancript at 4685), it is understandable but not justifiable that the Army would seek to distribute any increase in revenue requirement proportionately to each division.

3. City of Irving Proposal

In its brief on rate design, the City of Irving asserts that because the customers of the TP&L division will receive a greater percentage rate increase under the proposed consolidation of rates, the resulting rate structure is discriminatory. In support of this argument, the City of Irving asserts that TP&L is more efficient and cost effective in serving its customers than either DP&L or TESCO because it has tied up substantially less of the customers' money in its plant investment which is not used or useful than do either DP&L or TESCO. The City of Irving argues that TP&L customers should not now be required to pay for the inefficiencies of the DP&L and TESCO systems. Moreover, the City of Irving argues that a uniform rate will eliminate any incentive for TP&L, DP&L, and TESCO to operate efficiently. TUEC argues that the material contained in the City of Irving Brief on rate design is not part of the record, and therefore can not be considered in determining whether rates should be consolidated for all TUEC divisions.

4. Tex-La Proposal

Like the City of Irving, Tex-La argues that it is inappropriate to consolidate the rates for the three operating divisions without the load research information needed to properly analyze the group of customer classes and to develop a proper cost of service study. Because that data is not available in this proceeding, Tex-La argues that it is difficult if not impossible for the Commission to determine whether TUEC's proposed customer classes are reasonable and whether the cost of service study is appropriate. Tex-La proposes to postpone consolidation of rates until the next TUEC rate case, when the needed data will be available. Tex-La also supports the approach recommended by Mr. Neidlinger in proportionally allocating any revenue increase or decrease to existing customer classes. Tex-La asserts that to do otherwise results in misallocation which could increase costs to customers who in fact should have received a rate reduction. TUEC argues that its noncoincident peak data are amply sufficient for analyzing the grouping of customer classes and developing a proper cost of service study. TUEC also notes that in Docket No. 5294, Tex-La unsuccessfully argued that the Commission should postpone consolidation of fuel charges since the company's operating divisions would retain separate non-fuel base rates until TUEC's first consolidated rate case.

5. Recommendation

TUEC has adequately supported its proposed consolidation of rates which will apply systemwide. Such a proposal is consonant with the consolidation of fuel charges in Docket No. 5294, and with the mandate of Docket No. 4713, and with the recommendation regarding the wholesale class in the following section.

B. Single Wholesale Class

1. TUEC, TNP and City of Bowie Proposals

As part of its tariffs filed in this case, TUEC proposed that all wholesale customers be included within a single rate class, a position also urged by the City of Bowie and TNP. Therefore, these proposals will be discussed together herein. These parties assert that the clear evidence in this record demonstrates that all wholesale customers of TUEC have homogeneous load and usage characteristics, which not only justify but compel their being included in a single rate class.

In Docket No. 3250, a TESCO rate case, TESCO and the Coops entered into a stipulation which treated the Coops as a separate rate class. The final Order in that docket conformed to the stipulation, creating a separate rate class for the Coops. In the subsequent TESCO rate case, Docket No. 5200, the examiner recommended that a single wholesale class be created. The Commission did not accept that recommendation, but did state that the consolidation of the wholesale classes should be considered in the first filing made by TUEC, when the classing of all TUEC wholesale customers could be taken up in one proceeding.

City of Bowie witness Larry Gawlik presented a detailed analysis of the 268 wholesale delivery points on the TUEC system, without regard to customer ownership of these various points of delivery. Mr. Gawlik proceded from an intitial determination of appropriate considerations for developing wholesale classes. Mr. Gawlik states that a customer class of service should consist of those customers who, one, have similar demand and energy requirements, that is load and usage patterns; two, require similar electric facilities from the supplying utility; three, are served within a predefined range of voltage levels, that is transmission and primary; and four, have similar uses of electricity. These same criteria were supported by TUEC witness Johnston. Transcript at 4438. In addition, TNP witness Larry Laux testified that load characteristics are a key criterion in developing a rate class. TNP Exhibit 3 at 5.

The analysis presented by Bowie witness Gawlik presented a range of load factors unrelated to the entity which may pay the bill at each point of delivery. Transcript at 4437. In Exhibit 1 to Mr. Gawlik's testimony he notes that the annual load factors of the customers in the combined resale class range from as low as 22.64 percent to as high as 81.33 percent, and that investor owned utilities, electric cooperatives and cities fell at various points between the high and low load factors. Of the 268 points of delivery in the proposed consolidated class, 65 percent fell in a narrow range with load factors between 30 percent and 45 percent. Approximately 88 percent of the points of delivery of the proposed consolidated class fell between load factors of 30 percent and 60 percent. Bowie Exhibit 3 at 7.

TUEC argues that the exhibit demonstrates that the variance among the point of delivery load factors as a whole is not more significant than the variations among the load factors for each of the cooperative points of delivery. City of Bowie Exhibit 3 at 9. TUEC concludes that such variances that may exist among the point of delivery load factors are not characterized by their identity with any particular party which may pay for the service rendered at such points of delivery. TUEC points out that Gawlik Exhibit 1 shows that the TESCO Coop points of delivery exhibit greater load factor dispersion than those of the other wholesale customers. Bowie Exhibit 3 at 10.

Exhibit 2 of Mr. Gawlik's testimony demonstrates that the most similar customers in his load factor analysis are the subclasses of the TP&L-REA class and the TESCO W-1 class; he concludes from that analysis that based upon load factors there was no data available to warrant continued separation of the resale customer based upon usage characteristics, much less on the basis of the type of utility which is purchasing resale power and energy. Bowie Exhibit 3 at 9.

Mr. Gawlik also did an analysis of the contribution to peak of the existing classes, contained in Exhibit 3 to his testimony. He concludes that there is little difference existing among the present individual resale classes from the standpoint of contribution to peak to warrant continued separation of resale classes. Bowie Exhibit 3 at 11.

Finally, Mr. Gawlik presented his analysis of the load factors for the HV-6 class for 1982, contained in his Exhibit 4. The analysis demonstrates annual load factors for the HV-6 class varying from a low of 41.65 percent to a high of 91.10 percent and pointed out that TUEC had also proposed one rate for the general service class despite the wide variations in load characteristics for that class as well. TNP witness Laux also referred to the proposed rate class G as an example of a situation where the load characteristics of the members of the class differ in larger measure than do the load characteristics for the members of the proposed wholesale class. TNP Exhibit 3 at 11.

TNP witness Laux also testified that the coincidence factors of each point of delivery of all wholesale customers fall within the narrow band of 75 to 100 percent for the peak months, the time during which most costs are imposed upon the TUEC system. The range narrows to 87 percent in June, 91 percent in July, 95 percent in August and 90 percent in September. TNP Exhibit 3 at 9, Exhibit LJL-5. The exhibit further shows that all types of wholesale customers are represented as contributing to the total wholesale class contribution to peak.

TNP also argues that Mr. Laux's testimony showed that 86 percent, or 230 of the 268 total points of delivery of the proposed wholesale class, have a load factor within 20 points of each other, that is, within the range of 30 percent to 50 percent. TNP Exhibit 3 at 10. In addition, a study of 71 percent or 190 points of delivery, of the proposed wholesale class indicated that the power factors fell within a range of 85 percent to 100 percent, which TNP considers an extremely narrow band. TNP Exhibit 3 at 11, Exhibit LJL-15.

TUEC refers to Mr. Laux's testimony as demonstrating that none of the wholesale class members "have distinct coincidence factors sufficient to merit separation into" distinct rate classes. TNP Exhibit 3 at 10. TUEC Brief on rate design at 28. TUEC further cites the testimony of Coop witness Stover where he agreed that "usage and load characteristics are what describes the customer to the electric system" (Transcript at 4923), and that customer groupings for the purpose of rate design should "reflect homogeneous usage and cost characterization-cost causation characteristics." Transcript at 4924. TUEC argues that the Coops' opposition to a single resale class is based upon considerations other than the objective load and usage characteristics demonstrated by the wholesale delivery points, instead focusing on characteristics relevant only to the Coops' operations beyond the company's point of delivery. TUEC Brief on rate design at 28. Conceding that the manner in which Coops treat wholesale power costs in designing their own rates and the manner in which Coops designed their own distribution systems may distinguish the Coops from other wholesale customers of TUEC, TUEC argues that those considerations are not relevant to the determination of the costs imposed upon TUEC's system by the wholesale points of delivery. TUEC Brief on rate design at 2829.

2. The Coops Position

The Coops oppose the consolidation of the wholesale classes of the three TUEC operating divisions, and urge the continuation of a separate class of rural systems in the consolidated TUEC tariff. The Coops took no position regarding whether urban systems whould be placed on a single rate, as is the case with the present TP&L WP-500 rate classification, or into two classifications, as is the case with the present TESCO W-2 and W-3 classifications. Arguing that the Commission's task in this case is to consolidate the wholesale sections of TP&L and TESCO (DP&L has no wholesale customers) into a single wholesale section of the TUEC tariff, the Coops further argued that this objective is not justification for ceasing to recognize distinctions which exist and are recognized systemwide. Coops' Brief on rate design at 3.

Through the testimony of its witness Carl N. Stover, Jr., the Coops set forth their reasons for opposing the consolidation of the wholesale customer class. Coop Exhibit 25 at 9-20. Mr. Stover distinguishes consolidation of rates, which the Coops do not oppose, and consolidation of customer classes, which the Coops do oppose. According to Mr. Stover's interpretation of various proceedings before the Commission involving the consolidation of the TUEC operating divisions, the Commission has ordered a consolidation of rates, which would mean that customers in a class should pay the same rates systemwide. Coop Exhibit 25 at 9. Mr. Stover considers this a completely different issue from the company's proposal in this docket to consolidate all wholesale customers into a single class. Coop Exhibit 25 at 9-10. At the present time, the wholesale rates of the TUEC operating divisions include the following classifications:

Cooperative Class
(1) TESCO W1/WLH - TESCO service to Cooperatives at primary and transmission level voltage.
(2) TP&L REA/REAT - TP&L service to Cooperatives at primary and transmission level voltage.

Investor-Owned Only
(1) TESCO W2/W2H - TESCO service to TNP at primary and transmission level voltage.

Cities Only
TESCO W3 - TESCO service to the cities of Bowie and Goldsmith at primary level voltage.

Investor-Owned and Cities
(1) TP&L WP5/WP5T - TP&L service to SWESCO, TNP and the city of Bridgeport at primary and transmission level voltage.

(Note: T and H both refer to high voltage of transmission level service.)

Coop Exhibit 25 at 10.

Mr. Stover noted that only the Cooperatives are served under rates applicable solely to the Cooperatives as a part of rate schedules TESCO W-1 and TP&L REA. The Cooperatives believe that the existing three rate classifications should be maintained and that the rates within the class should be consolidated on a company wide basis. Coop Exhibit 25 at 10. The Coops acknowledge one problem in implementing this option which is the fact that the City of Bridgeport is served under a rate applicable to the investor owned class. Coop Exhibit 25 at 10-11. The Coops therefore proposed two classification options which do not reflect a position but simply a convienent approach, given the limitation of data available to separate the Cities from the investor owned utilities. Coop Exhibit 25 at 11. Option one: Three separate classes, one each for the Cooperatives, the Cities and TNP/SWESCO; option two: two classes, Cooperatives and one for the one for TNP/SWESCO/Cities.

Mr. Stover considered it essential that a clear definition of "customer" be established. Coop Exhibit 25 at 11. Mr. Stover considers the distinction crucial because in his opinion it bears directly on the question of the applicability of any proposed rate schedule. As an example, Mr. Stover referred to the City of Bowie, which takes delivery at one point. He considers the customer to be the City of Bowie and the usage characteristics are those for the single point of delivery. If Bowie should require a second point of delivery, however, then Mr. Stover argues that the customer is still the City of Bowie, and the usage characteristics are the combined characteristics of the two points of delivery. Coop Exhibit 25 at 11. Mr. Stover testified that the usage characteristics associated with each individual point of delivery may change depending upon how the City of Bowie may choose to serve the load within the city; however, the combined load characteristics do not change. Coop Exhibit 25 at 12.

By analogy, Mr. Stover voiced his opinion that the individual cooperative is the customer of TUEC. Cap Rock, for example, takes delivery at five different transmission points and fourteen different distribution points. Although the number of delivery points for Cap Rock will likely change in the future, the changes are a function of the power supply planning activities performed by Cap Rock. Such planning affects the number of delivery points and the voltage level of the delivery points, but it does not necessarily change the total capacity and energy requirements imposed by Cap Rock on TUEC's system. Coop Exhibit 25 at 12. Mr. Stover points out that the manner in which wholesale power costs are recovered should be a consideration in establishing rate classes. He states that Cap Rock will establish retail rates based upon the total cost for the entire system. The important point to Mr. Stover is that the customer is not the individual delivery point, but rather the entity performing the power supply function, and the entity responsible for recovering the wholesale power cost from the retail customer. Coop Exhibit 25 at 12-13.

Mr. Stover also refers to prior rate cases for separate operating divisions of TUEC; in Docket No. 3250, he points out, TESCO agreed as a part of a settlement to maintain separate wholesale rates for the different wholesale classifications. Mr. Stover also referred to Docket No. 5200, where the Commission reversed the examiner's recommendation that the wholesale rate classes be combined. Coop Exhibit 25 at 14.

Mr. Stover also suggests that serving all wholesale customers under a single rate creates a mismatch in the revenues and the cost of service. In his Schedule A-1.0, a summary showing the base rate increases proposed by TUEC, the comparison Mr. Stover makes shows that the Cooperatives are receiving an increase in base rates of approximately 20.8 percent while the cities are experiencing a decrease of 0.76 percent. Mr. Stover argues that because the existing rates as approved by the

Commission track costs, one would expect a reasonably uniform increase in base rate requirements. Coop Exhibit 25 at 14. Mr. Stover also compares the relationship of the overall increase for the Cooperatives versus the other wholesale customers. Under the proposed rates, the average increase for the Cooperatives is 20.8 percent, while that for the other wholesale customers is 11.8 percent. It is Mr. Stover's opinion that because existing rates are cost based, it is difficult to understand why the rate increase for the Cooperatives is almost double that for other wholesale customers. Coop Exhibit 25 at 15.

Finally, Mr. Stover points out that combining all wholesale customers into a single class and billing the customers under a single rate causes a mismatch in revenues and expenses. Based on testimony given by Mr. Michael Moore for the Cooperatives, and using the company's demand allocation methodology, Mr. Stover stated that the Cooperatives would provide revenues approximately $249,000 greater than the cost of service for the Cooperatives. Coop Exhibit 25 at 15. Mr. Stover cites as further evidence of the mismatch between cost and revenues the comparison on his Schedule C-1.0. This schedule demonstrates that the Cooperatives have responsibility for 52 percent of the demand allocated to the entire wholesale class using the company's demand allocation methodology. Mr. Stover points out that the demand component of the proposed rates recovers 55.9 percent of the demand revenue from the Cooperatives. His primary concern is the effect a particular rate design can have in terms of distributing demand responsibility between customers when a consolidation takes place. Coop Exhibit 25 at 16. Mr. Stover also refers to his Schedule C-3.0 which shows the relationship between on peak and off peak metered demand. Mr. Stover found that 38 percent of the Cooperatives' metered demand requirements occurred during the peak months as opposed to 42 percent for the other wholesale customers. Coop Exhibit 25 at 17. Mr. Stover's Schedule C-4.0 is a demonstration of the ratio of billing demand to metered demand, assuming the company's proposed rate. This comparison shows that the billing demand units for the Cooperatives are approximately 12.3 percent greater than the actual metered demand as compared to a value of 19.1 percent for the other wholesale customers. Coop Exhibit 25 at 17. Apparently the Coops fear that the consolidation of the wholesale customers into one class will result in a higher ratio of billing kw to metered kw for the Coops than they now experience.

In brief, the Coops place a great deal of emphasis on prior decisions of this Commission regarding wholesale rate classifications for the three TUEC operating divisions. The Coops also emphasize that there is a significant distinction in load pattern between urban and rural systems. Coop Exhibit 23. The Coops argued that such differences between urban and rural systems result in unavoidable prejudice if such systems are placed on a single wholesale rate. The Coops argued that if the present REA rate classification is retained, there would be no dispute, each group would pay its own cost of service, and each group would have a rate structure appropriate for that group. The Coops characterize other intervenors' opposition to such an approach as having no basis other than greed. Coop Brief on rate design at 7. The Coops further argued that TNP's efforts have been made with a view to "getting some sugar for themselves in the rate design process at the expense of anyone but the company while at the same time basically supporting the company in its case." Coop Brief at rate design at 9-10. The Coops argue that the City of Bowie now embraces the same idea. The Coops charge that both TNP and the City of Bowie are apparently totally unconcerned about their total cost of power but only about how much of the total they can unload on others. Coop Brief on rate design at 10.

Finally, the Coops argue that under the TUEC proposal, the City of Bowie will have a rate decrease, and TNP will have a slight increase. While the proposed wholesale class as a whole would have a rate increase of approximately 12 percent, the Cooperatives would experience an increase of 20.8 percent, a result the assert urge would not occur if proper classification were maintained. The Coops urge that this proves consolidation is improper, because if it were proper, this result would not occur. Coop Brief on rate design at 11.

3. Positions of Other Parties

Tex-La opposes consolidation of rates and urges that such a consideration should be postponed until the next TUEC rate case when the needed accurate and complete load research data is available. Tex-La Brief on rate design at 3. Staff witness Kepner advocated consolidation of the wholesale classes for reasons other than those advanced by the intervenors. The General Counsel argues in brief that consolidation is proper for three reasons: first, the fuel factor utilized by TUEC is already consolidated; second, any impact arising from consolidated rates will be tempered by the staff's proposed revenue reduction; and third, any differences between the classes can be captured by the staff's proposed time differentiated prices. Staff Exhibit 36 at 7. Coop witness Stover recognized that customers have different needs and peak at different times (Transcript at 4977-4978), and Dr. Wilson, the witness for Nucor Steel, recognized this fact also. Transcript at 5312. The General Counsel urges that in such a case, diurnal and seasonal rates are not only necessary for cost based reasons, but are also necessary in order to capture any differences caused by consolidation of the classes. The General Counsel therefore supports consolidation of the wholesale classes so long as the differences in the usage of those classes can be captured with the seasonal and diurnal rates proposed by the staff.

4. Recommendation

It is clear that a major dispute between TUEC, TNP and the City of Bowie on the one hand, and the Coops on the other is the dispute regarding the definition of the term "customer." The Coops have taken the position that a customer should mean the entity responsible for paying the bill, and not individual points of delivery. While it is true that the Coops must design their own rates in order to recover their power costs, that is not relevant to a determination of the way in which costs are imposed upon the TUEC system by the individual points of delivery. Variances which exist among point of delivery load factors are not related to or characterized by the entity paying for the service rendered at such points of delivery. The proper basis for establishing rate classifications is the degree to which usage and load characteristics reflect homogeneity and not whether the wholesale customer is a cooperative, an investor owned utility or a city. The credible evidence in this case supports the positions urged by TUEC, TNP and the City of Bowie that it is appropriate to establish a single wholesale class for the TUEC system and it is so recommended.

In addition, the testimony of Coop witness Moore showed that the company's proposed recovery of costs from Coop customers was within .23 percent of its cost of service. Coop Exhibit 24 at 8. This is a deviation of only $249,000 from a total base rate revenue requirement as proposed by the company of $106,919,000. Coop Exhibit 24 at 5. As pointed out in brief by TNP, a disagreement of this magnitude , considering the amount of dollars being allocated, is really no disagreement at all. TNP Brief on rate design at 6. Indeed, the company's proposal demonstrates an extremely high degree of accuracy. Even Coop witness Stover admitted that all classes which consist of more than one customer will involve some degree of "subsidization" and some degree of discrimination. Transcript at 4958. TUEC witness Johnston also agreed that any class grouping necessarily involves an imperfect allocation of costs at best (Transcript at 4438), but that a class rate is specifically designed to recognize that some class members will not possess exactly the same chaacteristics and cost incurrence patterns as all other class members. Coop witness Stover admitted that looking at the dollar effect of combining the resale classes is putting the cart before the horse; "it doesn't seem to me that the question of consolidation hinges on final rate design." Transcript at 5058.

The fact that the Coop rates are going up a greater percent than the rates of other members of the class is not necessarily reflective of any improper consolidation. While the rates set in Docket No. 5200 may in fact have been designed to track costs, that does not mean that rates determined in this proceeding are not equally cost based because the rate design results in shifting a relatively small amount of costs among common class members as compared to a prior rate order or because the rates for one group will rise a greater percentage than those for other groups. The proposal of the company to consolidate the wholesale rate classes of its three operating divisions into a single wholesale class should be adopted.

XI. Allocation of Costs Among Customer Classes
A. CWIP Credit to Tex-La

1. Tex-La Proposal

Tex-La's position is that if TUEC is awarded any construction work in progress (CWIP) in its rate base, then the primary issue in the rate design and the cost allocation phase of this docket for Tex-La is the retention of the CWIP credit for Tex-La that is currently in TP&L's rate schedule. Tex-La advances two reasons for this proposal: first, the CWIP credit corrects a misallocation of costs which occurs if CWIP is included in rate base, and second, even if no revenue increase is granted to TUEC, and if CWIP is left in the TUEC rate base and the CWIP credit is eliminated, Tex-La will nevertheless receive a rate increase.

Tex-La is a generating cooperative, whose members are distribution cooperatives. In 1980, Tex-La purchased a 2 1/6 percent interest (50 megawatts) in the Comanche Peak project. Transcript at 3892-3893. At the end of TUEC's test year in this docket, Tex-La had an investment of $67,493,000 in the direct costs, plus an additional amount of interest for constructing the two units. Tex-La Exhibit 19 at 8. Tex-La argues that without its investment, TUEC's invested capital would have been at least that much higher, and in fact greater, since TUEC's financing costs would have to be included. Tex-La Exhibit 19 at 8. In an agreed settlement in the previous TP&L rate case, Docket No. 4321, the rate design included a credit of $1.048 per kilowatt of billing demand applicable to all delivery points of the member cooperatives of Tex-La. The CWIP credit was to be discontinued when Comanche Peak Unit No. 1 is placed in service, or in the event Tex-La terminates its 2 1/6 percent ownership interest, or upon further order of the Commission. The Examiner's Report in that docket was accepted by the Commission, which found that the CWIP credit was an issue of first impression in Texas. Because the case was settled, the issue was not fully developed and the examiner recommended that the approval be given no precedential weight. Tex-La believes however that the weight of the evidence in this docket demonstrates conclusively the validity of the requirement for the credit and its equity. Tex-La Brief on rate design at 5-6.

Tex-La points out that there is a need for the CWIP credit only if TUEC is granted CWIP in rate base. Transcript at 4839; Tex-La Brief on rate design at 6. Tex-La argues that this credit is necessary to avoid a double payment by Tex-La for Comanche Peak. Transcript at 4839; Tex-La Brief on rate design at 6. If CWIP is retained in TUEC's rate base and the CWIP credit is eliminated, as TUEC has proposed, Tex-La argues that its rates will increase. Tex-La further argues that the company has presented no justification for the elimination of the CWIP credit and thus the company has not met its burden of proof, mandating that the CWIP credit must remain. Tex-La Brief on rate design at 7.

Tex-La further argues that the CWIP credit is simply a rate design methodology for correcting an incorrect allocation of costs to Tex-La which are the responsibility of other customers of TUEC. Transcript at 4766, Tex-La Exhibit 19 at 13. Tex-La argues that each customer pays for a pro rata share of each plant on the TUEC system. Cost allocation methodologies assign the same pro rata share of this cost of every plant to each customer. Since TUEC's cost allocation to Tex-La is roughly 0.9 percent, had Tex-La not purchased a share of Comanche Peak, Tex-La would be expected to pay for 0.9 percent of TUEC's share of that plant. Tex-La concludes that TUEC has allocated to Tex-La about 0.9 percent of the financing costs included in the revenue requirement resulting from the company's proposed inclusion of CWIP in rate base. Tex-La Brief on rate design at 8. Tex-La points out that it already has its own share of CWIP associated with Comanche Peak. Tex-La asserts that it is paying the financing costs on 2.4 percent of the total CWIP of the portion of Comanche Peak that will serve TUEC's system load. Tex-La Brief on rate design at 9. In this description, TUEC's system load is defined as including the Tex-La load in which Tex-La will serve from its share of Comanche Peak. Tex-La argues that since it is already financing more of Comanche Peak than its load ratio share (that is, cost allocation pro rata share), the financing costs on the CWIP related to TUEC's share of Comanche Peak are the responsibility of TUEC's other customers. Transcript at 4758-4759, Tex-La Brief on rate design at 9. Tex-La argues that TUEC's proposed cost allocation methodology has nevertheless incorrectly assigned Comanche Peak CWIP to Tex-La. Therefore, in Tex-La's view, the CWIP credit simply corrects for the assignment to Tex-La of costs that are the responsibility of TUEC's other customers. Tex-La asserts that TUEC's other customers are responsible for financing TUEC's share of Comanche because Tex-La is financing the CWIP related to its portion of Comanche Peak that will serve Tex-La's load.

Tex-La concludes that it is entitled to the CWIP credit and that it will not produce significant effects for the other customer classes. Using the staff's recommended CWIP level and using test year kwh sales proposed by TUEC for customers other than Tex-La, the CWIP credit of $2,538,000 to Tex-La would result in about 0.004¢ per kilowatt hour to TUEC's other customers. Tex-La Brief on rate design at 9. Tex-La argues that this is an insignificant amount on an individual customer basis. Tex-La Exhibit 19 at 15. This results in a cost of approximately 4¢ per month for a residential customer using 1,000 kilowatt hours per month. Transcript at 4847.

Tex-La also argues that other customers of TUEC benefit from Tex-La having purchased and financed a portion of Comanche Peak. Tex-La witness Mr. Solomon used TUEC's proposed cost of service, including Comanche Peak CWIP in rate base, to demonstrate that if Tex-La had not purchased a share of Comanche Peak, TUEC's proposed revenue requirement would have been approximately $14.4 million higher. Tex-La Exhibit 19 at 9-11; Tex-Brief on rate design at 10. The reason for this is that TUEC's CWIP rate base amount would have been higher by the $67.4 million that Tex-La has paid toward the direct construction cost of Comanche Peak. Since Tex-La would be allocated about 0.9 percent of the $14.4 million, TUEC's other customers would have rates higher by about $13 million if Tex-La had not purchased and financed a portion of Comanche Peak. Tex-La Exhibit 19 at 9-11; Tex-La Brief on rate design at 10. Tex-La concludes that TUEC's other customers are saving approximately .0205¢ per kilowatt hour after funding Tex-La's credit. Tex-La Brief on rate design at 10.

Tex-La also argues that the $2.5 million CWIP credit to Tex-La which would be allocated back to TUEC's other customers is only a fraction of the $13 million Tex-La is saving TUEC's other customers by virtue of Tex-La having purchased an interest in Comanche Peak. Furthermore, Tex-La argues that the CWIP credit reduces TUEC's capital construction requirements which would have had to be financed through a combination of internally generated funds and equity and debt offerings. Tex-La Exhibit 20 at 8. Tex-La concludes that it has reduced the investment risk for Texas Utilities. Tex-La Exhibit 20 at 8; Tex-La Brief on rate design at 11.

Tex-La finds an additional benefit to TUEC's other customers in the early years of the operation of Comanche Peak. In the initial years of operation, TUEC will utilize Tex-La's excess capacity in Comanche Peak for the TUEC system as Tex-La phases in its ownership interest to meet its load growth. Tex-La Exhibit 20 at 1. According to Tex-La, this will allow both TUEC and Tex-La to split the savings to benefit both groups of customers, an amount which Tex-La estimates at $11 million for the customers of TUEC. Transcript at 47814782; Tex-La Brief on rate design at 12.

Tex-La also argues that not allowing a CWIP credit to Tex-La is anticompetitive. Tex-La argues that it as well as other TUEC customers are prepaying demand costs they otherwise would only have to pay in the future if CWIP were not allowed in rate base but instead Allowance for Funds Used During Construction (AFUDC) were added to plant. Tex-La views this as TUEC obtaining a loan which it will repay to customers over the life of the plant. Tex-La Exhibit 20 at 10; Tex-La Brief on rate design at 12. Tex-La reasons that because it will not receive any power or energy from the TUEC share of Comanche Peak, Tex-La will never have its loan repaid. Tex-La Exhibit 20 at 11.

Tex-La asserts that as it continues to purchase shares in TUEC's plants, TUEC's demand cost allocator to Tex-La will decline. It cites as an example the instance of Tex-La purchasing capacity sufficient to meet 1/3 of its load, in which event TUEC's Tex-La allocator would decline to about 0.6 percent. In this example, then, Tex-La would have prepaid 0.9 percent of Comanche Peaks's financing costs, but would benefit from only 0.6 percent of the lower plant costs, which were lower because in effect AFUDC was prepaid and not capitalized. Tex-La concludes that it would have overpaid by 50 percent. Tex-La concludes that it is discriminatory and anticompetitive to force Tex-La to prepay for a plant from which it will not be able to benefit from its prepayment. Tex-La Exhibit 19 at 14; Tex-La Brief on rate design at 13. Tex-La concludes that elimination of the CWIP credit will discourage Tex-La from participating in additional plants because it would not only have to pay for its share of the plant but for the shares being used by the other customers. Transcript at 4824-4825. Tex-La views this as a disincentive for Tex-La and other TUEC customers seeking participation in TUEC's future generating units.

Tex-La further argues that it will not benefit from TUEC's portion of Comanche Peak. Tex-La's ownership interest in Comanche Peak is for the purpose of meeting Tex-La's own load growth. Tex-La Exhibit 20 at 1-2. Tex-La reasons that TUEC will not therefore be required to construct generation to meet Tex-La's load growth. Tex-La Exhibit 20 at 2. Tex-La asserts that its future load growth will be met by purchasing interests in new units. Tex-La Exhibit 20 at 2; Tex-La Brief on rate design at 14.

Tex-La also argues that its interpretation of its Comanche Peak contract with TUEC means that in calculating the costs of Tex-La's partial requirement purchases, TUEC will not allocate any costs associated with its ownership interest of Comanche Peak to Tex-La. Tex-La Exhibit 20 at 3. Tex-La argues that Brazos witness Ms. Taylor is in error when she states that a firm purchase of power must come from "the mix of plants that the utility system has at any point in time." Transcript at 5142. Tex-La argues that its agreement with TUEC requires keeping track of Comanche Peak costs for 30 years. While Tex-La agrees that it may only be a paper barrier keeping the remainder of Comanche Peak from being allocated to Tex-La (Transcript at 4779), it is a barrier that cannot be crossed. Tex-La acknowledges that no one knows exactly where any one kilowatt comes from when several plants are interconnected, however, parties by contract routinely agree on how to sell and purchase kilowatts. Tex-La concludes that by contract it will never benefit beyond its ownership interest in Comanche Peak. Tex-La also refers to testimony by Coop witness Stover who stated that "if Tex-La never utilized TUEC's portion of Comanche Peak" then "there should be some reconciliation of these costs that they have paid in for the use of the resource for which they never use." Transcript at 4980. Tex-La argues that there is no need for a reconciliation if the CWIP credit is maintained for Tex-La. Tex-La Brief on rate design at 14-15.

Tex-La argues that in addition to the benefits of Comanche Peak, it also bears the risk of Comanche Peak. Tex-La will pay for its share of Comanche Peak regardless of whether Comanche Peak ever operates commercially. Trancript at 4795. If Comanche Peak does not come on line, Tex-La argues that it will have paid two and a half times its load ratio share. Even with the CWIP credit, Tex-La further asserts, it will be paying for more on a pro rata basis than any other TUEC customer for a plant which is not operational. Transcript at 4796-4797. Tex-La asserts that it is willing to assume the risk for its share, but does not desire to bear the risk for the portion of Comanche Peak it will never use. Tex-La Brief on rate design at 15.

Tex-La analogizes the CWIP credit to a high voltage discount. Tex-La Exhibit 20 at 5. Tex-La argues that since the Commission recognizes the logic of voltage discounts, the Commission should also recognize the validity of CWIP credit.

Tex-La also points out that TUEC had both planned and begun construction of Comanche Peak long before Tex-La became an owner. Tex-La's share of Comanche Peak, while large to the Tex-La system, is relatively small for the TUEC system. Tex-La also argues that when Comanche Peak was planned, Tex-La's load was included in TUEC's plan. Tex-La therefore concludes that as a result, the change of ownership from TUEC to Tex-La has no impact whatsoever on the timing or the amount of capacity TUEC must construct. Transcript at 4791. Tex-La's ownership interests are the capacity and energy that TUEC would have had to construct in order to meet Tex-La's load. Tex-La's Exhibit 20 at 3.

Tex-La generously argues that the CWIP credit methodology is generic and can be applied to any customer. Tex-La would grant the credit to any customer which has a direct load ratio or greater investment in the supplier's construction program where that investment is used to reduce load growth on the supplier and where the rates for the customer's partial requirement purchases for the supplier are calculated without the costs of the capacity or the energy from the plant. Tex-La Exhibit 19 at 16-17. Tex-La points out that under its plan, Brazos Coop would be entitled to the same credit if it were going to do the same thing with its share of Comanche Peak that Tex-La plans to do with it. Transcript at 4767. Because Brazos Coop is not planning to reduce its load on TUEC's system as a result of its Comanche Peak ownership (Transcript at 4768), but instead intends to use its ownership share of Comanche Peak to displace load on its own system, not TUEC's system, Tex-La therefore concludes that Brazos Coop's ownership of Comanche Peak and its use of such ownership is not the same as Tex-La's, and thus Brazos is not entitled to the same CWIP credit. Tex-La Brief on rate design at 17-18.

Nucor Steel supports Tex-La's arguments for a CWIP credit. Nucor Steel Brief on rate design at 30.

2. TUEC Proposal

TUEC has a different view of Tex-La's participation in the Comanche Peak project. Beginning with the second year of commercial operation of Comanche Peak, Tex-La will begin to retain small increments of its capacity. Transcript at 3898, Tex-La Exhibit 20, Schedule 14. Tex-La's retained capacity increases thereafter until in year eleven of commercial operation, Tex-La has retained its entire capacity. Transcript at 3898. Until that time, however, TUEC must buy Tex-La's unretained output from Comanche Peak by virtue of what is, in effect, a purchased power arrangement. Transcript at 3899. TUEC argues that the agreements between

Tex-La and TP&L have never provided for any CWIP credit. Transcript at 3906. TUEC points out that Tex-La will remain a full requirements wholesale customer of TUEC during the entire period the rates which are set in this docket are in effect. Transcript at 3903. Sometime thereafter, Tex-La will be a partial requirements customer of TUEC, continuing to rely on TUEC to supply the shortfall between Tex-La's load requirements and its entitlements from Comanche Peak and to back up Tex-La's own generation in the event of outages. TUEC Brief on rate design at 14.

TUEC argues that as long as Tex-La is any manner relying upon TUEC to supply all or a portion of Tex-La's electric needs, it is just as much in Tex-La's interest that TUEC's financial integrity be maintained as it is in the interest of any other TUEC customer. Because Tex-La will rely on TUEC for electric power and energy during the period the rates set in this docket will be in effect and thereafter, TUEC urges that Tex-La should be given no free ride but should be required to pay the full cost of the electric power and energy purchased from TUEC, just like any other customer, including the part of that full cost attributable to maintaining TUEC's financial integrity through the inclusion of CWIP in rate base. TUEC Brief on rate design at 14-15.

TUEC points out that Tex-La received the CWIP credit as as result of a number of compromises going into the settlement agreement in the last TP&L rate case, Docket No. 4321, in 1982. Transcript at 3912. Neither the Commission nor the parties to the settlement agreement accepted the methodology, precedent or principle of the CWIP credit (Transcript at 3912); therefore Tex-La's urging the continuation of the credit should in no way be construed as implying that Tex-La has ever had the CWIP credit issue adjudicated in its favor, because, TUEC argues, that is emphatically not the case. TUEC Brief on rate design at 15.

TUEC argues that the evidence is overwhelmingly to the contrary of Tex-La's argument that it will never receive the benefit of capacity or energy from Comanche Peak. Tex-La Exhibit 20 at 4. First, TUEC argues that it must meet that portion of Tex-La's load growth that exceeds its retained capacity in Comanche Peak. Transcript at 3894-3895. Tex-La will thus benefit from the 87 5/6 percent of Comanche Peak owned by TUEC. Tex-La's load growth requirements will be far in excess of its generation entitlement from Comanche Peak. Transcript at 3818-3819. Tex-La's needs will therefore be satisfied from TUEC plants other than Tex-La's retained interest in Comanche Peak (Transcript at 4849), and other sources such as Southwest Power Administration (SPA), which would clearly consist of all TUEC plants including Comanche Peak, since customers are served by the entire mix of plants on the utility's system. Transcript at 4778-4779, 5142; TUEC Brief on rate design at 15. TUEC argues that Tex-La's own witness Gordon Taylor recognizes that Tex-La's load growth will not be served solely from its share of Comanche Peak, and that Tex-La will need TUEC's cooperation in purchasing interests in other TUEC plants to meet its load growth. Transcript at 4756, 4793. TUEC characterizes as hypothecation Tex-La's plan to purchase interests in other TUEC plants so as not to add load to the TUEC system. Transcript at 4817-4818; TUEC Brief on rate design at 15. Tex-La is unable to state what it will purchase or when it will make such a purchase. Transcript at 4818-4819. TUEC concludes that Tex-La is only speculating as to what the future may hold and should not be given the benefit of its own self serving, unsubstantiated desires. TUEC asserts that Tex-La is eager to assume that it will purchase such additional capacity, but submits that is equally reasonable to assume that Tex-La will once again reduce its desires for obtaining its own generation. Transcript at 4814-4815; TUEC Brief on rate design at 15-16.

TUEC bases this conclusion on the fact that Tex-La had earlier reduced its retained interest in Comanche Peak from 4 1/3 percent to 2 1/6 percent. Transcript at 4814. TUEC finds this reduction revealing in light of Tex-La's contention that it will meet its future load growth from Comanche Peak. TUEC argues that if and when Tex-La ceases to rely upon TUEC to supply any of its electrical requirements, then and only then will Tex-La have no responsibility for paying rates sufficient to maintain TUEC's financial integrity, because then Tex-La will not be purchasing power from TUEC. Unless and until that happens, TUEC argues, Tex-La should be accorded no different treatment than TUEC's other customers and should be held jointly responsible along with those other customers for maintaining TUEC's financial integrity through the rates paid for electric power and energy purchased. TUEC Brief on rate design at 16.

TUEC also refutes the argument that by paying more than it should for its share of Comanche Peak, Tex-La is doing the other customers of TUEC a favor. TUEC argues that Tex-La's ownership interest in Comanche Peak has served to reduce the amount of debt TUEC would otherwise have issued in only an infinitesimal way. Transcript at 3889. Tex-La purchased a part of Comanche Peak of its own volition (Transcript at 3892), because it felt it was economically beneficial to its ratepayers. Transcript at 4845. TUEC cites as one of the principal reasons for the purchase that of obtaining the long term benefits of cheap fuel to be utilized in the nuclear plant. Transcript at 4845. In TUEC's opinion, for Tex-La to argue that it has paid $67 million for its own generation to date and, therefore, should not be allocated $21 million of the company's CWIP, is to ignore the long term benefits accruing to Tex-La. TUEC argues that these long term benefits, which Tex-La believed were at least equal to the money expended (Transcript at 4846), are no longer available to TUEC's other ratepayers. Transcript at 4845; TUEC Brief on rate design at 16.

TUEC further argues that Tex-La's position is even more specious in light of the fact that Comanche Peak is not only being built to supply load growth but also to replace other generating units that will be retired in the future. Transcript at 4743-4744. TUEC concludes that not only will Tex-La's portion of Comanche Peak not meet its load growth, but in addition, Comanche Peak will in part replace other plants which are serving Tex-La's current needs and will continue to serve Tex-La's needs in the future. Finally, TUEC argues that the record is clear that it would be an administrative nightmare to apply the credit and make sure that Tex-La had not received benefits from Comanche Peak over the 30 year life of that plant. Transcript at 5158-5159.

3. Brazos Coop Proposal

In brief, Brazos Coop took the position that if Tex-La demonstrates its entitlement to a CWIP credit because of its ownership interest in Comanche Peak, Brazos should also receive a similar credit based upon its ownership interest in Comanche Peak. Brazos discerns no distinction between its position in regard to Comanche Peak and that of Tex-La, except perhaps that whatever benefits to TUEC and its ratepayers Tex-La ascribes to its 2 1/6 percent ownership interest in Comanche Peak should be proportionately larger for Brazos' 3.8 percent ownership interest. Transcript at 3907, 4764.

Brazos discounts Tex-La's attempt to distinguish Brazos' use of Comanche Peak from its own use by saying Tex-La intends to meet its own load growth with Comanche Peak power and energy and that it intends contractually to eliminate Comanche Peak costs from future rates to be paid by Tex-La for supplemental capacity and energy. Brazos argues that whatever Tex-La's future intentions may be, they are not now known and measurable. Brazos points out that the Tex-La and TUEC contract for supplemental capacity and energy contains a present commitment to meet Tex-La's anticipated and extraordinary load growth. Transcript at 4770-4771. Brazos further argues that it has shown that periodically it discontinues points of delivery on the TUEC system and transfers the loads to its own system. Coop Exhibit 21, Transcript at 3995-3997, 4772-4776. Tex-La's witness Taylor stated that if Brazos is taking load off the TUEC system instead of putting load growth onto it by leaving points of delivery there, then they should be entitled to the same CWIP credit. Transcript at 4775-4776.

4. Coops Proposal

The Cooperatives argue in brief that Tex-La will clearly receive electric service from the portion of Comanche Peak that it does not own, assuming that Comanche Peak is placed in service. The Coops further argue that Tex-La should be required to pay the financing costs of that portion of the plant to the same extent that other customers are required to pay in their rates today for plant investment used to provide service in the future. Coop Exhibit 25 at 48-51.

5. Staff Proposal

Staff characterized Tex-La's voluntary contractual arrangement with TP&L to purchase a portion of Comanche Peak as a management decision by Tex-La from which it would receive benefits. Transcript at 3892, 3905-3906, 4803, 4841. One of those benefits was the fuel savings Tex-La anticipated realizing from its share in Comanche Peak. Transcript at 4845. General Counsel also asserts that Tex-La chose to enter into this contractual arrangement despite its being a risky venture. Tex-La Exhibit 20 at 7. Tex-La witness Taylor testified that Tex-La's investment saved TUEC customers significant sums because of the investment risks in nuclear plants and the attendant increased costs of money. Dr. Taylor also testified that the investment community saw the risk of nuclear plants approximately five years ago (Transcript at 4811), yet it was not until 1980 that Tex-La first entered into its contract with TP&L. Transcript at 4809. Tex-La modified the contract in 1982. Transcript at 4809. General Counsel concludes that the benefits to Tex-La must have been substantial in order for it to continue with its investment in Comanche Peak despite the investment risk.

General Counsel also points out that Tex-La entered into the agreement to purchase a portion of Comanche Peak without any commitment or support from TUEC regarding a CWIP credit. Transcript at 3906. General Counsel argues that Tex-La faces no real risk because of its investment in Comanche Peak. TUEC is obligated to meet any load growth experienced by Tex-La which exceeds its retained capacity in Comanche Peak. Transcript at 3895-3896, 4802. Furthermore, TUEC will have to provide all of Tex-La's requirements during any unscheduled or scheduled outages of Comanche Peak. Transcript at 3885.

General Counsel also argues that Tex-La receives advantages because of its share of Comanche Peak that do not necessarily benefit the other TUEC customers. General Counsel identifies one of those advantages as Tex-La's purchase power agreement with TUEC by which TUEC will purchase Tex-La's generated power from Comanche Peak in the early years of its operation. Tex-La Exhibit 20, Schedule 14; Transcript at 3897-3899. In addition, General Counsel points out that Tex-La has capitalized its investment in Comanche Peak as AFUDC. Transcript at 4741-4742. Tex-La's finance charges for Comanche Peak will be rolled into the purchase power price Tex-La will require of TUEC. General Counsel concludes that TUEC customers will be paying for Tex-La's finance charges. Trancript at 3900. In addition, General Counsel argues that the costs of Comanche Peak will not meet lignite costs until the seventh year of Comanche Peak operation, therefore, TUEC customers will bear the higher costs of the energy because Tex-La will not begin to take its full share of capacity until the eleventh year of Comanche Peak operation. Transcript at 4788-4790.

General Counsel identifies four benefits which Tex-La would receive from its ownership interest in Comanche Peak and receipt of a CWIP credit. First, its base rates would not reflect TUEC CWIP for Comanche Peak; second, it would be receiving inexpensive fuel from its share of Comanche Peak; third, TUEC customers will reimburse Tex-La for its financing costs in Comanche Peak via the purchase power agreement; and fourth, TUEC customers will be paying for the higher cost of fuel which will occur during the early years of Comanche Peak operation through the purchase power agreement. General Counsel submits that in light of these advantages, the CWIP credit is questionable. In addition, General Counsel points out that if a CWIP credit is granted, this amount must be recaptured from the other customers on the TUEC system. Transcript at 3900, 3916A, 4396-4397.

General Counsel also takes exception with Tex-La's argument that it will never benefit from the portion of Comanche Peak owned by TUEC. Transcript at 3920, 4805. General Counsel asserts that there are significant fallacies with this argument. Tex-La is a firm requirements customer of TUEC. Transcript at 4784. There is no physical barrier prohibiting Comanche Peak electrons from flowing to Tex-La. Transcript at 4750, 4779. In addition, General Counsel points out that there is no agreement by the company that Tex-La will never receive service from Comanche Peak. Transcript at 4750, 4777-4778. Tex-La's capacity comes from the generation mix of fuel of the TUEC system; thus, Tex-La cannot dictate or determine what company generating units will be serving it. Because of the company's use of economic dispatch, the company will use the most cost effective manner of distributing energy, which could very well include the use of the Comanche Peak units. Transcript at 3926, 4751. According to the General Counsel, it is possible that all of Tex-La's power could come from Comanche Peak. Transcript at 4786-4787.

General Counsel also asserts that Tex-La is inconsistent in its belief that it will never benefit from the TUEC retained portion of Comanche Peak. Tex-La witness Dr. Taylor testified that Tex-La would probably be able to meet its own load growth (Tex-La Exhibit 20 at 2); he also testified that it was Tex-La's objective not to place any load growth on the TUEC system. Tex-La Exhibit 20 at 16. General Counsel argues that because there is a real question as to whether or not Tex-La will ever be able to meet and maintain its objective of not placing any load growth on the TUEC system, it is not clear that Tex-La will never receive any benefits from Comanche Peak.

The General Counsel also explores the flip side of the scenario described by Tex-La, that is, the reconciliation of the CWIP credit in the event that Tex-La fails to meet its objective and does indeed place additional load on the TUEC system. General Counsel refers to the reconciliation process addressed in testimony of Coop witness Stover in his proposal for a CWIP credit. Mr. Stover proposed that no CWIP credit be provided unless and until it was determined that the customer would never utilize the facility, that is, CWIP would be charged and if that customer never used that facility, then a CWIP reconciliation process would be appropriate. Mr. Stover believes it would be more appropriate to perform the reconciliation at the time the plant comes into operation and it becomes clear that the customer will not utilize the plant. Transcript at 4979-4980. Mr. Stover's testimony, however, fell short of a complete formula for making that reconciliation. Furthermore, Mr. Stover did not recommend that any CWIP credit or any reconciliation be made available to any residential customers because of the administrative burden he foresaw in dealing with the large number of residential consumers. Coop Exhibit 21 at 51.

General Counsel also points out the problem alluded to by Brazos witness Ms. Taylor, of how to compensate the residential customer who has retrofitted his home and spent a considerable amount of money doing so, that is, the customer who reduces load growth on the company's system. General Counsel asserts that under Tex-La's reasoning, such a customer could be eligible for a CWIP credit since he has placed no extra load growth on the system. Transcript at 5157-5158. General Counsel also argues that Brazos witness Ms. Taylor adequately addressed one concern critical to a CWIP credit policy: that of deciding who is eligible and who is not eligible for such a credit. In addition, there is the question of the way in which the company and the Commission handle the administrative burden of the reconciliation process; for example, treatment of a customer who has paid rates which include CWIP and who then leaves the system one day before or one day after the subject plant goes into operation.

Finally, General Counsel addresses the treatment of a CWIP credit at the federal level. Tex-La referenced the Federal Energy Regulatory Commission (FERC) discussion in FERC Docket No. 12M81-38, on CWIP credit and FERC Order No. 298. Tex-La witness Solomon asserts that FERC examined the propriety of not charging CWIP to wholesale customers who are not going to benefit from the plant under construction and who may be investing in the facilities themselves. Tex-La Exhibit 19 at 6, Transcript at 4842-4843. General Counsel describes the FERC criteria in determining whether CWIP will be in a wholesale customer's rate base as being one, that the wholesaler's load did not affect the company's decision to construct the plant, and two, the wholesaler will purchase no power from the new plant. Rehearing on Construction Work in Progress for Public Utilities, 48 Fed. Reg. 46012 (1983). General Counsel points out that TUEC witness Spence testified that the 2 1/6 percent portion of Comanche Peak purchased by Tex-La was originally considered in TUEC's decision to build Comanche Peak. Transcript at 3905-3906, 3923-3924.

Tex-La addresses the question of eligibility raised by General Counsel in its reply brief. Tex-La argues that residential customers are not eligible for a CWIP credit because they are not financing directly the costs of plant to serve their load growth. To the extent that a residential customer undertakes conservation measures, that customer benefits from reduced purchases of electric power. The residential customer will benefit from TUEC's portion of Comanche Peak through lower energy costs, unlike Tex-La, which will have the rate for its partial requirements purchases from TUEC determined without the benefit of these lower costs. Tex-La concludes that Brazos, which meets the first criterion for a CWIP credit (a customer having a direct load ratio or greater investment in the supplier's construction program when that investment is used to reduce load growth on the supplier), is not eligible for a CWIP credit because it does not meet the second criterion (rates for the customer's partial requirement purchases from the supplier are calculated without the cost or benefit of the capacity and energy from the plant).

Tex-La addresses the General Counsel's concern about a customer who has paid rates which include CWIP and then leaves the system without a refund. Tex-La asserts that this is a strong argument against the inclusion of any CWIP in rate base and that it strongly supports a CWIP credit. Tex-La further argues that in the case of the CWIP credit, it is known that Tex-La will leave the TUEC system to the extent of its load growth. Tex-La concludes that reconciliation is an issue only if Tex-La is unable to purchase plant sufficient to meet its load growth and therefore at some subsequent date places additional load on TUEC, implicitly benefiting from TUEC's share of Comanche Peak. In Tex-La's view, reconciliation of the amounts prepaid through CWIP when a customer subsequently leaves the system is a problem of allowing CWIP that arises when a customer is expected to benefit from plant under construction but does not. Since in its opinion it is known that Tex-La will not benefit from TUEC's share of Comanche Peak, Tex-La argues that there is no basis on which to eliminate the CWIP credit. Tex-La Reply Brief on rate design at 11.

Tex-La took strong exception to the General Counsel's suggestion that any consideration of a CWIP credit or reconciliation should be deferred until the time when the plant goes into operation. Tex-La argues that since it is currently shouldering two and half times its load ratio share of the Comanche Peak capacity that will serve TUEC system load, it is unreasonable to require Tex-La to finance an even greater share. Tex-La takes the position that if it eventually benefits from TUEC's portion of Comanche Peak because it failed in its attempts to purchase shares in other new TUEC plants or if TUEC refuses to allow Tex-La's participation in its new plants, then reconciliation may be appropriate at that time, but in the meantime, since Tex-La is not planning to benefit from TUEC's portion of Comanche Peak and is helping to hold the costs to other customers down because of its purchase of Comanche Peak, Tex-La should receive the CWIP credit now. Tex-La Reply Brief on rate design at 12.

Tex-La continues to assert that if Tex-La is denied CWIP credit, it is less likely that Tex-La and other wholesale customers of TUEC would purchase shares of future TUEC plants. Tex-La argues that its purchase of Comanche Peak has reduced the rates to other TUEC customers, and that the General Counsel should focus on these benefits and how to achieve future benefits, instead of focusing on whether Tex-La should subsidize CWIP for plant that will only serve other customers. Tex-La argues that since the CWIP credit is simply a correction of the allocation of Comanche Peak CWIP to Tex-La that never should have been made, CWIP credit must be continued regardless of any benefits received by Tex-La by its participation in Comanche Peak. Tex-La Reply Brief on rate design at 13. Tex-La refutes the four benefits which General Counsel listed in its brief as flowing to Tex-La as a result of its purchase of a portion of Commanche Peak: first, Tex-La argues that it is a rather broad interpretation of benefits to say that a customer does not pay for costs related to a plant it will not utilize. Second, General Counsel contends that Tex-La receives inexpensive fuel from its share of Commanche Peak; Tex-La responds that it will also be paying the expense of the high demand costs of Comanche Peak. Tex-La says that it should not be required to pay the demand costs of the portion of Comanche Peak that will serve only other customers. The third benefit perceived by General Counsel, that until Tex-La retains all of its share of Comanche Peak, TUEC's other customers will reimburse Tex-La for its annual financing costs via the purchased power agreement, is refuted by Tex-La's argument that it is reasonable under a purchased power agreement to pay for both energy (or fuel) costs and demand costs. Tex-La asserts that General Counsel believes that Tex-La should not be reimbursed for its demand costs when TUEC's other customers receive the benefit of Comanche Peak's inexpensive fuel. By elimination of the CWIP credit, Tex-La argues that the General Counsel wants Tex-La to pay the Comanche Peak demand costs of other customers. Tex-La, however, asserts that it is paying more than its load ratio share of the demand costs directly through its purchase of Comanche Peak. Fourth, in response to the General Counsel's statement that TUEC customers will pay for the higher cost of fuel during the early years of Comanche Peak's operation through the purchase power agreement, Tex-La argues that whether Comanche Peak fuel costs will be lower than lignite fuel costs during the first seven years of operation is not material, since Comanche Peak will displace expensive gas-fired generation to the benefit of TUEC's customers. Tex-La further argues that during the period TUEC uses part of Tex-La's share of Comanche Peak, TUEC pays only Tex-La's annual cost and does not have to make any investment in order to make use of the plant.

Tex-La also argues that the question of reconciliation is not a basis for eliminating CWIP credit in this case, since reconciliation will only arise if Tex-La were to benefit at some future date from Comanche Peak, which Tex-La argues that it cannot do by contract. Tex-La further argues that if such an event were to occur, the Commission could develop a method for reconciliation. Finally, Tex-La argues that contract notwithstanding, Tex-La cannot benefit from Comanche Peak until it is on-line, so this issue is not ripe for adjudication.

Tex-La asserts that the General Counsel has misinterpreted the application in this case of the FERC order on rehearing on Opinion No. 298 concerning the CWIP credit. Tex-La argues that it bears no responsibility in the decision to build Comanche Peak because it was TUEC's decision, not Tex-La's, to build Comanche Peak and Tex-La was not consulted on that decision. Tex-La also argues that its load growth is not responsible for TUEC's decision to build that portion of Comanche Peak for which TUEC now requests CWIP. Tex-La points out that it is financing the portion of Comanche Peak that will serve its load, and therefore has relieved TUEC of the responsibility to meet that load growth. Tex-La concludes that is has shown it is entitled to continue to receive the CWIP credit if CWIP is allowed in TUEC's rate base.

6. Recommmendation

Tex-La's testimony and arguments in support of retention of the CWIP credit are not persuasive. Tex-La will remain a full requirements wholesale customer of TUEC during the entire period the rates set in this case are in effect (Transcript at 3903), and sometime thereafter, Tex-La will be a partial requirements customer of TUEC, relying on TUEC to supply the shortfall between Tex-La's load requirements and its entitlements from Comanche Peak, and to back up Tex-La's own generation in the event of outages. Tex-La's load growth requirements will be far in excess of its generation entitlement from Commanche Peak (Transcript at 3818-3819), thus, Tex-La's needs will be satisfied from TUEC plants other than Tex-La's retained interest in Comanche Peak (Transcript at 4849), and other sources such as SPA, which would clearly constitute all TUEC plants, including Comanche Peak. Tex-La's own witness Dr. Taylor recognized that Tex-La's load growth would not be served solely from its share of Comanche Peak,. and that Tex-La would need TUEC's cooperation in purchasing interests in other TUEC plants in order to meet its load growth. Transcript at 4756, 4793. At this point, it is Tex-la's objective to purchase interest in other TUEC plants so as not to add load to the TUEC system. Transcript at 4817-4818. Tex-La is unable, however, to state what it will purchase or when such a purchase will be made. Transcript at 4818-4819. TUEC's argument is correct that Tex-La is only speculating as to what the future may hold. Tex-La is eager to assume that it will purchase additional capacity, but again, fails to demonstrate that such purchases have been or will be made. It also worthy of note that Tex-La reduced its share of Comanche Peak by one half, from 4 1/3 percent to 2 1/6 percent (Transcript at 4814), which appears to undercut Tex-La's argument that it intends to purchase interests in TUEC plants in order not to add load to the TUEC system.

Comanche Peak is being constructed not only to meet load growth, but also to replace other generating units that will be retired in the future. Transcript at 4743-4744. Comanche Peak therefore will in part replace other plants which are serving Tex-La's current needs and will continue to serve Tex-La's needs in the future. Tex-La will be relying on TUEC for electric power and energy, and therefore should be required to pay the full cost of electric power and energy purchased from TUEC, just like any other customer, including that part of the full cost attributable to maintaining TUEC's financial integrity. The problems identified by General Counsel in brief concerning eligibility for and reconciliation of CWIP credits simply illustrate the problems inherent in attempting to identify which customers will benefit from plants under construction which will come on-line at a time in the future. Moreover, the determination of which customers will benefit from particular plants which will come on line in the future is not the proper focus of a determination of whether CWIP should be included in rate base. As TUEC correctly notes, the one and only purpose for which CWIP is includable in rate base is to maintain the utility's financial integrity. When it has been determined that such an inclusion is appropriate, the return on CWIP becomes a part of the total cost of electric power and energy. In addition, TUEC correctly points out that as long as Tex-La is in any manner relying upon TUEC to supply all or a portion of Tex-La's electric needs, it is just as much in Tex-La's interest that TUEC's financial integrity be maintained as it is in the interest of any other TUEC customer. From that perspective, it is appropriate that Tex-La pay wholesale rates to TUEC on the same basis that other wholesale customers pay rates to TUEC. The fact that Tex-La also owns a portion of Comanche Peak is simply irrelevant to the determination of the appropriateness of Tex-La paying rates to TUEC which include CWIP. It is recommended that the CWIP credit sought by Tex-La should be rejected.

B. Franchise Fees/Gross Receipts Tax

A substantial controversy arose in this case over the staff's proposal to surcharge municipal franchise fees and state gross receipts tax to customers residing within municipal boundaries only. Staff Exhibit 36 at 23-33. TIEC made the same proposal through testimony of its witness Jeffrey Pollock. TIEC Exhibit 2 at 33-34.

1. TUEC Proposal

TUEC proposed no change to its present method of recovering franchise fees charged for its use of streets and other privileges associated with use of city property; that is, TUEC includes these costs in its cost of service and recovers them from all its customer classes through base rate charges. These charges are collected from all customers whether they take service within or without the corporate limits of a municipality. In rebuttal testimony, TUEC witness Charles F. Johnston explained that it is the company position that it is unfair to assign local franchise fees and state gross receipts tax only to customers within the city while ignoring other offsetting specific items such as customer density, line losses, etc. TUEC Exhibit 41 at 3. Mr. Johnston also identified as a major problem the possiblity of having as many as seven different rates applicable to the company's residential customers. Mr. Johnston's opinion is that this would create an administrative nightmare for the company and would create customer confusion. As an example, he explained that each company local office would have separate cities within its service territory. Each time a customer inquiry is received, a determination of where the customer lives would need to be made so it could be determined on what rate the customer is billed. In many instances, according to Mr. Johnston, customers living across the street from each other would receive a different billing amount for the same consumption. TUEC Exhibit 41 at 3.

In its brief, TUEC conceded that municipal franchise fees do go to the local governments that collect them, and that it is therefore easy to conclude that city residents should be surcharged for them. TUEC points out that there is no logical distinction between specifically allocating franchise fees and the many different local ad valorem taxes paid by the company (Transcript at 6861-6867), but that such a scheme would unduly complicate the rates and greatly add to the company's administrative burden. TUEC argues, however, that it is neither fair nor appropriate to surcharge such fees or ad valorem taxes based on the record in this case, because no comprehensive study has been made of offsetting factors associated with providing rural service. TUEC Exhibit 41 at 3; Transcript at 4404, 5180, 5828-5829, 6956, 6962. TUEC further argues that the opinion testimony of several experts in this case establishes that the cost to serve rural areas exceeds the cost to serve in urban areas even if the franchise fees are allocated only to urban customers. Transcript at 4405-4406, 5795, 5808, 5829, 5840, 6962. A study made for HL&P, which has a greater density of customers than does TUEC (Transcript at 5586), was determined by the expert witnesses to be inapplicable to the company because of the difference in density of the two systems. Transcript at 5829-5830, 5840. TUEC concludes that in light of the evidence and the questions raised about cost differentials between urban and rural locations, it is inappropriate to identify one item of expense and allocate it on the basis of a geographical distinction without doing a complete cost of service analysis by geographical areas. TUEC cites the Texas Supreme Court decision in City of Corpus Christi v. Public Utility Commission, 572 S.W.2d 294-296 (Tex. Sup. 1978), as approval of the Commision policy of setting systemwide rates. TUEC has based its decision not to attempt a cost of service analysis by geographical area upon that court case. Such a cost of service analysis would be necessary, however, in order to be fair, if a particular cost of service item were broken out for different treatment on a geographical basis, even though such an analysis would not be cost beneficial to any of the company's customers. TUEC Brief on rate design at 10.

TUEC asserts that the proposal to distinguish between urban and rural areas would result in additional expense and customer confusion. TIEC Exhibit 41 at 3. TUEC argues that once geographic ratemaking has begun, there is no logical end to the distinctions that can be made between different cities, different rural areas, and specific customer locations. Transcript at 6960. Customers pay rates based upon the average cost of serving large classes of customers because of the tremendous expense that would be incurred to perform cost studies for small groups or even individual customers and to administer numerous rates. Trancript at 4404, 5830-5832, 6963. TUEC alleges that such expenses would more than offset any benefits to selected customers of performing such studies and maintaining numerous rates. TUEC also argues that all customers are served from an integrated system, which further supports systemwide ratemaking. Because the system is integrated, TUEC urges that all customers benefit from the rights of the company to maintain facilities on municipal property. Transcript at 5805.

The Cities supported the company's approach to recovery of franchise fees and state gross receipts tax from all TUEC customers regardless of their geographical location. The Cities argue, as does TUEC, that such an approach is consistent with the decision of the Supreme Court in City of Corpus Christi v. Public Utility Commission, supra. The Cities also point out that with the exception of HL&P, this method of recovery has been virtually universal in the regulation of electric utilities. The Cities also refer to the differences between the HL&P service territory, which is generally urban, and that of the TUEC system which is both urban and rural. The Cities also remind us that there is no cost of service study or even the data to perform one in this case. Further, the Cities contend that in 1980, the Commission expressly declined to adopt a rule which would have required the institution of the very policy which the Commission staff has proposed in this docket. Cities Brief on rate design at 10-11.

The City of Irving urged in brief that until such time as a cost of service study is performed, franchise fees paid to municipalities should continue to be included in the cost of service and recovered from all TUEC customers. The City of Irving argued that selecting one cost of service item from many is arbitrary and capricious, and would result in discriminatory rates. The City of Irving further submitted that if there were no cities populated by enough customers to pay the major part of the plant investment costs, the rural rates would be substantially higher. City of Irving Brief on rate design at 9.

2. Tex-La Proposal

In brief, Tex-La argued that since the wholesale customer already pays municipal franchise fees and local gross receipts taxes in the cities they serve, it would be improper to also assign a portion of TUEC's local taxes to the wholesale customers. Tex-La Brief on rate design at 67. Tex-La urges that if the Commission adopts the company's proposal for recovering municipal franchise fees and local gross receipts taxes, these items must not be allocated to wholesale customers. Tex-La Brief on rate design at 68.

3. Proposal of Staff, TIEC and Nucor Steel

It is the position of the staff in this case that direct assignment of local gross recipts taxes is necessary, proper and supported by legal authority. General Counsel argues that a franchise fee is the creature of the municipality because it, and not the residents of the unincorporated areas, demands the payment. This tax is based upon the revenues the utility receives from its customers within the municipality. Transcript at 5854-5855. The amount of revenue the utility generates from within a municipality determines the exact dollar amount the utility pays to the municipality; the municipally imposed local gross recipts tax arises from the use of the city's facilities, according to the General Counsel. What the General Counsel finds disturbing about the relationship of the utility with the municipality is that the utility is a conduit for the cities to collect a tax from citizens who reside in unincorporated areas over whom they would normally have no taxing authority. General Counsel Brief on rate design at 35. General Counsel points out that approximately 135,000, or 8 percent, of TUEC's customers reside in unincorporated areas. The General Counsel then concludes that the remaining 92 percent of the municipal residents have portions of their taxes being paid by the 8 percent of nonmunicipal residents. Cities Exhibit 13 at 8. General Counsel concedes that it is an expense in which the utility incurs, but that it is an expense solely incurred due to the charges levied by the municipality.

General Counsel asserts that this is approriately characterized as a tax. Referring to Tex. Tax Code Ann. Sections 182.021, 182.022, and 182.025, General Counsel argues that these statutes make it clear that the gross receipts tax is a tax and that the amount paid is based on the total revenue generated within a city and is not based on the costs, if any, imposed upon the municipality by the utility, and that municipalities may charge no more than 2 percent for the utility's use of city streets, alleys or public ways. General Counsel argues that the statutes contemplate that the utility should pay the local gross receipts taxes to compensate the municipality for the use of its facilities, and is not predicated on any costs incurred. General Counsel argues that the gross receipts tax assessed under Section 182.022 is mandatory, but that the cities' amount, set forth in Section 182.025, is not to exceed 2 percent, which provides the municipality with the authority to decrease the amount required of a utility.

General Counsel urges that the evidence reflects the total gross receipts tax of the company ranges from 2 percent to 4 percent. Staff Exhibit 36 at 32. By adding the maximum amount delineated in the statutes, the General Counsel derived an approximate 4 percent figure, which she asserts is "ironically" the same figure the City of Dallas charges TUEC. Trancript at 5898-5899; General Counsel Brief on rate design at 37.

General Counsel disputes the arguments of witnesses who claimed that TUEC is able to negotiate the level of these taxes on the basis that the clear language of the law and facts in this case do not support such arguments. TML witness Pous testified that he knows of no municipality in the TUEC service area that has set this fee at less than the statutory maximum. Transcript at 5813.

General Counsel also asserts that there is no evidence in the case as to the cost relationship between the local gross receipts tax and the expenses, if any, which the municipality incurs in providing the utility the privilege of serving the municipality's residents. General Counsel argues that no witness was able to quantify one dollar of this alleged cost. Transcript at 5803-5804, 5810, 5865; General Counsel Brief on rate design at 38. Cities witness Pous testified that the cities incur costs, such as additional costs for the city mowers to mow around utility poles (Transcript at 5803), yet he also admitted that the city would have to cut the grass near the poles anyway (Transcript at 5802). General Counsel argues that if the city incurs these alleged additional costs, it could also be argued that there is less concrete which the city has to pour for the poles embedded in concrete located within the city, and that these savings inure to the benefit of the city.

General Counsel also finds significant the fact that the city does not apportion the revenues collected as gross receipts tax with its nonmunicipal resident neighbors, but instead the gross receipts go into the coffers of the municipalities. Transcript at 5803-5804. General Counsel argues that none of these funds are ever marked for the alleged purpose for which they were collected, that is, to defer expenses allegedly caused by the utility's service to the municipal residents. Transcript at 5804-5805. General Counsel asserts that because the local gross receipts taxes are commingled with the other revenues of the city, they go toward assisting the municipality in providing municipal services to its residents, services which are generally not available to nonmunicipal residents. Staff Exhibit 36 at 32. General Counsel concludes that the parties have not demonstrated a relationship between the amounts collected and any costs incurred, nor have they quantified any of the alleged costs. General Counsel asserts that this item is clearly not cost based. General Counsel Brief on rate design at 39.

General Counsel also charges that TUEC and the Cities did not submit studies which provided any quantification or qualitative analysis of the benefits which nonmunicipal residents receive for their payment of this tax. General Counsel refers to the testimony of Cities witness Pous, who stated that nonmunicipal residents benefit from the voltage distribution system of the city because of the integrated TUEC system. Transcript at 5806. General Counsel also refers to prior Commission decisions involving HL&P as supporting its position, that direct assignment of local gross receipts tax is reasonable. Docket No. 2676, Application of Houston Lighting and Power Company for Authority to Increase Rates within Austin, Brazoria, Chambers, Colorado, Fort Bend, Galveston, Liberty, Matagorda, Montgomery, Waller and Wharton Counties, 5 P.U.C. BULL. 323 (January 9, 1981); Docket No. 2960, Application of Houston Lighting and Power Company for Review of Rate Ordinances Passed By the Cities of Houston, Lake Jackson, Galena Park, Baytown, and Shore Acres, 6 P.U.C. BULL. 16 (August 6, 1980); and Docket No. 3461, Appeal of Houston Lighting and Power Company from the Rate Ordinance of the City of Houston, 7 P.U.C. BULL. 504 (July 7, 1981). General Counsel argues that in these cases, the Commission addressed the issue of the proper treatment of local gross receipts taxes and determined that the direct assignment of such taxes was reasonable. General Counsel urges that the basis for this decision was that the Commission did not find that nonmunicipal residents benefited from the payment of municipally imposed local gross receipts taxes. Analogizing the reasoning in those dockets to the instant case, the General Counsel submits that the evidence does not establish that any benefits are received by nonmunicipal ratepayers, thus, the arguments of TUEC and the Cities must fail. General Counsel also cites the case of City of Houston v. Public Utility Commission of Texas, 656 S.W.2d 107 (Tex.App. - Austin 1983, writ ref'd. n.r.e.) as supporting its position. In that case, according to the General Counsel, the court found that the true benefits derived from local gross receipts taxes are reaped by municipal residents, and that a question exists as to the possible overrecovery of funds since the cities' gross receipts tax is not based on the municipalities' incurred costs but rather is based upon the revenues generated within the municipality. General Counsel argues in conclusion that since there is no quantification of costs in the record, and since the local gross receipts tax is unquestionably based on the revenues the utility receives from the municipal residents, a distinct possibility exists that the municipalities could be overrecovering funds, over and above any alleged costs. General Counsel further argues that this overrecovery of funds indicates that the nonmunicipal residents are indeed supporting the municipal governments. General Counsel Brief on rate design at 43.

General Counsel also criticized arguments that it is more expensive to serve rural customers than urban customers. General Counsel asserts that no studies were performed to support the alleged increased costs (Transcript at 5794-5795, 5808), and that TUEC witness Johnston was unable to quantify the additional expense involved in serving rural customers. Mr. Johnston could not indicate how rural customers caused the company to incur its approximately $100 million in costs, the estimated figure of the total amount of local gross receipts taxes TUEC paid. Transcript at 6960-6961. General Counsel also argues that although the record does not reflect any quantification of costs incurred to serve urban compared to rural customers, there are nevertheless additional costs associated with serving urban rather than rural residents. As an example, General Counsel points out that urban areas have more construction taking place than rural areas and utilities may need to move their facilities because of this construction. Transcript at 5861. These costs are passed on to all customers, including rural customers, as a cost of service item, unless a franchise fee agreement states otherwise. Transcript at 5861-5862. General Counsel asserts that the mere allegation of additional costs to serve rural customers is not a substitute for the evidence which is lacking in this record. General Counsel Brief on rate design at 44.

General Counsel also points out what it identifies as inconsistencies between the assertions made by the parties and the facts of the case. Cities' witnesses Pous and Wilson both testified that TUEC should collect these charges from all customer classes and from all customers (Cities Exhibit 13 at 5; Cities Exhibit 14 at 5), yet Mr. Wilson testified on cross-examination that TUEC is not charging wholesale customers these taxes. Transcript at 5855-5856. Mr. Wilson's justification for this is that the TUEC wholesale customers already pay local gross receipts taxes to the cities in which they serve. General Counsel argues that the Commission is unable to compare the gross receipts taxes allegedly being paid by the wholesale classes to those cities in which they serve to that amount that these wholesale customers would have paid under the company's cost of service study since the company did not allocate local gross receipts taxes to its wholesale customers. According to Mr. Wilson's testimony, the local gross receipts tax is a cost of service expense incurred by the company. Transcript at 5858. General Counsel argues that to be consistent, the tax, if spread as a cost of service item and not on a direct assignment basis, should be passed to all of the company's customers including the wholesale customers. General Counsel also argues that the company's testimony is inconsistent. Mr. Johnston testified that all TUEC customers should bear the cost of the local gross receipts tax (TUEC Exhibit 41 at 3), however, the record reflects that this is not what the company has done. Company Exhibit 1-H, page 98-II, Proposed Rates. General Counsel cites an additional inconsistency in the testimony of TUEC witness Johnston, who stated that rural customers cause additional costs which are imposed on all the company's ratepayers. Although Mr. Johnston was unable to quantify the additional costs, he believed that the range of differences in the costs of service, depending on the areas served, were apparent. Transcript at 6962. General Counsel points out that Mr. Johnston further testified that such differences were minimal, and that it would not make any sense to do a cost of service study to capture "the slight degree of differences you would get if you had all the data upon which to make the judgment in the first place." Transcript at 6962. General Counsel submits that the arguments of TUEC and the Cities are biased, self-serving and inconsistent, and that little weight should be given to the assertions of such parties.

General Counsel argues that the allegation made by TUEC and the Cities that the customers' bill will become complicated to read if taxes are allocated on a direct assignment basis is a straw man to conceal the municipalities' true concern: their desire to shield their citizens from the truth. General Counsel argues that municipalities do not want their residents to discover that an additional tax has been placed on them. The reason for this, according to the General Counsel, is since the cities' taxing power is directly controlled by the voters, it is more beneficial for the cities to maintain the status quo. Staff Exhibit 36 at 34. General Counsel argues that municipalities have no better way to obtain desired revenue than to have the citizens remain unaware that they are being taxed. General Counsel Brief on rate design at 47. Moreover, General Counsel argues that since the citizens do not know that the tax paid to the utility is based upon their total consumption, there is no incentive for them to conserve electricity, thus lowering their bills and the tax paid. General Counsel finds even more disturbing the fact that nonmunicipal customers do not have this option available to them since the tax is allocated on the basis of the consumption of the municipal residents and not their own consumption. Thus, General Counsel finds its to the cities' benefit that the consumption levels remain high because it is the consumption level and the revenues generated therefrom which determines the revenues received by the city. General Counsel Brief on rate design at 47. Staff witness Kepner testified that not only do nonmunicipal residents receive no direct benefit from the local gross recipts tax, they are also helpless in removing this imposition. Staff Exhibit 36 at 30. The only persons who can mitigate these expenses are the municipal residents, by their voting power and by their consumption patterns, yet they cannot receive any price signals until they become aware of the existence of the local gross receipts tax. General Counsel argues that this point was squarely addressed by the Commission in Docket No. 2960, in which the Commission found that the nonmunicipal residents were unable to alleviate their plight, but moreover, without a direct allocation of costs, the municipal residents were unaware of the effect they personally could exert on the dollar amount of the local gross receipts tax. General Counsel Brief on rate design at 47. General Counsel argues that this decision was upheld in Docket No. 3461. General Counsel Brief on rate design at 48.

Contrary to the testimony of Cities witness Wilson, that if the local gross receipts tax is only levied upon municipal residents it would be deemed inequitable (Cities Exhibit 13 at 3), General Counsel submits that recovery of the local gross receipts tax from all customers instead of the direct assignment of these taxes constitutes the inequity. General Counsel argues that this has clearly been the view of the Commission in prior dockets. Based on prior Commission decisions of the propriety of the direct assignment of these taxes, not only in the electric utility area but also in the telephone area, General Counsel submits that the direct assignment of local gross receipts tax is required to eliminate actual inequities which currently exist with the present method of allocation of the company's local gross receipts taxes. General Counsel also argues that based on the prior Commission decisions, the continued use of the present method of recovery of local gross recipts tax could indeed be considered discriminatory under Sections

38 and 45 of the Public Utility Regulatory Act, Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon's Supp. 1984), as the Texas courts reasoned in the City of Houston case, supra. Finally, General Counsel takes exception to the interpretation of TUEC and the Cities of City of Corpus Christi case, supra. General Counsel argues that the Supreme Court of Texas did not order uniform rates, but held only that the data used to compute those rates must be on a systemwide basis. The court did not find that the allocation of that data or the design of rates from that data must be done in a particular manner, but that the cost allocation and rate design procedures are properly left to the experts. The court further held that the utility may collect from the citizens of the respective municipalities a surcharge for rate case expenses. General Counsel argues that in the City of Houston case the court cited the City of Corpus Christi case as precedent and specifically stated that it perceived an analogy between the surcharge payment for rate case expenses in the City of Corpus Christi case and the local gross receipts tax to be directly passed to the municipal residents in the City of Houston case. General Counsel argues that the surcharge recovery and the local gross receipts tax are conceptually similar since both are caused by the city and the city alone receives a substantial benefit from the services provided by the utilities. General Counsel submits that the distincition is clear: systemwide data must be used in the regulatory bodies' decision making, however, there is no prohibition in the distribution or proportioning of that systemwide data on the basis of costs, nor is there any prohibition against the collection of these expenses through the cities' rates. General Counsel Brief on rate design at 56. General Counsel argues that the discrimination does not occur with the implementation of a surcharge, since the rates are the same for electric service. It is only the additional franchise fee caused by the cities which would be directly payable by municipal residents. General Counsel carefully points out that it is not urging the disallowance of local gross recipts taxes as an operating expense of the utility, but rather, is urging the direct assignment of local gross receipts taxes to the municipal residents.

Although not addressed in its brief, TIEC supported the proposal of the staff through the testimony of its witness Jeffry Pollock. TIEC Exhibit 2 at 33-34. Mr. Pollock reasoned that since it is the revenues within an incorporated city or town that cause the utility to incur the franchise fees and gross receipts taxes, it is not appropriate to recover these taxes from all customers since, for certain classes, a large portion of revenue is generated outside an incorporated municipality. Mr. Pollock further reasoned that if cost causation is the standard by which a cost of service study is conducted, it is not appropriate to recover franchise fees and gross recipts taxes from customers residing outside incorporated municipalities, since the revenues generated by these customers by definiton and by statute do not cause TUEC to incur these taxes. TIEC Exhibit 2 at 33-34.

Nucor Steel also supported the position taken by the staff and TIEC, finding the reasons offered by their witnesses persuasive on the issue. Nucor Steel Brief on rate design at 23.

TUEC criticized the testimony of Mr. Pollock on cross-examination when he stated that he doubted that the higher cost to serve rural customers would offset the franchise fees. Transcript at 5584. The sole basis for this opinion was a study made for HL&P, which TUEC asserts has a greater density of customers than does TUEC. Transcript at 5586. TUEC points out that other witnesses confirmed that the density of the HL&P system would make a study of that system inapplicable to TUEC. Transcript at 5829-5830, 5840. TUEC concludes that in light of the evidence and the questions raised about cost differentials between urban and rural locations, it is clearly inappropriate to identify one item of expense and allocate it by geographical distinction without doing a complete cost of service analysis by geographical areas.

In brief, the Cities criticized the staff proposal on a number of different grounds. Initially, the Cities argue that the charge in question is not a tax. The Cities refer to Section 182.024 of the Tax Code as prohibiting a city from imposing an occupation tax on a utility and to Section 182.025 as authorizing a reasonable lawful charge for the use of city streets, alleys or public ways. Furthermore, the Cities argue that contrary to staff witness Kepner's assertion, such a charge is not a type of levy imposed upon utility companies by cities for the right to do business within the city which is no longer applicable since the creation of the Commission. The Cities argue that nothing regarding such a charge has changed since the creation of this Commission and that Mr. Kepner's characterization of such a charge as being one imposed for the right to do business within a city is not now and never has been correct. The Cities cite the case of <u>West Texas Utilities Company v. the City of Baird</u>, 286 S.W.2d 185, 189 (Tex. App.-Eastland 1956, writ ref'd. n.r.e.) as holding that a utility's right to sell electricity was not dependent upon a franchise from the City of Baird. Likewise the Cities aver that Article 1181 provides that cities may grant franchises or rights to use and occupy the public streets, avenues, alleys and grounds of the city but does not provide any authority to require a franchise to do business within the city. The cities find unconvincing Mr. Kepner's testimony on redirect that he used the term "tax" as an economic term.

The Cities further argue that it is inconsistent to single out the franchise fees for direct allocation to municipal customers on the basis that such an amount can be readily determined and hinges upon the level of the customers' bills. The Cities argue that certain other charges, such as the state gross receipts tax and the regulatory fees, are equally easily discernable but are not singled out by the staff for such treatment. The Cities urge that if one governmental charge is singled out, all should be afforded the same treatment. In the Cities' opinion, if bringing out governmental charges is good for cities, as Mr. Kepner testifies (Staff Exhibit 36 at 35), it is equally good for the charges of the state gross receipts tax and the Commission regulatory fee.

The Cities argue that it becomes immaterial whether franchise fees are taxes or not, either in actuality or in the language of economists, because franchise fees are not treated the same way as taxes in the staff's proposal. The reason advanced for treating franchise fees differently, the Cities charge, is based on Mr. Kepner's vague understanding of the flow of benefits from governmental charges. As an example, the Cities cite Mr. Kepner's testimony at Transcript at 6830, that ad valorem taxes should not be surcharged separately because they flow to everyone while franchise fees flow only to municipalities and benefit only a portion of the company's customers. The Cities charge that subsequent cross-examination established that Mr. Kepner "simply does not know what he's talking about" (Transcript at 6861-6867; Cities Brief on rate design at 13).

The Cities assert that the Texas system of home rule government imposes extensive responsibilities upon municipalities rather than upon the state (Article 1175), and thus it is debatable whether much, if any, gross receipts taxes finds its way to benefit citizens living within municipalities. The Cities assert that ad valorem taxes, which Mr. Kepner claims benefit all ratepayers on the system, are not expended for the benefit of those outside the particular jurisdiction, and in the case of county ad valorem taxes, are not even expended throughout the jurisdiction that imposes such taxes. Cities Brief on rate design at 13. The Cities assert that Mr. Kepner simply failed to investigate thoroughly the subject of franchise fees and gross recipts taxes prior to making a recommendation which, according to the Cities, would impose substantially higher utility rates upon customers within corporate limits. Transcript at 6867. Mr. Kepner assumes but does not know if counties have ad valorem tax rates. Transcript at 6862. He does not know if the evaluation systems are uniform throughout the state. Transcript at 6863-6864. The Cities argue that if such rates and evaluation systems vary, ad valorem taxes paid by TUEC are obviously going to vary depending upon the location of its faciltities. Therefore, the Cities argue that Mr. Kepner's assertion that the cost to serve a particular area does not vary because of the location of company facilities is unsubstantiated. Staff Exhibit 36 at 47. The Cities argue that the company's cost of doing business, not only within a particular area but throughout the system, will vary as a result of the location of facilities because ad valorem tax levels differ from county to county and school district to school district, depending upon the wishes, needs and characteristics of the particular taxing jurisdiction. Cities Brief on rate design at 14.

The Cities also urge that Mr. Kepner's argument that city charges are different from charges of the state, counties or school districts because only a limited number of ratepayers benefit from city charges, does not hold water. Mr. Kepner admitted that county and school district taxes are probably expended only within the jurisdiction in question. Transcript at 6864. The Cities argue that by Mr. Kepner's own concession, his ultimate overriding reason for surcharging franchise fees only to those who "benefit" from them falls because of its inconsistent application. The Cities conclude that singling out charges of one governmental entity to be imposed upon the ratepayers of that jurisdiction without doing the same regarding other governmental charges amounts to the rankest form of discriminatory treatment. Cities Brief on rate design at 15.

In support of its contention that Mr. Kepner's assumption that the expenditure of county ad valorem taxes was made proportionately throughout the county was without substantiation, the Cities refer to his testimony that county ad valorem taxes are expended for the benefit of all residents. Transcript at 6864. He made no study, however, to determine if this was true. He testified that he did not know how tax revenues are spent within Texas. Transcript at 6865. He testified that he did not know if the county provides police protection within corporate limits. Transcript at 6765. He testified that he did not know if county ad valorem taxes are expended within corporate limits of cities for fire protection. Transcript at 6866. He testified that he did not know whether the county ad valorem taxes are expended within corporate limits for maintenance of streets or acquisition of rights of way. Transcript at 6866. Although he asserted that the franchise fees in question benefit only residents of cities, Mr. Kepner also testified that he did not know whether city facilities are available to all persons regardless of their place of residence. Transcript at 6866-6867. Thus, the Cities charge that Mr. Kepner simply failed to conduct an investigation which would support his recommendation. Transcript at 6867. The Cities also criticize the staff's attempt to justify its recommendation on the basis that there is no cost justification for franchise fees or gross receipts taxes. The Cities refer to the opinion testimony of the expert witnesses in this docket that the cost to serve in rural areas exceeds the cost to serve in urban areas, even if the franchise fees are all allocated to urban customers. TUEC witness Johnston stated that the cost to serve in rural areas would be substantially higher, in the range of 15 percent to 30 percent. Transcript at 4406. Brazos Coop witness Taylor provided testimony discussing the higher cost to serve in rural areas. Brazos Exhibit 1 at 9-10. TIEC witness Gail Hafer testified that the investment per customer is greater in less densely populated areas, which was the basis for many utility companies at one time having separate rates for urban and rural areas. TIEC Exhibit 1 at 3-4. Cities witness Pous discussed the differences in line losses which vary according to the density of the system. Cities Exhibit 14 at 6. TUEC witness Johnston verified the difference, testifying that he knew of no other basis for the differences in line losses between the DP&L and TESCO systems other than the differences in customer density of the two. Transcript at 6972. Mr. Pous also testified that a rural customer requires the dedication of a single transformer, while several customers can be served from a single transformer in urban areas. TML Exhibit 14 at 6. TUEC witness Johnston confirmed that in normal subdivisions, four to six customers may be served from each transformer while in rural areas, "you normally find not more than one customer per transformer." Transcript at 6972. The Cities argue that there are a number of other items, such as meter reading costs, which one could identify in the process of developing a cost of service study which would distinguish between urban and rural costs to serve. Transcript at 6957-6958. The Cities argue that all cost differences should be identified, rather than only a few, and then properly assigned. The Cities suggest that the appropriate method of accomplishing this would be for the Commission to direct TUEC to develop such data so that the parties will have a fair opportunity to argue a reasonable allocation of costs based upon the classes of customers which the Commission desires to have created. The Cities point out that Mr. Kepner agreed that the first step in establishing rates on a geographic basis would be to develop cost studies. Transcript at 6738. The Cities assert that once such urban/rural cost studies are completed, the result will reflect a considerably higher cost of service for rural customers.

In response to the arguments of General Counsel that the Cities are motivated by a desire to raise revenues, the Cities point out that if such is the case, it makes little sense for the Cities to appear in opposition to the company's rate increase requests. The Cities also argue that it is fundamentally inconsistent for the staff to take a position in favor of consolidating rates for three different systems which ignore such differences as widely differing customer mixes, fuel costs, density characteristics, past CWIP cost levels and growth characteristics, while seizing upon the opportunity to penalize certain ratepayers because of one isolated item. The Cities identify this issue as a policy question on which the Commission must make a statement. The Cities urge the Commission to recognize that it is making a choice regarding the continuation of its policy of uniform systemwide rates.

The Cities respond adamantly to the staff's argument that franchise fees are taxes, and refer to Attorney General Opinion H-1265 as authority on that point. The net effect of the staff's recommendation, in the Cities' opinion, is that rates would be different not because of any difference in value or level of service, but only because of geographical location. The Cities claim that despite the staff's efforts to demonstrate otherwise, the surcharging of franchise fees does not make such charges any less a part of the rate charged by the utility. The Cities argue that such surcharging may preserve technical, but not practical, uniformity. The Cities further argue that the staff has done nothing more than establish a new customer class by claiming it has found one cost that can be directly allocated. The Cities assail the staff's reliance on the Commission precedent as novel in two respects. First, the Cities assert that the staff has shown little regard for Commission precedent in Docket No. 3437, the PURPA proceeding. Second, the Cities argue that the General Counsel has cited as prevailing Commission precedent what is done in one out of ten major electric utilities in Texas. The Cities point to other Commission decisions which the Cities assert are the product of the Commission decision in 1980 not to adopt a rule which would have mandated for the rest of the state treatment of franchise fees similar to that for HL&P. The Cities also point out that the HL&P decisions cited as precedent by the General Counsel were based on a record which contained an urban/rural cost study not present in this docket.

The Cities point out that Section 182.022 of the Tax Code establishes state gross receipts taxes, which are undeniably taxes; on the basis of Attorney General's Opinion H-1265, city street use charges are not taxes. The General Counsel's argument that Section 182.025 of the Tax Code sets a ceiling on the amount utilities can contract to pay for the use of city streets is refuted by the Cities' reference to the next section of Subchapter 182 of the Tax Code which states that Subchapter 182 does not apply to any contract, agreement or franchise made between a city and a public utility relating to a payment made to the city. The Cities argue that Section 182.025 therefore relates to charges levied absent a contract and therefore there is no statutory limit on contractual franchise fee rates.

The Cities further argue that trying to identify who benefits from the expenditure of revenues received from a utility is simply not a valid basis for allocating costs. The Cities argue that if payments to governmental entities are to be allocated based on who beneifts from services provided by that governmental entity, then municipalities provide services which benefit the general public as a whole (construction and maintenance of roads, public buildings, parks, police protection, etc.), while other governmental entities, such as school districts, clearly provide services which never benefit those residing outside their geographic limits.

The Cities also assert that it is the staff, not other parties, which is promoting a new method of classifying TUEC's customers, that is, on the basis of geographical location. The Cities refute the argument that the Cities' position cannot be adopted because no studies were prepared supporting the Cities' claim that it costs more to serve rural areas. The Cities point out that the company made no attempt to change the status quo with respect to the regulatory treatment of franchise fees. The Cities argue that the General Counsel's desire to shift the burden of proof to the Cities should be rejected, and that if the staff wishes to present a recommendation changing the status quo, it is the staff which should present such studies.

The Cities claim deletion of the wholesale class from allocation of franchise fees does not present an inconsistency as the staff claims. The Cities see a distinction in that the payment of a charge for general use of city-owned property is an incident of the company's retail business which would not be incurred if the the company were only in the wholesale business.

General Counsel responds to the criticism of the staff's proposal by stating that Mr. Kepner did not apply his rationale of local gross receipts tax to state gross receipts tax or to the Public Utility Commission assessment because it would have been irrational to do so. The reason advanced for this distinction is that the revenues collected from these charges flow specifically to the state general fund (Transcript at 6830), which is utilized to serve the people of the State of Texas. General Counsel also argues that a discussion of ad valorem taxes is irrelevant because there is no relevant nexus between ad valorem taxes and local gross receipts taxes as has been illustrated in Mr. Kepner's testimony. Staff Exhibit 36 at 37-38. General Counsel argues that even if differences exist between the treatment of different costs, the Commission has already held that such differences do not justify the exclusion of a direct assignment of local gross recipts taxes which are clearly identifiable expenses. Docket No. 2960, Application of Houston Lighting and Power Company, supra at 20. General Counsel also asserts that the Commission in Docket No. 2960, supra, and the Austin Court of Civil Appeals in the City of Houston case, supra at 110, determined that discrimination would not exist with direct allocation, but, on the contrary, to permit delineated items to go unchecked would constitute the discrimination. The General Counsel also argues that the Commission and the Texas Courts have denied the arguments that a complete cost study must be done prior to deciding whether to directly assign local gross receipts taxes. General Counsel submits that the Commission has taken the position that the direct assignment of such items is not only necessary but proper in order to prevent discrimination in rates and that the appellate courts in Texas have supported the Commission on this issue.

4. Recommendation

The most troubling aspect of the staff's proposal on franchise fees is that there is no accompanying geographical cost of service study prepared by the staff. It appears to be fundamentally unfair to ascribe as a cost of service peculiar to municipal customers the franchise fees which TUEC pays to the cities it serves without a detailed investigation of the differences in the costs of serving rural and urban areas. Not only is it inappropriate to single out this one cost of service item for direct assignment to municipal residents on the basis of the record in this case, it is also inappropriate to do so on the basis of decisions made by this Commissoin in which a very different record was developed. A cost of service study made for HL&P cannot be the basis on which the Commission determines that direct assignment of franchise fees is appropriate for the TUEC system. Furthermore, it is likely that TUEC would incur a tremendous expense in performing a cost study which would identify in detail the cost differentials between urban and rural areas. TUEC and the Cities are correct in asserting that it is inappropriate to identify one item of expense and allocate it on the basis of geographical area without doing a complete cost of service analysis by geographical areas. In addition, as TUEC argues, once geographic ratemaking has begun, there are any number of distinctions which can be made between different cities, different rural areas and specific customer locations. All of TUEC's customers are served from an integrated system; thus all customers benefit from the rights of the company to maintain its facilities on municipal property.

Furthermore, it is clear that customer confusion and administrative burdens to the company would increase by virtue of geographical rates. Ratemaking at this Commission has proceded from the premise that within customer classes, customers pay rates based upon the average cost to serve. While it may be technically possible to identify the actual cost of serving each of TUEC's approximately 1.7 million customers, it is obviously not practical to do so.

There is no need to determine whether franchise fees are taxes; the fact remains such fees are part of the company's cost of service and must be recovered through its rates. It is recommended that the staff's proposal on this issue not be adopted, that the position of the Cities and TUEC be adopted, and that TUEC continue recovering these amounts from all customers other than the wholesale customers. While it is not recommended that the Commission should set rates based on differences in cost of serving different geographical areas, should the Commission decide that it is appropriate to do so, such rates should be developed from a cost of service study which has been developed on a geographical basis.

C. Allocation of Distribution Plant

1. TUEC Proposal

TUEC used its modified average and excess allocation methodology for the allocation of most distribution plant accounts between the demand and customer components. TUEC did use a minimum system approach to split two distribution plant accounts between the demand and customer components: Account 368, line transformers and Account 369, service drops. Transcript at 6922. TUEC acknowledges that in the past it has proposed a broadened view of what constitutes a minimum system and the appropriateness of making additional assignments based on customers. Transcript at 4282. This approach has been adopted by the Commission in the past, although TUEC argues that there is no clear precedent or policy. TUEC Brief on rate design at 11. TUEC concedes that there are good arguments on both sides of the issue (Transcript at 4282-4285), but submits that in view of the controversy and subjectivity involved, a conservative approach, such as that proposed by TUEC in this docket, should be taken.

2. TRA Proposal

TRA takes the position that a certain amount of distribution plant is recognized as that required to serve a customer regardless of the load that customer places on the system's capacity. TIEC Exhibit 1 at 2; Coop Exhibit 25 at 24; Transcript at 4355, 4918-4919. Under that view, the portion of the distribution plant which varies by the number of customers on the system, regardless of their load requirements, should be properly allocated to the customer component of the utility bill, and is often referred to as a minimum distribution system approach. Transcript at 5880; Coop Exhibit 25 at 23. TRA asserts that the remaining distribution plant should be classified as demand related and should be properly allocated to the demand portion of the customer's bill, thereby recognizing the load requirements of the customers served by the distribution system. TRA Brief on rate design at 34. TRA argues that while is correct that a developer may size the load required by a new subdivision, and the equipment used to serve that development must meet minimum load requirements, it is undisputed that the load between individual customers on a minimum-load-designed distribution system will still vary. Transcript at 4532, 4918; TRA Brief on rate design at 35. TRA submits that its proposal recognizes that the distribution system varies by number of customers and is related to the load or the demand placed upon the system (TRA Exhibit 48 at 15), and that, to a limited extent, distribution facilities are shared. Transcript at 5872.

TRA charges that the company failed to make this allocation by function in proposing their rates for the various classes (TRA Exhibit 48 at 15), except for Accounts 368 (transformers) and 369 (service drops). TRA Exhibit 48 at 17. TRA argues that if the objective of cost allocation is to properly classify and allocate plant investment and expenses into groups, each bearing a relationship to a measurable cost-defining characteristic of the services which are rendered, then it is axiomatic that the customer component characteristic of distribution plant should be allocated to the customer portion of the customer's bill. TRA Brief on rate design at 35. TRA submits that the demand and customer charge splits which TUEC proposes for Accounts 368 and 369 should also be applied to Accounts 364 (poles), 365 (overhead lines), 366 (underground conduit), 367 (underground conductors), 583 (overhead lines operation), 593 (overhead lines maintenance), and 594 (underground lines maintenance). It is TRA's position that the result of such an allocation is to have each customer pay for the relative costs associated with connecting that customer to the distribution grid. Coop Exhibit 25 at 24; TRA Brief on rate design at 35-36.

TRA proposes that the demand and customer split should be based upon demand and customer components weighted by circuit miles maintained by each operating devision. TRA Exhibit 48 at 18-19; Transcript at 5874-5878. In TRA's view, this weighting has the effect of removing the objections to weighting based upon meters, while answering the objections based on considerations of customer density. TRA also proposed to develop customer and demand splits for certain underground facilities. TRA refutes the company's suggestion in cross-examination that contributions in aid of construction required for underground facilities remove the customer split aspect of the costs for underground construction. Transcript at 5883. TRA argues that underground facilities are still common facilities which serve a number of customers. Transcript at 5878; TRA Brief on rate design at 37. The amount of plant contained in the underground accounts varies with the load demand, and it also varies to a certain degree by the number of customers rather than load. TRA submits that it is proper to recognize that variance by a split between the demand and customer components. TRA Brief on rate design at 37.

In brief, OPC criticized TRA's recommendation because TRA performed no independent analysis of what should constitute a minimum system on the TUEC system, but made recommendations based on manipulations of the results of prior minimum studies performed by TESCO, TP&L and DP&L. Transcript at 4697, 4699, 5874, 5877. OPC pointed out that TRA witness Stanley used TESCO data that is at least four years old. Transcript at 5875. OPC also charged that TRA witness Stanley agreed that all fixed costs should be classified as demand when addressing fuel issues, but in considering the allocation of the distribution system, which OPC views as obviously a fixed cost, Mr. Stanley ignored the definitions and allocated a substantial portion of the distribution system as customer costs. OPC Brief on rate design at 33.

TRA responds to the criticism of OPC by first pointing out that the information used by Mr. Stanley was obtained from the company, and that if the splits proposed by TRA are rejected because of some deficiency of the available information, once again an appropriate adjustment will have been discarded and the company will have successfully avoided an appropriate distribution rate base allocation. TRA Reply Brief on rate design at 3. TRA also argues that OPC has misrepresented and oversimplified Mr. Stanley's testimony concerning the allocation issues in nuclear fuel in process and fuel stock inventories, which addresses allocation splits between the demand and energy billing components, and his allocation for distribution plant using the minimum distribution system concept, which addresses allocation splits between customer and demand billing components. TRA submits that it is not inconsistent to recover fixed costs in the customer billing component if those costs relate to the customer nature of the costs. TRA asserts that Mr. Stanley carefully examined the true nature of the distribution system, and determined that a portion of that system relates to the number of customers on it, not the load imposed by those customers. TRA Reply Brief on rate design at 3.

3. TIEC Proposal

TIEC opposed the company's use of the modified average and excess methodology for the allocation of distribution costs. Conceding that distribution facilities must be sized in order to meet the maximum demand imposed on them, TIEC argues that these facilities must also be sized to meet localized maximum demands, which could occur at times different from the system peak. TIEC Exhibit 2 at 10-11. TIEC therefore recommends that a class noncoincident peak method be used to allocate demand related distribution capital costs and operating expenses. TIEC Brief on rate design at 22.

TIEC also opposes the company's proposal to include transmission voltage level customers in the allocation of distribution capacitors as being inconsistent with the principle of cost causation. TIEC argues that distribution capacitors are designed to improve the power factor of the utility's distribution system, and therefore distribution level customers cause the company to incur these costs. Transcript at 4916-4917. Therefore, according to TIEC, it is appropriate to allocate these costs only to distribution level customers. TIEC Brief on rate design at 21. TIEC asserts that the only justification offered by TUEC for its proposal was its assertion that all TUEC customers benefit from the installation of distribution capacitors because the capacitors improve the system power factor. Transcript at 4328-4329, 4857. TIEC argues that all customers benefit from the existence of high load factor customers, because they reduce the per-unit costs of production for all customers and enable the utility to operate its equipment more efficiently. Transcript at 3970-3971. TIEC points out that this benefit is not recognized in a cost of service study because such studies are designed to take into account costs, not benefits. TIEC submits that the company has therefore failed to justify its "benefit allocation" methodology and therefore its proposal to allocate distribution capacitors to transmission level customers should be rejected. TIEC Brief on rate design at 21-22.

TIEC also recommends that the Commission direct TUEC to perform a study of the minimum distribution system prior to its next rate case. Transcript at 5436-5437; TIEC Brief on rate design at 22.

4. Nucor Steel Proposal

As stated above, TUEC allocated the costs of distribution capacitors to all of its customers, including those taking service at transmission voltage. Transcript at 4327. Such facilities are intended to correct what would otherwise be an inadequate power factor downstream on the distribution system. Transcript at 4889. Nucor Steel urges that the testimony of several witnesses demonstrates that TUEC's allocation method is inappropriate because it has not been shown that transmission level customers benefit from these distribution capacitors. Coop Exhibit 24 at 31-34; Coop Exhibit 25 at 32; Tex-La Exhibit 21 at 41; TNP Exhibit 2 at 8-9; Transcript 4870. Nucor Steel asserts that the record indicates that wholesale customers provide their own distribution capacitors (Transcript at 4871, 4915-4916), and that high voltage power lines serving transmission customers inject large amounts of reactive power into the TUEC transmission system, thereby functioning like capacitors. Transcript at 4888. Nucor Steel accordingly argues that TUEC's proposed allocation of distribution capacitors to transmission voltage customers should be rejected. Nucor Steel Brief on rate design at 27.

5. TNP Proposal

TNP argues that because all wholesale customers purchase power from TUEC and resell to their own retail end use customers, they are mirror images of TUEC, having many of the same customer costs and service obligations. TNP argues that while the wholesale customers individually have distribution retail customers similar to TUEC, as a customer of TUEC, their cost causation patterns are radically different from TUEC's retail distribution level customers. TNP Brief on rate design at 35. TNP witness Schuman testified that all distribution level related expenses, other than some metering expenses, have been improperly imposed on the wholesale class in TUEC's cost of service study. TNP Exhibit 2 at 3-5. TNP asserts that TUEC has not shown that the wholesale customers are responsible for the cost of constructing and operating its distribution system and thus should be charged for those costs. TNP Brief on rate design at 35. TNP argues that wholesale customers do not cause those costs because they take power at higher service levels. TNP Brief on rate design at 35. It is TNP's position that since TUEC does not propose that its distribution level customers bear the cost of its transmission system, except to the extent those costs are necessary to energize and serve the distribution system, it therefore follows that the higher voltage level customers should not bear the cost of the distribution system which does not serve them. TNP Brief on rate design at 36.

6. Coops Proposal

The Coops oppose TUEC's proposal for allocation of investment and expenses in overhead lines. (Accounts 364 and 365). The Coops argue that the company incurs these costs as a function of both the number of customers and as a function of customer demand. Coop Exhibit 24 at 20; Coop Exhibit 25 at 24; Coop Brief on rate design at 13. Under the Coops' proposal, the number of miles of line and the number of poles and devices is a customer related cost, while the size of the facilities is a function of demand. The Coops urge that use of the minimum system approach to measure the customer component and allocation of the balance based upon demand is necessary to track the way in which the system is actually designed and operated. Coop Exhibit 25 at 24. Under this proposal, 82 percent of the account balances of Accounts 364 (poles) and 365 (overhead lines) should be allocated by the customer allocation factor and 18 percent upon the demand allocation factor. Coop Exhibit 24 at 24; Coops Brief on rate design at 13.

The Coops also oppose the company's allocation of investment and expenses in underground lines. Coop Exhibit 24 at 28-30; Coop Exhibit 25 at 27-30. The Coops urge that this cost assignment to the wholesale classes is improper and should be rejected. Coop Exhibit 24 at 28-30; Coop exhibit 25 at 30-33; Coops Brief on rate design at 13.

The Coops also submit that no revenue responsibility for distribution capacitors should be borne by transmission level service customers. Coop Exhibit 24 at 31-36; Coop exhibit 25 at 30-33. Finally, the Coops urge rejection of the company proposal to allocate to the wholesale classes a portion of the company's retailing expenses. Coop Exhibit 24 at 37-38; Coop Exhibit 25 at 33-35; Coops Brief on rate design at 13.

TRA challenged the Coops opposition to the company's proposal to allocate distribution capacitors to all classes of customers, including the wholesale customers. TRA points out that Coop witness Moore admitted on recross-examination that without the presence of distribution capacitors, the sytem power factor at the busbar would be reduced. Transcript at 4894. TRA argues that a reduction in system power factor has an adverse effect on all customers because such a reduction requires that additional generation be provided to account for such reduction. Transcript at 4859. TRA submits that allocation of distribution capacitors to the wholesale classes of customers is appropriate. TRA Brief on rate design at 38. OPC points out in brief that although the Coops proposed a minimum system to avoid allocation of Accounts 364 and 365 to wholesale customers, Coop witness Stover admitted that the desired result could be achieved through direct assignment. Transcript at 4974-4975; OPC Brief on rate design at 34.

7. Tex-La Proposal

Tex-La identifies two issues regarding assignment of distribution related costs: first, what portion of the investment in each distribution plant account should be classified as demand related and what portion should be classified as customer related, and second, what are the proper allocation methodologies to be used in allocating the demand component and the customer component of the distribution related plant. Tex-La argues that the company's proposed classification of distribution plant assigns either too little or none of the investment in certain plant accounts as being customer related. As an example, Tex-La points out Accounts 362, 364, 365, 366 and 367, which include investment in station equipment, poles, towers, fixtures, underground conduits and overhead and underground conductors and devices, which TUEC classified as entirely demand related. Tex-La argues that a portion of the investment in these accounts should properly be classified as customer related. Tex-La Exhibit 21 at 37-38; TRA Exhibit 48 at 15-18; St. Regis Exhibit 2 at 21; TIEC Exhibit 1 at 2-4; Coop Exhibit 25 at 22-26; Coop Exhibit 24 at 19-20; Tex-La Brief on rate design at 54. Tex-La further argues that in Docket No. 4321 (TP&L's last rate case) and Docket No. 5256 (DP&L's last rate case), the applicant utilities both classified a portion of the distribution system as customer related, and those classifications were approved by the Commission. Tex-La also points out that with the exception of its last rate case, Docket No. 5200, TESCO had previously classified a portion of these costs as customer related. TUEC witness Johnston, formerly employed by TESCO and sponsor of

TESCO's last cost of service study in Docket No. 5200, testified that the only reason he switched methodologies in that docket was in response to a preference of the staff to simplify the classification process. Transcript at 4824-4825. Therefore, he classified the amounts in these accounts as being either entirely demand related or entirely customer related. Tex-La asserts that the consensus of witnesses in this proceeding is that a portion of TUEC's distribution costs in each of its plant accounts should be classified and allocated as being customer related. Tex-La Brief on rate design at 56.

Tex-La then moves to the question of determining what portion should be classified as customer related. Tex-La acknowledges that there is a problem with available data in determining the proper classification of distribution related costs. Tex-La Exhibit 21 at 38-39; Tex-La Brief on rate design at 56. One generally accepted methodology, a minimum system approach, has been used by TP&L, TESCO and DP&L in previous rate proceedings, has been accepted by this Commission, and, Tex-La argues, should be used in this case. Tex-La refers to the testimony of several witnesses in this docket who advocate that a portion of distribution plant should be classified as customer related and have agreed that the minimum system approach should be used for TUEC. Tex-La Exhibit 21 at 37-39; TIEC Exhibit 1 at 5; Coop Exhibit 25 at 23-24; Tex-La Brief on rate design at 56. Because the company has not provided the data necessary to conduct a complete system study on the consolidated TUEC system, the proposals are based on estimates of the customer component. Tex-La argues that the most reasonable and accurate estimates are those based on the previous minimum system studies performed by the three operating companies, which were used by both Tex-La witness Daniel and St. Regis witness Eisdorfer. Mr. Daniel used the most recent minimum studies performed by TP&L and DP&L as a guide to classification of TUEC's distribution related costs. Tex-La Exhibit 21 at 39-40. Mr. Eisdorfer used DP&L's most recent study. St. Regis Exhibit 2 at 21-22. Tex-La submits that its propsoal is therefore the most reasonable and should be adopted. Tex-La Brief on rate design at 57.

Tex-La submits that because there are certain customer classes or subclasses which do not use or benefit from the company's investment in certain distribution plant, those classes or subclasses should not pay those costs. Tex-La identifies the primary costs in this category as underground facilities, distribution capacitors tand voltage regulators. Tex-La Exhibit 21 at 40-41. Tex-La disagrees with he company's allocation of a proportionate share of costs for distribution capacitors and voltage regulators to customers taking service at the transmission level. Tex-La argues that since these customers do not use TUEC's distribution plant, they should not pay for the associated costs. In response to TUEC's claim that distribution capacitors and voltage regulators reduce total system costs, thereby benefiting all customers, and should thus be allocated to all customers (Transcript at 4329), Tex-La argues that most if not all of the benefits flow to customers taking service at the distribution level. Tex-La concludes that customers served directly by TUEC's distribution system should pay for the costs associated with distribution capacitors and voltage regulators. Coop Exhibit 25 at 31; Tex-La Brief on rate design at 58 With respect to TUEC's investment in underground facilities, Tex-La argues that such plant is built to serve the company's urban customers. Tex-La Exhibit 21 at 41. Because TUEC's wholesale customers are not served from underground facilities and have their own investment in underground facilities to serve their own retail customers, Tex-La concludes that wholesale customers should not be required to pay for TUEC's underground facilities. Coop Exhibit 2 at 27-30; Staff Exhibit 38 at 8; Tex-La Brief on rate design at 59.

Tex-La also objects to the company's allocation of its classified distribution demand related costs on the basis of its modified average and excess factor adjusted to exclude the transmission level customers and to allow for losses to the distribution system. Tex-La argues that while the average and excess methodology may be a proper basis for allocating power supply costs, it has no relationship to the cost causation of demand related distribution costs. TIEC Exhibit 2 at 10-11; Tex-La Brief on rate design at 59. Tex-La supports the staff's position as recommended by staff witness Erdwurm that class noncoincident peaks should be used to allocate the demand component of distribution costs. Staff Exhibit 38 at 5-8; Tex-La Brief on rate design at 59.

Tex-La argues also that the allcoation of distribution customer related costs should not only vary with the number of customers, but also by the average investment per customer by class for a particular plant account. Transcript at 4705. Tex-La suggest that the customer component of line transformers should be allocated not only on the basis of the number of customers in each class but also on the basis of the average investment per customer in each class. Tex-La Brief on rate design at 59-60. The average investment for industrial or wholesale customers is usually more than for residential or commercial customers. Tex-La concludes that as a result, the customer allocatin factor for each distribution plant account should be based on the number of customers in each class served by those facilities, weighted by the average investment required to serve a customer in a particular class. Tex-La acknowledges that the information needed to make a proper weignting of customer related costs is unavailable. Transcript at 4705. Tex-La therefore recommends that the Commission order TUEC to provide the information necessary to perform a minimum system study and develop weighted customer allocation factors in its next rate filing package, but for purposes of this proceeding, Tex-La recommends use of the customer allocation factors developed by the company. Tex-La Brief on rate design at 60.

8. OPC Proposal

OPC recommended adoption of TUEC's allocation of the distribution system except for the corrections which OPC submits should be made to the allocation of load management costs and line transformer costs. OPC Exhibit 55 at 27-31. OPC witness Dr. Andersen criticized TUEC's direct assignment of load management costs because the benefits of load management are shared among classes. OPC Exhibit 55 at 28-29. TUEC witness Tanner testified that the planning process begins with projections of demand and energy requirements in contemplation of load management. TUEC Exhibit 1B, Tanner at 4-5. OPC submits that to the extent that load management permits the avoidance of future generation, transmission and distribution facilities, all customer classes avoid additional costs. OPC Exhibit 55 at 28; OPC Brief on rate desing at 32. Therefore OPC recommends that the costs of load management programs be allocated to classes in proportion to class responsibility for the composite of generation, transmission and distribution plant. OPC Exhibit 55 at 30; OPC Brief on rate design at 32.

OPC also criticized TUEC's allocation of the costs of line transformers. OPC witness Dr. Andersen allocated the costs of line transformers based on diversified class demands at secondary voltage, rather than by the TUEC method which establishes a customer component based upon a hypothetical minimum sized facility and demand component in excess of the assumed minimum. OPC Exhibit 55 at 30. OPC argues that the problem with the minimum system approach is that low volume customers are charged twice for the same transformer: once in the customer component of the minimum sized transformer serving their needs, and again through the demand allocation of transformer costs in excess of the minimum. OPC points out that if the minimum transformer is capable of meeting all of a customer's demand, that customer's share of excess costs should be zero, but the company has not made the required adjustment to demand. OPC Exhibit 55 at 30; OPC Brief on rate design at 32. OPC further argues that the unfairness of the TUEC approach was demonstrated by use of a hypothetical during cross-examination of staff witness Erdwurm. Transcript at 6928-6929. OPC asserts that the staff's approach in allocation of line transformers compounds the problem of the TUEC approach. The staff accepted the company's minimum sized facility concept but Mr. Erdwurm also removed TUEC's weighting by meters. OPC alleges that this adjustment magnifies the errors generated by a minimum system analysis. OPC argues that recognizng that the distribution system is sized to meet demand and that costs increase as demand increases (Transcript at 5123-5125A, 6927-6929), the cost based and fair way to allocate line transformer costs is on the nondiversified demand basis proposed by OPC witness Dr. Andersen. OPC Brief on rate design at 32-33.

OPC further criticized the recommendations of those parties proposing that a minimum system concept should be applied for the entire distribution system. TIEC Exhibit 1; TRA Exhibit 48; Coops Exhibit 24; Tex-La Exhibit 21. OPC points out that primary voltage customers would favor such an approach because a substantial portion of distribution costs would be classified as customer related, and that as much as 99 percent of the customer related costs in Accounts 364 and 365 would be allocated to customers served by the secondary distribution system. Transcript at 4970; OPC Brief on rate design at 33. OPC criticizes Tex-La and TRA for not performing an independent analysis of what should constitue a minimum system on the TUEC system but instead making recommendations based on manipulations of results of prior minimum system studies performed by the TUEC operating divisions, TESCO, TP&L and DP&L. Transcript at 4697, 4699, 5874, 5877. OPC argues that the notion that distribution investment would be required without any demand does not mean that such investment varies with the number of customers; rather, OPC urges that it means distribution investments are based on engineering expectations of demand and upon the size and difficulty of the terrain and the number of miles that must be transversed. OPC Brief on rate design at 33-34. Coop witness Stover recognized that variables in distribution cost incurrence include number of miles, difficulty of terrain, pole height, etc. Transcript at 4972. OPC submits hat the minimum system concept overlooks a weak correlation between the area or mileage of a distribution system and the number of customers served. Transcript at 5818. OPC argues that the primary cost consideration of the TUEC system planners who designed the distribution system is expected load or demand (Transcript at 5123-5125A), and that cost classification and allocation should reflect that fact. OPC Brief on rate design at 34.

TRA challenges OPC's notion that customer density relates to the minimum distribution system concept. TIEC witness Hafer testified that although customer density may affect a distribution system, density itself has nothing to do with the customer component of the minimum distribution system. Transcript at 5431. TRA argues that density is a problem in designing rates within a class, but that the density aspect itself does not negate the fact that there is still a customer component involved in providing the equipment necessary to make electricity available to customers. Transcript at 5431. TRA alleges that OPC's attempt to raise the issue of direct assignment of facilities is a straw man and the facts remain that it is impossible to assign all distribution facilities and that distribution facilities may not be customer specific. TRA Brief on rate design at 36-37. TRA argues that assignment begs the question and fails to recognize that a certain amount of plant varies by number of customers rather than by load imposed, even though it is not necessarily customer specific. TRA Brief on rate design at 36-37.

9. Staff Proposal

Through the testimony of staff witness Erdwurm, the staff proposed the allocation of distribution plant utilizing annual *noncoincident* peak demand. Mr. Erdwurm utilized the annual class peak to reflect the fact that the company annualizes its system planning process. Because the winter peaking areas of predominantly electric homes contributed to the company's decision to provide and plan for facilities, the staff determined that it is more appropriate to allocate the distribution plant on an annual rather than a summer peaking basis. Staff Exhibit 38 at 6-7; TIEC Exhibit 1 at 4; General Counsel Brief on rate design at 20.

The only other issue related to allocation of distribution plant discussed by General Counsel in brief is with respect to the allocation of distribution capacitors to transmission level customers of TUEC. TUEC witness Johnston testified that all TUEC customers taking service at less than unity power factor caused the addition of some caacitors. Transcript at 4328. Staff also points out that capacitors are not installed for a particular class of customers but rather to make the transmission of energy and power over distribution lines and transmission lines more efficient and with fewer line losses. Transcript at 4328. General Counsel argues that capacitors correct low power factors, thus minimizing line losses to the benefit of all customers on the TUEC system. Transcript at 4622. If the system is not at its proper power factor, capacitors must be added to correct it. Transcript at 4859. Therefore, General Counsel submits that the distribution capacitors on the TUEC system do assist the company in maintaining the appropriate power factor, limiting line losses, to the benefit of all customers.

10. Recommendation

OPC's suggested refinements to TUEC's allocation of the distribution system should not be adopted. The direct assignment of load management costs to the classes within which they were incurred appears to be reasonable. OPC's proffered justification for its proposed allocation of line transformers assumes that the minimum transformer is capable of meeting all of a customer's demand, an assumption not revealed to be factually based.

The proposition that transmission level customers should not be allocated the costs of distribution capacitors should also be rejected. TIEC argues that transmission level customers do not cause incurrence of these costs, and Nucor Steel argues that transmission level customers do not benefit from them. As with any cost assignment, it is sometimes difficult to determine causation of an benefit from specific categories of costs. Nevertheless, distribution capacitors improve the system power factor; without them, the reduced system power factor would have an adverse effect on all customers by requiring that additional generation be provided to compensate for such a reduction.

TUEC is correct when it argues in brief that absolute exactness in the assignment of costs is not expected and would be an impossible goal in ratesetting where generalizations and averages must necessarily be made. TUEC Brief on rate design at 11. While conceding the theoretical validity of a minimum system approach for distribution plant accounts, it must also be recognized that there is no evidence in this record supporting the recommendations of the proponents of the minimum system approach. Re;oamce on minimum system studies performed by one or more of the TUEC operating companies for prior rate cases is not adequate to support the estimates proposed by these parties. TRA suggests that an appropriate adjustment should not be avoided simply because there is some deficiency in the available information. This argument simply does not support use of data which is inadequate and outdated. It is therefore recommended that the company's allocation of distribution system accounts be accepted; TUEC should also be required to perform a study of the minimum distribution system and present that study in its next rate case.

D. Allocation of Costs to Wholesale Customers

1. TUEC Proposal

In response to the proposals of the wholesale customers to seek to reduce the allocation to them of certain distribution plant as well as expense accounts from cost of service TUEC responds that its allocation process has been illustrated to be based on averages and that it is fair to all customers. TUEC argues that an attempt to dodge certain expenses without offering a perfect cost of service study which also recognizes and reallocates benefits that the wholesale customers receive (even though such benefits are not generated by them), is unfair. Without such a study, TUEC argues, the wholesale customers' recommendations are no more than an offer "to tote the stool and require others to shoulder the piano." Docket No. 5200, Examiner's Report at 56; TUEC Brief on rate design at 14.

2. TNP Proposal

TNP characterizes as improper the TUEC proposal to recover from the wholesale customers some of the costs of its customer service and customer information and sales programs, because in TNP's view these programs do not benefit wholesale customers. TNP argues that as resellers of power, the wholesale customers cannot take advantage of these retail customer programs. TNP witness Schuman testified that these costs apply only to retail customers, both high and low voltage level retail customers. TNP Exhibit 2, Exhibit AHS-2. TNP argues that these types of programs benefit the wholesale customer class only when they individually participate, or when their own retail customers can take advantage of such programs. Conceding that it is arguable that anything which reduces the overall power needs of TUEC as a whole inures to the benefit of all customers, TNP still contends that the benefits of the programs identified by its witness Schuman to the wholesale class are so tenuous as to be nonexistent. TNP argues that to have a quantifiable benefit, a program must allow the utility's customer to influence his/her own bill by the economic choices presented by the program, and that while TUEC's residential conservation program may directly benefit TUEC residential customers, they are of no significant value to a TNP customer who cannot take advantage of those programs. TNP Brief on rate design at 36. TNP further argues that while the overall dollar impact of TUEC's cost of service proposal may not be significant when flowed through to the wholesale utilities' end users' bills, TUEC's cost of service study in this respect violates the cost causation principles governing electric rate design in this state. TNP Brief on rate design at 37. TNP concludes that TUEC has not shown that the costs identified by Mr. Schuman are caused by the customers from whom TUEC proposes to recover them, and that TUEC has failed to meet its burden of proof on this issue. TNP Brief on rate design at 37.

TNP also argued that TUEC had failed to demonstrate that the general advertising expenses in Account No. 930 are caused by or are a benefit to its wholesale customers, and that therefore these costs should not be recovered from this class. TNP refers to the testimony of TUEC witness Scarth, who stated that TUEC advertising expenses were not incurred to promote sales, but to encourage energy conservation, inform customers of special services available to them, and provide customers with sufficient information to make informed decisions which directly affect their electric bills. TUEC Exhibit B-1 Scarth at 2-3. TNP concludes that since TUEC's energy conservation related expenses are already included in Account No. 909, the $2,815,251 in Account No. 930 relates solely to the last two categories. Thus, TNP argues, TUEC has failed to show that these costs were incurred to benefit the wholesale customers, because neither the wholesale customers individually nor their respective retail customers can take advantage of the programs TUEC is advertising. TNP characterizes the benefit of such programs to wholesale customers as being too nebulous to be given credence. TNP Brief on rate design at 38. TNP argues that while it may help a TNP customer who reads the newspaper in which TUEC advertises its residential conservation programs to know that generically such programs exist, that TNP customer benefits only that when he/she learns that TNP has such programs that he/she can take advantage of. TNP Brief on rate design at 38. TNP argues that TUEC proposed to violate the principle of imposing costs only on cost causers without conclusively demonstrating why an exception to that principle is in the general public interest. TNP Brief on rate design at 38-39. TNP argues that without such a showing, TUEC's rate would be unreasonably preferential in violation of the Public Utility Regulatory Act. TNP concludes that none of the Account 930 general advertising expenses identified by Mr. Schuman in his testimony should be imposed on the wholesale class.

TNP also argues that TUEC has not demonstrated that miscellaneous general expense items in Account No. 930 benefit wholesale customers and these costs should not be recovered from this class. In TNP Exhibit 2, Exhibit AHS-6 and Exhibit AHS-7, TNP witness Schuman identified $128,758 which he concluded in no way benefits TUEC's wholesale customers or their respective retail end use customers. TNP argues that these costs might not even benefit TUEC's own customers, but conceded that since that might fall within the categories allowed by the Commission's current Substantive Rules, they should be recovered only from those customers who do benefit from them. TNP alleges that TUEC's wholesale customers do not benefit from the fact that TUEC has generated good will through charitable contributions in cities in which TUEC serves. TNP's position is that the wholesale customers receive no tangible or quantifiable benefits from puppet shows and movies shown to schools in TUEC's retail service areas, except perhaps in the few areas of multiple certification. TNP Brief on rate design at 40. TNP argues that this cost allocation proposal also violates the cost causation and recovery principles without demonstrating a paramount public interest benefit, and that therefore these costs should not be recovered from the wholesale class. TNP Brief on rate design at 40.

3. Tex-La Proposal

Tex-La agrees with the other wholesale customers of TUEC that the wholesale class should not be allocated any customer service and information expenses. Tex-La Exhibit 21 at 31; Coop Exhibit 25 at 33; TNP Exhibit 2 at 3; Tex-La Brief on rate design at 63. Tex-La witness Daniel testified that the Uniform System of Accounts describes these expenses as costs "incurred in providing instruction or assistance to customers, the object of which is to encourage safe, efficient and economical use of the utility's service" and as costs "incurred in activities which primarily convey information as to what the utility urges or suggests customers should do in utilizing electric service to protect health and safety ,to encourage environmental protection, to utilize their electric equipment safely and economically, or to conserve electric energy." Tex-La Exhibit 21 at 30-31. It is Tex-La's position that the majority of these expenses relate directly to the end use of electricity or retail activities, and should be allocated to such end users. Tex-La Exhibit 21 at 31; Coops Exhibit 25 at 34; Tex-La Brief on rate design at 63. Tex-La further points out that the retail customers of TUEC's wholesale customers are being asked to bear the cost of services either not available to them or not caused by them. TNP Exhibit 2 at 4; Tex-La Brief on rate design at 63-64. Tex-La argues that wholesale customers must incur similar expenses in the course of providing service to their own retail customers (Coops Exhibit 25 at 34), and therefore the end users of TUEC's wholesale customers should not be required to pay for both TUEC's customer service and information expenses and for their own supplier's customer service and information expenses. TexLa Brief on rate design at 64.

With respect to Account 908, customer service and information expenses, TUEC segregated the load management expenses and allocated them directly to only those customer classes for which the cost was directly related. Transcript at 4483. Tex-La argues that as was done in allocating the load management expenses included in Account 908, none of the other TUEC load management expenses should be allocated to the wholesale class because the members of that class pay for their own load management programs, which likewise benefit every customer in the TUEC system. Tex-La Exhibit 21 at 31; Transcript at 4330, 4439; Tex-La Brief on rate design at 64.

Tex-La also opposes the allocation of TUEC's sales expenses to the wholesale class. Tex-La Exhibit 21 at 32; Coops Exhibit 25 at 33; TNP Exhibit 2 at 3; Tex-La Brief on rate design at 64. Tex-La witness Daniel testified that according to the Uniform System of Accounts, sales expenses are made up of demonstration, sales and advertising costs incurred "to promote or retain the use of utility services by present or prospective customers." Tex-La Exhibit 21 at 31-32. TUEC's activities giving rise to expenses and Accounts 911, 912 and 913 include advertising, providing information to prospective new industrial customers in the TUEC service area and advice to residential customers on energy conservation, community service activities such as demonstrations and energy management, educational presentations, lectures, exhibitions and displays on energy conservation. TNP Exhibit 2, Exhibit AHS-3; Tex-La Exhibit 21 at 32. Tex-La argues that these activities are directed towards TUEC's retail customers and that in addition, the wholesale customers should not be expected to pay for TUEC's efforts to attract new industrial customers that the wholesale customers themselves may be trying to attract. Tex-La Exhibit 21 at 32; Tex-La Brief on rate design at 65. Thus, Tex-La concludes that sales expenses are related primarily to retail customer activities and as such should be allocated to TUEC's retail customers only. Tex-La Exhibit 21 at 32; Coops Exhibit 25 at 35; Tex-La Brief on rate design at 65.

Tex-La also opposes the allocation of any general advertising expenses to the wholesale class. Tex-La Exhibit 21 at 33; Coops Exhibit 25 at 33; TNP Exhibit 2 at 15; Tex-La Brief on rate design at 65-66. Tex-La witness Daniel referred to the testimony of TUEC witness Scarth that the principle purpose of general advertising is to inform customers of "special services available-average billing plan, bank draft payment of electric bills, third party notification and special due dates for senior citizens." Tex-La Exhibit 21 at 32-33; TNP exhibit 2, Exhibit AHS-4. General advertising also includes efforts to "inform customers of corporate plans and events that impact the availability of the price of electricity." Tex-La Exhibit 21 at 32-33. Tex-La argues that TUEC's advertising programs are directed at its retail customers, that these advertised services are not available to the wholesale customers' own retail customers, and that the wholesale customers must do their own advertising of such services. Tex-La Exhibit 21 at 33; Tex-La Brief on rate design at 66. Tex-La argues that these expenses should not be allocated to the wholesale class because TUEC's general advertising expenses are direct toward the retail customers. Tex-La Brief on rate design at 66.

Finally, Tex-La argues that customer service and information expenses, sales expenses and general advertising expenses usually are not allocated to wholesale customers. Coops Exhibit 25 at 34. Tex-La refers to Docket No. 4321, the last TP&L rate case, in which these expenses were not allocated to the wholesale class. Coops Exhibit 25 at 34. Tex-La concludes that they therefore should not be allocated to the wholesale customers in this case. Tex-La Brief on rate design at 66.

4. Coops Proposal

In brief, the Coops argue that the company's proposed allocation to the wholesale class of a portion of the company's retailing expenses should be rejected. Coops Exhibit 24 at 37-38; Coop Exhibit 25 at 33-35; Coops Brief on rate design at 14.

5. Staff's Proposal

In brief, General Counsel points out that upon cross-examination, TNP witness Schuman could not specifically quantify any of the benefits received by the residential consumers for certain advertising expenses. Mr. Schuman had not conducted any studies regarding benefits received from these expenditures. Transcript at 5991-5993. Te-La witness Daniel could not identify how certain advertising costs benefited one class customers more than another. Transcript at 4708-4709. General Counsel argues that certain customer services provided by the company to wholesale customers would not be needed by the residential customers of TUEC, for example, any discussion concerning bulk power supply contracts or delivery points is solely within the realm of services provided to wholesale customers, and yet this too would be a customer service expense of the company. Transcript at 5000-5001. General Counsel argues that if TUEC's load management services lead to a reduction of load on the TUEC system, all TUEC customers would benefit from this reduction (Transcript at 5002), perhaps in the form of deferring construction of plants and the attendant costs. General Counsel concludes that the wholesale customers do in fact receive a benefit from the load management services provided by TUEC. General Counsel Brief on rate design at 21. General Counsel submits that the expenses for customer accounts should be allocated to all TUEC customers since these accounts do not benefit only the retail class but also provide benefits to the wholesale class. General Counsel points out that although the wholesale customers argue that the residential customers either caused or benefited from the company's expenditures, no studies were done which truly capsulized such benefit. General Counsel Brief on rate design at 22.

6. Recommendation

It is conceded that while a perfect cost of service study which functionalizes, classifies and allocates costs necessary to serve each and every customer of a utility is technically possible, it does not appear to be practical. Even if the costs of such a study were not prohibitive, the utility's cost of service study would necessarily be required to be completely redone in order to pursue such a philosophy of ratemaking to its ultimate limit. No wholesale customer intervenor presented a cost of service study which completely evaluated both the costs and the benefits caused and received by each and every customer class. While it can also be concluded that expenditures such as general advertising expense, contributions and donations, membership dues and fees and public relations expenses, often result in no tangible or direct benefit to individual customers, the piecemeal reallocation of such costs on the basis that certain customers do not benefit from them is not advisable. Such a reallocation would need to be approached after a thorough reevaluation and cost of service study. To the extent recommended elsewhere in this report, the expenditures are reasonable and should be recovered from all customer classes as recommended by TUEC.

E. Classification of Production Maintenance Expense

St. Regis witness Eisdorfer proposed that production maintenance expense be classified to demand rather than to energy as proposed by TUEC. St. Regis Exhibit 2 at 22. Mr. Eisdorfer reasoned that maintenance is largely preventative in nature and that the magnitude of the expense is affected by the amount of capacity employed to meet peak demand. TUEC asserts that there is no factual support in the record for his statements. TUEC argues that a power plant is a machine, and that if it is not used, very little effort is necessary to keep it in proper condition; conversely, if it is used, more maintenance will be needed. TUEC urges that absent a conclusive showing that maintenance is a function of demand, the St. Regis proposal should not be adopted. No other party discussed this issue in brief. TUEC's proposal to classify production maintenance expense to energy is reasonable, and should be adopted.

F. Allocation of Federal Income Tax

Through the testimony of its witness Gail Hafer, TIEC proposed an alternative approach for allocating federal income tax liability. TIEC Exhibit 1 at 6. TUEC allocated all federal income tax expense relative to taxable income for each class. Transcript at 4329. Ms. Hafer used various allocation methods based upon particular aspects of tax expense. TIEC Exhibit 1, Exhibit GHH-1, Schedule 4, page 1 of 2. A comparison of the proposals of TUEC and of TIEC is shown on TIEC Exhibit 1, Exhibit GHH-1, Schedule 4, page 2 of 2. TUEC points out that transmission customers fare better under her approach by approximately $500,000, whereas residential customers would bear an additional $800,000.

TUEC argues that TIEC's proposal is an attempt to refine a particular aspect of the cost of service study without making similar refinements throughout. TUEC argues that a cost of service study is necessarily general in nature and that it would always be possible for a particular group to point out possible refinements that have potential merit. Transcript at 4479-4480. As with the proposals of the wholesale customers to reduce the allocation of certain expenses to the wholesale customers, this proposal of TIEC must also fail. It is inappropriate to make piecemeal adjustments to a cost of service study without a full scale revision of the cost of service study. TIEC did not discuss this issue in brief; no other party made a similar recommendation. TUEC's proposal for allocating federal income tax liability is reasonable, consistent with prior Commission decisions, and should be adopted.

G. Allocation of Fuel Inventories

1. TUEC Proposal

In this docket, TUEC proposes to allocate fuel stock on the basis of its energy allocation factors. Other parties in this docket object to such an allocation methodology; TUEC asserts that all fuel, whether maintained in inventory on an average basis or burned, is for the purpose of providing energy. TUEC Brief on rate design at 12.

2. OPC Proposal

OPC witness Dr. Andersen classified fuel inventories in lignite and oil, and nuclear fuel in process as energy, but performed the allocation in a more detailed manner. Dr. Andersen determined the fuel inventories for each station and then allocated the inventories to months based on monthly fuel burn by fuel type. Within each month, inventories were allocated to classes on the basis of energy. OPC Exhibit 55 at 21. Dr. Andersen allocated nuclear fuel in process on the basis of class contribution to loss adjusted energy. OPC Exhibit 55 at 22; OPC Brief on rate design at 31.

3. Proposal of TRA, Tex-La and Nucor Steel

TRA witness Stanley proposes that nuclear fuel in process and fuel stock inventories should be treated as fixed costs and allocated in the manner in which fixed costs are ultimatley allocated in this docket. TRA Brief on rate design at 29. TRA refers to the company proposal to allocate $156,128,052 in nuclear fuel in process and $96,581,903 in fuel stock inventories on the basis of the annual energy consumed by each customer class. TRA Exhibit 48 at 10. TUEC has included both nuclear fuel in process and fuel stock inventories in its rate base upon which it is requesting a return to be paid by its customers. Rate filing package, Schedule B, page 1 of 5; Transcript at 4346. TRA claims that in essence the company is treating these two items at the present time as an asset, not as an expense. TRA Brief on rate design at 30. TRA argues that it is undisputed that at the time nuclear fuel in process and fuel stock inventories are used to produce actual kilowatt hours of electricity, the appropriate accounting treatment is to expense these two items because their consumption is directly related to the number of kilowatt hours of electricity actually produced by the company. Therefore, TRA argues, at the time of actual consumption these expenses should be recovered through the energy component of the customer's bill. TRA Brief on rate design at 30.

TRA asserts that the question presented is whether it is appropriate to allocate these two items in the manner in which other fixed costs are allocated prior to their actual consumption. TRA argues that the treatment by the company of these two items before actual consumption is distinguishable from the company's proposed treatment at the time they are used to produce kilowatt hours, that is, these two items are treated as assets at the present time, upon which a return is earned; at the time of consumption, they will be treated as items to be expensed. Transcript at 4346; TRA Brief on rate design at 30. TRA asserts that such treatment recognizes that at the present time the account levels of these two items are not directly related to the number of kilowatt hours actually being produced. TRA Brief on rate design at 31.

TRA further asserts that nuclear fuel in process cannot be tied to current kilowatt hours generated because the generation plant to which it has been allocated is not in service, nor has that plant been fuel loaded. Therefore, according to TRA, nuclear fuel in process cannot vary with kilowatt hours presently produced or with seasonal energy demand variables. Transcript at 4349. If nuclear fuel in process is currently being used to generate kilowatt hours, it cannot be related to the energy consumption of the company's categories and it is inappropriate to treat it as though it were. Transcript at 4349; TRA Brief on rate design at 31. Thus, argues TRA, the level of this account at the present time and until such time as it is expensed is related to the size of the plant for which it has been acquired rather than kilowatt hours produced. TRA Exhibit 48 at 12. Further, TRA points out that an examination of the fluctuations in the fuel stock inventories reveals that the level of this account also does not vary in relation to kilowatt hours actually generated. TRA Exhibit 48, Exhibit RJS-2, page 3 of 3.

TRA asserts that the purpose for maintaining fuel stock inventories is to insure system reliability as a hedge against shortages in fuel supplies caused by curtailment. Fuel that is maintained as a fallback in the event of shortages, as compared to fuel which is acquired for day-to-day burning purposes, does not relate directly to the actual kilowatt hours generated until such time as it is actually burned. TRA Brief on rate design at 31. Transcript at 4350-4351. At the time it is actually burned, the fuel should be expensed and be recovered in the energy component of a customer's bill. TRA Brief on rate design at 2.

TRA concedes that fuel stock inventories actually consist of fixed and variable cost components because of some usage. TRA Exhibit 48 at 11; Transcript at 4350-4351. TRA argues, however, that minimum fuel stock inventories are kept on hand at all times. The inventories should be split between the demand and energy billing components, recognizing the minimum volumes kept on hand and the limited consumption. TRA argues that this split accounts for both the fixed and variable nature of these inventories. TRA Exhibit 48 at 11; Transcript at 4350-4351. The fixed portion of the inventories, TRA argues, should be based upon the monthly volumes of inventory for the test year as set forth in the testimony of TRA witness Stanley. TRA Exhibit 48, Exhibit RJS-2, page 3 of 3. Reference to this exhibit reveals that fuel stock inventories at year end were higher than at any other time during the test year with the exception of January 1983, year end being September 30, 1983. It also reveals that the levels of fuel inventory were at their highest on a consistent monthly basis during the colder parts of the year, December through February. The company's system peaking month of August 1983 had higher inventories than did October 1982. TRA concludes that the actual balance in the company's fuel stock inventory does not vary in relation to seasonal variation of energy production or actual generated kilowatt hours as do fuel supplies purchased to be burned on a daily basis. TRA Brief on rate design at 32.

TRA further points out that the NARUC cost allocation manual recognizes the different treatment of nuclear fuel in process and fuel stock inventory and properly allocates those items to the demand component of the customer's bill. Finally, TRA argues that in Docket No. 5256, DP&L's last rate case, the Commission adopted TRA's request concerning the allocation of nuclear fuel in process and fuel stock inventories, but modified that request to place only one half of the amounts in the demand component and one half in the energy component. TRA argues that it is appropriate to move all the way in this docket; by whatever cost allocation methodology is ultimately adopted, the Commission should allocate fuel stock inventory and nuclear fuel in process in the same manner that the remainder of all fixed capital costs are allocated. TRA Brief on rate design at 33.

In its Reply Brief on rate design, Tex-La stated its concurrence with the position of TRA. Tex-La Reply Brief on rate design at 26. Conceding that fuel use is related to energy production, Tex-La asserts that fuel stock is retained regardless of the level of energy production. Transcript at 4348-4349; TRA Exhibit 48 at 11. Tex-La agrees that fuel stock inventories are maintained to insure system reliability in the event of fuel shortages. TRA Exhibit 48 at 11; Transcript at 4348-4349. Tex-La concludes that fuel stock and nuclear fuel in process should be classified as demand related and allocated according to the demand allocators for production. Tex-La concurs with the position of TRA to allocate the minimum inventory on demand data and the remainder on energy. Tex-La Reply Brief on rate design at 26.

Nucor Steel, in its Brief on rate design, agreed with the recommendation of TRA regarding allocation of *fuel inventory*. *Nucor Steel Brief on rate design* at 28-29. With respect to nuclear fuel in process, Nucor recommends that it be allocated on the basis of one-half as demand and one-half as energy, as ordered by the Commission in Docket No. 5256, the most recent DP&L rate case. Nucor Brief on rate design at 29; Nucor Reply Brief on rate design at 8-9.

OPC criticized the position taken by TRA and concurred in by Tex-La and Nucor Steel, as solely dependent upon the archaic notion that fixed costs must be classified as demand. Transcript at 5877. OPC argues that if consumption of lignite and nuclear fuel displaces consumption of natural gas, then consumers receive the benefits of lower fuel expense in proportion to their kwh consumption. If the benefits of nuclear and lignite fuel are to be distributed on an energy basis, OPC argues that it is appropriate to allocate the costs associated with fuel inventories on an energy basis rather than by class coincidence with peak demand. OPC concludes that it is more logical to suggest that all fuel should be classified as energy than to suggest that arbitrary notions of fixed versus variable costs should determine classification. OPC Brief on rate design at 31.

TUEC pointed out that the TRA proposal to reallocate fuel stock results in the shifting of approximately $3,250,000 of revenue requirement away from the general service class, and also results in shifting approximately $4,600,000 to the company's residential class. TRA Exhibit 48; Exhibit RJS-2, page 2 of 3. TUEC challenges TRA's rationale that fuel stock remains relatively constant and therefore should be equated entirely with demand (reliability) and so allocated. TUEC argues that while such theory may sound meritorious, the fact remains that all fuel, whether maintained in inventory on an average basis or burned, is for the purpose of providing energy. TUEC Brief on rate design at 12.

4. Recommendation

TRA, Tex-La and Nucor Steel presented some good arguments for distinguishing in the cost allocation process fuel inventories maintained for the purpose of insuring reliability and fuel acquired for day-to-day operations, and for allocating fuel inventories maintained to insure reliability on both demand and energy, since such inventories consist of both fixed and variable costs. However, the shifts in revenue requirement appear to be significant under the TRA proposal, as pointed out by TUEC in brief. Because of the increase to the residential class, it is recommended that the approach offered by Nucor Steel be utilized here, that is, to allocate one-half as demand and one-half as energy, as ordered by the Commission in Docket No. 5256, because of the difficulty in defining these costs as energy related or demand related.

XII. Rate Design
A. Allocation of Revenue to Classes

1. TUEC Proposal

In its brief, TUEC asserts that the concept that each customer class should generate a rate of return approximately equal to the system rate of return was uniformly endorsed by the parties. TUEC Brief on rate design at 2. The company's cost of service study reveals that all customer classes are essentially at unity except the municipal classes (Transcript at 4339); the company urges that the move toward unity which it proposes in this docket for the municipal classes is essential. TUEC Brief on rate design at 2. While it is accurate that no party mounted an ardent challenge to this goal, several parties did point out that movement toward unity must be tempered with other considerations.

2. Cities Proposal

The Cities point out in brief that they have not opposed the policy of the Commission of allocating the revenue requirement among the various classes of customers in such a way as to avoid unsubstantiated differences in rates of return for different classes of customers. Cities Brief on rate design at 3-4. The Cities argue that their proposals would have the effect of continuing the movement toward equalized rates of return among the customer classes; however, the Cities urge recognition of the fact that it may not be possible, proper or desirable to actually achieve the goal of equalized class rates of return. Cities Brief on rate design at 4.

Cities witness Patterson discusses the variables affecting the class contribution to the system return; for example, changes in demand allocation methodologies, shifts in consumption patterns, consolidation of separate rate groups and reassignment of customers from one class to another can cause the objective of uniform rates of return not to be achieved. Cities Exhibit 15 at 6-7. The Cities argue that, assuming the desirability of uniform rates of return, perfection in achieving that goal is not necessarily attainable despite the best intentions. The Cities urge that it is therefore entirely reasonable to pursue a somewhat more modest objective and to adopt a revenue allocation method which continues the movement toward equalized rates of return for the major customer classes, but which moderates the impact of the rate changes on those customer classes or subclasses which would otherwise experience as much as twice the system average increase or decrease. Cities Brief on rate design at 4. The Cities urge adoption of Mr. Patterson's proposal which would allocate increases for rate classes as follows: for municipal pumping, street lighting and municipal service, the increase or decrease should be capped at 1.5 times the general business average increase; for the guard lighting class, the increase would be 0.9 of the general businees average increase; the wholesale rate should be the general business average increase and for the residential, general service and transmission service classes, the resultant balance should be allocated in proportion to the percentage base rate revenues. Cities Exhibit 15 at 6.

3. TRA Proposal

TRA urges that the relative rate of return is an effective measure for examining the relative subsidization between classes of customers, and that without such a yardstick, it is impossible to determine to what extent one class is being called upon to bear the costs of serving another class. Relative rates of return inherently consider not only return but allocation of plant and expenses as well, and TRA urges retention of relative rates of return as an effective tool for guaging the impact of the ultimate decision concerning revenue recovery from the classes. TRA further urges the Commission to move all classes to a relative return of unity. TRA Brief on rate design at 28. TRA argues that placing customers at a unity relative rate of return in conjunction with properly designed rates will convey the correct pricing signal concerning the cost of providing electricity utilizing nonrenewable energy resources. TRA Exhibit 48 at 7; TRA Brief on rate design at 29. TRA further urges that the Commission should no longer hestitate to set all classes at unity, thereby removing subsidization, and should do so in this docket. Transcript at 5870-5871; TRA Brief on rate design at 29.

4. St. Regis Proposal

Through the testimony of its witness Kenneth Eisdorfer (St. Regis Exhibit 2, Schedule 8), St. Regis concluded that TUEC's proposed class revenue distribution was deficient because six of the company's eight customer classes would fail to move toward cost. St. Regis Exhibit 2 at 23. Mr. Eisdorfer recommended a class revenue distribution which would move each class to the maximum extent possible toward its respective cost of service, on the condition that no class be assessed a revenue increase more than twice the average percentage increase in the total company base rate revenues at TUEC's proposed revenue requirement. St. Regis argues that this approach would have the effect of increasing the equity among customer classes, as well as reducing the potential for earnings instability. St. Regis Exhibit 2 at 24. As an alternative, St. Regis proposed that if TUEC is granted a different base rate revenue requirement than that intially requested, the amounts recommended in Mr. Eisdorfer's testimony should be reduced proportionately. St. Regis Brief on rate design at 24.

As a third alternative, St. Regis proposed that in the absence of valid class coincident peak data, the company's cost allocation methodology is the most appropriate for this docket. Transcript at 5273; St. Regis Brief on rate design at 26. As another alternative, St. Regis recommended that if the Commission decides that neither the coincident peak nor the non-coincident peak data is reliable, any base rate revenue change resulting from this docket should be allocated to classes based on their proportionate share of current base revenues. Transcript at 5723; St. Regis Brief on rate design at 26. St. Regis argues that in the absence of reliable cost of service data, an across-the-board distribution on base rate revenues would be the only logical way to distribute any base rate revenue increase or decrease resulting from this case. St. Regis Brief on rate design at 26.

5. TIEC Proposal

TIEC concedes that the primary goal in allocating the revenue requirement among the various classes based on the cost allocation study is to bring all classes to a system average rate of return, or cost of service. TIEC Brief on rate design at 23. TIEC asserts that the revenue allocation decision should begin with an analysis of the rates of return and interclass revenue subsidies at present rates under the selected cost of service methodology used to allocate costs between the various classes. Such an analysis is complicated in this docket because the parties have proposed widely varying levels of revenue increase or decrease to TUEC in arriving at their proposed increases to the various classes. TIEC Brief on rate design at 23. TIEC correctly asserts that as a matter of pure mathematics, the smaller the revenue increase, the more difficult it is to distribute that increase among the classes in such a way as to bring the classes to cost of service. As an example, TIEC points out that if the company is granted only a $1.00 revenue increase, no possible distribution of that $1.00 increase among the classes could significantly affect the class rates of return. Therefore, TIEC urges that a means of scaling the proposed class increases up or down to match the system increase ultimately approved must be utilized. TIEC Brief on rate design at 23-24. TIEC based its recommended class revenue increase on the full revenue increase requested by TUEC; TIEC also illustrated how the recommended increase to each class could be scaled down proportionately to correspond to a much smaller increase. TIEC Exhibit 2A, Exhibit JP-2, Schedules 3 and 4; TIEC Exhibit 2B; TIEC Exhibit 2 at 27-28.

TIEC argues that under the company's proposed interclass revenue allocation, the rates of each class, with the exceptions of the residential and general service classes, would move closer to cost of service. Using the company's average and excess cost of service study modified to reflect TIEC's recommendations that distribution plant should be allocated on a class non-coincident peak basis and that federal income tax expense should be reallocated consistent with the recommendations-of TIEC witness Hafer, TIEC demonstrated that under the company's proposed revenue allocation, the interclass subsidy granted the residential class would increase from approximately $5.6 million to almost $8 million; similarly, the interclass subsidy granted the general service class would be increased by $288,000. TIEC Exhibit 2A, Exhibit JP-1, Schedule 5. TIEC Brief on rate design at 24.

TIEC urges that the revenue allocation proposed by its witness Pollock would better achieve the objective of moving all classes closer to costs. TIEC Exhibit 2A, Exhibit JP-2, Schedules 3 and 4. TIEC asserts that although it seeks to eliminate the interclass subsidies from all rate classes, the complete elimination of such subsidies in this proceding would require unduly large rate increases for the municipal pumping, street lighting and miscellaneous service classes. TIEC urges application of the principle of gradualism, limiting to 1.5 times the system average percent increases, excluding fuel cost recoveries, the increases for the municipal pumping, street lighting and miscellaneous service classes. TIEC further proposes to eliminate subsidies from all classes having below average rates of return at present rates, provided that the 1.5 times constraint was not violated. TIEC Exhibit 2 at 26; TIEC Brief on rate design at 25. In addition, the increases assigned to the classes having above average rates of return at present rates were designed to reduce the subsidies being provided from these classes by approximately 42 percent. TIEC Exhibit 2 at 26-27; TIEC Brief on rate design at 25. TIEC concludes that under its recommended revenue allocation, rates would generally be moved closer to costs than under TUEC's proposal.

6. Tex-La Proposal

In its brief, Tex-La asserts that the rates of return imposed on all classes should be equal, and that the Commission should maintain a goal of moving toward equalized rates of return. Cities Exhibit 15 at 5; Tex-La Brief on rate design at 69. Tex-La urges the Commission to set TUEC's relative rates of return for all classes at unity, thereby achieving the desirable regulatory goal of cost based rates. Tex-La Brief on rate design at 69-70. Tex-La points out that since relative rates of return measure cost based rates, the design of cost based rates is a goal that most utilities, including TUEC, have strived for. TRA Exhibit 48 at 7; Transcript at 5880. Tex-La asserts that cost based rates are equitable to all customers, promote efficiency and result in the proper distribution of non-renewable resources. TRA Exhibit 48 at 7-8. Further, TUEC witness Mr. Johnston testified that providing relative rates of return which approach unity is the objective of TUEC. Transcript at 4303. Tex-La urges the Commission to finish its goal in establishing all rates of return at unity, thereby insuring that appropriate regulatory goals are met. Tex-La Brief on rate design at 71.

7. Army Proposal

The Army urges that the most logical and sensible alternative for any increase or decrease in revenue requirements is to spread any change on an across-the-board basis to all current rate schedules. Army Exhibit 1 at 4. Army witness Neidlinger asserted that the company's proposed revenue allocation in some instances moves class returns away from cost of service rather than closer to the average system return. Army Exhibit 1 at 7. Mr. Neidlinger's recommended class revenue allocation provides for slightly higher increases for the residential and wholesale classes than were recommended by TUEC, a slightly lower increase for the general service primary class, municipal pumping and street lighting classes and a zero increase for guard lights. Army Exhibit 1 at 7. The recommendations proposed by Mr. Neidlinger were provided as a guideline for adjusting class revenue levels to achieve the overall revenue requirement requested by the company, but were not an endorsement of that overall request. Army Exhibit 1 at 7.

8. OPC Proposal

In OPC Exhibit 55, Schedule SA-18, Dr. Andersen set forth his proposed rates for the various customer classes derived from his cost of service study, but cautioned in his testimony that those rates indicate appropriate rate relationships rather than absolute levels. OPC Exhibit 55 at 37. For demand metered customers, the information in Schedule SA-18 was intended to indictate the direction in which energy charges should be moved and that diminished reliance on demand charges for intraclass recovery is appropriate. OPC Exhibit 55 at 40; OPC Brief on rate design at 34-35. Dr. Andersen also urged that wholesale rates be moved immediately to the cost of service rate levels reflected in Schedule SA-18, since in his opinion, the structure of wholesale rates has implications for the rate design of the customers of the wholesale class. OPC Exhibit 55 at 40; OPC Brief on rate design at 35.

OPC acknowledges a need for rate moderation; Dr. Andersen set forth his moderation proposals for three different levels of net revenue requirement. OPC Exhibit 55, Schedule SA-17. For example, if rates are reduced by 2.55 percent, or $95.8 million, as recommended by OPC, the rates for all customers paying more than cost of service would be reduced, but rates for remaining customers would be uncahaged. Transcript at 6472. Assuming a 1 percent reduction in rates, OPC proposes giving those classes currently below cost of service a moderate increase. Finally, under a no rate change scenario, OPC would give the same below cost of service classes three times the increase they would receive under the 1 percent reduction scenario. Transcript at 6472-6473; OPC Brief on rate design at 35. The maximum increase under any of the scenarios would be a 6 percent increase for the street lighting class, which according to Dr. Andersen is the farthest away from cost based rates. OPC Exhibit 55, Schedule SA-15; Transcript at 6472.

TIEC argues that since the OPC methodology is a radical departure from methodologies previously utilized by TUEC, one would expect that the rates of return by class at present rates established under that methodology would have a wide variance from system average. TIEC Brief on rate design at 25-26. OPC did not calculate rates of return or relative rates of return by class, so TIEC states that the magnitude of that variance is not apparent. Therefore, TIEC argues that it is impossible to tell what the starting point is in terms of the present rates of return or relative rates of return by class. TIEC Brief on rate design at 26. Dr. Andersen testified that relative rates of return are not a useful benchmark for judging the appropriate magnitude of required rate adjustments (OPC Exhibit 55 at 35), and that "the only unbiased basis for determingng required rate adjustments is a comparison of revenues and total cost of service." OPC Exhibit 55 at 36. Thus, TIEC asserts, Dr. Andersen's proposed revenue allocations are a function of his cost of service analysis. TIEC Brief on rate design at 26. TIEC argues that because of the critical flaws in Dr. Andersen's cost of service analysis, his revenue allocations have no more validity than the study behind them. TIEC Brief on rate design at 26. TIEC points out that his allocation methodology shifts so many costs to high load factor customers that a zero percent increase in TUEC's revenues would require a 2.25 percent increase in the amount of revenues recovered from the industrial class, and a 1.58 percent decrease for the standard residential class. TIEC Brief on rate design at 26. TIEC argues that such a disparate impact on TUEC's customer classes is grossly inequitable, and therefore recommends that Dr. Andersen's revenue allocation recommendation should be rejected. TIEC Brief on rate design at 27.

9. Staff Proposal

Staff witness Kepner proposed that no class receive more than twice the system average decrease and no less than one half the system decrease. based on the staff's recommended revenue decrease. Exhibit 36 at 18, Staff Exhibit 42, JWK-14,15. General Counsel argues that these recommendations evidence a policy of gradualism, reflecting a reasonable and gradual approach to reach the level where all classes pay their exact cost to serve. General Counsel Brief on rate design at 32. Further, General Counsel asserts that the proposed rates would permit TUEC to generate sufficient revenues to meet its revenue requirement. General Counsel Brief on rate design at 32.

10. Recommendation

Despite the parties' basic agreement that each customer class generate a rate of return approximately equal to the system rate of return, there was some disagreement about how quickly those classes below unity should be moved toward unity. Comparison of the proposals is difficult because they are generally based on different proposed revenue requirements for TUEC. Because the revenue requirements recommended herein is only a slight increase, it is probable that a move toward unity for the rate classes will not have as great an impact as such a move would have had under the requested increase. Nevertheless, the principle of gradualism should still apply. It is recommended that classes presently below unity receive increases of no more than 1.5 times the system average percent increase, excluding fuel cost recoveries. Classes presently above unity should receive no less than one-half the system average percent increase, excluding fuel cost recoveries. This recommendation is consistent with that adopted by the Commission in Docket No. 5560, and should move the classes closer to unity without an unduly large rate increase for any class.

B. Residential Rates

1. TUEC Proposal

Through the testimony of its witness Charles F. Johnston, TUEC proposed a residential rate structure (Rate R) which has a single rate for summer use and a two-step charge for winter use. The second step in the winter begins after 600 kwh and designed primarily to provide a lower rate for space heating sales which improve the system load factor. TUEC Exhibit 1B, Johnston at 9; Transcript at 4389-4390. Mr. Johnston explained that based on demand during the peak season, the average space heating customer has an annual load factor of about 45 percent, whereas the average non-space heating customer has an annual load factor of about 31 percent. This means there are more kwh over which a given amount of annual fixed costs can be recovered, thereby producing a lower cost per kwh for space heating. TUEC Exhibit 1B, Johnston at 9. Mr. Johnston further explained that a single all purpose rate is better than having specific end use riders two reasons: first, most customers do not understand why a kwh consumed in the winter by non-space heating customers should cost more to produce than a kwh consumed in the winter by space heating customers. Therefore, TUEC views customer understanding and acceptance as an important reason for its two-step rate. Second, end use rates, such as space heating and water heating riders, are difficult to administer, that is, to determine which customers should have the rider. The use of writers involves considerable time and administrative effort in insuring their proper application. TUEC Exhibit 1B, Johnston at 10. Mr. Johnston further testified that if a single all purpose rate with the two-step charge for winter is not approved, a space heating rider providing for a lower winter step would be necessary in order to insure that space heating customers, which constitute 29 percent of the total residential customers, would not be paying for more than their reasonable cost of service. TUEC Exhibit 1B, Johnston at 10. In brief, TUEC argues that the declining block winter rate flows from the company's cost of service study and accommodates customers with electric space heating. Transcript at 4277, 4390; TUEC Brief on rate design at 18. The declining block provides for a lower rate beyond 600 kilowatt hours and is designed so that space heating customers provide only a slightly higher return than that of all standard residential customers. TUEC Exhibit 1B, Johnston at 10; Transcript at 4390. TUEC argues that if its proposed residential rate design is rejected, the rate of return for space heating customers will be far above average. Transcript at 4401; TUEC Brief on rate design at 18.

The company also proposes a summer/winter differential in the standard residential rate. Mr. Johnston bases this rate design on the fact that TUEC is a summer peaking system with the average weekday load in the summer months being about 1.5 times the average weekday load in the other months. According to Mr. Johnston, there are substantial costs for customers to bear in order to have additional capacity available for use in the summer months over and above the capacity required in other months. Thus, a summer/winter differential in the residential rate results in an effective economic signal being delivered to customers, which promotes desirable load management and conservation practices by the customers. For example, customers would perceive that installation of insulation in homes, more efficient air conditioners and other conservation practices are economically attractive and as a result, the company would have to install less additional generating capacity. TUEC Exhibit 1B, Johnston at 11. TUEC points out in Brief that the rates currently in effect for the TP&L division contain a summer/winter differential (Transcript at 4275-4277) and that the rate recently approved by this Commission for DP&L in Docket No. 5256 is similar to that proposed by the company in this case, and contains a declining block in the winter months. Transcript at 4277; TUEC Brief on rate design at 18.

Finally, the company is proposing to maintain two existing experimental rates currently in effect. The proposed experimental Rate RLL (Residential Limited Load) oad) is designed specifically for those small use customers who have little, if any, refrigerated air conditioning equipment in use, and is virtually identical in form to the existing rates. Rate RLL will be available to 6,000 customers who require the rather limited capacity of approximately 1.8 kVA or 15A. The proposed experimental rate RTU (Residential Time of Use) will be available to 2,000 customers and is designed for those customers willing to reduce their usage during the on-peak period. Mr. Johnston states that some interest in this rate has been shown by TUEC customers, and approximately 300 customers are presently receiving electric service under this rate. TUEC Exhibit 1B, Johnston at 11.

TUEC opposes the City of Dallas in its attempt to reinstate a net-gross billing feature in its tariff. TUEC points out that this feature was disapproved and deleted from DP&L's tariff in Docket No. 5256, and that the Commission has amended its rules to remove reference to that practice. TUEC Brief on rate design at 39.

2. Cities Proposal

The Cities did not recommend specific rates for each customer class, but did offer specific recommendations for designing rates for the residential class. The Cities recommend rejection of a residential summer/winter differential, consistent with the Commission's rulings in Docket No. 5256 and Docket No. 5200. The Cities argue in brief that if reserve margins are greater than needed for system reliability, the Commission has chosen not to reinstitute seasonally differentiated base rates. Cities Brief on rate design at 5. The Cities concede that TUEC reserve margins at the time of the summer peak appear to have come closer to a more appropriate level than in the past; however, the Cities submit that TUEC still has ample reserves at the time of the system peak. Cities Exhibit 15 at 12, Exhibit LNP-5; Cities Brief on rate design at 5. The Cities further argue that the contribution of the residential customer class to the system peak does not appear to be significantly increasing even in the absence of a summer/winter differential. Cities Brief on rate design at 5-6. It is the Cities' position that residential customers appear to have clearly received the appropriate price signals and it is not necessary to further aggravate the distress presently suffered by residential ratepayers during the summer time when it is so unclear that any useful purpose would actually be served thereby. Cities Brief on rate design at 6. Cities witness Patterson testified that even without a summer/winter differential, the average residential summer bill of $100.00 is still two times the average winter bill of $48.37. Cities Exhibit 15 at 11; Cities Brief on rate design at 6. The Cities submit that the residential customers are receiving an appropriate price signal without a summer/winter differential. In addition, the Cities argue, an additional 1.0¢ differential would cause the average summer bill to be increased by $21.00 or 43.4 percent of the average winter bill. Cities Exhibit 15 at 11. The Cities also argue that TUEC's reasoning that a summer/winter differential is necessary in order to send an appropriate price signal is inconsistent with the company's advertising campaign intended to encourage participation in an average billing plan. Cities Exhibit 17; Transcript at 4009-4010; Cities Brief on rate design at 6. This average billing plan allows the customer to smooth out over the year the higher summer bills (Transcript at 4010), and company witnesses Scarth and Johnston both agreed that the number of customers taking advantage of the average billing plan is growing. Transcript at 4011, 4386; Cities Brief on rate design at 6.

The Cities urge the Commission to consider the fact that TUEC's conservation programs are designed to reduce the summer peak. Company witness Scarth testified that as the cost of electricity goes up, customer response to conservation efforts increases. Transcript at 4000. Mr. Scarth also testified that customers under present rates are aware that summer billings are going to be high (Transcript at 4001), a proposition with which company witness Johnston agreed. Transcript at 4382. The Cities argue that such testimony reinforces the opinion of its witness Mr. Patterson that TUEC customers have indeed received the message, without a summer/winter differential, that consumption in peak periods must be reduced. Cities Exhibit 15 at 9-10; Cities Brief on rate design at 7.

Finally, with respect to the proposed summer/winter differential, the Cities refer to Docket No. 5256 and Docket No. 5200, prior rate cases for TUEC operating divisions in which the Commission did not approve the requested summer/winter differential.

The Cities recommend adoption of the company's proposal to delete the specific end use riders for space heating, water heating and all electric residential customers. The Cities submit that the elimination of such riders, in combination with a two-step winter rate, offers distinct advantages in terms of simplification of rate design and reduction of administrative burden. Cities Brief on rate design at 8. This recommendation was supported in the testimony of Cities witness Patterson; the impact analysis which he provided indicates that such an all purpose rate, without riders, and with a two-step winter rate, provides reasonable and moderate results. Cities Exhibit 15, Exhibit LNP-7; Cities Brief on rate design at 8. The Cities contend that the residential rate design proposed by Mr. Patterson is the most moderate and reasonable residential rate design in evidence, because it takes into consideration cost recovery, recent Commission decisions and customer impact. Cities Brief on rate design at 9.

3. Brazos Coop Proposal

Brazos Coop focused its analysis of TUEC's proposed residential rate design on the alleged anticompetitive effect of such rates on cooperatives which are either dually certificated with TUEC or which serve in areas adjacent to TUEC's certificated service areas. Brazos asserts that experience with switchover customers and the adoption of a switchover rule by the Commission are clear indications with customer choice, the cooperatives face a threat of loss of customers to another utility certificated in the same area. Brazos Brief on rate design at 2. The rate differential between TUEC's all electric residential rate and a cooperative's residential rate, according to Brazos, has been the deciding factor in the switching customer's mind. Brazos asserts that the competition is real and that the ability of a cooperative to compete with TUEC is significantly tied to rates. Brazos Brief on rate design at 2. Brazos additionally asserts that there is a competitive squeeze, not only in dually certificated areas, but also in singly certificated areas when potential customers of either TUEC or the cooperative are able to look at the advantages of the residential electric space heating winter rate of TUEC as compared with the cooperatives' rate, and can make a decision on where they will locate based on the rate differential. Brazos Brief on rate design at 2. Brazos concludes that the cooperative has a potential for loss of would-be customers in addition to the customers who actually switch over. Brazos

Brief on rate design at 2. Brazos argues further that this area of competition becomes critical if rates are lower in TUEC's service area because of a preference given to its residential electric space heating homes or because TUEC does not take into consideration its rural line losses, its extra investment to serve in rural areas, or its extra vehicle, meter reading and other costs. Therefore, Brazos submits that even between two singly certificated areas there is unfair competition between the two utilities. Brazos Brief on rate design at 3.

Brazos intially focuses on the price squeeze and the anticompetitive rate structure issue which the Commission addressed in Docket No. 3780, TP&L's 1981 rate case, in which Brazos and Rayburn Country referred to price squeeze and anticompetitive problems with TP&L's proposed rate structure. Brazos argues that for years it and other cooperative customers of TUEC have been attempting to get the Commission to recognize in rate design that the cost to serve rural areas is greater than the cost to serve in urban areas. Brazos Brief on rate design at 5. Brazos's complaint is that by blending its rural and urban costs, TUEC is able to sell power cheaper in the competitive rural market than it would otherwise be able to do. That is, the company is able to serve its rural customers at the same rates as its urban customers only because it is able to spread the higher costs of rural service over its entire customer body, including its urban customers which constitute the majority of that customer body. Brazos Brief on rate design at 5. Brazos asserts that when faced with a proposal to assign franchise fees by geographical location, TUEC, in resisting such a proposal, readily agrees that it costs more to serve in the country than in the city. Brazos Brief on rate design at 5. Brazos refers to the testimony of TUEC witness Johnston when he said he would be surprised if a comparitive study of urban versus rural costs did not show that it cost 15 or 20 or maybe even 30 percent higher to serve in the rural areas. Transcript at 4406; Brazos Brief on rate design at 5. Brazos also refers to Mr. Johnston's testimony that if there were sufficient cost data and an appropriate cost study, it would be possible to design separate rates for urban customers and for rural customers. Transcript at 4407; Brazos Brief on rate design at 6. Brazos goes on to assert that TUEC now admits that it costs more to serve in rural areas and admits that at one time it had studies with which it could differentiate between urban and rural costs. Brazos Brief on rate design at 6. Brazos alleges that TUEC ignores the issue that the price squeeze is between the company's proposed wholesale rate and its residential and residential space heating rate. SWESCO Exhibit 1 at 2-3; Brazos Exhibit 1 at 3-4; Brazos Brief on rate design at 6. Brazos argues that the anticompetitive pricing comes about by the subsidy of the company's rural residential and residential space heating customers by the company's urban customers. Brazos Brief on rate design at 6. Brazos further urges that there is no proof that the higher costs to serve in the rural areas are offset by franchise fees, and that Mr. Johnston admitted there was no dollar for dollar matching or quantification of his alleged offsetting amounts. Brazos contends that only a study of rural service costs can properly match the costs to determine their relationships, a study which Brazos seeks and which Brazos urges the Commission to order TUEC to perform. Brazos Brief on rate design at 7. Brazos concludes that in the absence of such a study, the only reasonable conclusion from the evidence in this case is that rural costs to serve are higher than urban costs to serve, therefore Brazos's recommendations to alleviate the price squeeze and unfair competition plaguing the cooperatives should be implemented in this docket. Brazos Brief on rate design at 7.

Brazos bases its recommendation on a limited cost of service study which it performed to determine if TUEC, purchasing at its own proposed wholesale primary rate and selling at its own proposed residential rate could meet its return objectives on an annual basis. Brazos Exhibit 1. According to Brazos, the result of the study shows that while TUEC's revenue would have exceeded its cost of power, the excess would have been wiped out by TUEC's distribution expenses and there would be no provision for return or for federal income taxes. In other words, Brazos asserts, if TUEC had to buy at its wholesale rate and sell at its retail rate, TUEC's own cost of service between the wholesale level and the residential level would produce a loss, with no return. Brazos Brief on rate design at 7-8.

According to Brazos, the PURA mandates consideration of competitive issues. Section 47 of the PURA prohibits discrimination by a public utility against competing utilities and any other practices that restrict or impair competition. Brazos Brief on rate design at 8.

Brazos witness Ms. Taylor disagrees with TUEC's allocation methodology which depicts the residential space heating class as yielding a greater rate of return on an annual basis than do regular residential customers. Ms. Taylor testified that the company's study is not adequate in comparing the residential standard and residential electric space heating costs of service or for designing TUEC's proposed residential rates. Brazos Brief on rate design at 9. Brazos further asserts that there is no justification for a 3.62 ratio between TUEC's summer and winter base rates. Brazos submits that the largest ratio that can be justified is a 1.19 summer to winter ratio. Brazos Exhibit 1 at 27-33; Brazos Brief on rate design at 9. Brazos further argues that there is no system cost basis for charging a declining block rate in the wintertime. Brazos Exhibit 1 at 33. Brazos refers to the testimony of TUEC witness Johnston regarding the 1.45¢ residential tail block which he justified on the basis of incremental costing. Since almost all the facilities required to provide service for space heating kwh are already in place for normal service, the last block for space heating, which adds very little requirement for additional capacity, reflects the concept of incremental costs. TUEC Exhibit 1B, Johnston at 9. Brazos contends that it is "amazing" that, even if the alleged incremental cost could be identified, for kwh above 600 such incremental costs would be less in 1984 than in 1976. Brazos Brief on rate design at 10. Brazos submits that the proposed 1984 base rate winter charge for 1,000 kilowatt hours, as a ratio of winter to summer, is 5.7 percent less in 1984 than in 1976. A similar comparison for 2,000 kwh is 19 percent less; for 3,000 kwh, 25 percent less; for 4,000 kwh, 28 percent less; and for 5,500 kwh, 31 percent less. Brazos Brief on rate design at 10. From this, Brazos submits that TUEC is engaging in a pricing practice tending to restrict or impair competition form its wholesale rural electric cooperative customers, and to fail to take into account the competitive impact of any recommended rate structure would render any such recommendation devoid of a basic criterion by which such rate should be tested, that is, whether or not such a rate would impair competition by a utility providing similar service. Brazos Brief on rate design at 10.

As might be expected, TUEC took strong exception to the arguments advanced by Brazos Coop. TUEC points out in brief that it is attempting to set one residential rate for its entire service area (Transcript at 5165-5166, 5180), and that it is not seeking a separate rate for dually certificated areas. TUEC Brief on rate design at 19. In response to Brazos's complaint that TUEC's proposed residential rate is not cost based, TUEC points out that Ms. Taylor explained Brazos did not perform a cost of service study to support its allegations (Transcript at 5177) because of the limited scope of Brazos's intervention. Brazos Exhibit 1 at 24; TUEC Brief on rate design at 19. TUEC argues that its cost of service study clearly shows that residential space heating customers provide a 105 percent relative rate of return even under the company's proposed rate design. Transcript at 5179; TUEC Brief on rate design at 19. TUEC criticizes Brazos attempt to justify its allegations of price squeeze on its study of its Ovilla, Texas, point of delivery. TUEC points out that no other points of delivery were examined by Brazos witness Ms. Taylor. The object of the study was to illustrate that TUEC, purchasing at its wholesale primary rate and reselling at its proposed retail rate, could not meet its return on an annual basis. Transcript at 5181; TUEC Brief on rate design at 20. The study showed that while revenue exceeded costs by $111,500, this excess was supposedly wiped out by the expense of distribution. Transcript at 5191-5192; TUEC Brief on rate design at 20. TUEC criticized this study first because although Ms. Taylor stated that she selected the Ovilla point of delivery based on three factors which made Ovilla comparable to a point of delivery on the TUEC system, (Brazos Exhibit 1 at 12-13), it was demonstrated on cross-examination that the factors relied upon in the selection of the Ovilla point of delivery simply illustrated the erroneous nature of this purported comparability. Transcript at 5185-5188; TUEC Brief on rate design at 20. TUEC argues that Ovilla's kwh sales are almost entirely residential, and that the Ovilla point of delivery has a residential load factor in excess of 41 percent. Transcript at 5294.

TUEC asserts that according to Ms. Taylor's own testimony such a load factor is substantially in excess of the systemwide load factor of either the standard residential class or the residential space heating class for TUEC. Transcript at 5195. Demand costs are sensitive to load factor changes (Transcript at 5291) and TUEC asserts that the selection of Ovilla, with its high residential load factor, accounted for the high distribution costs which Brazos needed in order to reach the result it desired. TUEC Brief on rate design at 20. TUEC argues that bringing the company's systemwide residential load factor even halfway to the Ovilla residential load factor reverses the results which Ms. Taylor obtained. Transcript at 5201, 5296; TUEC Brief on rate design at 20.

TUEC further asserts that Brazos has not supported its allegation of difficulty of competing with TUEC in dually certificated areas. Brazos has done no study to compare its growth rate in dually certificated areas with that of the company (Transcript at 5174), and Ms. Taylor did not know how Brazos's growth rate compared to that of TUEC. Transcript at 5174; TUEC Brief on rate design at 19. TUEC also disputes Brazos's argument that any difficulty Brazos perceives in competing is not attributable to TUEC. TUEC Brief on rate design at 19. The company provides a small portion of Brazos's power (Transcript at 5163), and 92 percent of Brazos's costs for power are attributable to sources separate from the company. Transcript at 5164. TUEC argues that even if it <u>gave</u> electricity to Brazos, 92 percent of Brazos's costs would remain. Transcript at 5164. TUEC argues that it verges on the absurd for Brazos to attempt to assign to TUEC the responsibility for any perceived difficulty in competing. TUEC Brief on rate design at 19.

Finally, TUEC characterizes as ill-founded and unsubstantiated Ms. Taylor's contention that TUEC's residential rate design is intentionally designed to be anticompetitive. TUEC argues that DP&L has no wholesale customers (Transcript at 5168), and serves no dually certificated areas. Transcript at 5171. In the last

DP&L rate case, TUEC proposed,and the Commission and approved, a residential rate design substantially similar to that proposed in this docket. Transcript at 5168-5170; TUEC Brief on rate design at 19. TUEC submits that it defies logic and common sense for Brazos to argue that this rate design is intended to be anticompetitive, when the company has advocated an almost identical residential design in areas where it does not compete with any cooperatives, and particularly when the TUEC customers in question, the residential space heating customers, are paying a rate of return in excess of the system average. TUEC Brief on rate design at 19.

TUEC also points out that the evidence that Brazos discusses at page 10 of its Brief and attaches to the Brief is not part of the record in this case. TUEC Reply Brief on rate design at 6.

In its Reply Brief, Brazos charged that TUEC's comparison of residential load factors is erroneous. According to Brazos, TUEC compares the annual CP load factors in Brazos Exhibit 1, Exhibit AJT-7 to the residential load factor under the total column on Brazos Exhibit 1, Exhibit AJT-4, page 6 of 6. Brazos then calculates what it asserts is the correct factor to be utilized in the comparison and argues that using the correct load factor does not reverse the results Ms. Taylor obtained, but confirms them. Brazos Reply Brief on rate design at 2.

In response to TUEC's criticism that Brazos had not performed enough studies to show the anticompetitive design of TUEC's wholesale and residential rates, Brazos contends that the first place for additional studies to start should be with the company, to identify its higher costs to serve in the rural areas where the competition is, yet the company resists such efforts. Brazos poses the rhetorical question of whether TUEC will now cooperate in these endeavors. Brazos Reply Brief on rate design at 2.

Brazos further asserts that it is absurd for TUEC to say that its rate design must be good because it is similar to its DP&L rate design. Brazos contends that it is undisputed that the DP&L rate design has never been examined in the light of an anticompetitive challenge. Brazos argues that the same subsidies which it challenges in this case as being anticompetitive in the rural markets are no less anticompetitive because DP&L's ratepayers have not challenged them. Brazos argues that in fact the reverse is the case, where TUEC's broad residential customer base in a noncompetitive area is burdened with the subsidy of a more costly service area, the rural areas. Brazos Reply Brief on rate design at 3.

4. OPC Proposal

OPC witness Dr. Andersen did not propose specific tariffs, but instead proposed that TUEC develop separate tariffs for standard residential customers and space heating customers. In Dr. Andersen's view, separate tariffs permit elimination of a promotional declining block, and at the same time permit recognition of the fact that space heating customers have an overall lower cost of service than standard residential customers. Transcript at 6470; OPC Brief on rate design at 35. In the alternative, OPC urges that if the examiners decide not to adopt Dr. Andersen's proposal for two distinct residential tariffs, the staff's residential rate design proposal should be adopted instead of continuing a declining block rate. OPC Brief on rate design at 35-36.

In support of its position, OPC argues that TUEC has a rapidly growing residential load, and the company appears to be promoting that growth. For example, TUEC projects that residential space heating saturation as a percentage of total residential customers will increase from 27.7 percent in 1983 to 41.7 percent in 1990. These percentages include heat pumps. OPC Exhibit 56. Further, TUEC offers financial incentive payments to individuals who replace air conditioners with more efficient air conditioners or heat pumps. While the higher efficiency appliances may cut summer peak consumption, OPC points out that the heat pumps may well increase winter consumption if the customer previously heated the home with natural gas. The incentive payments for heat pumps is greater than what is paid for comparable air conditioning. Transcript at 1690-1692.

OPC further alleges that a declining block rate structure during the off-peak periods fits in with TUEC's promotional activities. Sustained growth in winter load at a rate that exceeds the rate of growth in summer load (7 percent compared to 4.8 percent) will develop into justification for construction of additional capital intensive base load generating units which will add costs to all consumers, according to OPC. OPC Brief on rate design at 36. As an example, OPC points out that the promotional effect of a declining block rate may be partially revealed in evaluating the total bills and consumption of space heating customers to the total bills and consumption of standard residential customers for the winter months of the test year. Standard residential had 5.9 million bills and 3.6 billion kwh consumption, compared to space heating customers who had 2 million bills but 3.3 billion kwh consumption. OPC Exhibit 57; OPC Brief on rate design at 36. OPC concludes that a declining block rate within the residential class cannot be justified under Dr. Andersen's cost of service study nor from a policy perspective. OPC Brief on rate design at 36. OPC further refers to Brazos witness Ms. Taylor's analysis which indicated that a declining block rate cannot be justified for any portion of the residential class. Transcript at 5134; OPC Brief on rate design at 36.

OPC contends that reflection of cost of service requires a flat but seasonally differentiated energy charge to the residential class. OPC Exhibit 55 at 37. Brazos witness Ms Taylor recognized that staff and OPC had performed seasonal or time differentiated cost analyses and to the extent that the Commission adopted one of tnese methodologies, the residential rate structure should reflect a summer/winter differential. Transcript at 5098; OPC Brief on rate design at 37. OPC refers to the staff costs of service whfich relected the existance of a seasonal differential exceeding 3¢ per kwh (Transcript at 6921), although staff witness Kepner recommended a 1¢ differential in his residential rate design proposal (Transcript at 6793). Dr. Andersen's cost of service study reflects a seasonal differential of 1.8¢ per kwh. OPC Exhibit 55 at 37. OPC argues that Mr. Kepner's recommendation was premised upon what would "sell" without compromising a rate design that reflects costs (Transcript at 6793-6794), but OPC points out that what should sell depends upon whether the focus is on the winter rates for space heating customers or the summer rates of all customers. OPC Brief on rate design at 37.

OPC argues that it is inappropriate to modify a rate design that reflects cost on the basis of considerations of the adverse impact to tremendously high volume consumers. Residential consumption levels between 10,000 and 25,000 kwh per month may be associated with tje operation of a mansion or commercial arc welding out of a garage. OPC Brief on rate design at 37. OPC contends that approximately 92 percent of all space heating customers during the winter consume at an average monthly level below 3,000 kwh, while approximately 93 percent of all residential customers, whether standard or space heating, during the summer consume at an average monthly level below 2,500 kwh. Therefore, OPC submits that use of TNP Exhibit 11 and OPC Exhibit 62 for impact analysis should not consider consumption above 1,000 kwh in the winter and 2,500 kwh in the summer. OPC Brief on rate design at 37-38. OPC assumes that individuals consuming above those levels can well afford to pay the cost of service. OPC Brief on rate design at 38.

Billing comparisons reveal that almost all residential consumers would receive reductions in their summer bills under the staff's proposal with a 1¢ differential. Above average (1,600 kwh) space heating consumers would realize increases in their monthly winter bills ranging from 7 percent to 22 percent, but the average (600 kwh) standard residential customer on the existing DP&L system will receive a 20 percent decrease. OPC Brief on rate design at 38.

OPC points out that with a 2¢ summer/winter differential, the adverse impact on above-average space heating consumers significantly drops under the same rate structure, and almost all standard residential and less-than-average space heating customers would receive significant decreases in winter bills. OPC Brief on rate design at 38. OPC submits that a 2¢ differential would substantially ameliorate the effect of the elimination of a declining block rate, however, a 2¢ differential would increase summer rates for virtually all TP&L and TESCO customers, while all DP&L customers wpi;d receive decreases. Overall, the summer rates would be approximately 7 to 8 percent less than what the company proposed. OPC Brief on rate design at 38.

OPC argues that an impact analysis based on bill comparisons is somewhat deceptive, because it is a snapshot at a particular point in time. Irrespective of the adverse impact which may be experienced by any particular customer during a particular month, that customer's consumption will probably be at a different level the next month and the imapct analysis would change, according to OPC. OPC Brief on rate design at 38. OPC takes the position that, on balance, only a few residential consumers would be adversely impacted over the course of a year under either a 1¢ or 2¢ differential. Thus, OPC submits that the 1.8¢ differential for the residential class is both cost justified and reasonable. It is OPC's recommendation that such a differential be adopted, and that the higher rate be applied in the months of June, July, August and September. OPC Brief on rate design at 39.

OPC argues that the major difference in its approach to rate design and that of the staff is that the staff relies upon a marginal cost approach, whereas OPC relies on time differentiated embedded costs. OPC Brief on rate design at 39. The only structural difference between the recommendations, other than the single tariff versus two tariff issue and the size of the summer/winter differential, is the issue of the size of the customer charge. The staff accepted the $6.00 customer charge proposed by the company, while OPC witness Dr. Andersen proposed a customer charge of $4.48 for the standard residential rate and $5.19 for the space heating rate. OPC Exhibit 55 at 37and Exhibit SA-18. OPC submits that the customer charges recommended by Dr. Andersen are cost based, but they arise from a narrower definition than that utilized by the comapny and the staff regarding what costs are properly recoverable through the customer charge. OPC Exhibit 55 at 38; OPC Brief on rate design at 39. OPC submits that customer charges are equivalent to charging for access to the electric market prior to any consumption and, as such, customer charges can become a benchmark for monopolistic discrimination. OPC Brief on rate design at 39. Dr. Andersen recommends that the Commission view his customer charge proposals as a ceiling, and to consider lower the charges and recovering the difference through the base energy charge. Such a decision could be justified on the basis of promoting conservation in the higher usage blocks and recognizing that the cost of service recommendation probably overcharges low volume customers. OPC Exhibit 55 at 38-39; OPC Brief on rate design at 39. OPC refers to Brazos Coop witness Ms. Taylor's analysis as confirming and supporting a decision to lower the residential customer charge. Transcript at 5129-5138; OPC Brief on rate design at 40.

5. Staff Proposal

Staff witness Kepner initially recommended a 1¢ seasonal differential in the kwh charge for the residential class, based upon his belief that this differential was conservative, and thus would cause the least amount of friction. Staff Exhibit 36 at 17; General Counsel Brief on rate design at 30-31. In brief, General Counsel argues that upon subsequent review, Mr. Kepner strongly urges the Commission to adopt a 2¢, rather than a 1¢, seasonal differential due to the potential adverse impact a 1¢ differential would have on TUEC space heating customers served by the TP&L operating division. General Counsel Brief on rate design at 31. As an example, General Counsel points out that at consumption of 2,500 kwh during the winter, a TP&L space heating customer would receive a 14.8 percent increase at a 1¢ differential, while the same customer would receive only a 6.1 percent increase at a 2¢ differential. Transcript at 6795; TNP Exhibit 11; OPC Exhibit 22; General Counsel Brief on rate design at 31.

General Counsel also submits that Mr. Kepner's recommendation of a distinct summer/winter differential is more appropriate than the company's proposed declining block rates for the residential class for several reasons. First, General Counsel argues that Mr. Kepner's proposed rates clearly send an appropriate price signal to the company's residential customers, that is, that TUEC incurs higher costs during the summer peak period. Second, General Counsel argues that the declining block rates proposed by TUEC send an inappropriate price signal, that is, that the more the customer uses in the winter the less it costs. Third, a declining block rate not only sends the wrong signal, it is a weak disguise for a seasonal differential in rates. Finally, General Counsel submits that flat rates reflect the economics of electricity generation, that is, it costs the same to produce the first kwh as it does the last kwh. General Counsel Brief on rate design at 31.

The Cities opposed the rate design offered by staff witness Kepner, on the ground that such a proposal would have a severe impact on residential space heating customers during the heating season, despite the staff's proposed revenue decrease. The Cities urge avoiding such disproportionate impact by adopting Mr. Patterson's rate design proposals. Cities Brief on rate design at 8-9.

6. Recommendation

The Cities have advanced the most cogent proposal for the modification of TUEC's proposed design of residential rates, and it is therefore recommended that TUEC design its residential rates without the proposed summer/winter differential but with the proposed declining block in the winter rate to prevent over-recovery from the electric space heating customers. The customers of TUEC appear to have received and understood the message that summer bills will be higher; customers have responded to higher bills by implementing conservation and load management techniques. In addition, it appears that the price-signal to be sent via the use of a summer/winter differential would be diluted when combined with the company's average billing plan. However, the Cities' proposal to reinstate net/gross billing is not recommended for adoption, and TUEC's other residential rate design proposals, including the two experimental tariffs, are recommended for adoption.

None of the summer/winter differentials proposed in this docket for the residential class (by TUEC, OPC, and staff) have been adequately demonstrated to be cost based. In addition, the proposal urged by General Counsel in Brief is somewhat different from the testimony presented by Mr. Kepner during the hearing; a proposal so internally inconsistent does not appear to have been well thought out and should not be adopted.

The use of two separate tariffs, one each for standard residential customers and for residential electric space heating customers, as proposed by OPC, presents administrative burdens disproportionate to the benefit of assuring that only those customers who have space heating receive the two-step winter rate.

Finally, Brazos Coop's allegation of unfair competition and price squeeze has not been adequately supported. Its cost of service study of the Ovilla point of delivery is too limited to be of much value in determining the alleged anticompetitive impact of TUEC's rates in its rural service areas, and the comparability of the Ovilla point of delivery to a TUEC point of delivery was seriously challenged. Brazos's conclusion that the evidence in this docket supports its contention that rural costs to serve are higher than urban costs to serve is simply erroneous. No cost of service study based on geographical location of customers was performed by any party to this docket, so the testimony of witnesses that rural costs to serve are higher is based on speculation, not informed opinion. TUEC has proposed a systemwide residential rate design based on its cost of service; there is no evidentiary support for the allegation that TUEC intentionally designed it rates to be anticompetitive.

C. Wholesale Summer/Winter Differential

1. TUEC Proposal

Through the direct testimony of its witness Charles F. Johnston, TUEC proposes a seasonally differentiated demand charge for the resale rate, Rate WP. TUEC Exhibit 18, Johnston at 19. The company justifies this summer/winter demand charge differential as being an effective means of encouraging load management and conservation practices by the resale systems, as well as proper rate design the resale systems to reflect the costs incurred by the company in providing resale electric service. Proper rate design, in turn, encourages customers of the resale systems to take actions aimed at conserving electric energy. TUEC Exhibit 18, Johnston at 19-20. As set forth in its proposed tariffs, the summer/winter demand charges for the wholesale class would be $10.50 per kw for the months June through October, and $5.25 per kw for November through May for primary service, and $9.18 per kw and $3.93 per kw, respectively, for transmission service. TUEC argues that the differential is based on the idea of peak load pricing, and is designed to give a strong pricing signal in the summer to encourage conservation as well as proper rate design. Transcript at 4273; TUEC Brief on rate design at 30. TUEC defends the proposed degrees of difference as being necessary to attain these desired effects. Transcript at 4273. Five months, rather than four, for the summer months signal is necessary because TUEC uses cycle billing, and this insures that peak consumption in September is properly priced. Transcript at 4360-4361, 4363; TUEC Brief on rate design at 30.

2. SWESCO Proposal

In its brief on rate design, SWESCO discussed the proposed summer/winter differential in connection with the proposed ratchet for the wholesale customers. SWESCO agrees with the logic of a summer/winter differential; SWESCO does not object to a summer demand charge of two times the winter demand charge, provided the proposed ratchet is not adopted. SWESCO Brief on rate design at 7. SWESCO agrees with Mr. Johnston's reasons for employing a summer/winter differential as an effective means of encouraging load management and proper rate design by the resale customers. SWESCO Brief on rate design at 7-8.

3. TNP Proposal

TNP states in its brief on rate design its position that a differential of two times the winter rate for the summer rate is inappropriate and has not been shown to be cost justified. TNP Exhibit 3 at 28-31; TNP Brief on rate design at 31. TNP agrees that a summer/winter differential in rates is appropriate because it is more expensive to serve customers during the summer than during the winter, because TUEC is a summer peaking utility and thus the maximum demand is imposed on the system during the summer months. TNP is not opposed to a summer/winter differential in the wholesale rate, but is opposed to one of the magnitude proposed by TUEC in this docket. TNP Brief on rate design at 31. TNP proposes that the charge per kw of demand during the summer months should be no greater than 1.2 times the winter charge per kw of demand. TNP Brief on rate design at 31.

4. Tex-La Proposal

Like TNP, Tex-La asserts that TUEC's proposed summer/winter demand charge differential is not cost justified. Tex-La Exhibit 21 at 8; TNP Exhibit 3 at 29-30; Coops Exhibit 25 at 36; Transcript at 5080; Tex-La Brief on rate design at 18. If any summer/winter differential in the demand charge is to be approved by the Commission, then Tex-La's position is that it should be based on the company's actual variance in demand costs between seasons. Tex-La Exhibit 21 at 9. Tex-La asserts that the differential proposed by TUEC is not cost based and appears to be arbitrary. Tex-La Exhibit 21 at 9; Tex-La Brief on rate design at 29. Tex-La further argues that TUEC has provided no information or data upon which one can determine whether the proposed differential reflects the proper recovery of costs incurred by TUEC. Bowie Exhibit 3 at 20; Tex-La Brief on rate design at 19.

Tex-La argues that the only response given by TUEC to various intervenors' RFI's requesting support for the seasonal differential was load curves showing the difference in the winter and summer peak demands. Coops Exhibit 25 at 36; Transcript at 5080. Tex-La asserts that these load curves do not justify the large differential proposed by TUEC; the curves merely show the difference in TUEC's summer and winter peak demands. Tex-La witness Daniel testified that a seasonal demand charge differential should not be justified merely on load curves but should be based on actual cost differences between seasons. Tex-La Exhibit 21 at 9; Tex-La Brief on rate design at 19.

Tex-La asserts that the only support offered for a summer/winter differential appears to be what TUEC witness Johnston refers to as a "well recognized fact" (Transcript at 4170), that a summer/winter differential encourages load management and conservation practices. Tex-La Exhibit 21 at 11; Tex-La Brief on rate design at 20. Tex-La charges that Mr. Johnston failed to demonstrate any support for this common "fact." Tex-La Brief on rate design at 20. Mr. Johnston testified that he had no studies to support the company's contention. Transcript at 4170. Tex-La argues that a two to one seasonal demand charge differential should not be accepted on blind faith. Tex-La Brief on rate design at 20. Tex-La refers to the testimony of several witnesses who urged the elimination of the proposed differential since it had no adequate cost based justification. TNP Exhibit 3 at 29-31; Bowie Exhibit 3 at 21; Tex-La Exhibit 21 at 13; Tex-La Brief on rate design at 20.

Tex-La further argues that adequate price signals already exist in both the company's fuel charge and demand ratchet. Tex-La Exhibit 21 at 10-12. An additional pricing signal in the form of a non-cost based summer/winter differential is therefore inappropriate and not necessary in Tex-La's view. Transcript at 5083. Given the seasonal differential in the demand charge, Tex-La argues that the price signal given to the customers will be stronger than necessary. Transcript at 5083; Tex-La Brief on rate design at 21.

Tex-La refers to the Commission decision in Docket No. 5294 in which a summer/winter differential in the fuel cost component of base rates for TUEC was approved. Tex-La argues that this differential already provides a price signal to resale customers for the higher energy costs during the peak summer months and encourages conservation. Tex-La Exhibit 21 at 9-10. Tex-La argues that the approved seasonal differential in the fuel cost component established a reasonable price signal which is based upon a demonstration of actual costs; having a rate that is cost justified sends the proper signal. Transcript at 5084; Tex-La Brief on rate design at 21. Tex-La further argues that providing an additional unnecessary price signal in the form of seasonal demand charge differentials creates a "pancake" effect when added to the existing fuel cost differentials. Coop Exhibit 25 at 36; Tex-La Brief on rate design at 22.

Tex-La asserts that Mr. Johnston's opinion that a summer/winter differential provides even more incentive for load management than a ratchet is unsupported either by him or by any other company witness. Transcript at 4185; Tex-La Brief on rate design at 22. Like SWESCO, Tex-La objects to both a summer/winter differential and an 80 percent demand ratchet. Tex-La also asserts that since TUEC's wholesale rate already provides enough incentive for its wholesale customers to engage in load management practices through the summer/winter differential in the fuel charge and the demand ratchet, it is not necessary or proper for TUEC to impose its load management policies on the wholesale customers. Tex-La Brief on rate design at 23. Tex-La refers to the recently adopted energy efficiency plan of the Commission, P.U.C. SUBST. R. 23.33, as putting in place a statewide policy on load management policies and practices. The rule requires TUEC as well as its wholesale customers to engage in certain load management programs in order to comply with the statewide policy. Tex-La argues that since the Commission has established what load management practices the wholesale customers must adopt, it is neither proper nor necessary for TUEC to impose its load management decisions on the wholesale customers through the rate structure to wholesale customers. Tex-La Brief on rate design at 23.

Finally, Tex-La asserts that the proposed summer/winter differential should be eliminated because it would cause cash volatility problems to the cooperative wholesale buyers. Tex-La witness Daniel testified that Tex-La's wholesale power rates to its member cooperatives reflect the existing TP&L wholesale rate to Tex-la which presently includes a summer/winter differential in the demand charge. (DP&L has no wholesale customers, and TESCO does not have a summer/winter differential in its wholesale rates.) The majority of the customers of Tex-La's member cooperatives read their own meters, which results in a thirty day lag in revenue collection between the time the cooperative pays its power bill and the time the cooperative receives payment from its customers. As a result, the member cooperatives can and have experienced cash shortage problems. Tex-La Exhibit 21 at 12-13. In addition to the problems which would be imposed on cooperative wholesale customers, Tex-La asserts that a summer/winter differential would also pose substantial cash flow problems for other wholesale customers who do not have seasonal differentials for their residential customers. Bowie Exhibit 3 at 21. Tex-La concludes that the summer/winter differential is not needed in order to encourage load management, and it results in cash volatility problems for the wholesale customers, and that therefore it should be disallowed. Tex-La Brief on rate design at 24. Tex-La contends that the elimination of the proposed summer/winter differential would not result in any revenue impact to the other customer classes. Transcript at 4692.

In its brief, TUEC refutes Tex-La's contention that an 80 percent ratchet renders the summer/winter differential unnecessary. Tex-La Exhibit 21 at 8-13; TUEC Brief on rate design at 30. TUEC asserts that Tex-La's witness incorrectly assumes that the ratchet's sole purpose is load management; however, TUEC witness Johnston explained that while the ratchet does provide some incentive for load management, its primary purpose is revenue stability and the avoidance of cross-subsidization within a class. Transcript at 4184; TUEC Brief on rate design at 30. TUEC also points out that Tex-La witness Daniel testified that the reason for the cooperative's cash flow problems is a result of lag in revenue collections because

Tex-La's member cooperatives allow their customers to read their own meters, while Tex-La requires payments from its cooperatives within sixteen days. Tex-La Exhibit 21 at 12; Transcript at 4726. TUEC indicates that this is not a problem with the summer/winter differential in and of itself. TUEC Brief on rate design at 30. Tex-La employs a differential reflecting the differential charged it by TP&L. Transcript at 4721. TUEC asserts that a strong price signal is necessary for the members of the wholesale class in order to assure that they will employ effective rate designs sending appropriate price signals to their customers. Transcript at 4184, 4201; TUEC Brief on rate design at 30-31.

TUEC points out that SWESCO also employs a summer/winter differential even though it too is concerned with revenue stability. Transcript at 6138-6139. TUEC further refers to the testimony SWESCO witness Fairbanks who acknowledged that a summer/winter differential can be an appropriate price signal in an equitable cost allocation (Transcript at 6125), but that is counter-productive to revenue stability. Transcript at 6137.

5. Coops Proposal

In brief, the coops assert that the summer/winter differential proposed in all rates by TUEC should be eliminated or drastically reduced. Coop Exhibit 25 at 35-38; Coops Brief on rate design at 17. As an alternative, the coops state that if any summer/winter differential, other than in fuel, is retained, the rate to the wholesale systems should have no greater differential than the company's residential class. Coop Brief on rate design at 17.

6. Recommendation

As with the proposed residential summer/winter differential, TUEC has failed to demonstrate that its proposed wholesale summer/winter differential is cost-based. While the cash flow problems of the cooperatives cannot be attributed to the presence of a wholesale summer/winter differential, it does appear that such a rate design would cause some revenue in stability for TUEC despite the use of a ratchet. The wholesale customers of TUEC do not have as much control of their load as do the retail or end use customers of TUEC; thus, despite the alleged strong price signal to wholesale customers to be sent through a summer/winter differential, there may be little response a wholesale customer can offer. It is therefore recommended that TUEC's proposed wholesale summer/winter differential not be adopted.

D. Demand

1. Ratchet

a. TUEC Proposal

The TUEC operating divisions' individual tariffs currently contain ratchets for General Service Rates G and HV, Municipal Rate MP and Wholesale Rate WP, at levels ranging from 65 percent to 80 percent. The company, through the testimony of its witness Charles F. Johnston, has proposed that ratchets continue to be applied at a uniform level of 80 percent for each of the referenced rates. TUEC Exhibit 1B, Johnston at 15-18. As explained by Mr. Johnston, a ratchet is a rate design feature which can cause the billing demand in the current month to be higher than the actual kw recorded in the current month. According to Mr. Johnston, normally ratchets are based on the contract kw or the highest kw recorded in some prior period. The need for ratchets arises from the fact that utility demand-related costs, for the most part, are incurred annually and not on a monthly basis. Since utility bills are rendered and collected on a monthly basis, however, some means to reflect annual costs in monthly bills is necessary in order to achieve three objectives which TUEC identifies as being important: one, effective load management; two, equity between customers of a given rate class; and three, revenue stability. TUEC Exhibit 1B, Johnston at 15-16. Mr. Johnston explained that ratchets help achieve load management because a ratchet assigns the annual cost of the peak load in monthly installments to the customer requiring the company to incur the annual costs; therefore, the customer realizes the true economic cost of adding peak load and has sufficient incentive to avoid unnecessary electric energy use during peak periods. TUEC Exhibit 1B, Johnston at 16. In addition, Mr. Johnston testified that a ratchet insures that customers within a given class contributing the same demand to the class's' peak demand pay for relatively the same demand. TUEC Exhibit 1B, Johnston at 17 and Exhibit CFJ-4.

In determining the ratchet percentage, Mr. Johnston stated that the ratchet must be set high enough to avoid subsidization between customers of a given class, while reflecting the load characteristics of a particular group. TUEC Exhibit 1B, Johnston at 17. The 80 percent level was selected because in Mr. Johnston's opinion it reflects most closely the relationship existing between coincidence factor and load factor for the majority of customers. TUEC Exhibit 1B, Johnston at 17 and Exhibit CFJ-5. Setting the ratchet at this level results in demand cost recovery being representative of the load characteristics of a given class, thus minimizing intraclass subsidization. TUEC Exhibit 1B, Johnston at 18.

In brief, TIEC stated its support for TUEC's proposed 80 percent demand ratchet; TIEC further recommends that the on-peak period should be redefined so that only the demands imposed during the summer peak period are utilized in calculating the 80 percent demand ratchet. TIEC Exhibit 2 at 31-33; TIEC Brief on rate design at 28.

b. SWESCO Proposal

SWESCO does not agree that a ratchet in the wholesale tariff is either necessary or desirable. SWESCO argues that the revenue received by TUEC is merely shifted from summer to winter by use of a ratchet. In terms of the overall system, the benefit, if any, which TUEC would receive through a ratchet in its wholesale tariff is insignificant, especially in view of what SWESCO terms the devastating effect which the ratchet has on SWESCO and its ratepayers. SWESCO Brief on rate design at 6.

SWESCO disagreed with Mr. Johnston's definition of load management; Mr. Johnston describes effective load management as a result of rate design as meaning that the rate effectively conveys to the customer the cost implications of his/her actions. TUEC Exhibit 1B, Johnston at 16; SWESCO Brief on rate design at 6. Mr. Johnston further cites as an example the residential customer, being charged on TUEC's requested summer/winter differential, who can readily determine that it is in his/her economic interest to minimize summer usage. SWESCO Brief on rate design at 6. Mr. Johnston goes on to say that the commercial/industrial customer, charged on a rate including a ratchet, can do similar things. SWESCO Brief on rate design at 7. SWESCO concludes that Mr. Johnston's analogy is inapplicable because he does not mention wholesale customers in his analogy. SWESCO Brief on rate design at 7.

SWESCO further argues that even though both a ratchet and a summer/winter differential are proposed for the wholesale class, both are not needed. SWESCO does not object to the summer demand charge being two times the winter demand charge provided the ratchet is eliminated. SWESCO argues that the ratchet in the wholesale tariff is counterproductive insofar as load management is concerned; and that its detriment to the revenue stability of SWESCO far exceeds the small benefit, if any, to TUEC's revenue stability. SWESCO Brief on rate design at 7.

SWESCO further agrees with the use of a summer/winter demand charge differential as an effective means of encouraging load management, but disagrees that a ratchet has the same effect. SWESCO argues that the effect of the ratchet is to shift revenue recovery from summer to winter, and the effect of the summer/winter differential is to shift revenue recovery from winter to summer. SWESCO concludes, therefore, that the ratchet has an opposite and offsetting effect from the summer/winter differential.

SWESCO also disagrees that a ratchet has the effect of promoting equity between customers of a given rate class. SWESCO witness Fairbanks testified that from the standpoint of the supplier (TUEC), the wholesale class contains relatively few customers, all with load factors that tend to be about the same. Thus, SWESCO argues that the concern for covering a large group of customers with widely varying load factors is simply not present, and there is relatively little, if any, subsidy between customers. SWESCO Exhibit 1 at 5. The need for a ratchet to achieve equity between customers of a given class is simply not present with respect to the wholesale class, according to SWESCO. SWESCO Brief on rate design at 8.

Finally, SWESCO asserts the detrimental effect on it of TUEC's imposing a ratchet on the wholesale customers. SWESCO witness Fairbanks stated that residential customers comprise 84 percent of SWESCO's customers. SWESCO Exhibit 1 at 7. SWESCO argues that it cannot ratchet its residential rate class. The small benefit to the revenue stability of TUEC is argued by SWESCO to be more than offset by the bad effects of the ratchet on SWESCO's revenue stability. SWESCO Brief on rate design at 9. In its reply brief, SWESCO points out that the current 65 percent ratchet in the TP&L tariff has been adequate for TUEC's revenue stability in the past, and that TUEC has offered no evidence to show any changed circumstances justifying the change in the ratchet level. SWESCO Reply Brief on rate design at 2. In its brief, TUEC assailed the testimony of SWESCO witness Fairbanks regarding the issue of a ratchet for the wholesale customers. TUEC refers to Mr. Fairbank's testimony where he states that the company's goals can be met through application of the ratchet to retail customers.

In its brief, TUEC assailed the testimony of SWESCO witness Fairbanks regarding the issue of a ratchet for the wholesale customers. TUEC refers to Mr. Fairbank's testimony where he states that the company's goals can be met through application of the ratchet to retail customers. SWESCO Exhibit 1 at 4-5. Mr. Fairbanks contends that the wholesale customers require a different approach, and that the ratchet should be set at the same level as TUEC's system load factor, that is, in the 50 percent to 60 percent range. SWESCO Exhibit 1 at 8; TUEC Brief on rate design at 21. TUEC points out, however, that on cross-examination, Mr. Fairbanks testified that in determining a ratchet for SWESCO's own wholesale customers, consideration of its system load factor was not and is not relevant. Transcript at 6141; TUEC Brief on rate design at 21. Mr. Fairbanks further testified that the similar load patterns of the wholesale customers would not aid in equalizing TUEC's revenues (Transcript at 6138), and that a lower ratchet level would not preclude intraclass subsidization. Transcript at 6140; TUEC Brief on rate design at 21-22. Although he recommended that TUEC's ratchet be set at 50 percent to 60 percent, Mr. Fairbanks admitted that a ratchet set below 55 percent would have little or no effect on SWESCO. TUEC Brief on rate design at 22.

c. TNP Proposal

TNP also opposes the 80 percent ratchet on the wholesale class proposed by TUEC in this docket. TNP first asserts that TUEC has failed to provide sufficient evidence supporting the 80 percent demand ratchet. TNP Brief on rate design at 10. TNP further argues that TUEC does not need an 80 percent ratchet on the wholesale class in order to assure revenue stability. Conceding that revenue stability is a proper ratemaking objective of a demand ratchet, TNP asserts that it is inappropriate to apply an increase to the demand ratchet of the wholesale class in this case because there has been no showing that it affects TUEC's revenues tability in any way. TNP Brief on rate design at 10. TNP refers to the testimony of TUEC witness Johnston on cross-examination when he stated that the effect of the ratcheted dollars, because of the increase in the level of the ratchet, would be only .37 percent. Transcript at 4504; TNP Brief on rate design at 10. TNP cites as an additional reason that revenue stability is an improper justification for the increase of the ratchet proposed in this case the failure of TUEC to demonstrate that there is a higher than normal risk of loss of load. TNP Brief on rate design at 11. TNP argues that since it has an identical customer mix and load pattern to that of TUEC, TNP imposes no greater risk on the TUEC system than all classes impose on the TUEC system; therefore, the ratchet should not be applied to such a high degree as proposed in this case. TNP concludes that to do so would in effect ratchet all TNP end use customers. TNP Exhibit 3 at 23; TNP Brief on rate design at 11.

TNP further asserts that TUEC has failed to show that a 70 percent ratchet as opposed to the proposed 80 percent ratchet is not equitable as between different customers in the wholesale class. TNP denies that any inequities exist, but argues that if there are any, such inequities can be compensated by use of a 70 percent ratchet and an adjustment of the level of the summer/winter differential in the final rates approved in this case. TNP Brief on rate design at 11-12. TNP cites the testimony of TUEC witness Johnston on cross-examination when he stated that he was unable to quantify the claim that an 80 percent ratchet was necessary to insure equity between the various customers of the wholesale class. Transcript at 4505-4508; TNP Brief on rate design at 12.

TNP also argues that the evidence in this case demonstrates that a high ratchet is not an effective load management tool for wholesale customers. TNP acknowledges that demand ratchets are useful load management tools for end use customers which have the ability to manage most of their load. TNP Brief on rate design at 12. TNP's own ratchets to its industrial and large general service class customers have been set by the Commission based upon a composite of TNP's suppliers' ratchets. TNP Brief on rate design at 12. While large end use customers of TUEC can effectively manage their loads (therefore justifying the imposition of a higher ratchet upon them), TNP argues that wholesale customers cannot avail themselves of many of the load management techniques available to large industrial and large general service customers, thus rendering inappropriate the imposition of a high ratchet. TNP Brief of rate design at 12-13.

TNP contends that TNP's load management has been found to be appropriate by this Commission in its most recent rate order for TNP, Docket No. 5568. TNP points out that on cross-examination TUEC witness Johnston could not recommend any other load management techniques that TNP could use which were also found to be reasonable by TUEC. Transcript at 4514-4520; TNP Brief on rate design at 13. Mr. Johnston further stated that he was not sure if any of his alternatives were viable for TNP. Transcript at 4518; TNP Brief on rate design at 13.

TNP takes issue with TUEC's contention that an 80 percent ratchet is necessary to send the price signal that costs are higher during the peak or summer months. TNP alleges that this reasoning ignores the fact that TNP is not an end use customer, but consists of thousands of residential, commercial, municipal and industrial customers. The ratchet raises costs in the winter, sending an entirely opposite signal to TNP's customers than that which TUEC argues it intends to send. TNP Exhibit 3 at 22; TNP Brief on rate design at 13. TNP urges that its characteristics as a utility company serving end use customers must be considered in determining the rate it pays to TUEC. TNP concludes that the demand ratchet should be set no higher than 70 percent to the wholesale class in this case. TNP Brief on rate design at 13-14.

TUEC in brief points out the testimony of TNP witness Laux who contends that the ratchet is inconsistent with cost based rates but admits that TNP deems the ratchet useful for its own revenue stability, and that such a purported inconsistency does not mean its application would be inappropriate in setting cost based rates. Transcript at 6066; TUEC Brief on rate design at 22. TUEC refers to Mr. Laux's testimony that a ratchet promotes equity with in whatever class it is applied (Transcript at 6062-6063), and that the higher the load factor, the less likely it is a customer would be affected by a ratchet. Transcript at 6063; TUEC Brief on rate design at 22. TUEC argues that given these facts, and Mr. Laux's belief that wholesale customers should not be ratcheted, it is only logical to assume that the level recommended will have little or no effect upon TNP or any member of the wholesale class. Transcript at 4499; TUEC Brief on rate design at 22.

d. Tex-La Proposal

Tex-La witness Daniel testified that the demand ratchet in the wholesale rate provides the same concept as a summer/winter differential, and that accordingly, the summer/winter differential in the wholesale rates should be disallowed. Tex-La Exhibit 21 at 10-11. Tex-La apparently did not challenge the imposition of the 80 percent ratchet, but only proposal proposition that both an 80 percent demand ratchet and a summer/winter differential are needed in base rates to provide the required load management incentives to wholesale customers. Tex-La Brief on rate design at 22-23.

e. Coops Proposal

The Coops argues that the ratchet level for the combined REA wholesale class should be fixed at the 75 percent level, and should be based upon the demand in the months of June through September. Coop Exhibit 25 at 41-44. The Coops assert that this has no impact on the revenues collected from the class because the same definition of billing demand used for billing will be used to calculate the rate. Coops Brief on rate design at 17.

In brief, TIEC points out that Coops witness Stover agreed with TUEC witness Johnston that customers should be responsible for their class peak and that the greater the ratchet, the greater the likelihood of revenue stability from the customer class. Transcript at 5011; TUEC Brief on rate design at 22. Further, Mr. Stover testified that ratchets play a legitimate role in designing rates, and some of his cooperative clients, such as Kaufman County Electric Cooperative, Inc., and Taylor Electric Cooperative, Inc., have rates that include a 75 percent ratchet (Transcript at 5011-5014), "to protect themselves and to provide the revenue stability on their system." Transcript at 5015; TUEC Brief on rate design at 22. TUEC contends that Mr. Stover recognizes that a ratchet protects the utility's earnings and smooths or equalizes revenues to cover fixed annual costs. TUEC Brief on rate design at 22.

f. Army Proposal

The Army took the position that the company's proposed increase in the ratchet provision implies that seasonal cost differentials are increasing, whereas the opposite is true: the ratio of summer to winter peak is decreasing. Army Brief on rate design at 3. The Army argues that ratchets are surrogates for seasonal rates and are inferior to seasonal rates from a regulatory perspective. Army Exhibit 1 at 10. Army witness Neidlinger was unable to develop seasonal rates for general service customers because, according to the Army, the company failed to provide the requested unratcheted billing demand data. Army Exhibit 1 at 11; Army Brief on rate design at 3. The Army asserts that the company has not presented sufficient evidence to justify the increase in the ratchet which it proposes. In 1981, the TP&L application for a rate increase, Docket No. 3780, included a proposal to increase the ratchet provision from 70 percent to 75 percent. In that case, the increase was held not to be justified. The Army argues that in this case, TUEC attempts to increase the ratchet provision under the guise of being a consolidation measure. Army Brief on rate design at 3.

TUEC criticizes Mr. Neidlinger's conclusions regarding the need for an increased ratchet. TUEC Brief on rate design at 22. Mr. Neidlinger's disagreement with the proposition that unstable load patterns of industrials and customers with similar characteristics require application of the ratchet was based upon his opinion that the company's seasonal differences in load were decreasing and that at some point in the future, if that trend continues, the importance of seasonal rates in ratchets would be likewise diminished. Transcript at 4683; TUEC Brief on rate design at 22. Mr. Neidlinger testified that his projection was based upon load data that included the winter of 1983-1984, but he did not know that it was an extraordinarily cold winter. Transcript at 4684; TUEC Brief on rate design at 22.

g. Recommendation

The major disagreements regarding a demand ratchet appear to be over the level at which such a ratchet is set and whether it is imposed in conjunction with a summmer/winter differential for the wholesale class. Since it is the recommendation herein that no summer/winter differential for the wholesale class be adopted, on major area of dispute is eliminated. With respect to the level of the ratchet, TUEC correctly asserts that it must be high enough to avoid intraclass subsidization while reflecting the load characteristics of a particular group.

SWESCO is correct that revenue recovery is shifted from summer to winter by use of a ratchet, but that is the purpose of a ratchet, to smooth out over a year the costs imposed at the time of system peak. SWESCO's contention that the ratchet is not needed for the wholesale customers because their load factors are all about the same (meaning there is little intraclass subsidy) ignores the other purposes for which a ratchet is imposed. Further, the fact that a 65 percent ratchet has been adequate for TP&L in the past is not evidence that no change is needed in this docket.

TNP's assertion that TUEC has failed to show the wholesale customers impose a higher than normal risk of loss of load and therefore that there is no revenue stability problem with the wholesale customers also ignores the fact that a ratchet smooths out over the year the recovery annual of demand costs imposed by each wholesale customer at peak periods.

TUEC has demonstrated that the proposed 80 percent ratchet is at the lower end of the relationship between coincidence factor and load factor, and that the 80 percent ratchet is reasonable for each of the rates for which a ratchet is proposed. The ratchet should be applied to the demands imposed during the summer peak period, that is, June, July, August and September.

2. Conjunctive and Coincident (Simultaneous) Billing

a. TUEC Proposal

Both conjunctive billing and coincident (simultaneous) billing involve the concept of adding metered demands at separate points of delivery for the purpose of measuring billing demand (kw) charges to a particular customer. The current TESCO tariffs do not provide for such a feature, but treat each point of delivery separately for the purpose of assigning and collecting cost of service. The current TP&L division tariffs do provide for conjunctive and/or coincident billing for some of the TP&L wholesale customers. In this docket, TUEC proposed tariffs which do not include any conjunctive or coincident billing features for three reasons: one, the company is attempting to consolidate its rates across its entire service area; two, the company's cost of service allocation and rate design treat each point of delivery as a separate customer responsible for its individual share of production, transmission and distribution costs (Transcript at 4255-4257, 4289, 4294); and three, the absence of conjunctive billing will prevent undue discrimination between customers having multiple points of delivery and those with one or two points of delivery. Transcript at 4296, 4902.

b. SWESCO Proposal

In its brief, SWESCO refers to the rebuttal testimony of TUEC witness Johnston that if a utility buying wholesale power determines it is more economical to build the necessary facilities to tie all its points of delivery together and therefore have the billing advantages of one point of delivery, it should do so. TUEC Exhibit 41 at 5; SWESCO Brief on rate design at 10. SWESCO asserts its agreement with Mr. Johnston on that issue and argues that since it has built the necessary facilities within each interconnected system, SWESCO should have each interconnected system billed accordingly. SWESCO Brief on rate design at 10.

TUEC responds to SWESCO's argument by pointing out that while certain portions of SWESCO's system may contain interconnecting ties, its system is not sufficiently integrated to permit delivery of its full system power needs at a single point of delivery. TUEC Reply Brief on rate design at 8. TUEC argues that as a result, the company's other customers must still bear the cost imposed in sending service to SWESCO at multiple points of delivery, and conjunctive billing would therefore be as inappropriate for SWESCO as it is for the Coops. TUEC Reply Brief on rate design at 8.

c. Coops Proposal

Through the testimony of witness Carl N. Stover, Jr., the Coops set forth their reasons for opposing the company's proposal to eliminate coincident demand billing and conjunctive billing. Coops Exhibit 25 at 38-41. Mr. Stover explains that under coincident demand billing, the billing demand in a particular month is the peak demand for those delivery points that are interconnected by the customer-owned transmission facilities. According to Mr. Stover, this insures that the customer is not billed twice for the same demand in any particular month, and provides a mechanism for tracking load shifts between delivery points. Coops Exhibit 25 at 38. Both conjunctive billing and coincident demand billing relate only to rate design and do not relate to cost allocation or revenue requirements for the class. The application of conjunctive and coincident demand billing, in Mr. Stover's opinion, tracks the concept that the customer served is not an individual delivery point, but rather a collection of delivery points which, taken together, serve the total retail load of the wholesale customer. These two provisions thus allow the customer to implement power supply planning on a total system basis. Coops Exhibit 25 at 38.

Mr. Stover asserts that use of conjunctive and coincident billing provisions will give greater assurance that the company will not earn amounts in excess of the authorized cost of service. Coops Exhibit 25 at 38. Mr. Stover provided examples of billing based on conjunctive and coincident provisions in Coops Exhibit 25, Schedules H-1.0 and H-2.0.

The Cooperatives propose that all wholesale customers be billed on either a conjunctive or coincident basis. According to Mr. Stover, the billing demand for those points of delivery belonging to an individual customer not interconnected by customer-owned transmission facilities would be based upon the sum of the non-coincident peak demands in each billing period; the ratchet would then be applied to the total non-coincident peak for all the customers' delivery points. For those delivery points interconnected by customer-owned transmission facilities, the peak metered demand for the month is equal to the maximum coincident peak for the delivery points that are interconnected. The coincident peak would then be added to the monthly peak demands for the other delivery points and conjunctive billing would be applied. Coops Exhibit 25 at 40-41.

In brief, the Coops stated they do not object to limiting conjunctive billing and coincident billing features of the tariff to contiguous service areas. This is provided for currently in the TP&L tariff where, unlike cooperative systems, TNP and SWESCO have noncontiguous, discrete service areas. Coops Brief on rate design at 16.

The Coops disagree with the rebuttal testimony of TUEC witness Johnston that distance between delivery points has a bearing upon conjunctive billing. The Coops assert that conjunctive billing refers to the proper determination of demand billing units, and that demand charges are not a function of distance and are not allocated as a function of distance. Coops Brief on rate design at 16. The Coops contend that without conjunctive billing, multi-point systems are called upon to bear a portion of the demand cost of serving single point systems. Allegedly this occurs because the demand imposed by the multi-point systems upon the production and bulk transmission facilities is overstated, consequently unfairly increasing the charge to such systems and thereby subsidizing the single point systems. Coops Brief on rate design at 16.

The Coops also claim that Mr. Johnston is in error when he asserts that the issue of conjunctive and coincident billing is related to the decision of the wholesale system to tie its individual points of delivery together. The Coops contend that the decision of the distribution system to tie points together should be based upon the cost of construction of feeder lines, not the cost of production plant. Thus, the decision should not be based upon the cost of production plant artificially inflated by overstating demand of the multi-point system. The Coops agree that Mr. Johnston is correct when he says that there is a discrimination problem here, but the Coops identify it as discrimination against multi-point systems if conjunctive billing is not adopted. Coops Brief on rate design at 17.

In brief, TUEC asserts that the Coops urge the adoption of conjunctive billing features in order to avoid the effect of any billing demand ratchets in the wholesale tariffs. Transcript at 4249; TUEC Brief on rate design at 32. TUEC refers to the testimony of Coop witness Stover who stated that conjunctive billing would not be sought by the Coops in the absence of such ratchets. Coops Exhibit 25 at 37; Transcript at 5009. TUEC asserts that the reason is that without any ratchet feature in the wholesale tariff, each point of delivery would be billed on metered demand, regardless of that point's poor seasonal load factor. TUEC Brief on rate design at 32. As a result, the company's reasons for including a ratchet, that is, to properly assign and recover higher costs imposed by poor load factor points of delivery, apply equally to the necessity for excluding conjunctive billing features. Transcript at 4255-4257; TUEC Brief on rate design at 32.

TUEC argues that the Coops mistakenly focus on he manner in which the Coops operate their distribution systems (Coops Exhibit 25 at 38-39), and design their rates to reflect diversity on their total systems benefits which accrue only to the Coops. Transcript at 5006, TUEC Brief on rate design at 32. TUEC contends that as with the case of the issue of consolidation of the wholesale class, the Coops ignored the actual cost impact upon TUEC of diverse and scatterd points of delivery, and treat each cooperative as if it were a single distribution system physically and geographically integrated by transmission ties constructed with the Coops' money. TUEC Brief on rate design at 32. TUEC asserts that to the contrary, any unitary operations of a cooperative system are largely the result of the company's expenditure of money to serve a multiplicity of delivery points, thus integrating the cooperative through the company's transmission system. Transcript at 4238, 4242; TUEC Brief on rate design at 32. TUEC concludes that the added costs of providing service at multiple points of delivery increases the total cost for the wholesale class, and unless properly recovered by ratchets, such costs will be unfairly placed on those wholesale class members with one, or very few, points of delivery. Transcript at 4289, 4291-4292; TUEC Brief on rate design at 32-33.

In their reply brief, the Cooperatives assert that they do not seek to circumvent application of the ratchet by way of conjunctive billing, but that conjunctive billing is necessary to fairly apportion ratcheted demand charges in the proportion that customers impose demand upon TUEC's generation and bulk transmission system. In order to do this, the Coops submit that it is necessary to ratchet based upon the sum of demands imposed, thus requiring conjunctive billing. Coops Reply brief on rate design at 6.

With respect to TUEC's claim that the Coops' proposal would be discriminatory, the Coops reply that this is the same assertion made by TUEC regarding all legitimate intervenor proposals that TUEC seeks to avoid. The Coops contend that TUEC uses the term discriminatory as an unreasoned epithet to be hurled at any proposal other than its own when reason fails to support TUEC's position. Coops Reply Brief on rate design at 7. The Coops further charge that TUEC ignores the legislative concern in Sections 38-45 of the PURA that utilities will seek to discriminate among customers in a manner which creates advantage in the utility. The Coops conclude that the Legislature therefore disagrees with the view of TUEC that it is the utility which is pristine in its motives regarding rate design and that it is the Commission's duty to dismiss out of hand, in blind deference to TUEC, complaints of customers about TUEC's rate proposals. Coops Reply Brief on rate design at 7.

TUEC replies to the Coops' attack on Mr. Johnston's rebuttal testimony regarding noncontiguous service areas as a reason for not utilizing conjunctive or coincident billing by asserting that the Coops missed Mr. Johnston's point. TUEC Reply Brief on rate design at 8. TUEC asserts that the service areas of the Coops encompass large geographical areas, and the higher costs imposed on the company's system to provide multiple points of delivery to the Coops is a function of the number of and the distances between such points of delivery, not whether one cooperative's geographical service area abuts another geographical service area, that is, is contiguous. TUEC Reply Brief on rate design at 8. TUEC further argues that if the Coops service areas had contiguous and integrated transmission and distribution systems, constructed with Coops capital, then they would have the benefits derived from conjunctive billing, since TUEC could then serve such an interconnected system at a single point of delivery. TUEC submits that the Coops continue to seek to avoid the cost responsibility of such interconnection but still want the benefits of an assumed single point of delivery through conjunctive billing. TUEC Reply Brief on rate design at 8.

d. City of Bowie Proposal

Bowie asserts that the Coops have proposed conjunctive billing in this proceeding as a fallback position in the event the examiners and the Commission recommend consolidation of the wholesale class in this docket. Bowie asserts that the cooperative utilities, because of their number of multiple points of delivery, will reap a windfall benefit to the detriment of Bowie and others with a single or limited number of delivery points. Bowie Brief on rate design at 9. Bowie further asserts that the Coops' proposal is without merit when considering appropriate and generally accepted ratemaking criteria, particularly in light of the fact that a vast majority of the Coops' delivery points are not electrically interconnected.

Bowie submits that the same argument the Coops make could be made by a large retail customer like HEB. Bowie Brief on rate design at 10. Bowie suggests that by making investments to interconnect electrically their delivery points, the Coops could accomplish the result they seek in this docket. Bowie further argues that the reason such electrical interconnection has not been made is that it is a function of economics, and the reason for cooperative existence, that is, to provide service to sparsely populated rural regions of the country. By its very nature, this type of service mandates multiple delivery points. Bowie Brief on rate design at 10. Bowie also notes that the Coops' position on conjunctive billing is closely tied to their definition of "customer," and would allow cooperative delivery points, irrespective of load and usage characteristics, to be billed on an average basis, and would detrimentally affect other members of the proposed wholesale class which have limited delivery points. Bowie Reply Brief on rate design at 5.

e. Tex-La Proposal

Tex-La asserts that conjunctive billing correctly tracks the concept that the customer is the entity which pays the total bill and not the individual points of delivery. Tex-La states that this is demonstrated by the fact that when a cooperative comes to the Commission to set rates, it does so on a total system basis, independent of the number of points at which it is served. Transcript at 5041-5042; Tex-La Brief on rate design at 27. Tex-La further argues that a cooperative's system planning takes place on a total cooperative basis and not on an individual point of delivery basis. Transcript at 5043. Tex-La refers to the testimony of Coops witness Stover, who stated that conjunctive billing allows the customer, whether it is a city, an investor-owned utility, or a cooperative, to implement power supply planning on a total system basis. Coops Exhibit 25 at 38. Tex-La concludes that ratemaking, system planning, and power supply planning on a systemwide basis all support the proposition that the entity being billed is the customer and not the individual delivery point. Tex-La Brief on rate design at 27.

Tex-La refers to the arguments of TUEC and the City of Bowie that conjunctive billing eliminates the effect of the ratchet and discriminatorily shifts revenue responsibility to customers with few delivery points. Transcript at 4249, 4436. Tex-La argues that considering the costing effects, every customer benefits from the diversity on the total TUEC system. Brazos Exhibit 1 at 35; Tex-La on rate design at 28. Tex-La argues that the entire class benefits from diversity within the class when determining cost of service, but when it comes to rate design in determining whether to apply conjunctive billing, the wholesale customers are told they cannot benefit from the diversity of their own systems because it will shift costs to those customers with few delivery points. Transcript at 4436; Tex-La Brief on rate design at 28. Tex-La argues that such reasoning ignores the basic ratemaking principle that the rate design should attempt to properly assign costs to customers within a particular customer class. Tex-La Brief on rate design at 28. Tex-La concludes that conjunctive billing is therefore necessary to consistently reflect cost causation in the design of rates.

Tex-La further argues that the elimination of conjunctive billing for the wholesale class is inappropriate because of the potentially adverse effects. Tex-La charges that TUEC has taken only a limited look at this change based on the total wholesale class, but that no impact for individual wholesale customers has been determined. Tex-La Exhibit 21 at 21. Tex-La submits that the elimination could result in adverse revenue impacts on particular customers within the wholesale class. Tex-La Exhibit 21 at 21. According to Tex-La, this is partly due to the fact that wholesale customers with more than one delivery point and with their own transmission and distribution systems have the ability to shift loads.

Further, Tex-La contends that conjunctive billing provides TUEC with more revenue stability, thereby assuring that TUEC will not earn amounts in excess of the authorized cost of service. Tex-La Exhibit 21 at 23; Coops Exhibit 25 at 38; Tex-La Brief on rate design at 29.

Tex-La also takes the position that simultaneous or coincident billing should be maintained in the wholesale rate for the same reasons Tex-La offered in support of retaining conjunctive billing. In addition, Tex-La argues that simultaneous billing is necessary to properly determine the billing demand for customers with unique operating capabilities. Such customers have the capability of operating a transmission loop connecting some of their delivery points as a single delivery point, thus permitting them to shift loads from one point to another. Tex-La Exhibit 21 at 24. Simultaneous billing insures that the customer is not billed twice for the same demand in any particular month and provides a mechanism for tracking load shifts between delivery points. Coops Exhibit 25 at 38; Tex-La Brief on rate design at 30. Tex-La states that if a customer qualifies for simutaneous billing, however, it should not also receive conjunctive billing on those interconnected delivery points. Tex-La Brief on rate design at 31.

f. Brazos Coop Proposal

Brazos supports continuation of the conjunctive billing demand feature applicable in TP&L's existing wholesale rate and application of that conjunctive billing demand feature to Brazos as an entity. Brazos Exhibit 1 at 35; Brazos Brief on rate design at 13.

g. Recommendation

As with the issue of consolidation of wholesale customers into one rate class, the Coops and SWESCO seem to be focusing on the manner in which they operate their own systems and set their rates, instead of looking at the way in which costs are imposed by them on the TUEC system. The fact that a wholesale customer may have a contiguous service area does not necessarily relate to the number of points of delivery or the distances between such points of delivery, which are the relevant factors in determining costs to the TUEC system. Wholesale customers taking service from TUEC at multiple points of delivery are "interconnected" through TUEC's transmission system, not their own systems, and reagardless of the way in which such customers operate their systems, they impose costs on TUEC as if each point of delivery were a separate customer. TUEC correctly points out that conjunctive billing ufairly discriminates against those wholesale customers taking service at a single point of delivery, and it is therefore recommended that TUEC's proposal to eliminate conjunctive and coincident billing be adopted.

3. Demand Interval for Metering

a. TUEC Proposal

TUEC witness Charles F. Johnston explained the company's proposal that the demand interval for all TUEC demand rated customers be uniformly set at 15 minutes. Mr. Johnston explained that the demand interval is the length of time over which energy use is averaged in determining demand or capacity requirements for billing purposes. All TUEC customers on demand rates are presently billed using a 15 minute demand interval except the TP&L resale customers, who are presently billed using a 30 minute demand interval. TUEC proposes a 15 minute demand interval for all customers, so that the basis for all billing kw will be consistent and comparable for cost of service and rate comparison purposes and meter inventories, and administrative effort should be lessened. Mr. Johnston explained that the change in demand interval would not have any revenue impact on the TP&L resale customers, because TUEC adjusted the existing TP&L resale customers' 30 minute demands to 15 minute demands for use of the proposed rate, and the revenue is the same as it would have been with a demand rate based on a 30 minute interval. TUEC Exhibit 18, Johnston at 20.

On cross-examination, Mr. Johnston testified that the conversion factors of 1.47 percent for primary points of delivery and .83 percent for the transmission points of delivery were reasonable. Transcript at 4191; TUEC Brief on rate design at 34. These conversion factors for the TP&L customers were developed with demand data of Brazos Coop and TNP, and were then verified by comparison with five or six points of a TP&L wholesale customer, Tex-La, from which the company actually had 15 -minute demand data. Transcript at 4190, 4192-4193. Mr. Johnston explained that because there is very little demand fluctuation in the company's wholesale customers as a group, and based upon the verification and his experience in developing such factors, the factors are reasonably accurate. Transcript at 4190-4193; TUEC Brief on rate design at 34.

b. Tex-La Proposal

In brief, Tex-La asserts that TUEC has not demonstrated that it is preferable to switch all customers to a 15 minute demand interval for consistency, as opposed to switching all customers to.a 30 minute interval. Tex-La charges that TUEC has not supported its proposal that it is necessary for all customers on a demand rate to be on the same demand interval. Tex-La Brief on rate design at 25.

In his direct testimony, Tex-La witness Daniel stated that while it might be appropriate to bill industrial customers on a 15 minute interval because of sporadic fluctuation in such customers' demands (Transcript at 4731), this reasoning does not apply to wholesale customers whose demands are relatively level from one 15 minute interval to the next. Tex-La therefore concludes that a 30 minute interval is more appropriate for billing wholesale customers. Tex-La Brief on rate design at 25. Tex-La also charges that TUEC has used an erroneous conversion factor for estimating the effect of the change to a 15 minute interval. Coops Exhibit 24 at 16-18; Tex-La Exhibit 21 at 15-16. Because TUEC developed conversion factors based on load research data for TESCO wholesale customers, and because TUEC did not demonstrate that the. load characteristics of its TESCO wholesale customers are similar to those of its TP&L wholesale customers, the conversion factors used to develop wholesale billing demands for purposes of designing the proposed wholesale rate may have resulted in an inflated and erroneous proposed demand charge. Tex-La Brief on rate design at 25-26.

As an alternative, Tex-La suggests that if it is determined that the TUEC wholesale rate should be based on a 15 minute demand interval, then the change should not be made until the next TUEC general rate case. SWESCO Exhibit 1 at 13. Tex-La submits that this would allow TUEC sufficient time to collect the load research data needed to develop an accurate and fair conversion factor. Tex-La Brief on rate design at 26.

TUEC points out that on cross-examination, Mr. Daniel's testimony indicated that he was not aware that the Commission approved a 15 minute demand interval for the wholesale customers of the TESCO division in Docket No. 5200. Transcript at 4729; TUEC Brief on rate design at 33. Mr. Daniel also admitted that as long as the conversion factors are correct, such a change in demand interval would make no difference. Transcript at 4730. Although Mr. Daniel contends that the company's conversion factors are not correct, he apparently agrees that the wholesale customers have similar load characteristics. Tex-La Exhibit 21 at 25; TUEC Brief on rate design at 33. Further, Mr. Daniel admitted that he had not attempted to develop conversion factors to test the reasonableness of the company's factors, and therefore, had no opinion on whether or not they are correct. Transcript at 4730, TUEC Brief on rate design at 33.

c. Coops Proposal

Coops witness Stover testified that the Coops did not oppose changing to a 15 minute demand interval, but they are concerned with the reasonableness of the conversion factor. Coops Exhibit 25 at 47. Mr. Stover recommended that the conversion factor as proposed by the company be accepted, and that each month a comparison should be made of the 30 minute and the 15 minute integrated demands. Then any difference between the assumed adjustment factor and the actual adjustment factor should be reflected in a reconciliation each month. Coops Exhibit 25 at 48.

d. Recommendation

TUEC's proposal to change the TP&L wholesale customers to the 15 minute demand interval (on which all other customers of the company on demand rates are billed) is reasonable. By switching to the 15 minute demand interval, the basis for all billing kw should be consistent and comparable for cost of service and rate comparison purposes and meter inventories; administrative efforts should also be reduced as a result. It is also recommended that the conversion factor as proposed by the company be accepted, and the Coops' proposal to compare the 30 minute and 15 minute integrated demands, with any differences between the assumed adjustment factor and the actual adjustment factor to be reflected in a reconciliation each month, also be accepted.

4. Demand Charge of Fifty Percent Contract kw Amount

a. TUEC Proposal

In this docket, TUEC proposes to continue and/or extend the application to all customers billed on a demand basis the minimum billing demand feature approved by the Commission for TESCO in Docket No. 5200 and for DP&L in Docket No. 5256. This feature would require all demand metered customers, including wholesale customers, to pay a demand charge based on at least one half of the capacity the customer has requested the company to provide. TUEC witness Johnston testified that the company has made this proposal to prevent cross-subsidization among customers for the costs of under-utilized points of delivery which do not produce sufficient revenues to recover the company's investment in facilities from the particular customer for whom the facilities were constructed and/or committed. TUEC Exhibit 18, Johnston at 13. Mr. Johnston testified that in the absence of such a feature, TUEC may only recover its cost of facilities in its demand charge which is based upon actual reported demand rather than contract kw. Transcript at 4475. Therefore, the cost of the excessive and the unneeded facilities would be allocated to and borne by other customers. Transcript at 4475. For example, if a customer contracts for 1,000 kw, but after the company installs the necessary facilities has actual electrical load of only 300 kw, without the minimum contract kw feature, other customers would be required to bear some of the costs associated with the additional 700 kw. The minimum kw feature gives an economic signal to the customer to do the best job possible in determining capacity requirements and to contract only for what is reasonably needed; it also insures that minimal revenue is recovered in order to avoid subsidization. TUEC Exhibit 18, Johnston at 14.

b. SWESCO and TNP Proposals

Both SWESCO and TNP took the position that the company's proposal on this issue was merely an attempt to obviate its contractual obligations with the members of the wholesale class through the ratemaking process. TNP Brief on rate design at 15.

SWESCO purchases all of its power from the TP&L operating division of TUEC under the terms of a contract. SWESCO Exhibit 1, Exhibit 1(A); SWESCO Brief on rate design at 2. SWESCO argues that TUEC has failed to demonstrate that circumstances have changed from those in existence at the time the contract was entered into. Although the statutory authority of the PUC is recognized in paragraph 6 of the modification of a written contract in the manner proposed by TUEC in this docket. SWESCO Brief on rate design at 2. SWESCO refers to the contractual provisions in the TP&L rate Schedule WP-500 dated May 1980 which is annexed to the contract in suport of its argument that that neither the contract nor the rate schedule nor any TP&L wholesale rate schedule in effect since 1980 contained the 50 percent of contract kw minimum billing clause which SWESCO characterizes as a penalty. SWESCO Brief on rate design at 3. SWESCO argues that the contract explicitly provides that TP&L will provide SWESCO's requirements up to the maximum provided for in the contract and additional costs are incurred if SWESCO requests and receives capacity above the contract amounts. SWESCO Brief on rate design at 3-4. SWESCO argues that paragraph 6 of the contract, in its view, permits a change in rates based upon costs. SWESCO Brief on rate design at 4. SWESCO then asserts that the 50 percent of contract kw minimum billing demand is not based upon costs, but is simply a penalty assessed if SWESCO's requirements do not equal the maximum capacity available. SWESCO contends that the effect of such a change would convert what the contract clearly provides as a maximum capacity to a minimum capacity, which SWESCO further contends is not the agreement of the parties. SWESCO Brief on rate design at 4.

SWESCO further argues that paragraph 2 of the contract contemplates that the maximum amount of power which TUEC has agreed to deliver at each point of delivery may be revised from time to time to reflect any mutually agreed upon change. SWESCO submits that it has not agreed to such a change as proposed by TUEC. SWESCO Brief on rate design at 4.

Finally, SWESCO witness Fairbanks testified that the multimillion dollars involved in the proposed penalties are hidden from view, because they are not included in TUEC's revenue requirements and they are not cost based since all costs are being recovered otherwise. SWESCO Exhibit 1 at 8-12; SWESCO Brief on rate design at 4.

Similarly, TNP argues that TUEC arbitrarily picked 50 percent of contract kw in order to force wholesale customers, with whom TUEC has had longstanding contractual arrangements, to come in and renegotiate their contracts, which TNP submits is not good faith ratemaking on the part of the company. TNP Brief on rate design at 15. TNP refers to the direct testimony of TUEC witness Johnston, who stated: "We fully expect that the charges made will be few in number and will involve few dollars of revenue because it will be in the best interests of customer and company to immediately adjust the contractual arrangements which would eliminate the charge." TUEC Exhibit 1B, Johnston at 15. TNP further refers to Mr. Johnston's testimony on cross-examination, when he stated that it is the intent of the proposal that resale customers renegotiate their contracts. Transcript at 4461; TNP Brief on rate design at 16. TNP submits that it is clear that TUEC's purpose was to have the Commission, by accepting this illogical and unfounded claim of the company, force customers to renegotiate their contracts when the company has not shown that actual additional costs are being imposed upon any other group of customers. TNP Brief on rate design at 16. TNP further argues that the record evidence shows that in many instances TUEC has the ability to sell and is selling unused capacity supposedly dedicated to wholesale customers where it has points of delivery serving more than one customer. Transcript at 6122; TNP Brief on rate design at 16.

TNP also asserts that the imposition of this proposal would have detrimental effects upon the wholesale customers, who by their nature as electric utilities, seek to find the most reliable long-term electric service available to their customers. TNP argues that to force them to renegotiate contracts entered into in good faith would be a serious breach of the sanctity of contract, especially where the company fails to present any evidence in support of its contention that other classes are shouldering costs properly borne by the wholesale class. TNP Brief on rate design at 17.

TNP offers as a further reason for rejecting the company's proposal that if there is unused capacity, the cost burden of which is being borne by other ratepayers, the wholesale customers should be allowed to sell this unused contractual capacity to whomever they please. TNP Brief on rate design at 17. It is TNP's position that this is the logical result if wholesale customers are going to be asked to shoulder what it characterizes as phantom costs. TNP Brief on rate design at 17. TNP argues that through its other contractual arrangements, TUEC specifically prohibits the resale by any wholesale customer of its capacity without permission of TUEC; thus the company should not be charging for unused capacity and then refusing to allow the wholesale customers to resell that capacity for which they are paying. TNP Brief on rate design at 17.

The contracts upon which TNP and SWESCO rely in arguing that they are being inappropriatley forced to relinquish rights thereunder contain the following or similar provisions:

> Customer understands and agrees that...the methods of billing multiple points of delivery as well as other conditions of service and charges therefor are subject to modification and change from time to time by regulatory authorities having jurisdiction, as well as the establishment of such authorities of new or different rate schedules and provisions for rendering service.

SWESCO Exhibit 1, Exhibit 1(A).

TUEC replies that both TNP witness Laux and SWESCO witness Chick agreed that replacement costs for production and transmission facilities have greatly increased over the last several years (Transcript at 6174, 6073), and the economy in general has caused the utility industry to be much more sensitive toward efficent planning. Transcript at 6073; TUEC Brief on rate design at 24. TUEC argues that the 50 percent contract provision is not principally designed to generate revenue, and will not do so except in cases where a customer's contract kw is extremely large in comparison to the customer's actual load. Transcript at 4458; TUEC Brief on rate design at 24. TUEC points out that TNP witness Laux recognized that, assuming the provision were adopted along with an 80 percent ratchet, a customer could contract for kw of 160 percent of his historic summer peak demand and still be insulated from being affected by the 50 percent provision. Transcript at 6068; TUEC Brief on rate design at 24. TUEC submits that in this context, the contract kw in the non-summer months would be much more than 160 percent without effect. Transcript at 6068. Mr. Laux also agreed that if the Commission adopts this provision, TNP's contract kw's could be set at a level logically related to its demand. Transcript at 6069. TUEC contends that its illustration clearly shows that the logical level would include future growth. TUEC Brief on rate design at 24.

TUEC also responds to the testimony of TNP and SWESCO witnesses that TUEC would be double recovering in the event that TNP and SWESCO chose not to renegotiate their contract kw's to a lower level. SWESCO Exhibit 1 at 8; TNP Exhibit 3 at 18. TUEC points out in brief that SWESCO witness Chick agreed that there are reasons why a logical relationship should exist between the contract demand and the load anticipated to be placed in effect (Transcript at 6173), and that such a logical relationship for billing purposes does not exist in SWESCO's contract with TUEC. Transcript at 6174. Mr. Chick further agreed that if the Commission extended the contract application to all wholesale customers of TUEC, he would recommend that SWESCO lower its contract kw's to a more realistic level. Transcript at 6171. Mr. Chick also testified that the purpose of the provision is to assure that there is a logical relationship between the billing (and anticipated) demand and the contract kw. Transcript at 6172. TUEC submits that Mr. Chick has therefore concurred with Mr. Johnston's explanation that the primary purpose of the provision is to provide an incentive to the customer to realistically reevaluate his load, and in the event he chooses to greatly overstate his needs, other customers will not be burdened with the excess costs. Transcript at 4470; TUEC Brief on rate design at 25.

In its reply brief, TNP offers another reason for rejecting the 50 percent contract minimum billing provision. TUEC witness Johnston stated that the tariff provision was not considered in TUEC's determination of the billing units from which the demand rate of the wholesale class was calculated. Transcript at 4460-4461. TNP submits that had it been considered in the determination of billing units, it would have increased the billing units, decreasing the demand rate. TNP submits that if this provision is adopted by the Commission, it will operate as a means to increase the amount of kw's a particular point of delivery is billed for, therefore, the company will double recover. TNP Reply brief on rate design at 6. By TUEC not having considered the tariff feature having a higher demand rate, when that higher demand rate is applied to a higher number of kw's being build as a result of the implementation of the 50 percent minimum, TNP alleges that TUEC will overrecover. TNP argues that this is a sufficent reason for rejecting this tariff provision. TNP Reply Brief on rate design at 6.

TNP also argues in its Reply Brief that TUEC has mischaracterized the testimony of Mr. Laux regarding TNP's objection to the 50 percent minimum billing demand feature. TNP Reply Brief on rate design at 5.

c. Coops Proposal

The Coops take the position that the 50 percent contract kw minimum provision is unwarranted and punitive. Coops Exhibit 25 at 44-46; Coops Brief on rate design at 18. The Coops contend that the contract kw is used to define the facilities to make the extension for service, and is in no way relied upon or related to the production and bulk transmission investments or investment decisions of the company. The Coops assert that these decisions are made on the basis of actual system demands, required reserve margins and fuel considerations. Coops Brief on rate design at 18. Thus, the Coops argue, the contract minimum is to protect TUEC in its investment in service extension facilities only (that is, distribution line and transformation) and has nothing to do with demand costs. Coops Brief on rate design at 18. Kw billing units are designed to cover the demand costs. The Coops refer to the testimony of TUEC witness Johnston that approximately $6.1 billion out of a total production facilities investment of $7 billion is for production investment. Transcript at 4293; Coops Brief on rate design at 18. That leaves what the Coops characterize as a paltry $900 million as needed to pay for the entire transmission system. The Coops argue that the customer charge is to cover the investment in local facilities, and the contract minimum is only to cover the diffence between the average cost of distribution extension and the cost of the particular extension in question. Coops Brief on rate design at 18. The Coops argue that using the kw figure used to size a service extension for the purpose of fixing a ratchet of 50 percent on kilowatt demand billing units creates protection not related to the cost of the extension but o the cost primarily of production and bulk transmission resulting in "overkill of enormous magnitude." Coops Brief on rate design at 18. The Coops express that alleged overkill by stating that TUEC requests the Coops to agree to again pay TUEC its portion of $7 billion in demand costs and then to agree to pay another one half of such cost ostensibly in order to protect a portion of TUEC's investment in a local service extension already covered by the customer service charge and line extension policy (Coops Brief on rate design at 19). The Coops charge that the so-called protection device covers an expense already fully protected by other tariff provisions, and that the resulting penalty is not only excessive and irrational, it is unwarranted and duplicative of other tariff provisions. Coops Brief on rate design at 19.

TUEC points out in brief that Coops witness Stover opposes the contract minimum (Coops Exhibit 25 at 44), but admits that his client employs a minimum billing feature to protect its local investment. Transcript at 5018-5019; TUEC Brief on rate design at 24. TUEC also argues that the Coops argument that a double recovery would result from the 50 percent minimum billing demand feature was discussed and rejected in Docket No. 5200. TUEC reiterates that in the absence of such a feature, TUEC may only recover its costs of facilities in its demand charge which is based upon actual recorded demand rather than contract kw, and without such a feature, the cost of excessive and unneeded facilities would be allocated to and borne by other customers Transcript at 4475; TUEC Reply Brief on rate design at 9.

d. Tex-La Proposal

Tex-La argues that TUEC has not presented any studies or cost support to show the 50 percent level for contract demand for billing is reasonable. Tex-La Brief on rate design at 34. Tex-La also charges that TUEC has not considered any increased billing units which would result from this new provision. In excluding these billing units from the rate design, Tex-La charges that TUEC has inflated the proposed demand rate and will receive a windfall when actual bills are rendered using the increased billing units. Bowie Exhibit 3 at 22; Tex-La Brief on rate design at 34.

e. Recommendation

TUEC's proposal is similar to provisions previously approved by the Commission for two operating divisions of TUEC. Such a provision is necessary to prevent cross-subsidization between customers for under-utilized points of delivery which do not produce revenues contemplated by both the customer and TUEC at the time facilities construction was agreed to. Such a provision does not result in the double recovery for the same facilities. TUEC's proposal is therefore recommended for adoption, however, TUEC should also recalculate the demand billing units taking into account the application of the 50 percent of contract minimum and make any upward adjustment to the billing units which may result from the recalculation.

5. $1.00/KW in Excess of Contract KW

a. TUEC Proposal

TUEC proposes the continuation or extension of the $1.00 per kw per month charge for each kw taken by a customer in excess of the capacity for which the customer has contracted. This feature is designed to avoid the costs associated with possible equipment failures and related engineering studies, and to cover the cost of the administrative work required in reevaluating and recontracting for higher electric loads. TUEC expects the actual charges under this feature to be very few. TUEC Exhibit 1(B), Johnston at 14-15. During cross-examination, TUEC witness Johnston testified that the company's transformers are sometimes damaged or destroyed as the result of a customer's taking loads in excess of the amount of capacity that the customer had advised TUEC was needed. Transcript at 4491. He further testified that because damage due to overloading actually occurs, and results in costs for engineering studies, contract evaluation and repair and replacement of equipment, the $1.00 per excess kw charge is reasonable and, the company hopes, sufficient to deter unnecessary expenses. Transcript at 4490-4492; TUEC Brief on rate design at 25-26.

b. SWESCO and TNP Proposal

SWESCO advanced the same argument in opposition to the $1.00 per kw in excess of contract kw which it set forth in opposition to the 50 percent of contract kw demand charge, supra. SWESCO Brief on rate design at 2-5. TNP also opposes the proposed charge and argues that it should be rejected on the grounds that it imposes a double recovery of TUEC's costs and has not been shown to be based upon any identifiable costs. TNP Brief on rate design at 19. TNP points out that TUEC has allocated its entire plant in service to each customer class in this proceeding and will, pursuant to the Commission's Order in this case, recover those costs. Such costs include generation plant, transmission and distribution facilities, and all other items of plant necessary for TUEC's operation. Thus, TNP concludes,the proposal to add a $1.00 per kw per month charge will result in a situation where the company will overrecover its costs. TNP Exhibit 3 at 13. TNP further argues that TUEC produced no data to justify the $1.00 charge; TNP asserts that it is no more than an estimate or guess of what any cost would be. TNP Exhibit 3 at 16; TNP Brief on rate design at 19.

TNP submits that the tariff proposal by the company is based on a belief that wholesale customers would act in an irresponsible manner causing such equipment failures to take place. TNP points out that Mr. Johnston, in the 27 years he had been with TUEC or one of its operating divisions, could not recall a single instance of such an occurance. Transcript at 4495; TNP Brief on rate design at 20.

been with TUEC or one of its operating divisions, could not recall a single instance of such an occurance. Transcript at 4495; TNP Brief on rate design at 20. TNP submits that since there is no evidence to support the $1.00 charge, it should be eliminated from the wholesale tariff. TNP Brief on rate design at 20.

TUEC points out that SWESCO witness Chick perceived no additional costs unless actual physical damage is sustained due to overloading. SWESCO Exhibit 2 at 5; TNP witness Laux testified that the costs associated with this problem are already being allocated in the company's total plant in service to various classes of customers. TNP Exhibit 3 at 14. Both Mr. Laux and Mr. Chick charge that the change is unnecessary because the resale customers would not overload to the point that damage would result. TNP Exhibit 3 at 14; Transcript at 6177. TUEC also points out that Mr. Laux on cross-examination admitted that there are costs involved in the company's reevaluation of contracts (Transcript at 6081), and agreed that such a provision would encourage customers to candidly advise the company of their actual needs (Transcript at 6080), although as TNP points out in its reply brief, Mr. Laux also testified that costs involved in reevaluating contracts are also assigned to specific accounts that are already allocated to cost of service. Transcript at 6081; TNP Reply Brief on rate design at 6. TUEC points out that Army witness Neidlinger admitted that the company is incurring additional engineering and facility costs because of demands that exceed contract levels. Transcript at 4686; TUEC Brief on rate design at 26.

SWESCO witness Fairbanks took the position that the $1.00 per kw in excess of contract kw provision should be denied if the 50 percent contract minimum provision is adopted. SWESCO Exhibit 1 at 12. As an example, Mr. Fairbanks states that the minimum provision would require a lowering of the contract KW at SWESCO's Lake Creek point of delivery from 90,000 kw to 26,000 kw (assuming an 80 percent ratchet), and if, through switching, the load at that point exceeds the latter amount, SWESCO would be penalized. SWESCO Exhibit 1 at 12. TUEC points out that Mr. Fairbanks testified that load switching at Lake Creek could easily exceed 30,000 kw, but offered no evidence of when or if such a load has ever occured. TUEC Brief on rate design at 26. On cross-examination, Mr. Fairbanks admitted that the normal load of Lake Creek is approximately 16,000 kw without switching, and the peak with switching during the test year was only 24,147 kw. Transcript at 6153-6154; SWESCO Exhibit 2 at 3; TUEC Brief on rate design at 26. TUEC argues that based upon the evidence, had both provisions been in effect during the test year, under Mr. Fairbanks' example SWESCO could have lowered its contract kw for its Lake Creek point of delivery to 26,000 kw without payment under either provision. TUEC Brief on rate design at 26.

c. Tex-La Position

Tex-La contends that TUEC has not shown that the $1.00 per kw charge is reasonable and cost based. Tex-La Exhibit 21 at 27. Tex-La argues that a wholesale customer should not be penalized if its demand exceeds its contract demand, because the company has planned its system to meet projected system peak rather than contract demands. TUEC Exhibit 1(B) Tanner at 4; Tex-La Brief on rate design at 35. Tex-La also points out that the Commission's Substantive Rules require it to prepare and submit to the Commission every two years a ten-year load forecast. Since the company will have access to the load forecast and can incorporate these projections into its own total system forecast for planning purposes, the company should not penalize Tex-La for having an outdated demand. Tex-La further argues that while this provision might be appropriate for industrial or commercial loads, it is not needed for Tex-La. Tex-La Brief on rate design at 36.

Tex-La also asserts that the $1.00 per kw provision is anticompetitive. Tex-La Exhibit 21 at 27-28. Tex-La points out that if both TUEC and the wholesale customer seeks to attract the same new customer, the $1.00 per kw penalty could put the wholesale customer at an economic disadvantage in serving the new customer. Tex-La Brief on rate design at 36.

d. Recommendation

TUEC correctly points out that the arguments by certain intervenors that this provision should not be adopted because the intervenors will not overload the company's facilities are unique. TUEC cannot reasonably be expected to rely on the simple assertion that a customer would never act in such an irresponsible manner. This is not to say that such behavior is comtemplated or expected; only that the proposal of the company to institute a tariff provision addressing this problem appears reasonable. Even if the intervenors are correct that the $1.00 per kw per month for each kw taken in excess of the contract kw is a penalty and is not cost based, it does appear that the intent of the provision, that of providing an incentive for customers to adjust contractual arrangements which would eliminate the charge, is prudent. While Tex-La may be correct that TUEC will have the benefit of its ten-year load forecast, such a forecast is simply a "best-guess" look at the future, and provides no protection for TUEC in the event that a customer fails to adjust its contract kw to realistic levels. The Commission has approved such a provision in the past, the provision is reasonable, and it should be adopted.

E. Design of Rates G and HV

1. TUEC Proposal

TUEC witness Charles F. Johnston presented the company's proposed general service rate (Rate G). This rate as proposed contains a customer charge, a demand charge, three energy blocks with a block extender in the second block, an 80 percent summer demand ratchet, a 50 percent contract minimum demand, and a primary service credit. It also includes an off-peak provision applicable to both seasonal and daily off-peak usage. It is a consolidation of DP&L Rate G, TESCO Rate G and Rider RW, and TP&L Rates GS and LP-20 and associated Riders GSH, OP and RW. TUEC Exhibit 1B, Johnston at 12.

Mr. Johnston explained that general service Rate G is available for primary and secondary voltage customers ranging in size from less than one kw to as high as 20,000 kw or more. The energy steps in the low-use range, up to 6,000 kwh, contain not only energy charges but also demand charges, since no direct charge is made until after 10 kw. Mr. Johnston describes Rate G as a combination demand and non-demand rate. TUEC Exhibit 1B, Johnston at 12. Compared to the alternative of having two or more general service rates, this type of rate is preferable in Mr. Johnston's opinion because it insures that the customer will be on the most advantageous rate at all times and, at the same time, it minimizes the administrative costs involved in maintaining more than one general service rate. Thus, the customer is not faced with the difficult decision, before taking electric service, of determining which rate is most advantageous for the customer's load size and use characteristics, and the company avoids the expensive, time consuming administrative efforts associated with borderline rate analysis, that is, determining on a regular basis whether or not the customer is in fact receiving service under the most advantageous general service rate. TUEC Exhibit 1B, Johnston at 13.

Rate G has three minimum billing demand features. The first is based on 80 percent of the maximum kw recorded during the peak months of June through October, and is designed to recover annual production and transmission costs and to encourage load management activities by customer, and is otherwise known as a ratchet. The second is based on the contract kw, and is designed to insure at least a minimal recovery of costs associated with providing electric service in the quantity requested by a particular customer. The third feature is based on the annual kw (the highest kw recorded on a customer's meter at any time during the twelve months ending with the current month) and is designed to adjust the contract kw upward for billing purposes if the customer's load exceeds the original contract amount. TUEC Exhibit 1B, Johnston at 13. Without the annual kw feature, the customer might have an inappropriate incentive to contract for less load than actually needed. In the case of a highly seasonal load, revenue from the customer would not be sufficient to support the investment required to serve the customer, and other customers would then be subsidizing the seasonal customer. Thus, Mr. Johnston explains, the contract and annual kw features give an economic signal to the customer to do the best job possible in determining capacity requirements and to contract only for what might be reasonably needed, also insuring that minimal revenue is recovered. TUEC Exhibit 1B, Johnston at 14.

The block extender in Rate G is designed to allow a single rate to follow very closely the cost of service of a non-homogeneous group of customers whose load factors may vary from as low as 15 percent to as high as 95 percent. The coincidence factors of the low load factor customers are usually less than the coincidence factors of high load factor customers. The block extender is merely a means of insuring that low load factor customers are charged according to their contribution to demand-related costs. TUEC Exhibit 1B, Johnston at 14. Finally, TUEC proposes to charge $1 per kw per month for each kw in excess of contract KW during a billing month to cover the costs associated with possible equipment failures and engineering studies and with the administrative work required in reevaluating and recontracting for the higher electrical loads. TUEC Exhibit 1B, Johnston at 15. The operation of the ratchet, the 50 percent contract minimum and the $1 per KW in excess of contract KW are more fully described in Section D above.

In order to treat all customers within a given rate group fairly, that is, not charge the lower monthly load factor customers more than a fair share of demand related costs and to insure that higher monthly load factor customers are not paying less than a fair share of demand-related costs, a small portion of the demand-related costs, about 5 percent, are proposed to be collected through the energy steps of the demand rates. The effect of this is to increase slightly the effective demand charge per kw for the high monthly load factor customers and helps insure equity for all customers in the group.

The general service high voltage rate is a rate designed only for large customers, and it does not require block extenders. It too has a customer charge, a demand charge, and an energy charge, all separately stated, with all other features virtually identical to those for proposed Rate G. TUEC Exhibit 1B, Johnston at 18-19.

In its brief, TUEC responds to the recommendations of TIEC and St. Regis that the amount of demand related costs recovered through energy charges should be lowered. TUEC Brief on rate design at 26. TUEC urges that the explanation of its witness Mr. Johnston adequately supports the TUEC proposal. As explained in Mr. Johnston's testimony, about 5 percent of the demand related costs are recovered through the kwh energy charge so that higher energy usage increases the effective demand charge to a customer, recognizing that high load factor customers have higher coincidence factors and thus greater responsibility for demand related costs than do lower usage customers. TUEC Brief on rate design at 26-27. TUEC submits that after class cost has been properly allocated to the G and HV classes, the rate is designed to properly collect that cost from the individual class members in a manner fair to all members in the class, regardless of load factor. Transcript at 4304; TUEC Brief on rate design at 27. In its Reply Brief, St. Regis submitted that TUEC's proposed energy charges for Rates G and HV are inappropriate for the following reasons: a comparison of the variable costs excluding fuel for Rates G and HV shown on page 127-I of the company's cost of service study with TUEC's proposed tailblock energy charge for Rate G and proposed energy charge for Rate HV reveals that TUEC, in formulating its proposal, grossed up its variable cost calculation by approximately 5 percent to obtain its proposed energy charges. St. Regis submits that TUEC's calculation of variable cost is flawed because it includes classification upon energy of costs relating to FERC Account 513-Production Maintenance Expenses Associated with Electric Plant. Mr. Eisdorfer's cost of service study reclassified that account to demand. When Mr. Eisdorfer calculated the variable cost of providing service to Rates G and HV customers excluding Account 513, the variable cost for Rate G was calculated to be no more than 5.9 mills per kilowatt hour. The corresponding figure for Rate HV was 4.4 mills per kilowatt hour. Following TUEC's methodology and increasing the variable costs by 5 percent, St. Regis points out that the Rate G tailblock would be 6.2 mills per kilowatt hour and 4.6 mills per kilowatt hour for the Rate HV energy charge. St. Regis points out that this is within two tenths of one mill of Mr. Eisdorfer's proposed tailblock energy charge for Rate G of 6.0 mills per kilowatt hour for secondary service and within one tenth of one mill of his proposed energy charge for Rate HV of 4.5 mills per kilowatt hour. St. Regis submits that this is considerably closer to the grossed-up variable cost figures (6.2 mills per kilowatt hour for Rate G and 4.6 mills per kilowatt hour for Rate HV) than the company proposed energy charges of 7.0 mills per kilowatt hour for Rate G and 5.5 mills per kilowatt hour for Rate HV. St. Regis Reply Brief on rate design at 2-3.

2. St. Regis Proposal

St. Regis witness Eisdorfer offered a proposal for the design of Rates G and HV. St. Regis Exhibit 2 at 25-30. Mr. Eisdorfer testified that the goals of rate design should be the eventual elimination of intra-class subsidization and minimization of the potential of overall earnings instability. Proper rate design should reflect to the maximum extent possible individual customer cost incurrence patterns and should allow the tracking of cost changes associated with varying consumption patterns. In his opinion, these goals are best achieved when tariff's tailblock energy charge is limited to the recovery of variable costs. Fixed costs should be recovered in other portions of the tariff. St. Regis Exhibit 2 at 25. Mr. Eisdorfer further testified that when variable costs are recovered in the demand charge, relatively high load factor customers would be subsidized by others. Conversely, when fixed costs are recovered in the energy charge, high load factor customers will subsidize low load factor customers. St. Regis Exhibit 2 at 26. It is also Mr. Eisdorfer's opinion that if one attempts to utilize a tailblock energy charge as a vehicle for fixed cost recovery, one implicitly assumes that customer energy consumption is fixed in nature, an assumption Mr. Eisdorder characterizes as precarious. St. Regis Exhibit 2 at 26. Specifically, Mr. Eisdorfer testified that TUEC's proposed design for Rates G and HV is deficient because it attempts to recover 1.1 mills of fixed costs for each kilowatt hour sold. St. Regis Exhibit 2 at 27; St. Regis Brief on rate design at 28. Mr. Eisdorfer points out that if sales to these customers decline from test year levels, there will be an underrecovery of fixed costs, and if energy sales to these customers increase, fixed costs will be overrecovered. In addition to being unreflective of cost, Mr. Eisdorfer states that the proposed Rates G and HV would impose an excessive burden upon those customers with high load factor operations and would result in intra-class subsidization. St. Regis Exhibit 2 at 28; St. Regis Exhibit 2, Schedule 14; St. Regis Brief on rate design at 29.

Mr. Eisdorfer's recommendation is to set the tailblock for energy in Rate G and the energy rate charge for Rate HV essentially at variable costs. Using TUEC's proposed revenue requirement, Mr. Eisdorfer recommends a tailblock energy charge for Rate G of 6.0 mills per kilowatt hour and an energy charge for Rate HV of 4.5 mills per kilowatt hour. St. Regis Exhibit 2 at 29; St. Regis Brief on rate design at 29. At his proposed class revenue levels, based upon his four-CP cost of service study, Mr. Eisdorfer recommended specific rates for Rates G and HV, and if a lower revenue increase is approved, Mr. Eisdorfer recommends that proportional changes be made to his recommended charges. If a larger revenue increase is ordered, he still recommends that the tailblcok energy charge for Rate G be set at 6.0 mills per kilowatt hour, and the energy charge for Rate HV be set at 4.5 mills per kilowatt hour with proportional changes made to his other proposed charges. St. Regis Exhibit 2 at 30; St. Regis Brief on rate design at 29.

3. TIEC Proposal

TIEC witness Pollock made recommendations with respect to the design of rates for Rate G and Rate HV. TIEC Exhibit 2 at 28-29. Mr. Pollock found that the revised average and excess cost of service study indicated that the demand charge credit for primary service under the company's proposed Rate G should be increased. TIEC Exhibit 2 at 29. Mr. Pollock's recommendations for Rates G and HV were based on his recommended revenue targets assuming that TUEC is granted its entire revenue request. Mr. Pollock accepted the company's proposed non-fuel energy charges because they would approximate energy costs, based on its cost of service study. Mr. Pollock qualified that recommendation, however, by stating that if an adjustment is made which would lower the non-fuel energy related costs in TUEC's cost of service study, he would recommend that a corresponding adjustment be made to the non-fuel energy charges. TIEC Exhibit 2 at 29, Exhibit JP-2, Schedules 3, 6 and 7. In addition, TIEC supports TUEC's proposed 80 percent demand ratchet (TIEC Exhibit 2 at 32), but would redefine the on-peak period so that only the demands imposed during the summer peak period are subject to the 80 percent demand ratchet. TIEC Exhibit 2 at 32-33. According to Mr. Pollock, the on-peak period would not apply to demands imposed prior to May 27 or after October 3. TIEC Exhibit 2 at 33. Finally, TIEC recommends that any increase assigned to Rates G and HV should be recovered primarily through higher demand charges, in order to track costs more accurately and to satisfy important rate design objectives such as revenue requirement recovery and revenue stability. TIEC Exhibit 2 at 29-31; TIEC Brief on rate design at 28.

4. Staff Proposal

Under the staff's proposal for high voltage rates, staff witness Kepner recommended a seasonal differential in the demand charge of $3, and of $0.005 in the seasonal base rate kw charge. Staff Exhibit 36 at JWK-16. General Counsel submits that although Mr. Kepner advocates cost based rates, he recommends a gradual movement towards time-of-use pricing. Staff Exhibit 36 at 19-20. General Counsel asserts that Mr. Kepner is concerned with minimizing the impact his method, which truly captures the company's costs as imposed by its customers, has on the company's ratepayers. General Counsel Brief on rate design at 30. General Counsel further asserts that Mr. Kepner's proposed rates are in line with the company's proposed rates. Mr. Kepner proposes a $7 demand charge for the summer peak hours and a $4 demand charge in the summer off-peak hours and for all hours during the winter. General Counsel submits that the staff's proposed rates are appreciably comparable to the company's flat rate of $6.24. General Counsel Brief on rate design at 30. Thus, General Counsel argues, the staff's proposed rates send a better, although more moderate, price signal than that proposed by TUEC. Staff Exhibit 36 at 20.

In brief, TIEC points out that in his testimony, Mr. Kepner specifically stated that he would go along with the proposed 80 percent ratchet in order to relieve the company's concerns about the impact of the time differentiated demand charges on their revenue stability. Staff Exhibit 36 at 36; TIEC Brief on rate design at 29. TIEC points out that upon cross-examination, however, Mr. Kepner changed his recommendation regarding ratchets and was unable to state precisely what high voltage rates he wanted this Commission to adopt. Transcript at 6592, 6593-6595. TIEC submits that the Commission should be reluctant to adopt rate design proposals which are clouded with this kind of uncertainty. TIEC Brief on rate design at 29.

5. Recommendation

Mr. Eisdorfer's proposal with respect to Rates G and HV was premised on his recalculation of variable costs excluding costs relating to FERC Account 513-*Production Maintenance Expenses Associated with Electric Plant.* As has been stated previously in this report, it is recommended that TUEC's classification upon energy of costs relating to this account be accepted. Therefore, TUEC's calculation of variable cost is not flawed, and its proposal for the design of Rates G and HV should be adopted. In addition, TIEC's recommendation that the on-peak period should be redefined so that only the demand imposed during the summer peak period are subject to the 80 percent demand ratchet is recommended for adoption; the on-peak period would not apply to demand imposed prior to June or after September. The recommendation of the staff on this issue is uncertain and should not be adopted.

F. High Voltage Credit

1. Nucor Steel Proposal

Nucor Steel argues that it is consistent with the calculation of line loss factors by voltage levels as permitted by Commission Substantive Rule that a high voltage demand charge credit should be established in this docket. Nucor Steel Brief on rate design at 17. Nucor Steel's position is that such a credit would recognize that TUEC's power lines perform different functions according to their voltage level and that TUEC's customers benefit from these lines in varying degrees according to the voltage level at which they take service. In support of this position, Nucor Steel points out that TUEC's system includes power lines of different voltages: large 345 kv backbone transmission lines, 138 kv and 69 kv lines, and smaller lines that deliver electricity to residential and other users. Typically, power flows from generating units and higher voltage lines to customers served at lower voltages. Transcript at 4868, 5254; Nucor Steel Brief on rate design at 17.

Nucor Steel witness Wilson testified that the 345 kv lines provide the basic bulk transmission backbone for the TUEC system. Nucor Exhibit 6 at 25. These lines deliver power throughout the TUEC system for use by customers at all voltage levels. Nucor Exhibit 6 at 26. On the other hand, Dr. Wilson testified that TUEC's 69 kv lines are not used primarily for overall system reliability or power transfer capability, but instead are used to perform a more localized delivery function. Nucor Steel Exhibit 6 at 27-30. Dr. Wilson states that the 345 kv and 69 kv lines cannot be used interchangeably because they have different power carrying capabilities. For example, Dr. Wilson points that a 345 kv power line can carry 25 times the power of a 69 kv line. Nucor Steel Exhibit 6 at 28-29. Dr. Wilson concludes that TUEC's 345 kv power lines benefit all customers because such lines perform a systemwide backbone transmission function. Nucor Steel Exhibit 6 at 27. Dr. Wilson concludes that the 69 kv lines, however, do not provide proportionate benefits to all customers because they serve a more limited, localized function. Nucor Exhibit 6 at 29-30. Dr. Wilson also testified that TUEC's 138 kv power lines function in some ways that are like the large 345 kv lines and in other respects like the smaller 69 kv lines. Nucor Steel Exhibit 6 at 27. The 138 kv lines link certain service areas together and connect generation to the 345 kv backbone; they also take power down from the 345 kv transmission backbone for ultimate delivery to customers at lower voltages, and therefore function more like 69 kv lines.

Nucor Steel witness Dr. Wilson analyzed TUEC's transmission system in order to assess the service and benefits that Nucor Steel receives from TUEC's 138 kv and 69 kv lines. Transcript at 5251-5252, 5396-5399. This analysis was based on Dr. Wilson's reference to two large transmission maps of the TUEC system, one obtained from the Federal Energy Regulatory Commission, the other obtained from TUEC in response to a Request for Information. Transcript at 5249, 5254-5255, 5391-5392. Based on his analysis of the transmission maps and taking into account Nucor Steel's location near the Jewett Substation and its status as an interruptible 345 kv customer, Dr. Wilson concluded that Nucor Steel receives little if any service from TUEC's 138 kv and 69 kv lines. Nucor Steel Exhibit 6 at 30-32. It was also Dr. Wilson's opinion that by taking service directly at 345 kv, Nucor Steel did not impose any step-down transformation costs on TUEC, absorbing all such costs itself. Nucor Steel Exhibit 6 at 32. Nucor Steel concludes that it would be inappropriate to charge Nucor Steel for the cost of facilities that it does not use. Nucor Steel Brief on rate design at 19.

Dr. Wilson further testified that even though the 138 kv facilities might, in some instances, provide a degree of backup capability for the 345 kv backbone system, there was little reason to believe that Nucor Steel would benefit substantially from this backup. Dr. Wilson based his opinion on the fact that Nucor Steel is located in the immediate vicinity of the Jewett Substation in proximity to multiple 345 kv lines connecting various bulk power sources. Nucor Steel Exhibit 6 at 30-31; Nucor Steel Exhibit 8; Transcript at 5396-5398; Nucor Steel Brief on rate design at 19. Nucor Steel further argues that in the event that a 345 kv line were out of service, power delivery to Nucor Steel would not be reduced because of a downstream bottleneck, or Nucor Steel itself would be interrupted given its status as an interruptible customer. Nucor Steel Exhibit 6 at 31-32; Transcript at 5252, 5398. Nucor Steel points out that TUEC acknowledges that such an interruption could occur given an outage of a high voltage power line. Transcript at 3938.

Dr. Wilson concluded that it would be inappropriate to charge Nucor Steel any of the costs related to TUEC's 138 kv and 69 kv lines. Transcript at 5258. After having discussed the matter with TUEC personnel and, in the interests of presenting a viewpoint that would be "conservative," (Transcript at 5255-5256, 5258), Dr. Wilson recommended that Nucor Steel be charged its share of between 1/4 and 1/3 of the cost of the facilities. Nucor Steel Exhibit 6 at 34; Transcript at 5258; Nucor Steel Brief on rate design at 20. Under this proposal, there would be a monthly demand charge credit of about 8 to 9 percent for HV service. Nucor Steel Exhibit 6 at 33-34, Exhibit JW-13, Page 1.

Nucore Steel submits that Dr. Wilson's analysis is correct, conservative, and amply supported by record evidence. Nucor Steel Brief on rate design at 20. Nucor Steel argues that it obtains relatively little if any service and benefit from TUEC's 138 kv and 69 kv facilities, Nucor Steel does not impose any stepdown transformation costs on TUEC, and Dr. Wilson's recommendation is consistent with the concept of the Commission's Substantive Rule 23.23(b)(2)(C)(ii) which permits recognition of different voltage levels in calculating line loss factors. Nucor Steel urges adoption of a demand charge credit of 8 to 9 percent. Nucor Steel Brief on rate design at 20.

2. Tex-La Proposal

Tex-La points out in brief that the company's wholesale rate includes a voltage discount of $1.32 per KW in the demand charge if service is taken at 69 kv or higher. Although Tex-La agrees that a discount should be provided for service at the transmission level, Tex-La proposes that this transmission level discount be refined to provide a further breakdown for service at different voltage levels within the transmission system. Tex-La Exhibit 21 at 17-18; Tex-La Brief on rate design at 31. Tex-La refers to the testimony of St. Regis witness Eisdorfer as confirming the principle that it is less costly to serve a customer at a higher voltage level than it is at a lower voltage level. St. Regis Exhibit 2 at 6-7; Tex-La Brief on rate design at 31-32. Tex-La also refers to the testimony of Nucor Steel witness Dr. Wilson, discussed above. Nucor Steel Exhibit 6 at 23-34; Tex-La Brief on rate design at 32.

Tex-La witness Daniel pointed out that the wholesale customers' transmission level delivery point receives service at either 69 kv or 138 kv. Tex-La Exhibit 21 at 18. TUEC's proposed wholesale rate provides the same discount for both levels. Tex-La argues that since TUEC incurs less cost to provide service at the 138 kv voltage level, a separate discount should be offered for each of the two voltage levels to reflect this cost difference. Tex-La Exhibit 21 at 18; Tex-La Brief on rate design at 32. Mr. Daniel also testified that the customer usually incurs a higher investment in order to take service at 138 kv an investment that would otherwise have been made by the company. Tex-La Exhibit 21 at 18. Mr. Daniel concludes that without a separate 138 kv voltage discount, a customer would receive the wrong price signal and would not have the incentive to make the additional investment to take service at the higher voltage level. The company would then have to make this investment which would result in increased costs to all customers. Tex-La Exhibit 21 at 18-19; Tex-La Brief on rate design at 33.

Tex-La further argues that several Requests for Information to the company in this case asked for the data needed to determine voltage level discounts for each transmission service level, and the company replied that the information was not readily available. Tex-La Exhibit 21 at 19. Tex-La argues that it has been shown that different voltage level discounts are proper and reasonable, and that therefore the company should be ordered to provide this information in its next general rate case. Tex-La also points out that other utilities in Texas, such as Gulf States Utilities, do offer separate discounts by voltage level of service. Tex-La Brief on rate design at 33.

3. Recommendation

Although the arguments advanced by Nucor Steel and Tex-La are appealing, there are some problems with the proposals as they have been presented in the testimony of the witnesses for these parties. Dr. Wilson testified that the 345 kv class benefits to some extent from the 138 kv transmission system, but his compromise position, that Nucor Steel be charged its share of between 1/4 and 1/3 of the cost of these facilities, was simply an approximation. Transcript at 5249. Although Dr. Wilson testified that he studied the company's transmission system, he further testified that it was not really possible to say exactly what lines should be excluded in determining the benefit Nucor Steel derives from the transmission system. He further testified that he had not done any detailed load flow study. Transcript at 5250-5251. Dr. Wilson testified that it was his opinion that the probability of Nucor deriving benefits from transmission capacity below 345 kv were virtually nil. Transcript at 5258-5259. Nucor Steel Exhibit 8, to which Nucor Steel refers in its brief, was nothing more than Dr. Wilson's recollection of the map of the TUEC system which he reviewed in making his recommendation regarding the high voltage credit. After Dr. Wilson had drawn the map on the blackboard during the hearing, he made changes to that map based on a review of the TP&L system map contained in Volume 5 of the company's rate filing package. Transcript at 5404-5405. Without more accurate data to rely on, it seems inappropriate to make a piecemeal adjustment to TUEC's cost of service study. This same concern can be voiced with respect to Tex-La's proposal, since it is not based on anything other than an assertion that transmission level customers receiving service at 138 kv should have a separate voltage discount and not any quantification of what that discount should be. It is therefore recommended that neither Nucor Steel's nor Tex-La's proposals be adopted in this docket and that TUEC's credit for high voltage customers be adopted, but that TUEC should be required to provide data needed to determine voltage level discounts for each transmission service level in its next rate case.

G. Interruptible Rate

1. TUEC and Nucor Steel Proposal

In its rate filing package TUEC proposed to reduce the existing 75 percent demand credit for interruptible service to 50 percent, to expand the interruption rights to permit continuous interruption without daily limit in the event of system emergencies, to extend the initial contract term from five years to eight years, to change the notice period for cancellation from one year to five years, and to increase the penalty for failure to curtail or for failure to give the specified notice for cancellation. Customers who take power under interruptible service are not guaranteed the same degree of reliability that firm customers receive. Interruptible customers agree to take power whenever the utility has it available and does not need such power to serve the load of its firm customers. Interruptible service can be provided from the utility's spinning reserves, which is an amount of capacity that is in operating state, on-line and running, but not utilized to serve load. The Electric Reliability Counsel of Texas (ERCOT) has operating guidelines specifying the amount of spinning reserve required. Up to 25 percent of the North Texas spinning reserve requirement can be sold as interruptible power so long as this power can be recalled within 1/3 of a second following a system disturbance. The interruptible load can be left off the system until the firm load decreases to the point that there is adequate capacity to meet the load plus the spinning reserve requirement. As an alternative, it may be kept off until the utility can start another unit in order to serve all the load. The interruption is normally achieved by under-frequency relays, but TUEC can interrupt load under any other capacity shortage situation even if the under-frequency relays do not remove the load. Interruptions are normally limited to no more than twelve hours in any day, but under certain emergencies during which the company makes a public request to restrict energy usage, TUEC's proposed tariff would permit it to interrupt the customers without daily limitation. The annual limit on interruption is 400 hours. TUEC does not plan or build capacity to serve its interruptible load, because this load can be removed from the system when capacity is required to serve firm customers.

By its nature, interruptible service does not impose the same costs upon a utility's system imposed by firm power demands, and thus to the extent spinning reserve power and energy are available for sale, the sale of interruptible power can provide increased system revenues and reduce the unit system cost to all firm customers. TUEC Brief on rate design at 34.

TUEC identifies the basic issue in this case as the appropriate interruptible rate, that is interruptible service credit, and other terms of service necessary to provide a balance of economic benefit and costs between the company's interruptible customers and the company's firm customers. TUEC Brief on rate design at 34. TUEC witness Johnston testified that such a balance is impossible to measure directly, since interruptible service is basically a by-product of providing firm power capacity and reserve (Transcript at 4370), nor can it be measured by future avoidable costs within a prior test year cost of service framework. Transcript at 4368-4369; TUEC brief on rate design at 34. In Mr. Johnstons's opinion, interruptible credits are best determined by judgement and negotiation as exemplified by the compromise settlement agreement between TUEC and one of its interruptible customers, Nucor Steel Corporation. Nucor Exhibit 7; TUEC Brief on rate design at 34. TUEC points out that the agreement modified in some respects the company's proposed interruptible tariff. TUEC Brief on rate design at 34. The agreement proposes that a compromise interruptible tariff be implemented on an experimental basis; TUEC considers any interruptible tariff experimental in light of its recent offering of such a rate and in order to determine the number of customers which may or may not elect to take service under any interruptible tariff. TUEC submits that whether such a tariff is appropriate can only be judged at a later date in light of the number of customers that elect to take interruptible service. TUEC Brief on rate design at 35.

Nucor Steel operates a steel mill facility approximately two miles south of Jewett, Texas. Beginning in March 1984, Nucor Steel contracted with TP&L for a supply of firm and interruptible power. Under the interruptible rate schedule, 42.5 MW of power is provided to Nucor by TP&L. Nucor's service under the interruptible tariff continues for an initial term of five years. Service thereafter is automatically extended for two year periods unless one party notifies the other at least thirty days prior to the expiration of the contract that the contract shall be terminated. When Nucor signed its interruptible contract with TP&L, the demand charge for interruptible service included a 75 percent credit. Nucor supports the joint proposal and stipulation (Nucor Exhibit 7), because it maintains the status quo under Nucor's contract with regard to the level of the interruptible credit, the length of the contract and the notice period required to terminate interruptible service. Nucor Steel Brief on rate design at 3.

Nucor Steel supports the 75 percent demand credit for several reasons. First, Nucor Steel points out that the presence of interruptible load on the TUEC system achieves cost savings which benefit all TUEC customers. TUEC's interruptible customers pay a demand charge and thereby make a contribution to TUEC's fixed costs even though there is no production related demand cost associated with interruptible service. Nucor Steel Brief on rate design at 4; Air Products Exhibit 6 at 4, 22. Because interruptible load is excluded from TUEC's power planning studies and load forecasts (Transcript at 3935, 4366-4367; Air Products Exhibit 1), generating capacity is not specifically constructed to serve interruptible load. Nucor Steel Brief on rate design at 5. Interruptible service may reduce average system fuel costs and maintenance related costs to the benefit of all customers. Nucor Steel Exhibit 6 at 7; Air Products Exhibit 6 at 9; Transcript at 4015. Finally, the option to interrupt load benefits other customers because it enhances system reliability throughout the year and is an efficient load management technique. TUEC Exhibit 1B, Scarth at 4; Transcript at 3981, 4363, 5782-5784; Nucor Steel Brief on rate design at 5. Nucor Steel points out that interruptible load enhances system reliability by permitting immediate curtailment of interruptible customers' load instead of curtailing other customers. Nucor Steel Exhibit 6 at 6; Air Products Exhibit 6 at 6; Nucor Steel Brief on rate design at 5-6. Lastly, interruptible service permits TUEC to defer or perhaps even avoid the construction of newer more expensive generating units. Nucor Steel Exhibit 6 at 7-9; Transcript at 40174019, 4364-4365. Interruptible service can be used to meet critical demands instead of building additional plants or contracting for purchased power, a planning flexibility benefiting all TUEC customers. Nucor Steel Brief on rate design at 6.

Nucor Steel argues that the interruptible rate offered by TUEC must be sufficient to induce a customer to take service, because the quality of interruptible service is lower than that of firm service and industrial customers will incur additional costs as a result of each interruption. TUEC Exhibit 1B, Scarth at 4; Nucor Steel Exhibit 6 at 8-9; Air Products Exhibit 7 at 7; Union Carbide Exhibit 2 at 3; Transcript at 5421-5422. If the credit is too small, customers will not accept interruptible service, thereby raising rates for all customers and rendering the interruptible tariff meaningless. Nucor Steel Exhibit 6 at 12; Nucor Steel Brief on rate design at 6.

Nucor Steel identifies the costs that an industrial customer incurs with each interruption as including additional labor and overhead costs, shut-down and start-up costs, and costs of uncertainty in scheduling a firm's operations and production. Nucor Steel Exhibit 6 at 8-9; Air Products Exhibit 7 at 8-9; Transcript at 5418, 5423, 5787. The actual disruption to operations can last beyond the time of the actual interruption, and the costs can be substantial because service can be interrupted frequently and for many hours under the rate schedule. Air Products Exhibit 6 at 14; Nucor Steel Brief on rate design at 7.

Nucor Steel argues that the current 75 percent interruptible credit is the minimum necessary to attract and retain interruptible customers. Nucor Steel Brief on rate design at 7. The current 75 percent interruptible credit was first adopted in Docket No. 4321, TP&L's prior rate case. Before that time, TP&L served no customers on its interruptible tariff and TP&L's witness in that docket specifically mentioned that the company's prior lower credit was one reason the company failed to attract interruptible customers. Air Products Exhibit 6 at 21-22. Union Carbide opposes a reduction of the 75 percent credit (Union Carbide Exhibit 1 at 5), as does Chaparral Steel (Air Products Exhibit 7 at 7; Transcript at 5422), and Nucor Steel indicated it might terminate its interruptible contract and take only firm service if the credit were reduced. Nucor Steel Exhibit 7 at 2; Nucor Steel Brief on rate design at 8. Thus, Nucor Steel submits, there is a substantial possiblity that any reduction of the current 75 percent credit would force TUEC's current interruptible customers to take only firm service, to the detriment of all TUEC customers. Nucor Steel Brief on rate design at 8. Nucor Steel also points out that the 75 percent credit should be maintained because a similar 70 percent credit was recently made effective in Docket No. 5200, TESCO's prior rate case. Air Products Exhibit 6 at 22. Nucor Steel further argues that the 75 percent credit should be maintained because it has been shown to be cost justified through the testimony of Nucor Steel witness Dr. Wilson and Air Products and Chaparral Steel witness Mr. Brubaker. Dr. Wilson's analysis was based on the concept of avoided costs, that is, identifying the long-term savings to TUEC attributable to providing interruptible load. Nucor Steel Exhibit 6 at 18. Mr. Brubaker's analysis calculates the credit taking into account TUEC's rate of return for interruptible service. Air Products Exhibit 6 at 11. Both analyses conclude that an interruptible credit of approximately 90 percent of the proposed HV demand charge would be cost justified. Nucor Steel Brief on rate design at 8-9.

Nucor Steel further argues in its brief on rate design that Dr. Wilson's long run avoided cost method is appropriate in calculating interruptible rates. Nucor Steel points out that this method is used by the Commission is setting rates paid to cogenerators. Transcript at 5613. Nucor Steel further points out that TUEC has recently filed with the Commission its own avoided cost calculations. Transcript at 4279, 4598. Nucor Steel characterizes as wholly without merit and easily dismissable the suggestions that an avoided cost method may not be appropriate for use in this case becasue it has been mandated by law for use in setting congeneration rates. Nucor Steel Brief on rate design at 9. Nucor Steel submits that if an avoided cost method is appropriate in setting cogeneration rates, it is also appropriate in determining a credit for interruptible service, because in each case, one measures the long run cost savings attributable to capacity that an electric company need not build, on the one hand because of the presence of the interruptible load, and on the other hand due to the generating capacity that can be supplied by the cogenerator. Nucor Steel Brief on rate design at 9. Nucor Steel concludes that an appropriate credit for interruptible service should be determined on the basis of long run avoided capacity cost. Nucor Steel Exhibit 6 at 9-18. Because the relevant load in this case is of relatively short duration (interruptible load may be cut off for up to 400 hours per year) the long run avoided cost is minimized based on capacity with the lowest fixed cost, for example, a peaking unit or any other low capital cost increment of capacity. Nucor Steel Exhibit 6 at 11; Transcript at 5651, 6878; Nucor Steel Brief on rate design at 9-10.

Nucor Steel submits that there are several reasons why the cost of a peaking unit is relevant in this case. First, Nucor Steel argues, reference to a peaking unit is a well recognized analytical tool used to identify the component of TUEC's capacity costs relating to service of a load of short duration. Transcript at 6872-6873. Therefore, Nucor Steel concludes that whether or not TUEC is actually planning to build a combustion turbine is totally irrelevant. Transcript at 5300. Second, Nucor Steel points out that TUEC currently owns and operates peaking capacity. Transcript at 6307A. TUEC has the option of adding peaking capacity, (Transcript at 6515), and would consider this option under appropriate circumstances. Transcript at 3949, 3976, 3978, 4372, 4568. (Nucor Steel concedes that one reason TUEC has not recently found it necessary to add combustion turbines is that its lignite and nuclear units under construction have made existing gas-fired units available for peaking and load-following service in the generation dispatch order. Transcript at 3976.) Third, Nucor Steel argues that low cost increments of capacity do exist and are relevant to generation expansion plans for TUEC. Transcript at 6637, 6878. Nucor Steel points out that a TUEC witness recognized the gas-turbine combined-cycle option of adding generating capacity. Transcript at 3973; Nucor Steel Brief on rate design at 10.

The cost of a peaking unit used in Dr. wilson's analysis was $400 per kw. Nucor Steel Exhibit 6 at 15. This amount was the average cost of a peaker supplied by the company in response to a Request for Information. Transcript at 3954, 4324. The carrying charge rate used in the analysis was 16.5 percent, rather than TUEC's 19 percent estimate. Nucor Steel Exhibit 6 at 15. Dr. Wilson thus calculated TUEC's avoided capacity cost due to interruptible load to be $81.60 per kw per year, or $6.80 per kw per month. Nucor Steel Exhibit 6 at 15. Nucor argues that this amount is not excessive in relation to TUEC's proposed demand charge of $6.24 per kw for the HV class for two reasons. First, TUEC's average and excess method allocates some fixed costs on energy, and second, TUEC's marginal costs are likely to exceed its revenue requirement. Nucor Steel Exhibit 6 at 15-16. On the basis of this analysis, Dr. Wilson concluded that an interruptible credit of $6.12 per kw per month, equal to 90 percent of TUEC's full avoided cost, would be cost-justified and sufficient to attract and retain interruptible customers. Nucor Steel Exhibit 6 at 18. He therefore recommended that the credit be set at a minimum level of 75 percent. Nucor Steel Brief on rate design at 11.

Nucor Steel urges that further support for maintaining the interruptible credit at the 75 percent level is found in the joint proposal and stipulation signed by Nucor Steel and TUEC. Nucor Steel Exhibit 7; Nucor Steel Brief on rate design at 12.

2. Air Products and Chaparral Steel Proposal

Air Products and Chemicals, Inc. (Air Products) and Chaparral Steel Company (Chaparral) both receive interruptible service from TUEC under the present TP&L Rider IS. Air Products and Chaparral point out that adoption of TUEC's proposed Rider I as originally proposed would impose radical rate increases on the interruptible class. TUEC Rider I would increase demand costs for interruptible customers by 146 percent. Air Products Exhibit 6 at 18. Air Products and Chaparral further point out that TUEC Rider I includes a number of changes in the terms and conditions of the present TP&L Rider IS which would in their opinion establish significant disincentives to the use of interruptible power. Air Products and Chaparral Brief on rate design at 2.

Air Products and Chaparral argue that none of the changes incorporated into TUEC Rider I is supported by testimony or exhibits of any kind. Air Products and Chaparral further point out that TUEC has entirely abandoned its proposal to change the demand charge for the interruptible class by entering into the joint proposal with Nucor Steel. Nucor Steel Exhibit 7; Air Products and Chaparral Brief on rate design at 2.

Chaparral began taking interruptible service in July 1983, and Air Products commenced interruptible service in February 1984. Air Products Exhibit 6A, Schedule 5. Along with Nucor Steel, these two companies represent all the present interruptible service on the TUEC system, which totals approximately 160 MW Transcript at 5772. During the test year, neither DP&L nor TESCO had interruptible customers. During the course of this proceeding, it became known that Liquid Air Corporation, located in the TESCO service area, had recently executed a contract for interruptible service. Air Products and Chaparral Brief on rate design at 3.

Air Products and Chaparral assert that they have been interrupted by TUEC on a number of occasions since the inception of their interruptible service. Chaparral has had fifteen separate instances of interruption between July 1983 and April 1984, and Air Products has been interrupted on six separate occasions for a total of 463 minutes in February, March and April of 1984. Air Products Exhibit 6A, Schedule 6; Air Products and Chaparral Brief on rate design at 4. Air Products and Chaparral assert that the important thing to note is that although the history of interruption is very brief, many of these interruptions did not occur during the system's summer peak period. Air Products and Chaparral note that TUEC has tended to interrupt at the time of daily peak, which indicates the estimate of the total generation load required for the days on which interruption occurred were somehow inaccurate. Transcript at 3981, 5783; Air Products and Chaparral Brief on rate design at 4. Contrary to implications that the failure of TUEC to interrupt during summer system peak period indicates that interruptible service is not of significant value, Air Products and Chaparral witness Brubaker related on redirect that interruptible service is similar to an insurance policy. Transcript at 5783; Air Products and Chaparral Brief on rate design at 4. According to Mr. Brubaker, interruptible service creates a back stop or an escape hatch, an ability for a utility to cover its losses in the event of unexpected system loads. Whether or not these circumstances occur at the time of system peak or at some other time is irrelevant. The point is that interruptible load provides a ready source of production capacity to serve firm load. Transcript at 5783; Air Products and Chaparral Brief on rate design 4-5.

Air Products and Chaparral assert that TUEC has proposed a complete reversal of its position as articulated in its testimony and its filed TP&L Rider IS approximately two years ago in Docket No. 4321. Air Products and Chaparral assert this reversal is totally without justification or rationale, that TUEC has offered no study of the effect of new interruptible service on its system nor any reasons for a change in policy which was so recently supported and implemented. Air Products and Chaparral Brief on rate design at 5.

As Nucor Steel points out, Air Products and Chaparral also consider the primary cost savings to result from the fact that a utility need not plan for or install generating capacity to serve interruptible load. Air Products Exhibit 6 at 7. TUEC witness Tanner testified that TUEC does not include interruptible load in its load forecast (Transcript at 3979), and does not purchase power to keep interruptible customers on-line. Transcript at 3943. Interruptible load is served not from committed production plant, but from spinning reserves which TUEC must maintain to meet the requirements of its firm customers. Air Products and Chaparral Brief on rate design at 6. Thus, as a factual matter, TUEC need not and does not invest in production plant to serve its interruptible customers. Mr. Brubaker's analysis indicates that the investment necessary to create production plant to serve the interruptible load on a firm basis would be approximately $48 million, and the annual fixed costs associated with such an investment would be approximately $10 million. These figures assume current average embedded costs, and if an analysis were predicated on the cost of new plant, the investment would be approximately $192 million and annual carrying charges would be $42 million. Air Products Exhibit 6 at 8; Air Products and Chaparral Brief on rate design at 7. Mr. Brubaker also testified that under certain circumstances, fuel costs to the system can actually be reduced by reason of the existance of interruptible load. Air Products Exhibit 6 at 9; Air Products and Chaparral Brief on rate design at 7.

Air Products and Chaparral assert that the trade off to the interruptible customer for providing these significant but low cost benefits to the system is service at a substantial discount but purchased at a significant cost. By definition, interruptible service is not reliable. For industrial customers this has serious implications. First, labor costs generally cannot be adjusted for unanticipated breaks in production caused by interruptions in utility service. Transcript at 5785. Plant managers generally cannot refuse to pay workers who have presented themselves for work but are unable to work because of an unexpected interruption in utility service. Secondly, interruptions of substantial duration may result in the loss of raw material in process or in damage to production machinery. Air Products witness Larry Clark testified that after ten hours of interruption, steel in process may become frozen, resulting in re-melt delays of more than twenty-four hours. Air Products Exhibit 7 at 8; Air Products and Chaparral Brief on rate design at 7-8. Third, an industrial facility may have to incur significant additional capital costs in order to accommodate its process and equipment to the possibility of unexpected interruption of indefinite duration. Chaparral Steel has invested approximately $60,000 in order to prepare its plant to effectively meet the problems associated with the interruption of electrical service. Air Products Exhibit 7 at 6; Air Products and Chaparral Brief on rate design at 8. Finally, Air Products and Chaparral identify as perhaps the highest cost associated with interruptible service the loss of the efficient, high speed pace of production which results when interruptions occur. Air Products and Chaparral submit that it is this pace which marks a competitive, efficient industrial process, and a decision to jeopardize this pace by accepting interruptible service cannot be taken lightly. Air Products Exhibit 7 at 8. Air Products and Chaparral conclude accordingly that the discount for interruptible service must be substantial in order to merit the economic costs associated with prospective interruptions. Because the capacity costs to the utility of providing interruptible service are in fact nonexistent, Air Products and Chaparral Steel urge, the discount can appropriately be a very large percentage of the firm capacity charges. Air Products and Chaparral Brief on rate design at 8.

Conceding that TUEC abandonded its original proposal to decrease the capacity payment discount from 75 percent to 50 percent, Air Products and Chaparral Steel point out that there is no evidence of any kind in the record supporting the reduction in the discount in capacity charges made to interruptible customers to the 50 percent level. Transcript at 5787; Air Products and Chaparral Brief on rate design at 9. Mr. Brubaker suggests in his testimony that the proper perspective regarding the value of interruptible load is not the value of future production plants, but instead the value of embedded costs which have already been incurred by the utility to serve its existing firm customers; therefore, it is neither necessary nor desirable to enter the marginal or avoided cost thicket to value interruptible service. This service has no capacity cost, and Mr. Brubaker concludes on the basis of embedded costs for existing firm customers that a credit of 92 percent can reasonably be justified. Air Products Exhibit 6A, Schedule 2; Air Products and Chaparral Brief on rate design at 10-11. In conclusion, Air Products and Chaparral submit that in the absence of testimony from TUEC justifying a decrease in the interruptible credit and particularly in light of TUEC's joinder in the agreement with Nucor Steel, the reasonable result in this case is upholding the existing TP&L tariff discount rate of 75 percent. Air Products and Chaparral Brief on rate design at 11.

Air Products and Chaparral point out that the terms and conditions proposed in TUEC Rider I remain a part of the joint proposal of TUEC and Nucor Steel. Air Products and Chaparral submit that the proposed changes have not been justified in any way, and that even on rebuttal, no company witness attempted to defend the new terms and conditions. Air Products and Chaparral Brief on rate design at 11-12. Air Products and Chaparral object to the changes, summarized as follows. First, TUEC's responsibility to endeavor to provide notice some hours in advance of probable interruption should be retained. Air Products and Chaparral point out that this is not an absolute requirement, but provides a reasonable obligation when there is an opportunity to provide notice of interruption. Air Products Exhibit 6 at 24; Air Products and Chaparral Brief on rate design at 12.

Second, the current TP&L Rider IS provides an initial contract period of five years and a one year notice of termination of interruptible service. Proposed Rider I sets an initial contract term of eight years and a five year notice requirement. Air Products and Chaparral submit that contract and notice periods of this type are not typical (Transcript at 5786), and all witnesses on this issue agreed that they were unnecessary. Air Products and Chaparral Brief on rate design at 12. Air Products and Chaparral point out that while Mr. Kepner's suggestion that a three year notice of termination would be reasonable (Transcript at 6654), it is not justified by TUEC's experience under the existing tariff or by reference to the experience of other utilities under similar clauses. Air Products and Chaparral Brief on rate design at 12.

Third, TUEC Rider I proposes a substantial penalty if customers fail to interrupt as requested by TUEC, or if customers desire to transfer their service to firm without giving the required minimum notice. Mr. Brubaker testified that this proposal is ill-conceived and in fact could actually require customers to pay back to the company an amount in excess of the credits they received under Rider I. Air Products Exhibit 6 at 26; Air Products and Chaparral Brief on rate design at 13.

Fourth, Air Products and Chaparral submit that TUEC's tariff filings in this case include a provision in the firm rates that billing demand will not be less than 50 percent of the contract capacity, and Rider I does not modify this condition. Air Products and Chaparral submit that it should be changed so that the minimum contract demand limitation cannot override the demand credit when a customer places substantially all of his requirement on an interruptible basis; otherwise, an interruptible customer's discount could be indirectly reduced by operation of the limitation. Air Products Exhibit 6 at 22; Air Products and Chaparral Brief on rate design at 13.

Air Products and Chaparral argue that the revisions in the terms and conditions of the interruptible service proposed in TUEC Rider I are designed to and would inevitably result in curbing the use of interruptible service by TUEC's customers. Air Products and Chaparral Brief on rate design at 13. Air Products and Chaparral also point out that the length of the contract term and the period required for notice of termination could prohibit new customers from using TUEC's interruptible service, raising questions of equity as to TUEC's other customers and of discrimination in violation of the PURA. Although the proposed changes in terms and conditions, at least as to the contract term and the required notice period for termination, would not apply to existing TUEC interruptible customers, the penalty provisions and other terms would apply. Air Products and Chaparral oppose these changes not only because they are prejudicial to prospective customers such as Union Carbide, but primarily because they are inconsistent with reasonable provisions applying in other jurisdictions for such service. Air Products and Chaparral therefore urge that the existing TP&L Rider IS should remain in effect and that the full 75 percent demand credit should remain in force. The only modifications Air Products and Chaparral Steel recommend are a modification in the minimum contract demand limitation in the firm rate so that it is expressly stated that such a limitation cannot override the demand credit for interruptible service and a clause in Rider IS which states that a customer can immediately terminate interruptible service without penalty in the event that there is a substantial change in the relationship between the firm rate and the interruptible rate. Air Products and Chaparral Brief on rate design at 13-15.

3. Union Carbide Proposal

Union Carbide proposes the continuation of a demand credit of at least 75 percent for interruptible service and terms and conditions for interruptible service no more onerous than those presently offered in the TP&L operating division Rider IS. Union Carbide owns an air separation facility in the TESCO service area. Transcript at 4417, 5769. Union Carbide is not presently an interruptible customer, but apparently is considering taking interruptible service.

Union Carbide initially argues that the joint proposal of TUEC and Nucor Steel Corporation violates Section 45 of the Public Utility Regulatory Act, because it proposes different terms and conditions for interruptible service creating unreasonable economic disadvantages for Union Carbide, and concurrent unreasonable advantages for a principle competitor of Union Carbide. Union Carbide Brief on rate design at 1. Union Carbide argues that the joint proposal permits customers currently taking interruptible service from the TP&L operating division to continue such service under terms and conditions more favorable than those in TUEC's proposed interruptible Rider I. Transcript at 5769-5772; Union Carbide Brief on rate design at 2. Union Carbide further asserts that the terms and conditions in the joint proposal are more favorable than those offered to Union Carbide by TUEC's TESCO operating division. Transcript at 4426, 4427; Union Carbide Brief on rate design at 2. Specifically, Union Carbide points out that customers receiving interruptible service under the TP&L Rider IS may continue taking interruptible service under terms providing for an initial term of five years instead of eight years, renewal periods of two years and minimum cancellation notice of one year instead of five years. Transcript at 4426-4427, 5769-5772; Union Carbide Brief on rate design at 2-3. In addition, Union Carbide argues that the joint proposal creates a new term for prospective interruptible customers, specifically, continuous interruptions of electric service without daily limit during system emergencies. Nucor Steel Exhibit 7; Union Carbide Brief on rate design at 3. Union Carbide argues that in contrast, the TP&L and TESCO interruptible tariffs do not provide for such unlimited interruption rights. Transcript at 4427-4428, 5771. Union Carbide argues that the differential terms and conditions detailed above create an unreasonable preference or advantage for Union Carbide's competitor, Air Products, and a concurrent unreasonable prejudice or disadvantage to Union Carbide, in violation of Section 45 of the Public Utility Regulatory Act. Union Carbide Brief on rate design at 3.

Union Carbide sets forth in detail the reasons the joint proposal violates Section 45 of the PURA. First, Union Carbide points out that Air Products is a principle competitor of Union Carbide in the air separation business. Transcript at 4420. Because Air Products owns an air separation facility in the TP&L service territory, Union Carbide Exhibit 1 at 3, Air Products was able to take advantage of TP&L terms and conditions allowing for a five year intitial term, a two year renewal and a one year cancellation provision. Under the joint proposal, Union Carbide points out, Air Products may continue its interruptible service under these terms. Union Carbide Brief on rate design at 4.

Union Carbide owns an air separation facitlity in the TESCO service area. Transcript at 4417, 5769. The TESCO operating division has offered Union Carbide an eight year intitial term and five year cancellation notice for interruptible electric service to this facility, which are identical to the intitial term and cancellation provisions of the joint proposal. Transcript at 4418; Union Carbide Brief on rate design at 4. To eliminate any discrimination in rates and services as between the TP&L and TESCO operating divisions, Union Carbide offered to purchase interruptible service under the TP&L terms and conditions. Transcript at 4417-4418; Union Carbide Brief on rate design at 4. The offer was rejected. Union Carbide asserts that it would be forced to take interruptible service under either the TESCO tariff or the joint proposal tariff but has not and will not be offered terms and conditions as favorable as those offered to its competitor. Union Carbide Brief on rate design at 4.

Union Carbide contends that under the terms of the joint proposal, it is more vulnerable than its competitor to so called "bait-and-switch" tactics. Union Carbide Brief on rate design at 5. Union Carbide argues that because TUEC has no contractual obligation to maintain the specified interruptible credit for the full term of the interruptible agreement, interruptible customers assume the risk that the interruptible credit may drop so low that it no longer offsets the additional costs the customer must incur to be an interruptible customer. Transcript at 5776; Union Carbide Brief on rate design at 5. Union Carbide submits that without some flexibility in converting from interruptible to firm service, interruptible customers could be required to continue service on what becomes an uneconomical rate until the agreement is cancelled or expires, or pay a large penalty to convert from interruptible to firm service. Transcript at 6550-6551. Union Carbide submits that the longer the intitial term and cancellation term, the greater the economic disadvantage to the interruptible customer. Transcript at 5775-5776.

Union Carbide asserts that the size of the economic penalty is of crucial importance in the air separation business. Union Carbide Exhibit 1 at 4. Approximately 70 percent of the manufacturing costs of an air separator are electric costs, and any differentiation in electric rates, however slight, may create a substantial disadvantage. Union Carbide Exhibit 1 at 4; Transcript at 5776, 6552. Union Carbide argues that because Air Products will continue to be served on the TP&L tariff, if the credit were to become uneconomical after expiration of the initial term, Air Products may convert to firm service on one year's notice, while Union Carbide would have to wait five years to convert. Union Carbide Brief on rate design at 5-6. Similarly, if interruptible service became unfavorably priced during the initial term, Air Products could convert, as a maximum, at the end of the five year initial term, but Union Carbide would be required to wait until the end of an eight year initial term. Union Carbide Brief on rate design at 6.

Union Carbide also points out that the joint proposal allows for continuous unlimited interruptions to interruptible customers during system emergencies without regard to daily limits. In contrast, the TP&L and TESCO terms do not provide for such unlimited rights. Transcript at 4427-4428, 5771. Thus, Union Carbide argues, for a prospective interruptible customer such as itself, under the joint proposal production could be shut down indefinitely while Air Products-indeed all industrials not on the new interruptible Rider-continue operations. Union Carbide Brief on rate design at 6.

Union Carbide also submits that there is no evidence to support the joint proposal's differentiation in terms and conditions. Union Carbide argues that all witnesses testified that in their opinions there was no economic basis for differentiation in interruptible rates, including terms and conditions, among TUEC's customers. Transcript at 5264, 5777, 6653-6654. Union Carbide Brief on rate design at 6. Further, Union Carbide asserts there was no adequate explanation from TUEC regarding why it might be appropriate to allow existing interruptible customers to continue to take service under terms and conditions more favorable than those offered in the joint proposal or by the TESCO operating company. Union Carbide Brief on rate design at 7. Union Carbide submits that if one of the principle purposes of this proceeding is to consolidate the rates of the TUEC operating companies, so that differentiations in rates and terms may be eliminated, TUEC should not be allowed to preserve, without explanation and without any of its personnel being subject to cross-examination, the very sort of differentiation this proceeding was meant to eliminate. Union Carbide Brief on rate design at 7.

Union Carbide further argues that the proposed initial term of eight years and cancellation period of five years have not been shown to be just and reasonable. Union Carbide Brief on rate design at 7. TUEC filed neither direct nor rebuttal testimony in support of its proposed interruptible tariff. Union Carbide Brief on rate design at 7. Nucor Steel witness Dr. Wilson testified that immediate conversion from interruptible to firm service is appropriate if the utility proposes a credit reduction. Nucor Steel Exhibit 6 at 22. Air Products witness Brubaker testified that a five year initial term is not unusual and a cancellation notice period of five years is not the norm. Transcript at 5786. Staff witness Kepner testified that a cancellation period of five years is "too long" and three years would be "plenty of time." Transcript at 6654, 6791; Union Carbide Brief on rate design at 7-8. In anticipation of arguments that the intitial term and cancellation period are justified by the lead time for constructing a new lignite plant, Union Carbide urges that that argument will not withstand scrutiny. In the first place, Union Carbide argues, it should be remembered that TUEC should be encouraging interruptible service. Such service is an economical substitute for new capacity and, according to Dr. Wilson, at approximately 162 MW (Transcript at 5772), TUEC's interruptible load is a small percentage of TUEC's total load, and hardly more than TUEC can handle. Transcript at 5278-5279. Long initial terms and cancellation terms discourage interruptible customers. Transcript at 5775-5776, 6792. Union Carbide considers significant the fact that three of TUEC's four interruptible customers are located in the TP&L service division, which has a shorter initial term and cancellation term. Transcript at 5772; Union Carbide Brief on rate design at 8.

Union Carbide further argues that it is incorrect to argue that the only alternative to interruptible service is the construction of a lignite plant. Union Carbide Brief on rate design at 8. As Dr. Wilson observed, interruptible service involves small increments of supply (Transcript at 5278-5279), which can be replaced in a short period by purchased power, gas turbine peakers, cogeneration and load management and conservation. Transcript at 6790-6793; Union Carbide Brief on rate design at 9. In fact, Union Carbide asserts, the utility's argument in this regard is flatly contradicted by Mr. Brubaker, Mr. Kepner and other expert witnesses, as well as the Commission itself in its new rules on certification of generating plants. Union Carbide submits that those rules do not treat lignite capacity as the preferred, much less the only, alternative for acquiring capacity. Union Carbide Brief on rate design at 9.

Finally, Union Carbide asserts that TUEC did not attempt to justify the new interruptible term allowing continuous interruptions of interruptible customers during system emergencies. Union Carbide argues that the provision in question is a change in rates, as to which the utility has the burden of proof. Union Carbide Brief on rate design at 9. Union Carbide urges that not one scintilla of evidence was introduced in support of unlimited interruptions during system emergencies, and thus the Commission is without power to approve this rate change. Union Carbide Brief on rate design at 9-10.

In response to Union Carbide, TUEC argues that Union Carbide's suggestion that such "grandfather" provisions place unfair competitive disadvantages on Union Carbide simply assumes that those provisions will in fact have an economic impact on Union Carbide. TUEC submits that no factual proof of such an effect was offered, and that cross-examination of Union Carbide witness Morgan made it clear that the presently effective interruptible tariff of TESCO, applicable in the area of Union Carbide's plant, is consistent with the terms about which Union Carbide complains. Transcript at 4421, 5769-5770; TUEC Brief on rate design at 35. TUEC further urges that Union Carbide is not an interruptible customer of TUEC and need not become one if it finds the terms of the interruptible tariff unacceptable; and even if Union Carbide were to become an interruptible customer, it would suffer no disadvantage so long as it continued as an interruptible customer. TUEC Brief on rate design at 35.

Union Carbide responds to TUEC by pointing out that the joint proposal creates a new term for only prospective interruptible customers, that is, continuous interruption of electric service during system emergenices without any limit on duration. In contrast, the TP&L and TESCO interruptible tariffs do not provide such unlimited interruption rights. Union Carbide submits that the provision in question is a change in rates under Section 40 of the PURA, on which TUEC has the burden of proof to show the change be just and reasonable. Union Carbide submits that TUEC put on no evidence to support the proposal. Union Carbide Reply Brief on rate design at 2. Union Carbide characterizes this proposal as unfair and quite likely unlawful and that every expert witness on interruptible service testified that there was no basis for this discrimination. Union Carbide Reply Brief on rate design at 2-3. Union Carbide also points out that contrary to the assertion of TUEC, there is unrebutted evidence that the longer initial term of service and cancellation period will subject Union Carbide to economic disadvantages. Transcript at 5775-5776, 6792; Union Carbide Reply Brief on rate design at 3. Finally, Union Carbide requests the Commission to reject the Hobson's choice offered to Union Carbide by the utility of declining interruptible service if Union Carbide finds the terms of the interruptible tariff unacceptable. Union Carbide points out that by virtue of the joint proposal, it must either decline the benefits of interruptible service or take service and receive an initial contract term three years longer and a cancellation term of four years longer than that of its principle competitor, in addition to being subject to unlimited interruptions during system emergencies. Union Carbide again concludes that the differentials in terms of service subject Union Carbide to unfair and unlawful economic disadvantages vis-a-vis its principal competition. Union Carbide Reply Brief on rate design at 4.

4. Staff Proposal

Staff witness Kepner recommended that the interruptible credit reflect the cost savings TUEC can expect for its ability to serve a nonfirm customer. Staff Exhibit 36 at 24. General Counsel argues that the company cannot predict when it will interrupt the interruptible customer (Air Products Exhibit 6 at 12), but will, in any event, interrupt the customer during system emergencies. Transcript at 3939; General Counsel Brief on rate design at 31. General Counsel points out that these emergencies could occur at any time, as revealed in the testimony of TUEC witness Tanner, that the interruption of load is not limited to the summer peak periods. Transcript at 3981. General Counsel argues that because TUEC incurs differing levels of seasonal costs, the value to TUEC to interrupt the customer during a peak period is greater than during an off-peak period. Therefore, the credit to the customer should be greater. Mr. Kepner recommends a 75 percent credit during the peak period and a 50 percent credit during other times as being cost based. Staff Exhibit 36 at 24-25. General Counsel submits that such a differential ingeniously reflects the fact that the capacity value of interruptible power is greater during the summer months. General Counsel Brief on rate design at 32. OPC witness Dr. Andersen further recognized that the amount of credit should bear a relationship to what it would have cost the company to meet that customer's demand had he stayed on the system. Transcript at 6396-6397; General Counsel Brief on rate design at 32.

Nucor Steel argues that the net effect of Mr. Kepner's credit would be to provide the interruptible customers with a $45 per kw annual offset against their demand cost repsonsibility. This amount is only 65 percent of Mr. Kepner's $69 per kw annual avoided cost estimate, 55 percent of Dr. Wilson's $82 per kw estimate and less than 50 percent of the $92 per kw avoided cost estimate obtained by using a $400 per kw capacity cost in Mr. Kepner's calculations. *Nucor Steel Reply Brief* on rate design at 7. Nucor Steel points out that because Mr. Kepner's proposed rate would collect 62 percent of his proposed demand charges for HV service during the off-peak periods (Staff Exhibit 36, JWK-16A), but would apply only a reduced 50 percent credit during these periods, interruptible customers would receive only about 55 percent of TUEC's avoided cost under his proposed rates rather than the 75 percent he would find appropriate based on peak period considerations. Nucor Steel argues that therefore the staff level of credits should not be adopted. Nucor Steel Reply brief on rate design at 7-8.

Air Products and Chaparral also assert that Mr. Kepner's analysis is fundamentally flawed. Air Products and Chaparral Brief on rate design at 9. First, Air Products and Chaparral argue that it is premised on the notion that the value of interruptible service is measured primarily in relationship to its availability in peak periods. Air Products and Chaparral point out, however, that all the testimony in the case suggests that interruptible load is valuable and has in fact been employed to meet daily peak loads in all periods, not just the summer months. Air Products and Chaparral Brief on rate design at 10. In addition, although Air Products and Chaparral do not agree with the rationale presented by Nucor Steel witness Dr. Wilson, they assert it is note worthy that Mr. Wilson's avoided cost analysis, also predicated on the value of a gas turbine, resulted in a recommendation that the discount rate should be set at 90 percent. Nucor Steel Exhibit 6 at 18; Air Products and Chaparral Brief on rate design at 10. Air Products and Chaparral assert that this disagreement between Dr. Wilson and Mr. Kepner serves to underline the speculative and erratic quality of results obtained from complicated marginal cost analyses, and it also casts substantial doubt on Mr. Kepner's approach. Finally, Air Products and Chaparral contend that Mr. Kepner's recommendation appears to be based primarily on a kind of "rule of thumb" compromise between the existing TP&L credit of 75 percent and the proposed TUEC credit in Rider I of 50 percent. Air Products and Chaparral assert that Mr. Kepner's discussion is devoid of any rationale for the proposed credit of 50 percent, and thus his position ultimately appears to be simply a superficial and arbitrary compromise. Air Products and Chaparral Brief on rate design at 10.

In reply to these criticisms, General Counsel urges that there is no evidence in the record to permit an assumption that interruptions would occur during a continuous and constant basis throughout the year. General Counsel Reply Brief on rate design at 21-22. General Counsel asserts that if the interruptions only occurred during off-peak times, and the costs to TUEC are lower during these periods, the credits must be lower to reflect these lower costs, and to do otherwise would ignore all cost principles advocated by this Commission in Docket No. 3437. General Counsel Reply Brief on rate design at 22. In response to Air Products and Chaparral, General Counsel points out that Mr. Kepner realized interruptions do not always occur during peak periods when costs are higher. Just as Mr. Kepner determined the distinction in costs for his proposed rates General Counsel submits that his method is the only method that truly reflects the cost differences to be transferred to the credits. Staff Exhibit 36 at 24-25; General Counsel Reply Brief on rate design at 22. General Counsel submits that Mr. Kepner's proposed interruptible credits more accurately reflect the value of the credit to the company and to the customer, and that to realize cost based rates, the costs must be fashioned not only in the proposed rates but also in the correllary credits of the company's tariff. General Counsel Reply Brief on rate design at 22.

5. Recommendation

It is virtually undisputed in this record that interruptible service offers the utility advantages such as enhancement of system reliability, flexibility in meeting daily load and the opportunity to defer construction of generating capacity. It is also clear that although TP&L had an interruptible tariff, no customers were served on that tariff until the credit was raised to 75 percent. Customers taking interruptible service clearly must make significant investments and commitments in order to avail themselves of the cost savings afforded by interruptible service. Unfortunately, the record here has not been benefited by testimony from TUEC witnesses concerning the originally proposed Rider I or the joint agreement between TUEC and Nucor Steel.

While Union Carbide presented its position forcefully and succinctly, it is very difficult to find that a utility's change in rates and tariff provisions is per se discriminatory treatment of a potential customer. If that were the case, utilities could never change their rates. It is also clear that TUEC has not been particularly ardent in defending any of its interruptible tariff provisions. Because of the investments interruptible customers must make, this service is one which requires the long term commitment of the utility, and any change in rates or tariff provisions must be scrutinized closely.

The record on this issue supports continuation of the rates, terms and conditions found in TP&L's present Rider IS, and it is recommended that this rider be adopted as the TUEC system-wide interruptible service tariff, with some additional changes, discussed below. This recommendation is not based on a finding that adoption of either proposed Rider I or the TUEC/Nucor Steel joint proposal would result in discrimination in violation of Section 45 of PURA. It rests on the failure of TUEC to provide any evidence supporting the changes in terms and conditions proposed in either Rider I or the joint agreement. Furthermore, this recommendation that the interruptible credit be maintained at 75 percent is not a recommendation that any particular costing methodology is appropriate in calculating interruptible rates: not Dr. Wilson's long run avoided cost methodology, not Mr. Brubaker's embedded cost analysis and not Mr. Kepner's seasonal cost approach. Without adopting any particular methodology as correct for pricing interruptible service, it is clear that under either Dr. Wilson's or Mr. Brubaker's approach, the 75 percent credit is justified. Finally, the interruptible tariff should contain one clarification sought by Air Products and Chaparral, that the minimum contract demand limitation cannot override the demand credit for interruptible service.

H. Late Payment Penalty

1. TUEC Proposal

TUEC proposed to include a 3 percent penalty for late payment in its wholesale tariff schedule. TP&L and TESCO each have authority to charge a late payment penalty. TP&L's service regulations authorize it to assess up to a 5 percent penalty, although the language of its service regulation does not specifically address wholesale customers but track the language of the Commission's Substantive Rule 23.45(b). TESCO's tariff schedules provide for a 3 percent penalty. TUEC argues that the language of the Substantive Rule allows for assessment of a late payment penalty against a wholesale customer. The language of the rule reads:

> A one-time penalty not to exceed 5.0% may be made on delinquent commercial or industrial bills; however, no such penalty shall apply to residential bills under this section.

TUEC argues that, assuming a sale for resale is a type of commercial service, P.U.C. SUBST. R. 23.45(b) provides all the authority needed by TUEC to apply up to a 5 percent penalty on any bill not paid by the 16th day after the due date. TUEC Brief on rate design at 38. Even if a sale for resale is outside the Commission's use of the term "commercial or industrial," TUEC argues that P.U.C. SUBST. R. 23.45(b) remains pertinent in that a late payment penalty is not prohibited except for residential customers. TUEC Brief on Rate Design at 38.

2. Tex-La Proposal

Tex-La witness Daniel testified that the proposed 3 percent late payment charge is unsupported, excessive and not necessary. Tex-La Exhibit 21 at 28. Tex-La argues that TUEC has not shown that a late payment provision is needed for wholesale customers. While such a provision may be necessary for TUEC's commercial and industrial customers, Tex-La argues that there is no evidence that the wholesale customers historically have been delinquent in paying their power bills. Tex-La Brief on Rate Design at 37. Tex-La further argues that the Commission Substantive Rules, while they do specifically allow for late payment charges for commercial and industrial customers, do not provide for late payment charges to wholesale customers. As an alternative, Tex-La argues that if the Commission allows a wholesale class late payment penalty, then the 3 percent should be reduced to a more reasonable level. Since the major cost incurred by the company because of a late payment is the cost of money, Tex-La argues that the late payment charge should reflect the company's cost of money. Tex-La Brief on Rate Design at 37. Tex-La asserts that since TUEC's annual overall rate of return is in the range of 12 percent to 13 percent, a late payment penalty of approximately 1 percent per month would be more reasonable. Rate Filing package, Schedule H-2; Tex-La Brief on Rate Design at 37. Tex-La argues that the company's 3 percent penalty for 20 days equates to an annual rate of approximately 55 percent (365 days divided by 20 days times 3%) which is much too high and should therefore be disallowed. Tex-La Brief on rate design at 37-38.

Tex-La argues that there is no basis or rationale for the company's assumption that a sale for resale is a commercial service. Tex-La argues that since wholesale customers serve mostly residential customers, wholesale customers should not be catagorized with commercial customers. Arguing that the PURA does not allow for inconsistent applications of rates between different classes of customers, and that Section 23.45(b) of the Substantive Rules of the Commission specifically disallows the application of late payment charges to residential customers, Tex-La concludes that a late payment penalty must be also disallowed for applications to wholesale customers.

3. SWESCO Proposal

SWESCO also opposes the 3 percent late payment penalty for wholesale customers as not cost based.

TUEC responds that there is no intent that a late payment penalty be cost based (Transcript at 4408), because it is an incentive for timely payment and is thus a cost avoidance technique. Transcript at 4409-4410. TUEC points out that SWESCO has a 5 percent late payment penalty in its own wholesale tariff schedule (Transcript at 5156), and refers to this as evidence that the Commission previously found penalties higher than the proposed 3 percent to be reasonable, even though no showing was made that the higher penalty was cost based. TUEC infers this by SWESCO's testimony in this case that its own 5 percent penalty is not cost based. Transcript at 5156-5157; TUEC Brief on Rate Design at 38.

4. Recommendation

TUEC is correct that there is no requirement that a late payment penalty be cost based because it is an incentive for prompt payment; P.U.C. SUBST. R. 23.45(b) does not qualify the allowance of a late payment penalty by conditioning its imposition upon proof that it is cost based. Tex-La's argument that because wholesale customers serve mostly residential customers and because residential customers cannot be charged a late payment penalty, wholesale customers cannot be charged the the late payment penalty either falls short of the mark. It is a reasonable interpretation of the term "commercial" that it includes a sale for resale, and P.U.C. SUBST. R. 23.45(b) specifically prohibits late payment penalties only for residential customers. TUEC's proposed 3 percent late payment penalty for its wholesale customers is reasonable, complies with P.U.C. SUBST. R. 23.45(b), and should be adopted.

XIII. Tariff Issues

A. Extension Policy

1. TUEC Proposal

TUEC's proposed tariff contains service regulations which include several sections dealing with non-standard electric service and extension of electric service under circumstances which may impose costs upon the TUEC system which are beyond the average costs incurred to provide service to customers. TUEC Exhibit 1C, Section IV, Section 3.09, et seq. TUEC argues that these regulations, if not wholly identical in language to those currently in effect for the three operating divisions, are the same in substance (Transcript at 4067, 4076), and represent the company's intention to simply continue in this case such prior regulations. Transcript at 4067, 4077, 4111, 4117; TUEC Brief on rate design at 35. TUEC further asserts that these regulations are intended to comport with this Commission's Substantive Rules, and will be applied consistently with such rules as they now exist or are later amended. Transcript at 4065, 4068-4069; TUEC Brief on rate design at 36. TUEC urges that the testimony of its witness E. D. Scarth made it clear that such regulations were not for the purpose of imposing charges upon customers without the approval of the Commission and cannot lead to such results. Transcript at 4048-4050; TUEC Brief on rate design at 36.

TUEC argues that a reading of the service regulations shows that they are intended to identify and charge to specific customers the costs which those customers impose through requests for new or additional service and service loads which are above those average standard costs imposed by any average customer seeking new or increased service. Transcript at 3985, 3988-3989, 4095; Coop Exhibit 20; TUEC Brief on rate design at 36. TUEC also points out that the language of such regulations is virtually identical to that found in the company's present tariffs. For example, Section 3.11(c), "All Other Extensions," is identical to the presently effective Section 207.10(b) found in TESCO's tariffs approved in Docket No. 5200. The formula set out in Section 3.11(d), "Standard Allowable Expenditure Formula," is identical to the formula found in Section 207.20 of TESCO's current tariff. TUEC contends that various provisions of the regulations are specifically designed to cover different types of customers, such that all customers, regardless of size and class, will bear any non-standard costs which they may impose on the system. Transcript at 4048-4049, 4076; TUEC Brief on rate design at 36.

TUEC witness Scarth testified that the regulations are designed to identify the standard or average cost of extending new or additional load to a customer based upon the average embedded cost for that class of customer with that customer's expected revenue, as determined in this rate case. Transcript at 4048, 4122, 4125, 4152-4153; TUEC Brief on rate design at 36. As Mr. Scarth explained, such average cost is then compared to the additional direct customer specific costs imposed by the customer, not benefiting other customers (Transcript at 4115), and if such additional costs exceed the standard costs, they are charged directly to that customer (Transcript at 4037), but not as an additional or different kw or kwh rate. Transcript at 4038, 4051; TUEC Brief on rate design at 36. Mr. Scarth did discuss an example of a rare instance in which such a customer might be charged under the regulation even where the direct costs were less than the average costs. Transcript at 4084, 4088-4089; TUEC Brief on rate design at 36. TUEC argues that even in such instances, the customer is charged only because the revenue will not support the cost of providing service to that customer. Transcript at 4084-4085; TUEC Brief on rate design at 36. In addition, Mr. Scarth explained that a failure to collect such non-standard costs from those customers who caused them will result in a higher cost of service being allocated to and borne by all customers in the next rate case. Transcript at 4037, 4085, 4112; TUEC Brief on rate design at 37. TUEC asserts that the rates set by this Commission are based upon an average embedded cost to serve various classes of customers, and are therefore designed to recover from present and future customers such average costs on an average basis. If, after the last rate case, new load or load increases impose more than average costs on the system without adequate corresponding revenue from that customer, then the average customer must inequitably bear a share of such abnormal costs imposed when such costs appear in the next test year. TUEC argues that by directly collecting such abnormal costs from the customer imposing them, for example in the form of a contribution in aid of construction, such costs do not appear in the company's cost of service and are not borne by other customers. TUEC Brief on rate design at 37.

2. TNP Proposal

TNP argues in brief that TUEC is seeking by way of the present docket to circumvent its contractual obligations entered into in good faith with TNP. Specifically, TNP urges that the proposed service regulations 3.01, 3.11(e) and 3.13 state that upon a triggering event, that event being either a request for additional load or a shifting of load, the company will run a specific cost of service study for such extension. TNP Brief on rate design at 32. TNP's objection to the proposal of TUEC is that such a provision provides for prospective ratemaking by TUEC without exposure to the regulatory process anticipated by the Public Utility Regulatory Act, and allows the company to unilaterally determine the appropriateness of costs without having to prove that these costs are valid within a regulatory framework. TNP Brief on rate design at 32.

TNP further urges that TUEC should be bound by its prior contractual agreements which were the result of arms length negotiations, and that allowing TUEC to make unilateral decisions regarding the matters anticipated in the service regulations is TNP's only alternative to applying to the Commission for relief. TNP Brief on rate design at 33. Meanwhile, TNP would be unable to receive the service addition or would be unable to shift its load since the company would not allow it if its supposed costs were not met. TNP Brief on rate design at 33.

TNP contends that the proposed service regulations, when read in conjunction with the company's proposal for a 50 percent of contract kw minimum billing demand, could impose higher costs on the customer. TNP Brief on rate design at 33. During cross-examination of TUEC witness Scarth, the following hypothetical situation was offered, and Mr. Scarth agreed that the result was possible under the company's proposal: a customer lowers his contract kw to avoid being billed under the 50 percent minimum, and later the customer wants to raise his contract kw becuase his increased load has obviated the 50 percent minimum problem. However, the new load is still less than his original contract kw. TUEC incurs no additional costs because of the additional load imposed by the increase after the original decrease, but Sections 3.11(d) and (e) impose higher costs on the customer. Transcript at 4150; TNP Brief on rate design at 33. TNP asserts that it is neither asking for a free ride nor requesting that its costs be borne by any customer other than itself. TNP's objections to these service regulations is based on its view that they are an attempt on the part of TUEC to circumvent the regulatory process and the contractual obligations TUEC has previously undertaken. TNP requests that either these sections should be reworded to comply with the existing contracts or they should be removed from the proposed service rules. TNP Brief on rate design at 33-34.

TUEC argues that TNP's concern that the company's proposed service regulations together with the proposed 50 percent contract minimum demand billing feature in the wholesale tariff could adversely effect TNP under its existing wholesale contracts with TESCO and DP&L (TNP Exhibit 8 and Exhibit 9) cannot legitimately be founded upon a contention that TNP's existing contracts protect it from alterations in wholesale rate tariffs approved by this Commission. TUEC Brief on rate design at 37. TUEC points out that the TNP-TESCO contract expressly provides:

> Customer understands and agrees that rate W-4 is subject to change when Company changes the rate for customers of this rate class. Changes in rate W-4 are subject to such regulation as may be imposed by any regulatory authority having jurisdiction.

TNP Exhibit 8 at 2. TNP argues that the maximum demand requirements in that contract are and have been renegotiated from time to time by the parties, most recently to cover the 1976-1981 period. TNP Exhibit 8. Further, TUEC argues that

TESCO's current rate applicable to TNP, Rate W-2, already contains a 50 percent of contract kw minimum billing feature. Similarly, the TNP-TP&L contract provides:

> Customer understands and agrees that said Rate Schedule WP-500, dated October, 1975, is subject to change from time to time by regulatory authorities having jurisdiction thereof, or by Company, to such rate as may in the future be established to apply to the class of service provided under this Agreement.

TNP Exhibit 9 at 6. TUEC argues that the TNP-TP&L contract imposes on the company a commitment to meet a contract demand which has more than doubled TNP's actual demand, which means that TNP is inequitably imposing a cost burden on the system in the form of generation, transmission and distribution capacity installed by the company and reserved for TNP's use. Transcript at 4143; TUEC Brief on rate design at 37-38. TUEC notes that Mr. Scarth provided an analogy in his testimony, that a party ought not to have the available benefit of a three bedroom house, whether or not all three bedrooms are used, without paying the fair rental value of a three bedroom house. Transcript at 4147; TUEC Brief on rate design at 38.

3. Nucor Steel Proposal

Nucor Steel focuses on testimony of TUEC witness Scarth who acknowledged that the application of the service regulation provisions as proposed would not be limited to only those instances where additional investment was required to serve the load (Transcript at 4041), but might mean that special charges would be assessed against the new load even when there were no construction costs at the point of delivery. Transcript at 4080; Nucor Steel Brief on rate design at 24. Nucor Steel advances several reasons why these provisions must be rejected. First, Nucor Steel asserts that as interpreted by the company, they are illogical. Such provisions could result in a situation where a new load, such as an amusement park, could be assessed special contract charges of $100,000 when the company was required to spend only $30,000 out of pocket to initiate service. Transcript at 4084-4085; Nucor Steel Brief on rate design at 24-25. Second, Nucor Steel asserts that the provisions are vague and not well defined. Transcript at 4115, 4116, 4119; Nucor Steel brief on rate design at 25. As an example, Nucor points out that the carrying charge included in the standard allowable extension formula is not clearly specified, as TUEC's witness admitted. Transcript at 4126. Although he stated that the application of the formula would be based on embedded costs (Transcript at 4122), Nucor Steel points out that an example provided by the company in response to an RFI on how the formula works (Coop Exhibit 20 at 7), shows a calculation of marginal capital costs. Nucor Steel brief on rate design at 25. Finally, Nucor Steel argues that the provisions are unreasonable and contrary to

Commission precedent to the extent that they they allow TUEC to assess against a new load certain costs incurred by the company after the end of the test year in the company's last rate case and which are not directly attributable to the load. Transcript at 4047; Nucor Steel Brief on rate design at 25.

Nucor Steel asserts that the assurances given by TUEC that the provisions will be properly and consistently applied are simply inadequate regardless of how well intentioned they may be. Nucor Steel contends that it is not enough for TUEC to tell its current and potential customers that although the provisions do "not precisely refer" to the relevant cost accounts that must be considered in applying the provisions, they do spell out certain principles (which Nucor Steel argues are undefined) in enough detail "so that anybody who is familiar with those accounts can go to the numbers and not have any room for any judgment." Transcript at 4125; Nucor Steel Brief on rate design at 25. Nucor Steel also takes the position that TUEC's customers can take no comfort from being allowed first to negotiate with the company and then if they are unsatisfied go to the Commission and file a complaint. Transcript at 4473; Nucor Steel Brief on rate design at 25-26. Nucor Steel concludes that the serious definitional and procedural defects of the extension service provisions require their rejection. Nucor Steel Brief on rate design at 26.

TUEC counters that Nucor Steel's complaints regarding the extension policy reflect a failure to recognize its purpose and perhaps an effort to shift non-standard costs to the other customers of the company. TUEC asserts that the extension policy does not permit the charging of costs incurred by the company after the end of the test year which are not directly attributable to the load. TUEC Reply Brief on rate design at 9. Mr. Scarth testified that the standard allowable extension formula, Section 3.11(d), is based only upon the company's embedded cost of service as approved in the company's last rate case (Transcript at 4110), as a measure of the average cost of service to a customer. TUEC Reply Brief on rate design at 9.

4. Tex-La Proposal

Tex-La's opposition to the service extension policy proposed by TUEC is similar to that of both TNP and Nucor Steel. Tex-La charges that such provisions would allow the company to automatically adjust a wholesale customer's rates with neither input from the customer nor a hearing before the Commission. Transcript at 4037-4038, 4050; Tex-La Brief on rate design at 38-39. Tex-La argues that Section

3.01 of TUEC's proposed service regulations allows for the automatic pass through of "costs" contrary to Section 43(g)(1) of the PURA, and thus it should be disallowed. Tex-La Brief on rate design at 39.

TUEC asserts that Tex-La also ignores the purpose and prior application of the company's tariff to properly assign non-standard costs. TUEC Reply Brief on rate design at 9. TUEC asserts that Tex-La may believe that it is entitled to demand special contract arrangements, non-standard service and other benefits not extended to other customers, and that such other customers must bear a portion of such costs for Tex-La's benefit. TUEC Reply Brief on rate design at 9. TUEC also refers to Commission Substantive Rule 23.38(b) which provides for utilities filing their line extension and construction charges, and further provides for a charge (disconnection fee) to customers switching from one utility to another in recognition of the fact that such customers' actions might otherwise impose non-standard costs on other customers. TUEC argues that the Commission has recognized the validity of service extension policies as a means of assigning costs and that any such failure to continue the extension policy in the tariffs of TUEC will only serve to impose customer specific costs upon other customers who have not imposed similar costs on the TUEC system. TUEC Reply Brief on rate design at 10.

5. Recommendation

The arguments that TUEC's proposed service extension policy provides TUEC a method of circumventing contractual obligations, changing rates without a hearing before the Commission, or is an automatic pass-through of costs in violation of Section 43(g)(1) of the PURA are without merit and must be rejected. TUEC must have some method for assessing non-standard costs against the customers causing them to be incurred; otherwise, all customers must bear such costs - clearly an inequitable result. On the other hand, the criticisms that the service extension policy provisions are vague are well-taken. Such vagueness does not require complete rejection of these sections, however; merely their rewording. TUEC should state specifically: that the standard or average cost is determined using the average or embedded cost for the class of customer seeking service as established in this rate case; the carrying charge or the formula for setting the carrying charge; and which cost accounts are considered in applying the provisions. With those changes, TUEC's proposed service extension policy should be adopted.

B. Other Tariff Issues

1. Structure of Tariff/Fuel Charges

Staff witness Kepner proposed that the energy portion of each separate tariff schedule include a fuel charge. TUEC asserts that such a proposal makes no practical sense and would create administrative burdens. TUEC Exhibit 41 at 1-2; TUEC Brief on rate design at 17. TUEC points out that as the tariff schedules have been proposed, each rate references Rider FC which will set out the fuel charges approved. The company's current fuel charges, those approved in Docket No. 5294, are differentiated by season and by voltage level which would greatly add to the complexity of each individual rate schedule if fuel charges were required to be rolled into the non-fuel base rate charges set forth on each schedule. TUEC asserts that there is no benefit to be derived from Mr. Kepner's proposal, particularly since he recommends a fuel schedule in addition to rolling the charge into other rates and, certainly, no benefit outweighing the administrative burdens and added complexity of rates inherent in his proposal. TUEC Brief on rate design at 17. TUEC's defense of its tariff structure is convincing, and staff's proposal should not be adopted.

2. Security Payments and Meter Accuracy Rules

General Counsel points out in brief that the company's proposed provision 4.03, while substantially complying with P.U.C. SUBST. R. 23.43(a)(3)(C)(ii) and (h)(2) regarding security payments, has omitted language regarding the voiding of the guarantee in compliance with the Substantive Rule. Staff recommends that TUEC amend its tariff to include such a guarantee, and it is so recommended. In addition, General Counsel suggests that the company's provision regarding accuracy limits should be changed to comply with the limits set by the American National Standards Institute as required by P.U.C. SUBST. R. 23.47. This recommendation should also be adopted. These recommendations are not anticipated to be a problem for TUEC, since TUEC witness Scarth testified that TUEC will comply with the Substantive Rules of the Commission. Transcript at 4069.

XIV. Findings of Fact and Conclusions of Law

A. Findings of Fact

1. On March 9, 1984, Texas Utilities Electric Company (TUEC) filed a statement of intent to increase its rates within the unincorporated areas served by it. The proposed increase published was a 7.98 percent increase, or $304.2 million, over adjusted test year revenues. TUEC's test year ended September 30, 1983.

2. TUEC is an electric utility engaged in generation, purchase, transmission, distribution, and sale of electricity wholly within the State of Texas. It is a subsidiary of Texas Utilities Company, and provides electric service to customers in 91 Texas counties and 350 incorporated municipalities, including the Cities of Dallas, Ft. Worth, Arlington, Irving, and Waco.

3. Texas Electric Service Company (TESCO), Dallas Power and Light Company (DP&L), and Texas Power and Light Company (TP&L), previously electric utilities which were wholly owned by Texas Utilities Company, underwent a corporate reorganization January 1, 1984, and became what is presently known as TUEC.

4. The quality of service provided by the applicant is good, and it has achieved and continues good relations with the customers it serves.

5. TUEC has instituted and continues to pursue a number of programs in the area of energy conservation; its efforts in this respect are commendable, which fact should be taken into account in the determination of the utility's proper return.

6. Permian Basin Units 1 through 4 were carried as plant in service on the company's books as of test year end. In accord with a determination that the utility's construction work in progress total should be ascertained by reference to books as of test year end, the plant in service total should not be adjusted to account for the retirement of the Permian Basin Units in January 1984, although the retirement of those units is a known event and the rate base consequences can be adequately measured. Section V. A. of the Examiners' Report explains this finding more fully.

7. TUEC does not have definite and specific plans for use, within ten years, of the items shown as plant held for future use as of test year end, with the exception of land held for two substations scheduled to go into service in 1984 and 1985. The reasons for this finding are set out in Section V. D. of the report.

8. Because of the reasons set out fully in Section V. C. of the report, there are exceptional circumstances justifying the inclusion of CWIP in rate base in this docket, the ceiling for CWIP expenditures shown to be prudently planned and managed is $1.8 billion, and the financial integrity of TUEC will not be impaired by disallowance of the company's request to add $1 billion in CWIP to the $1.474 billion already allowed a return pursuant to Commission orders.

Inclusion of the $1.474 billion of CWIP in rate base is necessary to TUEC's financial integrity.

9. Fuel inventories of $96,581,103 should be included in the applicant's rate base; both the test year oil inventory of 3,986,510 barrels (valued at $82,035,175)(51) and the $14,546,728 in average lignite inventory are reasonable amounts and are amounts necessary to provide uninterrupted service to TUEC's customers in the event of curtailment or other emergency.

10. Nuclear fuel in process in the amount of $156,128,052 should be included in TUEC's rate base; such expenditure is reasonably necessary for the company's continued provision of service to its customers.

11. The applicant had an average inventory of materials and supplies of $81,114,619 during the test year; that amount should be included in rate base as a working capital amount, the retaining of those items being necessary for the company's continued provision of service to its customers.

12. TUEC's invested capital total should not include a working cash allowance to account for investor capital necessary to meet the cash needs of the utility in its day to day operations; its excellent cash management practices make such allowance unnecessary. No negative working cash "allowance" should be used as an offset to the company's rate base, since such would discourage efficiency in management.

13. TUEC's invested capital should be valued at $5,230,301,493, as shown below, for the reasons fully set out in Section V. of the report:

Plant in Service	$5,559,390,336
Accumulated Depreciation	1,627,069,537
Net Plant	$3,932,320,799
CWIP	1,474,000,000
Plant Held For Future Use	341,276
Nuclear Fuel in Process	156,128,052
Working Cash Allowance	
Materials and Supplies	81,114,619
Prepayments	19,477,977
Fuel Inventory	96,581,903
Less	
Deferred taxes	442,245,943
Customer deposits	34,929,566
Property Insurance Reserve	11,926,092
Other Cost Free Capital	40,561,532
Total Invested Capital	$5,230,301,493

14. For purposes of computing a fair return on TUEC's invested capital, the following capital structures (with and without ITC's), and costs of capital are

appropriate, for the reasons fully set out in Section VI. of the report:

	amount	percentage of structure	cost	weighted cost
Long-term Debt	$2,657,374,529	38.48	9.851%	.03791
Notes payable	1,825,581	.03	8.779%	.00303
Preferred Stock	745,260,991	10.79	8.387%	.00905
Accumulated Deferred ITC's	461,111,883	6.68	12.442%	.00831
Common Equity	3,039,748,650	44.02	15.700%	.06910
Total	$6,905,321,634	100.00		.12441

	amount	percentage of structure	cost	weighted cost
Long-term Debt	$2,657,374,529	41.24	9.851%	.04063
Notes Payable	1,825,581	.03	8.779%	.00003
Preferred Stock	745,260,991	11.56	8.387%	.00970
Common Equity	3,039,748,650	47.17	15.700%	.07406
Total (wihtout ITC's)	$6,444,209,751	100.00		.12442

TUEC's overall rate of return should be set at 12.44 percent (rounded).

15. The appropriate methodology for calculating a return on TUEC's equity is the discounted cash flow (DCF) analysis, which sets return equal to the dividend yield (market price of common stock divided by anticipated dividends) plus anticipated growth.

16. The most accurate values in this record for dividend yield and growth are those set forward by TUEC witness Olson, but without the application of an adjustment for market breaks, flotation costs, or dilution prevention. Using the DCF analysis of TML witness Lattner as corroboration of overall reasonableness, TUEC's imputed cost of equity (determined by reference to Texas Utilities, since TUEC's shares are not publicly traded) is 15.7 percent, for the reasons fully set out in Section VI. B. of the report.

17. A return on common equity of 15.7 percent is reasonable for TUEC. An annual return of $650,649,506 is adequate under efficient management to provide for the continued financial integrity of the applicant, and to enable it to attract capital at reasonable rates to allow the proper discharge of its public utility duties.

18. TUEC has a cost of service of $3,662,401,067, including fuel, the components of which are shown on the revenue requirement Schedule I attached to

and incorporated in this report.

19. The cost of service items recommended by the report and utilized in deriving Finding of Fact No. 18 and revenue requirement Schedule I, attached hereto, are reasonable and should be adopted for the reasons fully enumerated in Section VII of the Examiners' Report.

20. TUEC's revenue deficiency, calculated in accord with all the recommendations made in this report, is $7,041,461, rather than the amount requested by the company, $304,196,722.

21. The specific identification methodology recommended by staff witness Allen is reasonable and should be orderedadopted by the Commission.

22. TUEC's application requested fuel costs at the level to be determined in Docket No. 5294, then on remand to the examiners. Although recoverable fuel costs in Docket No. 5294 were ultimately set at a level below what TUEC had argued for, TUEC has maintained in this proceeding that the Docket No. 5294 figure should be used in the final Order herein and need not be redetermined.

23. The Examiners' Eighth Order ruled that TUEC was not required to file a full fuel case.

24. TUEC had a cumulative fuel expense underrecovery of $38,942,688 as of May 31, 1984.

25. The prices charged to the company by its supplying affiliates are no higher than the prices charged by the affiliates to its other affiliates or divisions or to unaffiliated persons or corporations for the same item or class of items. The affiliates' fuel prices are "at cost." No return on equity or equity profit has been included in the affiliate fuel price.

26. All fuel and fuel-related affiliate expenses are reasonable and necessary. This finding should not prevent or restrict the scope of inquiry in any future reconciliation proceeding.

27. All of the intervenors' witnesses who testified as to adjusted test year fuel costs were discredited during cross-examination, and thus their testimony is insufficient to support any finding with regard to adjusted test year fuel costs.

28. The increase in kwh sales (between the figure indicated by the record and that set in Docket No. 5294) is not likely to cause TUEC to experience a cumulative overrecovery of fuel costs in the future.

29. The record supports the weather adjustment as proposed by the staff in this case, as discussed in Section VIII of the Examiners' Report. The customer adjustment proposed by TUEC is supported in the record.

30. The average and excess allocation methodology is fully supported by the testimony of expert witnesses in this docket as discussed in Section IX of the Examiners' Report; however, fuel stock inventories and nuclear fuel in process should be allocated so that one-half are allocated on demand and one-half on energy, becuase of the difficulty in defining these costs as strictly demand related or energy related, as discussed in Section XI. G. above. Use of the average and excess methodology has the virtue of consistency with past Commission decisions and should prevent radical shift in cost responsibility among the classes.

31. The record in this docket fully supports the consolidation of wholesale customers into a single class for the reasons set forth in Section X. B. of the Examiners' Report. The record also supports the setting of systemwide rates for each customer class rather than the continuation of divisional rates, as discussed in Section X. A. of the Examiners' Report.

32. The record herein (as discussed in Section XI. A. above) supports TUEC's proposed elimination of a CWIP credit to Tex-La Electric Cooperative, Inc.

33. Franchise fees and gross receipts tax should continue to be allocated to and collected from all customers of TUEC, except the wholesale customers. This treatment is consistent with prior Commission treatment of franchise fees and gross receipts tax for TUEC and is supported by the record herein, discussed in Section XI. B. of this report. Proposals for allocating franchise fees and gross receipts taxes only to municipal customers of TUEC were not supported by cost studies.

34. The allocation to various customer classes of distribution plant proposed by TUEC is supported in the record developed in this case for the reasons set forth in Section XI. C. of this report and should be adopted. TUEC should also be required to develop and provide in its next rate case the information necessary to develop a minimum system approach for allocation of distribution plant.

35. TUEC's proposed allocation to the wholesale customers of certain customer service and informational expenses, sales expenses, general advertising expenses and miscellaneous general expenses is reasonable, fully supported in the record as discussed in Section XI. D. of the report, consistent with prior Commission decisions, and therefore should be adopted.

36. The allocation of Federal Income Tax proposed by TIEC in this docket has not been adequately supported. TUEC's proposed treatment of this item is reasonable, consistent with past practice and should be adopted for the reasons set forth in Section XI. F. herein.

37. The revenue allocation to customer classes as recommended in Section XII. A. is supported in the record herein, is consistent with past Commission practice and will move all rate classes closer to unity.

38. None of the proposed residential summer/winter differentials should be adopted in this case. The record herein reveals that any such differential is unnecessary as a price signal, since customers have responded to rising electric bills by utilizing conservation and load management techniques. Further, none of the proposed differentials have been shown to be cost based, as discussed in Section XI. B. of the Examiners' Report; TUEC's other rate design proposals for the residential class are supported in the record and should be adopted, including a two-step winter rate (instead of two separate residential tariffs) to prevent overrecovery from the residential electric space heating customers. As also discussed in Section XI. B., Brazos Coop's claim of unfair price competition by TUEC has not been supported in this record.

39. The record does not support adoption of TUEC's proposed summer/winter differential for wholesale customers, as explained in Section XI. C. of the Report.

40. The proposed 80 percent demand ratchet for those classes on demand rates should be adopted for the reasons set forth in Section XI. D. 1. of the Examiners' Report. The application of the ratchet should be limited to the summer peak period, June, July, August and September.

41. The elimination of conjunctive and coincident billing for wholesale customers is fully supported in the record in this docket for the reasons set forth in Section XI. D. 2. above.

42. The 15 minute demand interval for metering wholesale customers will achieve consistency for comparison of cost of service, rates and meter inventories, and should be adopted along with the provision for reconciliation between the proposed conversion factors and the actual conversion factors each month, as explained in Section XI. D. 3. of the Report.

43. The record (as discussed in Sections XI. D. 4. and 5. herein) fully supports adoption of the proposed 50 percent of contract KW minimum billing demand and $1.00 per KW in excess of contract KW provisions.

44. The proposed design of Rates G and HV is supported by the record herein; the proposal of St. Regis for the design of Rates G and HV should not be adopted. This is explained fully in Sections XII. E. and XI. E. of the Report.

45. The high voltage credit sought by Nucor Steel and Tex-La Electric Cooperative, Inc. is not adequately supported herein and should not be adopted as explained in Section XII. F. above; however, TUEC should be required to develop and provide the information needed to determine voltage level discounts for each transmission service level in its next rate case.

46. Neither proposed Rider I nor the joint agreement between TUEC and Nucor Steel for provision of interruptible service was supported in the record, as set forth in Section XII. G. of this Report. TUEC should continue to offer

interruptible service under the rates, terms and conditions of the present TP&L Rider IS, with the clarification that the 50 percent of contract KW minimum billing demand provision cannot override the interruptible credit.

47. The 3 percent late payment penalty is reasonable and should be adopted, as explained in Section XII. H. of the Report.

48. The service extension policy proposed by TUEC should be modified as recommended in Section XIII. A. above and adopted.

49. TUEC's proposed tariff/fuel charges should be adopted for the reasons set forth in Section XIII. B. 1., but other tariff changes should be made as explained in Section XIII. B. 2.

50. The cost allocations and rate structures proposed by TUEC, if properly amended to conform to the cost allocation and rate design recommendations and guidelines set forth in Sections VIII through XII of this Examiners' Report, will be based on sound ratemaking principles and should be adopted. Such rates are not unreasonably discriminatory, preferential or prejudicial, and they will allow TUEC to recover from each customer class most of the costs associated with providing service to that class, without creating an unreasonable burden upon any single class of customers.

51. Amendments to TUEC's proposed service rules and regulations in conformance with the recommendations contained in Section XIII herein will result in nondiscriminatory and nonpreferential service to all TUEC customers.

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B. Conclusions of Law

1. TUEC is a public utility under Section 3(c)(1) of the Public Utility Regulatory Act, Tex. Rev. Civ. Stat. Ann. art. 1446c(Vernon Supp. 1984)(PURA).

2. The Commission has ratemaking jurisdiction in this docket, regarding customers not subject to the original jurisdiction of any municipality, pursuant to PURA Section 17(e). It also has jurisdiction over the rates in the cities from which timely appeal were taken and which appeals were consolidated with this docket. A list of those cities is set out in Section I of the Examiners' Report.

3. PURA Section 27(b) requires the Commission to fix proper and adequate rates and methods of depreciation, amortization, or depletion of the several classes of property of each public utility. TUEC's proposed depreciation, amortization, and depletion rates, as modified by the recommendations of this report, comply with that section of the act.

4. Pursuant to PURA Section 40, TUEC has the burden of proving its proposed rates are just and reasonable. To the extent recommended by the report, TUEC has met its burden of persuasion.

5. Pursuant to PURA Sections 40 and 41(c)(1), TUEC bears the burden of proving payments to affiliated interests for costs of services, or of any property, right, or thing, or interest expense, are no higher than rates charged by the supplying affiliate to its other affiliates or divisions for the same item or items as charged to unaffiliated persons or corporations. TUEC has established a prima facie case constituting the preponderance of credible evidence of such issues, discharging its burden of proof as to those matters.

6. The recommendations of the Examiners' Report will allow TUEC to recover its reasonable and proper operating expenses, together with a reasonable return on its invested capital pursuant to PURA Section 39.

7. Classification of construction projects as CWIP or plant in-service by reference to the test year end books usually requires that other items of rate base also be determined as of test year end, regardless of any known and measurable changes to rate base that may have occurred since test year end. The goal in determining a utility's rate base is to establish a representative level of investment on which a return may be allowed; a consistent temporal focus in ascertaining the various items of used and useful rate base is consistent with PURA Sections 38, 39(a), and 41(a).

8. The fuel oil inventory as of test year end of 3,986,510 barrels, sought by TUEC to be included in rate base, is "property used by and useful to the public utility in providing service" to the public, within the meaning of PURA Section 39(a).

9. The use of the term "financial integrity" in PURA Section 41(a) does not necessarily require inclusion of levels of CWIP to maintain a company's existent bond rating in all cases; the relevant facets of that test are subject to a factual determination on a case by case basis.

10. Inclusion of $1.474 billion of CWIP, an amount already earning a return pursuant to prior Commission orders concerning the three operating companies which merged into TUEC, is necessary to the utility's financial integrity, within the meaning of PURA Section 41(a). That amount, spread ratibly to the two Commanche Peak units in accord with the recommendation of staff witness Allen and Section V.C.4. of the report, does not include any amount attributable to inefficient or imprudent planning or management for major projects under construction, satisfying the requirements of PURA Section 41(a). TUEC did not show that a return on additional CWIP was necessary to its financial integrity under PURA Section 41(a). The high percentage of this utility's CWIP, as compared to its net plant in service, constitutes an exceptional circumstance, entitling it to inclusion of some CWIP in rate base, pursuant to P.U.C. SUBST. R. 23.201(c)(2)(D).

11. TUEC's nuclear fuel in process should be included in rate base if found to be reasonably necessary to the provision of service by the applicant; since it is not classed as CWIP, it is subject neither to the exceptional circumstance, the prudence of management, nor the financial integrity tests applicable to CWIP.

12. Under P.U.C. SUBST. R. 23.23(b)(2)(A), a review of fuel costs is not identical to a redetermination of fuel costs. A redetermination consists of determining a new fuel cost figure equal to reasonable test year expenses as adjusted for known and reasonably predictable changes. A review focuses only on actual fuel costs and revenues incurred since the last fuel cost redetermination.

13. A redetermination is necessary only if requested by the applicant; if the applicant has a cumulative fuel revenue overrecovery greater than one percent of allowable fuel costs (as set during the last fuel cost redetermination), as of the date of filing or the start of the hearing on the merits; or if a review indicates that due to increased kwh sales the applicant will experience such a cumulative fuel overrecovery in the future. Based upon Findings of Fact Nos. 22, 24 and 28, a redetermination of fuel costs is not required in this docket.

14. A utility may request a redetermination of fuel costs only during a general rate case, a reconciliation proceeding pursuant to SUBST. R. 23.23(b)(2)(I), or an emergency proceeding under SUBST. R. 23.23(b)(2)(F) and (G).

15. Based upon Findings of Fact Nos. 25 and 26 and Conclusion of Law No. 13 , the fuel cost figure and fuel factors set in Docket No. 5294 should not be modified.

16. No reconciliation is required in this docket because the utility has not requested one, nor has a redetermination been found to be necessary.

17. Rates designed according to the guidelines recommended herein, if properly implemented, are reasonable and nondiscriminatory and should be approved by the Commission as a proper discharge of its duties under PURA Section 38.

18. TUEC's present rates for service in unincorporated areas are insufficient to provide TUEC with the revenues approved herein; they should therefore be adjusted to conform to the rates established herein for each class of service.

Respectfully submitted,

Phillip Holder

PHILLIP HOLDER
ADMINISTRATIVE LAW JUDGE

Mary Ross McDonald

MARY ROSS McDONALD
HEARINGS EXAMINER

APPROVED on this the 21st day of September, 1984.

Rhonda Colbert Ryan

RHONDA COLBERT RYAN
DIRECTOR OF HEARINGS

jlc

PUBLIC UTILITY COMMISSION OF TEXAS

TEXAS UTILITIES ELECTRIC COMPANY
Operation and Maintenance Expense
DOCKET NO. 5640

Description	Amount	Examiner Adjustment
PAYROLL EXPENSE		
Examiner Recommendation	$ 13,006,275	
Company Adjustment	14,640,066	
Examiner Adjustment		$ (1,633,791)
PAYROLL RELATED EXPENSE		
Examiner Recommendation	$ (2,869,647)	
Company Adjustment	(2,776,149)	
Examiner Adjustment		$ (93,498)
UNCOLLECTIBLE EXPENSE		
Examiner Recommendation	$ 950,183	
Company Adjustment	2,316,354	
Examiner Adjustment		$ (1,366,171)
CONTRIBUTIONS & UNALLOWABLE		
Examiner Recommendation	$ (1,424,322)	
Company Adjustment	(1,186,834)	
Examiner Adjustment		$ (237,488)
LAKE FORK WATER RIGHTS		
Examiner Recommendation	$ (5,572,073)	
Company Adjustment	(2,508,573)	
Examiner Adjustment		$ (3,063,500)
PROPERTY INSURANCE RESERVE		
Examiner Recommendation	$ (3,941,000)	
Company Adjustment	(1,781,000)	
Examiner Adjustment		$ (2,160,000)
OTHER O&M EXPENSE		
Examiner Recommendation	$ (7,222,994)	
Company Adjustment	(2,984,491)	
Examiner Adjustment		$ (4,238,503)
CITIES RATE CASE EXPENSE		
Examiner Recommendation	$ 112,990	
Company Adjustment	0	
Examiner Adjustment		$ 112,990

MERGER EXPENSES		
Examiner Recommendation	$ (517,000)	
Company Adjustment	0	
Examiner Adjustment		$ (517,000)
CORPORATE EXPENSE		
Examiner Recommendation	$ (327,403)	
Company Adjustment	0	
Examiner Adjustment		$ (327,403)
Total Examiner Adjustment - O&M		$ (13,524,364)

PUBLIC UTILITY COMMISSION OF TEXAS
****
TEXAS UTILITIES ELECTRIC COMPANY - DOCKET 5640
****
REVENUE REQUIREMENT
****

	TEST YEAR PER BOOKS	COMPANY ADJUSTMENTS	COMPANY TEST YEAR	Examiner ADJUSTMENTS	Examiner TEST YEAR
FUEL	$1,503,166,305	$352,239,755	$1,855,406,060	$(158,111,539)	$1,697,294,521
OPERATIONS AND MAINTENANCE	645,101,800	(19,759,299)	625,342,501	(13,524,364)	611,818,137
DEPRECIATION AND AMORTIZATION	187,919,341	(10,239,358)	177,679,983	(7,645,640)	170,034,343
OTHER TAXES	194,321,033	46,203,403	240,524,436	(20,915,808)	219,608,628
INTEREST ON CUSTOMERS DEPOSITS	0	2,109,878	2,109,878	0	2,109,878
FEDERAL INCOME TAXES	232,829,411	183,918,667	416,748,078	(105,862,022)	310,886,056
RETURN	593,753,109	206,227,287	799,980,396	(149,330,890)	650,649,506
REVENUE REQUIREMENT	$3,357,090,999	$760,700,333	$4,117,791,332	$(455,390,265)	$3,662,401,067
LESS					
OTHER REVENUE	$44,275,842	$(3,777,326)	$40,498,516	$(42,000)	$40,456,516
BASE RATE REVENUE	$3,312,815,157	$764,477,659	$4,077,292,816	$(455,348,265)	$3,621,944,551

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PUBLIC UTILITY COMMISSION OF TEXAS

TEXAS UTILITIES ELECTRIC COMPANY - DOCKET 5640

REVENUE DEFICIENCY

	COMPANY TEST YEAR	Examiner ADJUSTMENTS	Examiner TEST YEAR
REVENUE REQUIREMENT	$4,117,791,332	$(455,390,265)	$3,662,401,067
LESS			
TEST YEAR REVENUES	3,357,090,999	0	3,357,090,999
REVENUE ADJUSTMENTS	456,503,611	(158,235,004)	298,268,607
REVENUE DEFICIENCY	$304,196,722	$(297,155,261)	$7,041,461

PUBLIC UTILITY COMMISSION OF TEXAS

TEXAS UTILITIES ELECTRIC COMPANY - DOCKET 5640

INVESTED CAPITAL AND RETURN

	COMPANY AMOUNT	Examiner ADJUSTMENTS	AS ADJUSTED
PLANT IN SERVICE	$5,559,859,832	$(469,496)	$5,559,390,336
ACCUMULATED DEPRECIATION	1,627,069,537	0	1,627,069,537
NET PLANT	$3,932,790,295	$(469,496)	$3,932,320,799
CONSTRUCTION WORK IN PROGRESS	2,400,000,000	(926,000,000)	1,474,000,000
PROPERTY HELD FOR FUTURE USE	5,969,712	(5,628,436)	341,276
NUCLEAR FUEL	156,128,052	0	156,128,052
WORKING CASH ALLOWANCE	36,458,066	(36,458,066)	0
MATERIALS AND SUPPLIES	81,114,619	0	81,114,619
PREPAYMENTS	19,477,977	0	19,477,977
FUEL INVENTORY	96,581,903	0	96,581,903
LESS			
DEFERRED TAXES	440,513,993	1,731,950	442,245,943
CUSTOMERS DEPOSITS	34,929,566	0	34,929,566
PROPERTY INSURANCE RESERVE	11,926,092	0	11,926,092
OTHER COST FREE CAPITAL	44,556,115	(3,994,583)	40,561,532
TOTAL INVESTED CAPITAL	$6,196,594,858	$(966,293,365)	$5,230,301,493
RATE OF RETURN	.1291	(.005)	.1244

PUBLIC UTILITY COMMISSION OF TEXAS
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TEXAS UTILITIES ELECTRIC COMPANY - DOCKET 5640
****

FEDERAL INCOME TAXES
****

DESCRIPTION	AMOUNT
RETURN	$650,649,506
LESS	
****	
INTEREST EXPENSE	198,228,427
AMORTIZATION OF ITC	9,979,243
SURTAX EXEMPTION	19,933
OTHER TAX SAVINGS	16,958,389
DEPLETION ADJUSTMENT	57,520,059
PLUS	

ADDITIONAL DEPRECIATION	15,601,203
OTHER DIFFERENCES	13,054,378
TAXABLE COMPONENT OF RETURN	$396,599,036
TAX FACTOR	.851851852
TOTAL TAXES	$337,843,623
LESS	
AMORTIZATION OF ITC	9,979,243
SURTAX EXEMPTION	19,933
OTHER TAX SAVINGS	16,958,389
TOTAL FEDERAL INCOME TAXES	$310,886,056

PUBLIC UTILITY COMMISSION OF TEXAS
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TEXAS UTILITIES ELECTRIC COMPANY - DOCKET 5640
****

SUMMARY OF OTHER TAX ADJUSTMENTS
****

	TEST YEAR PER BOOKS	COMPANY ADJUSTMENTS	COMPANY TEST PERIOD	Exaiminer ADJUSTMENTS	Examiner TEST PERIOD
AD VALOREM TAXES	$ 40,012,137	$ 8,695,215	$ 48,707,352	$ (4,788,169)	$ 43,919,183
PAYROLL TAXES	15,158,507	(13,295)	15,145,212	23,978	15,169,190
OTHER TAXES	15,221,957	2,503,170	17,725,127	584,095	18,309,222
NON REVENUE RELATED TAXES	$ 70,392,601	$ 11,185,090	$ 81,577,691	$ (4,180,096)	$ 77,397,595
TEXAS PUC ASSESSMENT	$ 0	$ 6,176,687	$ 6,176,687	$ (683,085)	$ 5,493,602
STATE GROSS RECEIPTS	45,758,518	10,243,444	56,001,962	(5,350,955)	50,651,007
LOCAL GROSS RECEIPTS	78,169,914	18,598,182	96,768,096	(10,701,671)	86,066,425
REVENUE RELATED TAXES	$123,928,432	$ 35,018,313	$158,946,745	$(16,735,712)	$142,211,033

SUMMARY OF OTHER TAXES
****

NON REVENUE RELATED TAXES	$ 70,392,601	$ 11,185,090	$ 81,577,691	$ (4,180,096)	$ 77,397,595
REVENUE RELATED TAXES	123,928,432	35,018,313	158,946,745	(16,735,712)	142,211,033
TOTAL OTHER TAXES	$194,321,033	$ 46,203,403	$240,524,436	$(20,915,808)	$219,608,628

DOCKET NOS. 5640 and 5661

APPLICATION OF TEXAS UTILITIES ELECTRIC COMPANY FOR A RATE INCREASE	§	PUBLIC UTILITY COMMISSION
PETITION FOR REVIEW OF TEXAS UTILITIES COMPANY FROM THE FINAL DECISION AND ACTION OF THE CITY OF LINDALE, ET AL.	§	OF TEXAS

ORDER

In a public meeting at its offices in Austin, Texas, the Public Utility Commission of Texas finds that the above styled application and petition were processed in accordance with applicable statutes and Commission rules by examiners who prepared and filed a report containing Findings of Fact and Conclusions of Law, which Examiners' Report is hereby ADOPTED and made a part hereof. The Commission further issues the following Order:

1. The petition of Texas Utilities Electric Company (TUEC) is hereby granted in part and denied in part, as set out in the Examiners' Report.

2. TUEC is hereby ordered to rerun its cost of service study, as modified to reflect the cost of service and cost allocation changes recommended by the examiners, and using the revenue adjustments approved herein. TUEC shall within 20 days from the date hereof submit the results of this study to the Commission for its review, showing how revenues will be allocated among rate classes. The cost of service study, when rerun, shall incorporate all changes in rates, schedules, and service rules ordered herein. A copy of the study shall be served upon each of the parties hereto at the time it is filed with the Commission.

3. TUEC shall file five copies of its tariff, revised in accordance with the Examiners' Report and the terms of this Order, and sufficient to generate revenues no greater than those prescribed in that Report and this Order, with the Commission Secretary and one copy with each of the Intervenors within 20 days of the date hereof. The Commission Staff shall have 20 days from the date of the filing to review and to approve or reject the tariff. All parties to this docket shall have 10 days from the date of that filing to file their objections, if any, to the revised tariff. The tariff shall be deemed approved and shall become effective upon the expiration of 20 days after filing, or sooner upon notification of approval by the Commission Secretary. In the event of rejection, TUEC shall have 15 additional days to file an amended tariff, with the same review procedures again to apply.

4. The revised and approved rates shall be charged only for service rendered in areas over which this Commission is exercising its original and appellate jurisdiction as of the adjournment of the hearing on the merits herein, and said rates may be charged only for service rendered after the tariff approval date.

5. Approval of the revised tariff in compliance with this Order shall be deemed to be final on the date its effectiveness either by operation of Item 3 of this Order, or by notification from the Commission secretary, whichever shall first occur.

6. TUEC shall use the specific identification of CWIP methodology recommended in Section V. C. 4. of the Examiners' Report for the calculation of AFUDC.

7. TUEC shall make no further accruals to its self-insurance reserve.

8. The next rate case filed by TUEC shall include a study of the minimum distribution system as the method oralternative method for allocating distribution plant.

9. The next rate case filed by TUEC shall include the information necessary to determine voltage level discounts for each transmission service level in its next rate case.

10. All motions, request, applications, and proposed Findings of Fact or Conclusions of Law not expressly granted herein are denied for want of merit and for being unsupported by the preponderence of the credible evidence in this docket.

SIGNED AT AUSTIN, TEXAS on this _____ day of October, 1984.

PUBLIC UTILITY COMMISSION OF TEXAS

SIGNED:______________________
PHILIP F. RICKETTS

SIGNED:______________________
PEGGY ROSSON

SIGNED:______________________
DENNIS THOMAS

APPROVED on this the ____ day of October, 1984.

____
RHONDA COLBERT RYAN
SECRETARY OF THE COMMISSION