Dennis L. Thomas
Chairman

Jo Campbell
Commissioner

Marta Greytok
Commissioner

PUC BULLETIN

A Publication of the Public Utility Commission of Texas

Volume 13, No. 10 June 1988

COMMISSION FORMS

Persuant to Commission Rules, a complete list of Commission forms and publications is listed below. This list will be updated whenever an addition or deletion occurs.

You may obtain application forms by contacting the Commission Filing Clerk at the following address: Public Utility Commission of Texas; 7800 Shoal Creek Boulevard, Suite 400N; Austin, Texas 78757; telephone, 512/458-0181.

All publications are available from the Commission's Central Records Office at the same address as shown above or by phoning 512/458-0225.

There is a charge for reproduction of Commission files: 8½x11" or 8½x14"--$.55 first page, $.15 per page for each additional page. Larger material will be provided at cost. There is a charge of $.55 each time a docket/file is opened.

APPLICATION FORMS

TELEPHONE & ELECTRIC

- Application for a sale, transfer or merger
- Preliminary construction report

ELECTRIC UTILITIES

- Electric utility application to amend certificated service area boundaries
- Application of electric utility for a certificate of convenience and necessity for proposed transmission lines and associated substations
- Application of electric utility for a certificate of convenience and necessity for proposed generating station/unit (coal fired)
- Rate filing package, Class A & B
- Rate filing package, Class C & D (electric & telephone)
- Class A & B annual electric report
- Class A & B quarterly electric report
- Class C & D annual electric report
- Annual peak demand and consumption report
- Quarterly peak demand and consumption report

TELEPHONE UTILITIES

- Application for a non-optional service upgrade with no change in existing rates
- Telephone utility application to amend a certificate of convenience and necessity
- Rate filing package, Class A & B
- Rate filing package, Class C & D (telephone & electric)
- Class A & B annual telephone report
- Class A & B quarterly telephone report

PUBLICATIONS

- Public Utility Regulatory Act ($7.50 plus tax)
- Rules of Practice and Procedure ($7.50 plus tax)
- Substantive Rules ($7.50 plus tax)
- Electric Utilities in Texas ($5.00 plus tax)
- Telephone Utilities in Texas ($5.00 plus tax)
- Bulletin ($50.00 plus tax)
- News Release Subscription ($30.00 plus tax)
- Precedent Manual - Volumes 1-4 ($7.50 plus tax)
- Precedent Manual - Volume 5 ($7.50 plus tax)
- Precedent Manual - Volume 6 ($7.50 plus tax)
- Precedent Manual - Volume 7 ($7.50 plus tax)
- Precedent Manual - Volume 8 ($7.50 plus tax)
- Precedent Manual - Volume 9 ($7.50 plus tax)
- Public Utility Commission Annual Report ($5.00 plus tax)

Austin sales tax rate is .08.

The PUC BULLETIN (0896-5927) is a monthly publication of the Public Utility Commission of Texas. Subscription requests should be accompanied by payment made out to the Public Utility Commission and sent to: Public Utility Commission; Central Records--Publication Sales; 7800 Shoal Creek Boulevard, Suite 400N; Austin, Texas 78757. Subscription rate is $50.00 per year plus tax. Second class postage paid at Austin, Texas. POSTMASTER: send address changes to the attention of PUC BULLETIN Coordinator; 7800 Shoal Creek Boulevard, Suite 400N; Austin, Texas 78757.

APPLICATION OF EL PASO ELECTRIC COMPANY FOR AUTHORITY TO CHANGE RATES

APPEAL OF EL PASO ELECTRIC COMPANY FROM THE RATEMAKING ORDINANCES OF THE CITY OF EL PASO AND THE TOWNS OF VINTON, CLINT AND ANTHONY

DOCKET NO. 6350

January 31, 1986
Rehearing Denied March 5, 1986

Examiner's Report adopted with modifications. $14,317,198 base rate revenue decrease granted, as opposed to utility's requested base rate revenue increase of $53,660,991.

[1] RATEMAKING - RATE BASE - ACCUMULATED DEPRECIATION

Commission reaffirmed propriety of increasing accumulated depreciation by one-half of any permitted increase in depreciation expense, on theory that, absent the adjustment, test year end plant will be depreciated throughout the rate year and net plant will decrease on the company's books yet the company will continue to earn a return on the investment at the same level as if it were not being reduced by depreciation expense on a monthly basis.

[2] RATEMAKING - RATE BASE - CWIP & AFUDC

Given EPEC's failure to demonstrate that its continued involvement in PVNGS at a 15.8 percent level was prudent, and given the absence of any direct means to quantify EPEC's decisional imprudence, Commission utilized the estimated excess capacity attributable to PVNGS as a surrogate quantification of the amount of CWIP excludable under the prudence and efficiency standard.

[3] RATEMAKING - RATE BASE

EPEC permitted to defer costs currently being capitalized and the depreciation which would be recorded for PVNGS Unit No. 1, effective with the commerical in-service date of the unit, and to recover those deferred costs at the time the unit is placed in-service for ratemaking purposes, subject to Commission's right to consider at that time the reasonableness and prudence of those deferred expenses.

[4] RATEMAKING - COST OF SERVICE - CAPITAL STRUCTURE

Common equity associated with utility's transactions with its unregulated subsidiary deleted from utility's capital structure.

[5] RATEMAKING - RATE DESIGN - ELECTRIC - RATE DIFFERENTIALS

Economic recovery rider (ERR) available only to certain industrial classes does not unreasonably discriminate if evidence demonstrates that: (1) utility system and general body of ratepayers are benefitted by maintaining existing industrial load; (2) such load is in serious danger of substantially shrinking or disappearing altogether; (3) unusually high industrial electric rates are major economic factor which elevate possibility of serious load loss; and (4) approval of ERR increases probability that needed industrial load will continue operating on utility's system.

[6] RATEMAKING - RATE BASE - USED AND USEFUL PROPERTY - CANCELLED PLANT

Commission rejected utility's request for inclusion of expenses associated with cancelled generation project.

[7] RATEMAKING - COST OF SERVICE - TAXES

Commission reduced cost of service by amount of tax savings which utility obtained from filing consolidated tax return with unregulated subsidiary.

[8] RATEMAKING - RATE BASE - WORKING CAPITAL

Although utility found to have a negative cash working capital requirement, the Commission declined to impute a zero working cash allowance since utility had not demonstrated that its working capital requirement was the result of good cash management techniques.

[9] RATEMAKING - COST OF SERVICE - ACCOUNTING ADJUSTMENTS

All EEI and AIF dues excluded from cost of service due to utility's inability to prove that no portions of such dues were related to legislative advocacy.

[10] RATEMAKING - COST OF SERVICE - ACCOUNTING ADJUSTMENTS

Charitable contributions excluded from cost of service given current financial condition of utility and fact that such expenses are not necessary to provide service.

DOCKET NO. 6350

APPLICATION OF EL PASO ELECTRIC COMPANY FOR AUTHORITY TO CHANGE RATES APPEAL OF EL PASO ELECTRIC COMPANY FROM THE RATEMAKING ORDINANCES OF THE CITY OF EL PASO AND THE TOWNS OF VINTON, CLINT AND ANTHONY	§	PUBLIC UTILITY COMMISSION OF TEXAS

TABLE OF CONTENTS TO EXAMINER'S REPORT

Subject | Page

Subject | Page

Subject Page

DOCKET NO. 6350

APPLICATION OF EL PASO ELECTRIC COMPANY FOR AUTHORITY TO CHANGE RATES	§	PUBLIC UTILITY COMMISSION
	§	OF TEXAS
APPEAL OF EL PASO ELECTRIC COMPANY FROM THE RATEMAKING ORDINANCES OF THE CITY OF EL PASO AND THE TOWNS OF VINTON, CLINT, AND ANTHONY	§	

EXAMINER'S REPORT

I. Procedural History

On June 24, 1985, El Paso Electric Company (EPEC or the Company) filed a statement of intent to increase its rates within the unincorporated areas of El Paso, Culberson and Hudspeth Counties served by it, in accordance with Section 43(a) of the Public Utility Regulatory Act (PURA or the Act), Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. 1985). Through its rate filing, EPEC is seeking to increase its rates by $61,222,878 or 25 percent over total Texas adjusted test year revenues, assuming Commission recognition of Palo Verde Nuclear Generating Station (PVNGS or Palo Verde) Unit One as a commercially operating unit. Alternatively, should Palo Verde Unit One be excluded from EPEC's plant in service, EPEC is seeking authorization to increase its rates by $67,487,922 or 27.63 percent over total Texas adjusted test year revenues. All customers and classes of customers are affected by the proposed changes.

By examiner's Order dated June 27, 1985, EPEC's proposed rate increase was suspended for 150 days beyond the otherwise effective date of July 30, 1985, until December 27, 1985, pursuant to Section 43(d) of the Act. On July 16, 1985, at the first prehearing conference in this docket, EPEC orally extended the effective date of the proposed rate increase to August 6, 1985, and the examiner resuspended the effective date until January 3, 1986. By motion filed with the Commission on August 12, 1985, EPEC again extended the effective date of the proposed rate increase from August 6, 1985, to August 27, 1985, and the examiner accordingly resuspended the effective date, by Order dated August 13, 1985, for the full 150 day statutory suspension period, until January 24, 1986. On October 25, 1985, EPEC extended the effective date from August 27, 1985 to September 3, 1985, and by Order dated October 30, 1985, the effective date was again resuspended by the examiner for the full statutory period of suspension, until January 31, 1986.

As required by P.U.C. PROC. R. 21.22(b)(1), EPEC published a statement of intent in conspicuous form and place once each week for four consecutive weeks, prior to the effective date of the proposed change, in newspapers of general circulation in the counties in which it serves. EPEC provided publishers' affidavits to that effect. EPEC also notified affected municipalities and its customers individually of the proposed change, as required by P.U.C. PROC. R. 21.22(b)(2) and (3).

The following parties have been granted intervenor status in this docket:

W. Silver, Inc. (W. Silver);
City of El Paso (El Paso or the City);
El Paso Iron & Metal Co. (EPIM);
Border Steel Rolling Mills, Inc. (Border Steel);
Texas Industrial Energy Consumers (TIEC);
United States Department of Defense (DOD);
Texas-New Mexico Power Company (TNP);
ASARCO, Inc. (ASARCO);
Office of Public Utility Counsel (OPC);
United Steelworkers of America (USWA);
El Paso County (the County);
R. Brian Jones

Pursuant to Sections 17 and 26(a) of the Act, EPEC appealed the ratemaking ordinances of the City of El Paso, the Town of Vinton, the Town of Clint and the the Town of Anthony by filing a petition for review on November 22, 1985. On November 19, 1985, the Town of Van Horn requested that the public hearings before the Commission in this docket be considered for all purposes as the public hearings of the Town of Van Horn on EPEC's Petition for Review.

By Order dated December 10, 1985, the examiner consolidated without objection EPEC's appeals of the ratemaking ordinances of the City of El Paso, the Town of Vinton, the Town of Clint, and the Town of Anthony with this docket.

A first prehearing conference was conducted on July 16, 1985. Representatives from the following parties made appearance: EPEC, El Paso, ASARCO, EPIM, Border Steel, DOD, TIEC, OPC and the Commission's General Counsel. At that prehearing conference and by subsequent order a procedural schedule and hearing guidelines were established.

The procedural schedule adopted at the first prehearing conference was subsequently modified by examiner's Orders dated August 13 and August 27, 1985, providing the parties with additional time to engage in discovery and the preparation of prefiled testimony, as a consequence of EPEC's extensions of the effective date of the proposed rate increase. By Order dated October 30, 1985, the commencement of the hearing on the merits was postponed until November 4, 1985, in order to provide the parties additional time for settlement negotiations.

A second prehearing conference was convened on October 14, 1985, for the purpose of resolving a discovery dispute between EPEC and TIEC. Appearances were made by Ms. Patrice Johnson on behalf of TIEC, Mr. Michael McQueen on behalf of EPEC, Ms. Jeanine Lehman on behalf of OPC and Mr. Alfred Herrera on behalf of the Commission's General Counsel. After taking oral argument from the parties regarding the merits of TIEC's motion to compel, the examiner orally and by subsequent order denied TIEC's motion to compel, on the basis that the requested information was not in existence and therefore was not discoverable under the discovery standard set forth in Section 14a(a) of the Administrative Procedure and Texas Register Act (APTRA), Tex. Rev. Civ. Stat. Ann. art. 6252-13a (Vernon Supp. 1985).

The hearing on the merits was convened on November 4, 1985, with the undersigned examiner presiding. Appearances were made at the hearing on the merits by Mr. David Wiggs, Mr. Mike McQueen and Mr. Eddie Rodriguez on behalf of EPEC, Ms. Martha Terry on behalf of W. Silver, Inc., Ms. Nanette Williams and Mr. Norman Gordon on behalf of the City, Mr. Michael Ginnings on behalf of Border Steel and EPIM, Ms. Patrice Johnson on behalf of TIEC, Mr. David McCormick on behalf of DOD, Mr. Michael Shirley on behalf of TNP, Mr. Alan Holman on behalf of ASARCO, Mr. Jim Boyle on behalf of OPC, and Mr. Alfred Herrera on behalf of the Commission staff. The County of El Paso, USWA and R. Brian Jones failed to make appearance or otherwise participate in the hearing on the merits. The hearing on the merits of the revenue deficiency phase of the docket was completed on November 22, 1985.

On November 21, 1985, the parties filed a written stipulation with the Commission resolving most cost allocation and rate design issues. Consequently a hearing was not conducted in the rate design phase of this docket. The stipulation was executed by all parties to the docket, with the exception of El Paso County, USWA and R. Brian Jones. At the time the stipulation was presented to the examiner, the examiner orally ruled that all parties who failed to make appearance or otherwise participate in the hearing waived their right to approve or disapprove the terms of the stipulation. The examiner has fully accepted the stipulated settlement of cost allocation and rate design issues.

On October 25, 1985, the City of El Paso filed a Motion to Dismiss and Alternative Objection to Palo Verde Filing which was taken up by the examiner on November 4, 1985, the first day of hearing. On November 5, 1985, the examiner denied the motion to dismiss EPEC's Palo Verde plant in service filing. On that same date the City, OPC, and DOD filed a joint interim appeal of the examiner's denial of the motion.

On November 6, 1985, after taking oral argument from the parties, the Commission granted the joint interim appeal and dismissed EPEC's Palo Verde plant in service filing. A written order to the same effect, containing findings of fact and conclusion of law, was issued by the Commission on November 18, 1985. As a consequence of the dismissal of the plant in service filing, the hearing on the merits in this docket was limited to EPEC's alternative construction work in progress (CWIP) filing.

On November 18, 1985, EPEC filed a motion for rehearing regarding the Commission's dismissal of the Palo Verde plant in service filing. The motion for rehearing was denied by the Commission on December 18, 1985.

On November 13, 1985, EPEC filed a Motion For Leave to File Amended Petition in order to include language in the petition for rate increase reflecting that EPEC is seeking to defer depreciation and costs currently being capitalized which would otherwise necessarily be recorded for Palo Verde Unit One on its commercial in-service date. On November 20, 1985, the examiner granted EPEC's motion and accepted EPEC's amended petition for a rate increase.

In the course of the proceeding, a number of motions have been filed on which the examiner has taken no action. To the extent to which no specific response has been made by the examiner to those motions, the examiner deems the motions to have been denied for want of merit.

II. Jurisdiction

The Commission has jurisdiction over this application and the consolidated appeals by virtue of Sections 16, 17(d) and (e), 37 and 43 of the Act.

III. Description of the Company

Electric energy in West Texas and South Central New Mexico is supplied by EPEC, which is headquartered in El Paso, the fourth largest city in the State of Texas.

Incorporated under the laws of the State of Texas in 1901, EPEC is an investor-owned electric utility engaged in the generation, purchase, transmission, distribution and sale of electricity in a two-state service area of approximately 10,000 square miles. EPEC supplies electric service to more than 200,000 customers in West Texas and South Central New Mexico. At the end of the 1984 calendar year, 163,434 customers in Texas and 42,469 in New Mexico received their electricity from EPEC.

Its service area extends 110 miles from the City of El Paso northwesterly to the Caballo Dam in New Mexico, and 120 miles southeasterly to Van Horn, Texas. The area includes the Cities of El Paso, Van Horn, Anthony and Clint in Texas; and Las Cruces, Hatch and the White Sands Missile Range in New Mexico. EPEC employs 1,067 persons in Texas and New Mexico, and operates in the Cities of Las Cruces and Sunland Park, New Mexico, and El Paso under franchise agreements that expire in the year 1993, 2009 and 2001, respectively.

In 1984, EPEC's fuel mix to generate electricity was 76 percent natural gas, 23 percent coal and one percent oil. Approximately 93 percent of fuel costs incurred through local generation went for natural gas, seven percent for coal and less than one percent for oil. 42.7 percent of all power sold by EPEC was purchased from other utilities.

EPEC and TNP are two-thirds and one-thirds participants, respectively, in an interconnection project known as the "Eastern Interconnection Project." The project consists of a 125-mile 345 KV transmission line from the White Sands Missile Range in New Mexico, to Artesia, New Mexico, and a back-to-back direct current terminal at Artesia. The "Eastern Interconnection Project" was placed in service on September 21, 1984.

EPEC owns a 15.8 percent undivided interest (200 megawatts from each of the three units) in the Palo Verde Nuclear Generating Station (PVNGS), located 50 miles west of Phoenix, Arizona. PVNGS is a joint effort of several Southwestern U.S. utilities to build the 3,810 megawatt nuclear generating station. Arizona Public Service Company is the operating agent for the project.

EPEC owns and operates or has interest in four electric generating stations, three of which are in the El Paso area. The Company owns a 7 percent undivided interest in two units at the Four Corners Generating Station near Farmington, New Mexico. The Company has a total net generating capacity of 989 megawatts.

IV. Quality of Service

The Commission staff is the only party to this proceeding which presented a quality of service witness. Mr. Paul Irish, a Consumer Analyst with the Commission's Consumer Affairs Office, testified regarding customer complaints against EPEC received by the Commission during the January 1, 1984 to December 31, 1984, test year.

According to Mr. Irish, the Commission received 115 complaints from 110 individual complainants concerning some aspect of service provided by EPEC during the test year, as well as three rate protest petitions signed by a total of 81 customers. Of the 115 individual complaints received, 87 were rate change protests.

Mr. Irish testified that of the remaining non-rate change related complaints, 22 were forwarded to EPEC for its investigation and response. It appears that the bulk of those complaints involved billing matters. EPEC was found by the Commission's Consumer Affairs Office to be at fault in four of the complaints and not at fault in 16 of the complaints. Fault could not be determined in the remaining two complaints. According to Mr. Irish, each of the responses from EPEC was adequate in its compliance with PURA and Commission rules.

Mr. Irish testified that EPEC makes information about complaint procedures and other customer services available to its customers both verbally and in writing through the Texas Residential Customer Handbook and Your Rights as a Customer publications, which are available both in English and in Spanish. After review of the customer service procedures of EPEC, Mr. Irish has found the Company's overall performance to be adequate. Mr. Irish has however recommended that EPEC establish a mechanism for tracking the number and types of complaints the Company receives, in order to provide indicators of customer satisfaction or dissatisfaction with EPEC's customer service operations. The examiner concurs in this recommendation.

Based upon Mr. Irish's testimony, the examiner concludes that EPEC's quality of service is adequate and that the quality of EPEC's service is not such that it should be considered either favorably or adversely in fixing a reasonable return on invested capital, as permitted by Section 39(b) of the Act. Reviewing the complaint summary sponsored by Mr. Irish, it is apparent that EPEC's customers are concerned not so much with the quality of service but with the cost of service provided by EPEC.

V. Conservation and Load Management

P.U.C. SUBST. R. 23.22 requires in major rate change proceedings that a utility include a copy of its most recent energy efficiency plan in its filing and that testimony be presented regarding the extent to which the goals of the utility's energy efficiency plan have been reached, the status of all energy efficiency programs and studies being undertaken, the costs expended and benefits achieved to date, and the extent to which the utility's achievements through its energy efficiency plan have offset the need for new generating facilities or permitted the utility to reduce reliance upon less efficient generation facilities.

The rule provides that a utility may be permitted to recover part or all of its expenses associated with energy efficiency as part of the utility's cost of service, that capitalization or other treatment allowing a return on conservation expenditures may be permitted and that rate of return or return on equity may be adjusted as a consequence of the utility's energy efficiency activities.

In addition to the rather comprehensive provisions of P.U.C. SUBST. R. 23.22, Section 39(b) of the Act provides that in fixing a reasonable return on invested capital, the regulatory authority shall consider the efforts and achievements of the utility in the conservation of resources.

In support of the Company's energy conservation efforts and its current energy efficiency plan, EPEC presented the testimony of Mr. Michael C. Conley, Manager of EPEC's newly created Energy Management Division. The only other witness who testified on the subject was Ms. Carol Biedrzycki, a Research Associate with the Commission's Energy Efficiency Division. After review of the relevant prefiled testimony, exhibits and cross-examination, the examiner concludes that, although EPEC has devoted much more time and money on this subject than has previously been the case, EPEC's energy efficiency plan and its conservation efforts in general are woefully lacking.

As reflected on Schedule 2 of Ms. Biedrzycki's testimony, EPEC spent only $69,381 on conservation and load management programs in calendar year 1984 (mainly for federally mandated RCS audits) but is contemplating spending approximately ten times that amount through calendar year 1985. As indicated by Mr. Conley on cross-examination, 8.8 full time equivalent professional or non-clerical persons have been allotted to EPEC's energy efficiency program, not including Mr. Conley, with budgeted salaries of $20,000 to $30,000 each. All of those individuals have been drawn from other divisions of EPEC and retrained as necessary, with the exception of Mr. Conley who had previously been employed by a utility in Missouri.

Given the personnel and budget allotted to EPEC's Energy Management Division, one would expect EPEC to have some very solid programs in place and positive benefits to report. By and large, the record reflects that that is not the case. The examiner has found Ms. Biedrzycki's criticism of EPEC's energy efficiency programs very convincing. Ms. Biedrzycki notes in her testimony that EPEC's energy efficiency plan fails to establish firm load objectives, to establish criteria for identifying appropriate alternatives or to present a supportable methodology for conservation and load management program selection. Further, both the original and updated plan fail to identify and evaluate energy efficiency alternatives.

As brought out on cross-examination of Mr. Conley, the Company's energy efficiency plan does not contain any load modification or load shifting objectives. Also, 60 to 70 percent of the energy management budget is devoted to residential programs although EPEC believes that the greatest opportunities for conservation and for energy efficiency development lie with commercial and industrial customers.

As to programs selected by EPEC, application of benefit/cost analysis to the programs included in the 1984 plan raises concerns about the suitability of these programs. As pointed out by Ms. Biedrzycki:

> Although the results of benefit/cost analysis should not be the last word on the suitability of a program, the results of EPEC's financial analysis of programs chosen for implementation certainly seems woeful. As shown in Schedule 1, the benefit/cost ratios for all the programs are very low for the non-participant and the utility. The High Efficiency Appliance and Demonstration Program has a negative benefit/cost ratio even for the participant.

The examiner does not intend to address the merits of each of EPEC's current energy efficiency programs. However, it is useful to mention two of them for illustrative purposes.

Under the Company's Home Builder Program, one of the stated purposes of the program is, "to provide the homeowner with information about the more efficient, comfortable and quieter advantages of electric living." This implies to the examiner that the Company is promoting, within the context of energy efficiency, the use of electricity over other forms of energy. The rebates offered under the Water Heater Program seem to confirm this. Under that program, EPEC will pay a customer $40.00 for the replacement of an existing electric water heater with a high efficiency electric water heater. But, if the customer has non-electric water heating, EPEC will pay the customer $125.00 for the purchase and installation of an energy efficient electric water heater. As pointed out by counsel for the City on cross-examination of Mr. Conley, the difference between the two rebates would encourage a person who has a gas water heater to switch to an electric water heater if he is in the market for a water heater. Mr. Conley testified that the rebate differential is attributable to a wiring allowance for the installation of the wiring for an electric water heater. In the examiner's opinion, the cause of the differential is irrelevant. The effect of the differential would clearly seem to encourage a customer to replace gas water heating with electric water heating, thus increasing the customer's level of electrical consumption. This is hardly a legitimate energy efficiency goal, especially when one considers that gas is a more cost effective fuel for water heating than is electricity.

The Company's response to criticism of its energy efficiency plan and energy efficiency programs is that P.U.C. SUBST. R. 23.22 was adopted quite recently and the Company has therefore had little time before filing this rate case to get its energy efficiency plans and programs in place. The examiner recognizes that that is in fact the case. However, that fact does not in any way transform an inadequate energy efficiency plan into an adequate one or a bad program into a good one. The Company in several instances has indicated that the next plan it files will contain a number of improvements. The examiner certainly hopes so because the current plan and programs in place suggest that although EPEC is going through the motions, it is not seriously attempting to achieve legitimate energy conservation goals.

Ms. Biedrzycki has recommended that the Commission strongly caution EPEC to scrutinize its current and proposed programs to properly identify and document expected impacts on the utility system and its customers for use in future proceedings. However, because this is the first time that EPEC's energy efficiency plan has been formally reviewed, Ms. Biedrzycki also recommends that EPEC be given the opportunity to comply with P.U.C. SUBST. R. 23.22 before negative consequences to EPEC in terms of its rate requests are recommended. The examiner fully concurs with Ms. Biedrzycki's position and recommends that the Commission give no consideration to EPEC's conservation and load management activities in setting a reasonable rate of return. However, absent improvement in this area, it may be appropriate to consider a rate of return penalty in EPEC's next rate case.

VI. Invested Capital

EPEC proposed invested capital of $1,127,876,274 in this case, composed of the following elements:

Plant in Service	$ 458,813,732
Less Accumulated Depreciation	(129,198,667)
Net Plant	329,615,065
Construction Work in Progress	883,279,029
Working Cash Allowance	6,063,018
Materials and Supplies	5,019,548
Prepayments	3,186,317
Fuel Inventory	83,358
Deferred Taxes	(94,553,035)
Pre 1971 Investment Tax Credits	(757,940)
Customer Deposits	(2,966,146)
Injuries and Damages Reserve	(100,000)
Customer Advances for Construction	(992,940)
Total Invested Capital	$1,127,876,274

A. Net Plant

1. Plant in Service

EPEC proposed a total company original cost of plant in service amount of $458,813,732, representing the per book plant in service as of the end of the test year. The only party which challenged EPEC's plant in service number was the City of El Paso. City witness Thomas C. DeWard proposed two adjustments which if accepted would reduce EPEC's total company original cost of plant in service amount by $19,082,131 for a total of $439,731,601. A discussion of each adjustment follows.

a. Transfer of Palo Verde transmission line to CWIP. Mr. DeWard has proposed that the Palo Verde transmission line be removed from plant in service and transferred to CWIP on the basis that the transmission line is directly tied to PVNGS and PVNGS is not yet in service. EPEC's position is that the line is properly classified as plant in service because the line was carrying power and closed to the books during the test year. The Palo Verde transmission line has been utilized by EPEC to deliver start-up and construction power to PVNGS since December of 1984. Additionally, the line is utilized by EPEC for its firm sales to Imperial Irrigation District (IID) and economy sales to San Diego Gas & Electric, City of Riverside and Southern California Edison in California. Additionally, through cross-examination of Mr. DeWard EPEC has intimated that the line is also used by EPEC to obtain purchased power, although there is no evidence in the record to substantiate that intimation.

After review of the very slim evidence of record pertaining to this issue, the examiner is of the opinion that the transmission line is probably best treated as a part and parcel of PVNGS and therefore most appropriately treated as CWIP rather than plant in service. As discussed by Mr. DeWard, the supply of construction and start-up power to PVNGS prior to its in-service date is essentially a function relating to the construction phase of PVNGS.

Additionally, as pointed out by Mr. DeWard, the use of the line for off system sales benefits EPEC as a whole although the benefit does not flow to the Texas jurisdictional ratepayer, since the sales presumably are not considered Texas jurisdictional sales. Use of the line for economy purchases by EPEC is a strong argument favoring inclusion of the line in plant in service prior to the in-service date of PVNGS, but as discussed previously, there is no evidence of record reflecting that the line is in fact used for such purchases. Even if the use of the line to make sales to IID and other western utilities was considered to be a solid basis for inclusion of the line in plant in service at this time, a question would necessarily arise as to whether the entire cost of the line should presently be included in plant in service, given that the line is surely underutilized pending placement of PVNGS in service. Until PVNGS is in service, one cannot say with certainty that the Palo Verde transmission line will be fully used and useful.

For the above reasons, the examiner recommends that Mr. DeWard's \$18,382,131 downward adjustment to plant in service attributable to transfer of the line costs from plant in service to CWIP be approved. However, in making this recommendation, the examiner recognizes that any booked depreciation as well as operations and maintenance expense and property taxes associated with the line must be reversed out and capitalized pending classification of the line as plant in service.

b. Removal of penalties associated with SPS transmission line. It appears that, due to EPEC's failure to meet construction deadlines in completing the SPS eastern interconnection transmission line, EPEC was required to pay \$700,000 in penalties. EPEC has included those penalties in the total cost of the transmission line which EPEC is requesting be included in plant in service. Mr. DeWard has proposed that the penalties paid by EPEC be deleted from plant in service on the basis that penalties do not constitute used and useful assets. According to Mr. DeWard, penalties incurred in the construction of the SPS transmission line should be charged directly to the shareholder and should not impact rates. The examiner fully concurs with Mr. DeWard on this matter. EPEC takes the position that one should not question whether penalties are used and useful, but rather, whether the total cost of the line, including penalties paid, is reasonable. The examiner finds this argument to be meritless. A penalty is the forfeiture of money to which an individual subjects himself by agreement in case of nonfulfillment of certain stipulations. A prudent individual insures that he is capable of fulfilling any agreement he enters into and then takes such steps as are necessary to fulfill that agreement. EPEC's actions in failing to avoid the penalty, assuming it was avoidable, or in agreeing to the penalty provisions of the Interconnection Agreement, if the penalty was not avoidable, were in the examiner's opinion, imprudent. The examiner notes that EPEC witness William Johnson fails to address the penalties in his prefiled testimony. If the penalties were totally unavoidable by EPEC, the Company has failed to demonstrate that that is the case. EPEC cannot reasonably expect the ratepayer to bear the consequences of EPEC's failure to timely fulfill its obligations to SPS. The costs of mismanagement should be borne by the stockholder rather than the ratepayer, since the stockholder selects the management.

c. Summary. Based upon the foregoing discussion, the examiner finds that EPEC's requested total company plant in service figure of $458,813,732 should be reduced by a total of $19,082,131 for a recommended total company plant in service figure of $439,731,601.

2. Accumulated Depreciation and Amortization

[1] EPEC proposed that accumulated depreciation and amortization in the amount of $129,198,667 be deducted from original cost of plant in service. As shown on Schedule D-1 of the Rate Filing Package, EPEC's accumulated depreciation and amortization balance as of the end of the test year was $127,181,197. This proposed $2,017,470 increase to accumulated depreciation and amortization represents one-half of EPEC's proposed increase to depreciation expense. Similarly, City witness DeWard has proposed a $688,070 decrease to EPEC's requested accumulated depreciation and amortization number, representing one-half of the depreciation expense adjustment proposed by the City in this docket. Both EPEC and the City rely upon Commission precedent (see, Docket No. 5779, Application of Houston Lighting and Power Company for a Rate Increase, unpublished), in support of the propriety of this type of adjustment which is commonly referred to as the "one-half convention." The theory behind the adjustment is that, since test year end plant will be depreciated throughout the period rates will be in effect, accumulated depreciation increases and net plant decreases on the Company's books, although the Company continues to earn a return on the investment at the same level as if it were not being reduced by depreciation on a monthly basis. Therefore, to prevent an over or under collection of return, an adjustment should be made to recognize that accumulated depreciation is in fact increasing. Assuming that a utility will likely seek rate relief each year, one-half of the permitted increase or decrease in depreciation expense is factored into test year-end accumulated depreciation.

The Commission staff, through accounting witness Janet Simpson, has contested the propriety of the one-half convention and has proposed an adjustment to EPEC's accumulated depreciation and amortization number to reverse EPEC's adjustment. According to Ms. Simpson, the adjustment is not theoretically sound from an accounting or ratemaking point of view. Ms. Simpson believes that it is inappropriate to isolate one component of rate base and argues that the adjustment will cause an over or under recovery. According to Ms. Simpson, consistency requires that if this adjustment is made, pro forma adjustments for expected changes must be made to all other components of invested capital.

In the examiner's opinion, the one-half convention is fully supportable from a theoretical standpoint, and use of the adjustment without the additional entry of pro forma adjustments to all other invested capital components does not constitute an egregious inconsistency. Further, the examiner believes that the adjustment is mandated by prior Commission precedent. Therefore, the examiner recommends that Ms. Simpson's proposed adjustment to reverse EPEC's one-half convention adjustment be rejected.

Application of the one-half convention to the examiner's recommended depreciation expense results in an increase of $1,371,792 to EPEC's test year depreciation and amortization balance, resulting in a $645,678 decrease in EPEC's requested depreciation and amortization balance. The examiner finds EPEC to have a total depreciation and amortization balance of $128,552,989.

3. Net Plant

The examiner proposes net plant in service of $311,178,612 computed as follows:

Plant in Service	$ 439,731,601
Accumulated Depreciation	(128,552,989)
Net Plant	$ 311,178,612

B. Construction Work in Progress (CWIP)

As of test year end, EPEC had adjusted booked CWIP totaling $1,089,561,822. Of this amount, EPEC has indicated on Schedule B of the Rate Filing Package that $1,080,133,745 is attributable to the Palo Verde project and $9,428,078 is non-Palo Verde related CWIP.

Of the total, EPEC has requested inclusion of $873,850,951 or approximately 80 percent of Palo Verde CWIP and $9,428,078 or 100 percent of non-Palo Verde CWIP, in rate base for purposes of maintaining EPEC's financial integrity. The aggregate amount of CWIP requested totals $883,279,029.

In Docket No. 5700, EPEC's last general rate case, the Company was granted a total CWIP level of $512,429,620 representing 50 percent of EPEC's booked CWIP related to Palo Verde and 100 percent of EPEC's non-Palo Verde related CWIP. Therefore, EPEC is in this docket seeking an increase of $370,849,409 over the level of CWIP included in EPEC's total invested capital in Docket No. 5700.

The only parties to this proceeding which prefiled testimony concerning CWIP, other than EPEC, are the City and the Commission staff. The City has recommended that EPEC be permitted to include as invested capital no more than 50 percent of EPEC's test year end CWIP. The Commission staff has recommended inclusion of 60 percent of EPEC's test year end CWIP.

The allowance of return on CWIP is by far the most important issue to be decided in this case, due to the substantial dollar impact upon both the Company and the Company's ratepayers occasioned by the inclusion of various levels of CWIP in the Company's rate base. Before discussing the evidence as it relates to this issue, it is necessary to first review the legal standard applicable to this issue which arises from the Act, the Commission's substantive rules and prior Commission precedent.

Section 41(a) of the Act sets forth the statutory test to be applied in determining the amount of CWIP to be allowed in rate base, as follows:

> (a) Invested Capital. Utility rates shall be based upon the original cost of property used by and useful to the public utility in providing service including construction work in progress at cost as recorded on the books of the utility. 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. . . .

P.U.C. SUBST. R. 23.21(c)(2)(D), enacted pursuant to the Commission's general rulemaking authority under Section 16 of the Act, implements the statutory mandate of Section 41(a) of the Act, as follows:

> (D) construction work in progress. The inclusion of construction work in progress in 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 circumstances, the Commission will include construction work in progress in rate base to the extent that the utility has proven that:
> (i) the inclusion is necessary to the financial integrity of the utility; 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.

As emphasized by the examiners in Docket No. 5779, both of the tests set out in P.U.C. SUBST. R. 23.21(c)(2)(D) must be met before any CWIP can be included in a utility's rate base. Additionally, as discussed by the examiners in Docket No. 5700 and Docket No. 5779, a quantification of allowable CWIP must be made for each of the two tests set out in the rule, and only the lower of the two quantifications can be included as an element of the utility's total invested capital.

It is extremely important to note that P.U.C. SUBST. R. 23.21(c)(2)(D) places the burden of proof pertaining to both threshhold CWIP tests squarely upon the utility and not upon any other party to this rate proceeding. With regard to the prudency test, notwithstanding the clear language of P.U.C. SUBST. R. 23.21(c)(2)(D) and the examiner's cogent discussion in Docket No. 5700 and 5779 of burden of proof under Section 41(a) of the Act, EPEC has argued in its brief that the United States Constitution mandates a presumption of prudence and reasonableness on the part of a utility and that the United States Supreme Court has found in several cases cited by EPEC that the Commission has the affirmative burden of showing the extent of inefficiency or imprudence of a utility by competent evidence supporting such a finding.

In the examiner's opinion, it is not necessary to engage in an extensive discussion of the case law cited by EPEC and the various ways in which those cases can be distinguished. The fact of the matter is that under traditional regulatory theory, ratepayers are responsible for none of the costs of utility plant until such time as that plant becomes used and useful. It is the investor, not the ratepayer, who under traditional theory must provide acquisition and construction capital prior to placement of plant in rate base. CWIP is an extraordinary form of rate relief which is not required under traditional regulatory theory and in fact is prohibited by law in certain jurisdictions. Therefore, to the extent that CWIP is permitted in Texas, it is permitted only on the terms and conditions set forth in the Act and the Commission's substantive rules. As neither the Act nor P.U.C. PROC. R. 23.21(c)(2)(D) establishes a presumption of prudence and efficiency on the part of a utility for purposes of establishing an appropriate CWIP level, EPEC's constitutional argument is wholly without merit. In Docket No. 5700, the examiners succinctly stated the limitations placed on CWIP by the Commission and the Legislature. A utility is not entitled to the inclusion of CWIP to the extent that: (1) it has not proved the necessity to its financial integrity; (2) there is a showing of imprudent or inefficient planning or management; or (3) doubt or uncertainty exists regarding whether or not a major project has been imprudently or inefficiently planned or managed and the utility fails to dispel this uncertainty by a showing of prudence and efficiency.

Before discussing the evidence in this case, it is appropriate at this time to address an additional argument set forth in EPEC's posthearing brief. EPEC argues that the requirement of proving efficient and prudent planning and management, which was added by amendment of Section 41(a) of the Act in 1983, relates solely to the planning and management of construction activities on a project and that any questions regarding the relative efficacy of coal-fired generation versus nuclear power, the necessity for participation at the capacity level contemplated, and potential fuel savings are permanently resolved through the certification process. The Company asserts that if these issues are to be reviewed on an ongoing basis, the certification provisions and procedures set forth in the Act are meaningless. This issue was previously raised and very effectively put to rest by the examiners in Docket No. 5700. The examiner concurs in and fully adopts the following analysis contained in the Examiner's Report in Docket No. 5700:

. . . First, the granting of a CCN does not bind the Commission in any manner with regards to subsequent ratemaking treatment to be afforded the certificated facilities. A CCN for generating facilities is essentially a license which indicates that a need for additional capacity has been demonstrated and at the time of certification the proposed/certificated facilities appeared to be a reasonable means of meeting the additional capacity needs. However, the CCN is not a guarantee that the facilities will be included in rate base. For example, when such facilities are requested to be included in plant in service, the Commission has the authority to review, not only whether or not the plant is used and useful but also, whether or not any portion of the costs of the project were unjustly or improperly incurred. If unwarranted costs are determined, such costs are to be excluded from the total cost of the plant. (See Section 38 of the Act which states in pertinent part that "It shall be the duty of the regulatory authority to insure that every rate made, demanded, or received by any public utility. . . shall be just and reasonable"; and Section 41(c)(3)(D) which states in pertinent part that ". . .The regulatory authority shall not consider for ratemaking purposes the following expenses. . . any expenditure found by the regulatory authority to be unreasonable, unnecessary, or not in the public interest. . .") The same is true for determining the amount of CWIP to be included in rate base; especially in view of the fact that CWIP is an exceptional form of rate relief not to be readily allowed, as previously discussed.

Second, a CCN is not equivalent to the receipt of unconditional authority to proceed with a project with cost, for example, as no object. Rather, as pointed out by OPC and the general counsel in their respective briefs, planning for a major project occurs on an ongoing basis; and, the examiners would note, does not end with the issuance of a CCN. A utility is under a continuing obligation to assess its commitment to a specific construction project. This position was expressed by the examiner (and adopted by the Commission) in Docket No. 1981. Specifically, the report stated:

> The management of the Company must continue to monitor load growth in order to avoid either deficient or excessive capacity and must continue to search for cheaper sources of generation.

Staff Exhibit No. 14 at 3.

On page 5 of the report the examiner stated:

> Due to the enormous cost, the uncertainty involved in the various growth forecasts, and the uncertainty of construction cost forecasts, the examiner would recommend that EPEC's management be directed to continually look for alternatives to the Palo Verde project and keep the lines of communication open to potential buyers of Palo Verde generating capacity.

Finally, Finding of Fact No. 16 in that Examiner's Report reads:

> A reasonable return on invested capital of EPEC is 10.1 percent or $21,801,681 plus a capital transition allowance of $1,406,653 <u>to permit the Company sufficient time to evaluate its continued level of participation in the Palo Verde Nuclear Project.</u> (emphasis added)

Third, the review of the prudence and efficiency of management regarding the continuation of a project as adverse circumstances arise is not something that can be reviewed by the Commission at the time a CCN is issued.

Fourth, and finally, CWIP is not to be allowed for <u>any portion</u> of a project which has been imprudently or inefficiently planned or managed. Certificated projects are not excluded from this review. This means that the burden is on the company to maintain adequate records to show not only that its initial planning was prudent, but also that its ongoing planning and management was likewise prudent.

For the foregoing reasons the examiners do not believe the scope of the Commission's review herein of the requested allowance for CWIP is narrowed by the CCN previously granted.

EPEC has raised no new argument in this docket in derogation of the above analysis, the analysis is in this examiner's opinion correct, and it was adopted by the Commission without dissent in Docket No. 5700. Therefore, there is no need to further belabor the merits of EPEC's arguments on this point.

The discussion and analysis which follows focuses first upon the issue of inclusion of CWIP in EPEC's rate base for financial integrity purposes and second, the extent, if any, to which CWIP should be disallowed on the basis that EPEC has failed to demonstrate that PVNGS and EPEC's participation therein has been efficiently and prudently planned and managed.

1. Financial Integrity

EPEC has requested that $883,279,029 or approximately 80 percent of EPEC's total Company test year-end balance of CWIP be included in rate base as the minimum amount of CWIP necessary to maintain the Company's financial integrity. EPEC presented three witnesses who addressed financial integrity: Dr. Joel Berk, Mr. John McCall and Mr. B. E. Bostic. In addition to the Company witnesses, Mr. Basil L. Copeland, Jr. addressed financial integrity on behalf of the City, and Mr. Robert Reilley addressed the issue on behalf of the Commission staff.

Section 41(a) of the Act provides that CWIP 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. P.U.C. SUBST. R. 23.21(c)(2)(D) provides that exceptional circumstances must exist before CWIP can be included in rate base. As all parties to this proceeding have conceded that some level of CWIP must be included in EPEC's rate base in order to preserve the financial integrity of the utility it appears that there is no dispute that EPEC's current situation constitutes exceptional circumstances. However, all of the parties presenting financial integrity witnesses are in disagreement as to how much CWIP is necessary to maintain EPEC's financial integrity. The Commission staff has recommended inclusion of $653,641,094 or approximately 60 percent of EPEC's CWIP (total Company) in rate base. The City's position appears to be, based upon the testimony of the City's financial integrity witness, that EPEC should not be permitted to include any CWIP in rate base above that dollar amount permitted in Docket No. 5700.

a. Company position. Dr. Joel Berk testified on behalf of EPEC regarding the amount of CWIP that should be permitted in EPEC's rate base to maintain the Company's financial integrity. Dr. Berk's basic thesis is that the maintenance of EPEC's financial integrity requires that sufficient CWIP be included in rate base to enable EPEC to meet Standard & Poor's (S&P) benchmark financial ratios for an A bond rating. Thus, while Dr. Berk discussed a number of financial ratios which he felt were relevant to a determination of financial integrity, his analysis concentrated on S&P's three benchmark ratios, to wit: Fixed Charge Coverage (Before AFUDC), Net Cash Flow/Permanent Capital, and Debt/Capitalization.

Believing it appropriate to use future projections of financial ratios in evaluating financial integrity, on the basis that investors and analysts look to future expectations, Dr. Berk started his analysis with projected 1986 Income Statement data provided to him by EPEC, as opposed to adjusted test year data, and adjusted some items and made simplifying assumptions as he felt were necessary. Dr. Berk then developed a simulation program using a spread sheet personal computer package and performed simulations using six possible levels of CWIP in rate base, those being 0 percent, 20 percent, 40 percent 60 percent, 80 percent and 100 percent. The following chart reflects EPEC's 1984 S&P benchmark ratios, Dr. Berk's projected ratios at the 40 percent, 60 percent and 80 percent CWIP levels and S&P minimum requirements for a A bond rating:

	1984 EPEC	40% CWIP	60% CWIP	80% CWIP	S&P Minimum
Fixed Charge Coverage (B. AFUDC)	1.69X	1.50X	1.96X	2.42	2.5X
Net Cash Flow/Permanent Capital	.00	.01	.04	.06	.05
Debt/Capitalization	.48	.51	.51	.51	.52

Based upon the above projected financial ratios, Dr. Berk concludes that EPEC must include more than 80 percent of its test year end CWIP in rate base if EPEC is to have any possibility of regaining an A bond rating. EPEC's current S&P bond rating is BBB+.

Dr. Berk performed a number of sensitivity tests with regard to the projected Income Statement data and assumptions he used in performing his CWIP simulations and concluded that an 80 percent CWIP level is needed to improve EPEC's bond rating to an A level even if relatively large changes in individual items in the forecast are considered.

In addition to Dr. Berk's testimony, EPEC presented Mr. John McCall, Senior Vice-President of E. F. Hutton & Company, Inc., who testified concerning EPEC's financial integrity. Based upon his review of the same projected 1986 Income Statement data as were used by Dr. Berk, Mr. McCall testified that, to raise EPEC's net cash flow/permanent capital ratio above .05, EPEC would require

107 percent of its total test year CWIP balance in rate base and to raise EPEC Fixed Charge Coverage (B. AFUDC) to a level comparable to other S&P A rated companies, more than 107 percent of EPEC's test year-end CWIP balance would need to be included in rate base. Mr. McCall concluded on the basis of his rather cursory analysis that 100 percent of EPEC's total CWIP balance at test year-end should be included in EPEC's rate base, although that inclusion would not, in his opinion, generate the financial indicators necessary for EPEC to attain "financial integrity."

b. City position. Mr. Basil L. Copeland, Jr. testified on behalf of the City regarding the financial integrity test which must be satisfied as a prerequisite to the inclusion of CWIP in rate base. According to Mr. Copeland, financial integrity should be evaluated in terms of the ability of a utility to raise the capital necessary to fulfill its public service obligations. Mr. Copeland maintains that there is no direct relationship between financial ratios and financial integrity per se, and that comparison and analysis of financial ratios is appropriate only to the extent that those ratios have some bearing upon the utility's ability to raise capital.

Mr. Copeland testified there is no support for Dr. Berk's thesis that an A rating is necessary to preserve EPEC's financial integrity. Mr. Copeland contends that the demands of a large construction program make it almost impossible to preserve the financial ratios associated with an A bond rating, noting that many utilities have had their bonds downgraded to BBB or Baa during construction programs without serious questions being raised as to the financial validity of the enterprise.

According to Mr. Copeland, the ability to raise capital, rather than cash flow generated by operations, is the best measure of a company's liquidity, and based upon EPEC's financial condition as represented in EPEC's 1984 Form 10-K, Mr. Copeland concludes that there is no basis for questioning the soundness of EPEC's financial integrity. Mr. Copeland's bottom-line recommendation is that EPEC should not be permitted to include more than $331.9 million CWIP in rate base, which he indicates represents that amount granted in Docket No. 5700. Actually, in Docket No. 5700, EPEC was permitted $325,223,800 on a Texas retail basis, or $512,429,620, on a total Company basis. Mr. Copeland's cited figure of $331,900,000 is apparently taken from EPEC's Form 10-K. The CWIP level granted in Docket No. 5700 constitutes approximately 31 percent of EPEC's current total Company test year-end CWIP balance.

c. Staff position. Mr. Robert Reilley testified on behalf of the Commission staff regarding inclusion of CWIP in rate base for financial integrity purposes. Mr. Reilley performed two analyses of EPEC's financial integrity under various levels of CWIP inclusion utilizing a personal computer spread sheet model which he assembled for use in this docket. The first analysis was performed utilizing projected calendar year 1986 financial data. The second analysis utilized adjusted test year data. According to Mr. Reilley, although the Commission staff has in the past presented financial integrity analyses based solely upon an adjusted test year basis, he performed analyses on both an adjusted test year and a prospective basis because of the Commission's finding in Docket No. 5779 that it is appropriate to base a financial integrity analysis at least in part upon the period that rates set in a proceeding will be in effect to avoid immediate erosion of the indicators on which financial integrity is based. According to Mr. Reilley, pretax interest coverage without AFUDC, AFUDC as a percent of income available to common, internal cash generation as a percentage of capital expenditures, and cash flow coverage of common dividends, are the financial indicators which he believes are most critically affected by the inclusion or exclusion of CWIP. Therefore, Mr. Reilley concentrated upon the current mean financial indicator levels for the test year period experienced by both A and BBB rated electric utilities and a sample of similar utilities with nuclear construction programs currently underway. Mr. Reilley testified that if EPEC can improve its financial ratios to a level more consistent with his sample groups, it can maintain its financial integrity and continue to finance its construction programs with capital costs at a reasonable level. The following chart reflects the median 1984 financial indicators for EPEC and each of the sample groups Mr. Reilley used:

Indicators	EPEC	Utilities With Nuclear Construction	BBB Electric Utilities	A Electric Utilities
Pretax Interest Coverage w/o AFUDC	1.69X	2.10X	3.2X	3.0X
AFUDC as % of Income to Common	104.63%	69.5%	15.0%	72%
Internal Cash Generation as % of Capital Expenditure	(7.93)%	20.33%	51.56%	39.15%
Cash Flow Coverage of Dividends	.81X	1.4X	2.85X	1.60X

Based upon the above median 1984 financial indicators and consideration of EPEC's historical financial performance, Mr. Reilley proposed target indicator ranges for EPEC's financial indicators.

The following reflects Mr. Reilley's target range for each indicator and the results of his CWIP simulations at 50 percent, 60 percent and 80 percent levels using both adjusted test year and projected financial data:

<u>Pre-tax Interest Coverage</u>:

Target Range	1.8 to 2.5 Times Adjusted Test Year	Pro-Forma 1986
50% CWIP	1.87	1.65
60% CWIP	2.13	1.94
80% CWIP	2.66	2.54

AFUDC to Income for Common:

Target Range	75% to 85% Adjusted Test Year	Pro-Forma 1986
50% CWIP	86.81	99.32
60% CWIP	68.71	82.50
80% CWIP	31.55	54.50

Internal Cash Generation:

Target Range	30% to 50% Adjusted Test Year	Pro-Forma 1986
50% CWIP	14.98	25.80
60% CWIP	31.35	39.86
80% CWIP	64.07	68.00

Cash Flow Coverage of Common Dividends:

Target Range	1.5 to 2.5 Times Adjusted Test Year	Pro-Forma 1986
50% CWIP	1.36	1.77
60% CWIP	1.75	2.19
80% CWIP	2.13	2.61

According to Mr. Reilley, EPEC's financial situation is critical and without some stabilization EPEC's level of credit worthiness will likely become impaired. Mr. Reilley testified that it is necessary to improve EPEC's financial health not to any specific level based on median coverages for specific bond ratings, but rather to a level sufficient to stop further erosion of EPEC's financial health and begin a pattern of steady improvement. Mr. Reilley concludes that inclusion of $653,641,094 in rate base, or 60 percent of EPEC total Company test year end CWIP, will insure the maintenance of EPEC's financial integrity in 1986.

d. Company rebuttal. Mr. B. E. Bostic testified on behalf of EPEC on rebuttal concerning what he perceived to be the inadequacy of the parties' recommendations concerning appropriate CWIP levels. Mr. Bostic has taken the position that under the CWIP recommendations of either the City or the staff, EPEC will experience a financial disaster as seen from the following financial indicators:

	60%	50%	City
Earnings per Share	$0.20	$(0.32)	$(0.57)
Cash Generated ($000)	$(54,056)	$(76,073)	$(84,776)
Bank Borrowing Required ($000)	$(208,404)	$(230,421)	$(239,124)
Common Dividend Coverage	0.24 x	(0.18) x	(0.35) x
Pretax Interest Coverage (w/AFUDC)	1.53 x	1.34 x	1.24 x
Pretax Interest Coverage (wo/AFUDC)	0.79 x	0.55 x	0.46 x

Mr. Bostic's projected indicators are derived from the basic Income Statement data used by Dr. Berk and Mr. McCall, but with adjustments made to numerous variables by Mr. Bostic to reflect changed conditions. Mr. Bostic concludes from his analysis that a severe cash crisis will occur if the City or staff recommendations are adopted, resulting in the need for EPEC to finance inan extremely adverse environment. According to Mr. Bostic, EPEC's short-term lenders will not lend to EPEC and the availability of long-term capital will be doubtful. Further, the lack of cash resulting from an adverse rate decision will precipitate cutbacks in areas of personnel, service, construction and expenses which Mr. Bostic believes will have a negative effect upon the City, its economy and development, and the ratepayers and employees of EPEC.

e. Examiner's discussion and recommendation. The examiner believes that the size of EPEC's construction program, the fact that EPEC's bonds were downrated in 1984 and the fact that EPEC has a cash flow coverage of common dividends ratio of less than 1x constitute exceptional circumstances sufficient to allow inclusion of CWIP in rate base, within the intended meaning of Section 41(a) of the Act and P.U.C. SUBST. R. 23.21(c)(2)(D). As noted earlier, all parties agree that some level of CWIP should be included in rate base to maintain EPEC's financial integrity. The issue is how much CWIP is necessary.

Of the witnesses who testified on this issue, Mr. Reilley espoused the most persuasive and credible approach to evaluating financial integrity. Mr. McCall and Dr. Berk take an unreasonable approach in advocating inclusion of sufficient CWIP in rate base to permit EPEC to regain an A bond rating, especially in light of Mr. McCall's admission that EPEC could not obtain an A bond rating even if more CWIP were included than has been amassed to date by EPEC. Further, as pointed out by Mr. Copeland, the demands of a construction program as massive as that undertaken by EPEC make it exceedingly difficult to preserve financial ratios associated with an A rating during the construction phase.

On the other hand, Mr. Copeland takes an unreasonable position in advocating that so long as a utility can raise capital, its financial integrity is not impaired. Clearly, one must consider not only the continued ability to raise capital but also the cost that must be incurred to raise that capital. Once a utility's bonds drop below investment grade levels, the ability to market those bonds is impaired.

Mr. Copeland has made no evaluation of the effect of his CWIP recommendation on the future ability of EPEC to attract capital at reasonable rates, other than to note that, according to EPEC's 1984 Form 10-K, EPEC has borrowing capability in excess of $700 million under the provisions of its indentures and related articles of incorporation. The examiner notes that EPEC's borrowing capability does not equate to the ability to raise capital at reasonable costs. No assessment is made by Mr. Copeland as to whether his CWIP recommendation would create the possibility that EPEC's current bond rating could again be downgraded. In the examiner's opinion, financial ratios must be used to evaluate that possibility, yet Mr. Copeland has made no analysis of likely financial ratios which would be experienced by EPEC under his CWIP recommendation. Mr. Copeland's strictly historical analysis provides less insight into EPEC's likely financial condition in 1986 under the rates to be set in this docket than does the combination of the two approaches.

Mr. Reilley's approach recognizes that EPEC's financial integrity can be maintained by stopping the further deterioration of EPEC's financial ratios and taking steps necessary to start a trend toward steady improvement in those indicators. The examiner agrees with Mr. Reilley that it is unrealistic to attempt to regain an A bond rating for EPEC in this docket. As long as a trend toward steady improvement is apparent, EPEC's financial integrity is maintained. Mr. Reilley's use of both adjusted test year and projected data in his analyses is, in the examiner's opinion, especially useful in evaluating the effect of CWIP inclusion on EPEC's financial condition over the coming year. The target ranges selected by Mr. Reilley appear more than reasonable to the examiner and his recommended inclusion in rate base of 60 percent of EPEC's test year end CWIP appears to provide sufficient improvement in EPEC's critical financial indicators to amply insure that EPEC's financial integrity will be maintained during 1986.

EPEC has criticized Mr. Reilley's CWIP recommendation, alleging that 60 percent CWIP will not permit EPEC to obtain the financial indicator levels reflected in Mr. Reilley's testimony. As EPEC correctly points out, Mr. Reilley assumed for simulation purposes that EPEC would have available $51,168,000 in cash resulting from collection of depreciation expense, but as the staff is recommending that EPEC collect only $14,502,226 in depreciation expense, Mr. Reilley's estimate of cash which EPEC can generate internally is overestimated by $36,665,774. This causes Mr. Reilley's projected internal cash generation and cash flow coverage of common dividends indicators to be overstated. Mr. Reilley conceded on cross-examination that if additional internal cash could not be obtained in some other fashion, such as increased sales or operational efficiencies, the financial indicators which relate to internal cash generation would not be as favorable as he initially projected. It appears to the examiner that Mr. Reilley has suggested legitimate sources for EPEC to increase its internal cash generation, thereby compensating for Mr. Reilley's inclusion of excessive revenues attributable to depreciation in his estimate of EPEC's 1986 level of cash generated internally. However, should that not be possible, it appears that even with less internal cash generation, Mr. Reilley's, CWIP recommendation will generate financial indicators much improved over those obtained in 1984 as shown on Schedule XVI of Mr. Reilley's testimony and will provide a cash flow coverage of common dividends ratio in excess of 1x.

Therefore, the examiner maintains that, despite EPEC's criticism of Mr. Reilley's projected data, his analysis remains the most credible in the record, and should be adopted. As to Mr. Bostic's rebuttal testimony, Mr. Bostic does not provide sufficient data to verify the legitimacy of the financial indicators he projects. Further, counsel for the City developed on cross-examination that the data and assumptions used by Mr. Bostic were highly questionable. The examiner does not have sufficient faith in the credibility of Mr. Bostic's projections to place any reliance upon them.

The examiner finds that from a financial integrity standpoint, inclusion in rate base of CWIP in the amount of $653,641,094 is warranted and will insure the maintenance of EPEC's financial integrity in 1986.

2. PVNGS Prudence and Efficiency

EPEC and the City are the only parties which presented substantive testimony regarding the prudence and efficiency of EPEC's planning and management related to PVNGS. Although the staff did present Mr. Sam Skinner as a prudence witness, Mr. Skinner testified that he could not make any findings or conclusions on this issue because the four-state audit of PVNGS is still in its infancy. Mr. Skinner has recommended that the prudence issue not be addressed in this docket. Finding that the Act requires that this issue be addressed, the examiner has rejected Mr. Skinner's recommendation.

There are two essential aspects of this issue to be discussed; first, the prudence and efficiency of EPEC's planning and management pertaining to EPEC's initial and continuing decisions to participate in PVNGS, and second, the prudence and efficiency of the planning and management at the PVNGS project itself.

a. <u>Prudence and efficiency regarding EPEC's initial and continuing decisions to participate in PVNGS</u>.

(1) <u>Initial involvement in PVNGS</u>. In the examiner's opinion, the record in this docket does not support a finding that EPEC's initial decision to become involved with PVNGS was the result of prudent and efficient planning and management on the part of EPEC. Mr. York's testimony is threadbare on this issue, and based upon the evidence presented by Mr. York concerning EPEC's decision to participate in PVNGS, the examiner cannot conclude that that decision was predicated by the type of reasoned and careful analysis one would expect prudent management to undertake before committing a business to a financial venture of such magnitude as PVNGS.

According to Mr. York, after the Company, based upon EPEC's 1972 load forecast, perceived the need for additional capacity in the early 1980s, EPEC considered alternatives for additional capacity and narrowed the choice to coal or nuclear generation. There is virtually no evidence in the record documenting EPEC's evaluation of alternative forms of generation. According to Mr. York, EPEC favored nuclear generation because it would diversify EPEC's generating mix, which was then composed of coal, gas and oil fired generating facilities. One of the only pieces of documentation in the record regarding EPEC's preference for nuclear power to meet EPEC's perceived additional capacity needs is a three page report prepared by EPEC, which is attached to the prefiled testimony of City witness Johnson as Schedule 18. The report concludes that nuclear generation of the size of PVNGS is not inferior to other sources of generation, that coal-fired and nuclear generating plants are economically comparable, and that nuclear generation will provide diversity in generation. However, the report contains only cursory analysis and is based upon a number of undocumented cost assumptions.

According to Mr. York, upon learning of the intention of Arizona Public Service (APS) and Salt River Project (SRP) to construct PVNGS, EPEC began discussions with those companies in 1972 regarding the possibility of EPEC's participation in the project. Mr. York testified that in making its decision to participate, EPEC took into consideration discussions with the project owners, preliminary cost estimates made by EPEC concerning coal generation versus nuclear generation and review of a study provided by the project owners comparing different nuclear steam supply systems (NSSS). However, EPEC did not engage any outside consultants to perform an analysis of the advisability of participating in PVNGS, nor did Mr. York produce any evidence of any possible in-depth studies undertaken by EPEC.

City witness Ben Johnson testified that there were indications as early as 1971-72 of increased risks associated with construction of nuclear generating plant. For instance, Mr. Johnson cites Florida Power & Light's (FP&L) decision in 1972 to cancel a second nuclear plant it had proposed to build in 1971. The following passage which Mr. Johnson cities from FP&L's 1972 annual report is illuminating on the issue of growing difficulties within the nuclear industry:

> A major concern in our efforts to meet the increasing need for electricity is being able to build new plants on schedule and at the planned cost. A key factor is the delay by the red tape of regulatory bodies. Sometimes, as was the case this year, this tangle of delay is just too much. In July, we cancelled plans to build a second nuclear plant at Crystal River.

Although EPEC could not have been oblivious to growing regulatory difficulties within the nuclear industry, the record does not reflect that EPEC gave much if any consideration to the effect of nuclear regulation on the cost of nuclear projects when EPEC elected in 1973 to participate in PVNGS. Mr. York testified that at the time the decision was made to participate in PVNGS, the environment in the nuclear power industry was very positive. The examiner does not necessarily question that fact, but it appears to the examiner that EPEC's management should nonetheless have carefully considered all factors which could reasonably bear upon the merits of nuclear versus other types of generating plant at the time the decision to participate in Palo Verde was made. If they did so, the record in this case certainly does not prove it.

The examiners found in Docket No. 5700 that the initial decision to participate was not imprudent, based upon the record in that case. This examiner does not so find, based upon the record in this case. Although in Docket No. 5700, the examiners placed reliance upon the 1976 Theodore Barry & Associates (TBA) study by the examiners in finding no imprudence in EPEC's initial decision to participate in PVNGS, the examiner in the present docket does not find that study to show that EPEC's decision to participate in PVNGS was predicated by the type of reasoned and careful analysis one would expect prudent management to undertake before committing to a financial venture of such magnitude as PVNGS. Rather, the TBA study concludes that, as of the date of that study, EPEC's continued participation in PVNGS was appropriate. The Company has failed to meet its burden of proof on this issue.

(2) Continued participation in PVNGS. In the examiner's opinion, the EPEC has failed to demonstrate that the Company's continued involvement in PVNGS at a 15.8 percent ownership level was prudent. As in the case of Mr. York's testimony regarding the initial decision to participate in PVNGS, Mr. York's testimony regarding EPEC's continued participation at a 15.8 percent level is sparse. Mr. York relies almost entirely on a number of studies which he attaches to his testimony as support for the prudence of EPEC's continued involvement in PVNGS at EPEC's originally subscribed level. The studies can be segregated into two general groups: (1) those comparing the cost of energy generated by PVNGS as opposed to coal plants, and (2) those analyzing the merits of EPEC's participation in PVNGS at various levels.

Mr. York also relies on a 1976 TBA management audit, a 1982 study performed by Ebasco on behalf of M-S-R Public Power Agency and a 1985 update of a study by Pickard, Lowe, and Garrick, Inc. (PLG) as support for the prudence of EPEC's continued involvement in PVNGS. Each of the studies referenced by Mr. York are attached as exhibits to his testimony, with the exception of the PLG study which was offered as part of EPEC witness Van Brunt's testimony. A discussion of each of those groups of studies follows below.

i. Cost of Coal v. Nuclear. The time period covered by the coal versus Palo Verde cost studies is from 1978 through 1984. According to Mr. York, two studies were done in 1978. The first study is actually Mr. York's testimony given before the FERC (REY-1). In that testimony, the project cost of electricity for PVNGS was compared by Mr. York to two hypothetical coal plants in Texas and New Mexico over a 40-year time period. Mr. York found that PVNGS's cost advantage over the coal plant in New Mexico ranged from 3 percent in the first year to 57 percent in the fortieth year. The cost advantage range of PVNGS over the Texas coal plant went from 12 percent in the first year to 67 percent in the fortieth year. The second 1978 study presented by Mr. York was performed by Arthur D. Little, Inc. (REY-2). This study compared PVNGS to alternative forms of generation with coal being the only one considered feasible. This study also compared PVNGS to coal plants in New Mexico and Texas. In comparing the levelized cost of electricity over the life of the plants, this study concluded that PVNGS would be 6 percent less expensive than a New Mexico coal plant and 17 percent less expensive than a Texas coal plant.

The examiner notes that both of these studies were prepared for purposes of persuading regulatory bodies of the merits of EPEC's participation in PVNGS and for that reason, their objectivity must be questioned. It would appear that, since these studies were undertaken for essentially defensive purposes, they cannot be viewed as ongoing evaluation by management of the continued appropriateness of past management decisions. With regard to the Arthur D. Little study, which was prepared in conjunction with EPEC's request for certification of PVNGS in Docket No. 1981, Mr. York testified that EPEC would not have filed Arthur D. Little's testimony had it not supported EPEC's participation in PVNGS. Interestingly, the author of the Arthur D. Little study comments in the study that forecasts such as the study makes are uncertain at best. With regard to Mr. York's testimony before the FERC, the examiner notes that no documentation is provided regarding the data utilized to support his conclusions. Some of the assumptions he makes, such as a 75 percent capacity factor for a 1270 MW nuclear plant, are suspect.

In any event, it seems clear that these studies were not intended to provide EPEC management with information regarding the appropriateness of remaining in the PVNGS.

Two studies were performed in 1979 on behalf of Arizona Public Service Company (APS) which Mr. York attached to his testimony. "A Comparison of the Projected Cost of Electricity from the Palo Verde Nuclear Plant and Selected Coal-Fired Alternatives" was the title of a study done by National Economic Research Associates, Inc. (NERA) (REY-3). In this study, the levelized cost of electricity from Palo Verde was compared to the levelized cost from two different coal plant sites in Arizona. NERA concluded that the levelized cost of electricity from Palo Verde would be 12 percent and 15 percent less expensive than from the two comparable coal plants. The other study in 1979 was by Sargent & Lundy entitled "Palo Verde Nuclear Generating Station versus Coal-Fired Generating Alternative" (REY-4). Their calculations showed that the levelized cost of electricity from Palo Verde would be 30 percent less expensive than from an equivalent coal plant. The report concludes "The principal conclusion of this study is that APS' plans for constructing and sharing in the electrical power output of Units 1 through 5 of the Palo Verde Generating Station represent the economic choice when compared to a coal-fired alternative, providing the same capacity in the same time frame and sequence."

The examiner has some difficulty in determining to what extent, if any, EPEC relied upon these studies commissioned by APS to evaluate its continued participation in PVNGS. As pointed out by the City in its brief, Mr. York revealed on cross-examination that he lacked virtually any familiarity with these studies. To the extent that EPEC's management utilized these two studies in evaluating their participation in PVNGS, their reliance would necessarily have been limited by the fact that both of these studies expressly tailored data to the particular environmental conditions prevailing in Arizona. Additionally, the NERA study expressly states that "this analysis does not evaluate the economics of the Palo Verde project from the perspective of all participants but focuses on the perspective of APS." The Sargent & Lundy study states that, "we believe the generating costs developed reflect costs that represent APS's situation rather than being considered generic." Mr. York presented no evidence that EPEC attempted to modify those two studies to reflect EPEC's economic or geographical circumstances.

It is also important to note, as pointed out by counsel for the City, that the NERA warned of uncertainties and potential problems which should be considered in evaluating coal versus nuclear generation. For instance, the NERA study states that:

> The cost of electricity from future coal and nuclear plants is subject to a wide margin of uncertainty. There are uncertainties with regard to capital construction costs, capacity factors, fuel costs, and other operating and maintenance (O&M) costs . . . the magnitude of these uncertainties in cost should be considered in evaluating the desirability of the Palo Verde plant and coal-fired alternatives. Given a desire to minimize risk, consumers may well prefer an alternative with higher average costs but a lower cost range to an alternative with lower average costs but a wider cost range.

The NERA report concludes in part:

> Thus, while the expected costs for nuclear are lower than those for coal, the range of probable costs for nuclear (about 3.5 cents) is considerably wider than that for coal (about 2.5 cents). As a consequence of this greater variability in cost, the probability of very high costs is as great, or greater, for nuclear as for coal.

In 1980, EPEC performed two studies which Mr. York attached to his testimony. The first was done in February (REY-5) and compared PVNGS to a coal plant in New Mexico. This study found that the levelized cost of electricity from Palo Verde would be 33 percent less than that from the coal plant. The study was updated in November (REY-6) using a higher capital cost for Palo Verde. The cost of Palo Verde was 14 percent less than the coal plant on a levelized cost basis. EPEC performed another update of the comparison of coal versus Palo Verde costs in 1984 (REY-7). This study found that the levelized cost of electricity from PVNGS would be 10 percent less than that from an equivalent coal-fired plant. Each of these studies were performed in-house by Stanley R. Gross, an EPEC engineer. The examiner finds all three studies to have very little if any credibility. First, none of the studies incorporates a sensitivity analysis, even though Mr. York admitted that studies which relate to costs of plant should generally have a sensitivity analysis if they are to be performed in a professional manner. Mr. York offered no explanation of why the three studies failed to include sensitivity analyses even though he concluded that changes in such variables as capacity factors would reduce the advantage of nuclear generation over coal. Second, although Mr. York indicated on cross-examination that the capital cost of a nuclear plant is 20 to 30 percent greater than the capital cost of a coal plant, and although the 1979 NERA study assumed a 27 percent differential, Mr. Gross' February 1980 study (REY-5) assumes in his comparison that the average capital cost per kw of a coal plant is $1,309 as opposed to $1,211 for a nuclear plant. Clearly, that assumption is ludicrous. In his studies, Mr. Gross used cost data pertaining to the

New Mexico Project coal plant for his comparisons of coal plant costs to nuclear plant costs although Mr. York testified that EPEC's decision to withdraw from the New Mexico Project was due to the abnormally high cost estimates for that coal generating facility.

Mr. Gross used identical capacity factors for his coal and nuclear plant comparisons, based on NERA data which reflects roughly equal average capacity factors for coal and nuclear plants. However, as pointed out by counsel for OPC, new coal plants should have higher capacity factors than the average factor which includes plant of all ages. Further, on clarifying cross, the examiner solicited data from Mr. York concerning equivalent availability factors for coal and nuclear plants. An equivalent availability factor measures what a generating unit is capable of operating at, whereas a capacity factor is subject to the impact of lower utilization associated with economic dispatch choices.

The equivalent availability factor for coal plants is 81.85 as opposed to 59.88 for nuclear plants. Clearly, Mr. Gross' use of equal capacity factors for coal and nuclear comparison purposes overstates the cost advantage of the nuclear plant.

Further, OPC pointed out through cross-examination that while the NERA study reflected a non-fuel O&M cost advantage for a nuclear plant of 10 percent, Mr. Gross used a 50 percent differential.

Aside from the specific criticisms of the coal versus nuclear studies brought out on cross-examination, City witness Ben Johnson cited several general criticisms of those studies which the examiner finds to be persuasive. Specifically:

1) Use of optimistic plant capacity factors for nuclear plants
2) Use of same cost of capital in comparing nuclear and coal alternatives when investors perceive the risks associated with nuclear plants to be greater;
3) Failure to include nuclear decommissioning costs in the studies;
4) Overstatement of the capital cost of the coal alternative; and
5) Assumption by many of the Company studies of inclusion of CWIP for the PVNGS alternative but not for the coal alternative thereby biasing the results in favor of PVNGS.

Dr. Johnson testified that, to test the impact of some of the above problems, he performed a sensitivity analysis on the EPEC studies attached to Mr. York's testimony as REY-1, REY-5, REY-6, and REY-7, changing such variables as the cost per kw of the coal alternative and PVNGS and changing capacity factors. The results of those analyses are set out in Schedule 21 attached to Dr. Johnson's testimony. The results of Dr. Johnson's analyses reflect that

EPEC's conclusion that PVNGS will be less expensive than a coal alternative is highly dependent upon the particular assumptions selected, and that realistic comparisons can result in a sizeable advantage for the coal alternative.

In summary, the coal versus nuclear studies which Mr. York attached to his testimony each have serious deficiencies which are readily apparent to anyone other than the casual reader. The examiner finds it difficult to believe that EPEC's management would not have noted and corrected those deficiencies if they were objectively relying upon those studies to evaluate the prudence of EPEC's continued participation in PVNGS.

ii. Levels of participation in PVNGS. As previously mentioned, the other major group of studies attached to Mr. York's testimony addresses the economic merit of various levels of participation in PVNGS by EPEC. The first of these was performed in 1979 by Stone & Webster Management Consultants, Inc. (REY-8). The conclusion to this study was that a reduced level of participation in PVNGS would penalize EPEC's customers due to higher alternate fuel costs. The study finds that if EPEC's level of participation was reduced from 200 MW per unit to 150 MW per unit, the levelized increase in costs to EPEC's customers would be \$24.8 million per year (1983 dollars). The bottom line of that study was that EPEC should have bought a larger interest in PVNGS.

In December 1980, Stone & Webster updated their 1979 report to analyze the effect of a decrease in the load and energy forecast, an increase in the capital costs of Palo Verde, and an increase in oil and gas fuel prices (REY-9). Two levels of participation were evaluated in this study, 200 MW and 100 MW per unit. Two load forecast scenarios were evaluated. Additional factors considered were capacity factor, fuel costs and decommissioning costs. For the base case, the 200 MW participation was shown to be the most economical with a levelized savings of \$25.5 million for the higher load forecast scenario and \$21.1 million for the lower one.

In March 1981, the December 1980 level of participation study was updated (REY-10). The Commission staff requested the evaluation of six additional cases reflecting varying assumptions on the load forecast, fuel cost for gas and oil, fuel cost escalation and decommissioning costs. The updated study found 200 MW per unit participation level to result in long-term savings varying from \$21 million to \$27 million per year. The annual revenue requirements at the higher level of participation were higher in the initial seven to eight years but this was overcome by the fuel savings after that period.

In June 1983, EPEC undertook an analysis of a 50 percent versus a 100 percent participation level (REY-12) in PVNGS and reached the same basic conclusions as the previous Stone & Webster studies. The study concluded that the Company's participation at the 100 percent level would ultimately result in lower overall expenses. Although the capital expenditures would be greater for the 100 percent level of participation, the offsetting benefits due to lower fuel cost would outweigh the initial expenses.

In addition to the above studies looking at various participation levels, in 1976, TBA was hired by the City of El Paso to perform a management and operations review of EPEC (REY-13). The report did not investigate the Palo Verde Project exclusively but did dedicate an entire section to it. In this section, TBA looked at the load forecasts, alternative sources of generation, and the sensitivity of their analysis to capacity factor variations. TBA recommended that EPEC continue its participation in PVNGS.

In the examiner's opinion, each of the above studies is deficient to the extent that they utilize over-optimistic load growth projections and load growth assumptions. The results of those studies are very sensitive to load growth variables and from the examiner's review of the evidence, it appears that most of those studies, even in the sensitivity analyses, used load growth assumptions which were overly optimistic.

For instance, the 1976 TBA report assumed an annual load growth for EPEC of from 6-8 percent for the period 1976 through 1988. That report, as pointed out by counsel for the City, concludes that . . . "Only when the peak demand growth rate falls to around 5 percent or below does an appreciable amount of excess capacity result." The average growth in MW peak demand from 1975-1984 is 2.1 percent.

The 1979 Stone & Webster analysis performed in 1979 utilized long-term load growth projections made by EPEC in June, 1979. For 1983, the first year reflected in the study, the study assumes EPEC will experience a 972 MW peak load, which is 223 MW more than EPEC's actual 1983 peak demand. Even the peak demand number used in the sensitivity test for purposes of a worst case scenario assumed a peak demand which was 90 MW in excess of 1983 peak demand.

The December, 1980, Stone & Webster update warned that one of the major parameters which could significantly affect the economics of PVNGS was a decrease in the load and energy forecast.

The 1975-1984 average growth in peak demand of 2.1 percent and the 1980-84 average of 2.5 percent are below any load growth variables used in the studies, with the exception of the March 1981 Stone & Webster update, wherein the Commission staff requested that load growth variables ranging as low as 2 percent be used. However, in that study, Stone & Webster omitted use of a variable capacity factor which had been used in the previous study to determine the effect of assumed lower capacity factor on the data results.

It appears that in most instances, the load growth assumptions used were provided by EPEC. Dr. Johnson attached several schedules to his prefiled testimony which provide an informative overview of EPEC's past performance with respect to load forecasting.

Schedule 31 compares EPEC's long term MWH Sales and Peak Demand forecasts from 1972 to 1984 with the actual MWH Sales and Peak Demand levels experienced by the Company from 1972 to 1984. The comparison reflects that, at least through EPEC's 1980 forecast, the Company consistently forecasted peak demand and MWH sales numbers grossly in excess of the Company's actual achieved load growth. Given the consistent pattern of load growth overestimation year after year, EPEC's management should surely have recognized that there were serious problems with the Company's forecasting abilities which cast doubt on the validity of the Company's forecasts as well as on the validity of studies utilizing those forecasts. A utility cannot plan its capacity needs in an efficient manner if it relies upon load growth projections which are consistently and excessively optimistic, and it is arguably imprudent not to undertake such steps as may be necessary to correct deficiencies in a company's load forecasting methodology.

According to Mr. York, the Arab oil embargo occurred in October, 1973. Referencing Schedule 28 of Dr. Johnson's testimony which depicts annual percentage increases in growth in peak demand and KWH sales, it is clear that after 1973, EPEC's load growth dropped tremendously. While Mr. York testified on cross-examination that this was a national phenomenon, it appears that EPEC never adjusted its forecasts to account for that occurrence judging from EPEC's post-1972 forecasts. Load growth forecasting is not an exact science. However, given EPEC's consistent overestimation of annual load growth, it would appear that use of more conservative load growth assumptions in those studies would have been warranted. With regard to other deficiencies with the participation level studies, Dr. Johnson testified that he was unable to obtain data necessary to test the validity of the Stone & Webster analyses, but he did offer the following criticisms regarding the assumptions used by EPEC in its June, 1983 in-house comparison of 50 percent versus 100 percent ownership of PVNGS, which criticisms the examiner accepts:

1) The study failed to examine the impact of the participation level on the ratepayer.

2) The study does not adequately consider the impact of EPEC's 100 percent commitment on rates during the construction period.

3) The cost of the PVNGS units used in the study are significantly lower than the most recent estimate.

4) The study assumes EPEC will require additional coal capacity in 1994, 1996, 1999, 2001 and 2002 under the 50 percent ownership scenario, based on EPEC's current load forecasts.

5) The study assumes Rio Grande Units 3, 4 and 5 will be retired in 1984.

iii. Summary. In the examiner's opinion, the studies which Mr. York attached to his testimony to support EPEC's decision to obtain and continue with a 15.8 percent interest in PVNGS suffer from numerous analytical deficiencies. The record does not reflect that EPEC's management critically evaluated those studies. As stated in Dr. Johnson's testimony, the Company seems to have had only minimal interest in questioning, analyzing, discussing, or verifying the results of those various studies.

To the extent that the studies warn of the risks associated with nuclear power, the record does not reflect that the Company heeded those warnings. According to Mr. York's testimony on cross-examination, the three PVNGS units will represent 39.9 percent of EPEC's total generating capacity. Given the tremendous size of EPEC's nuclear exposure relative to the size of the Company, it is difficult to believe that EPEC's management, in reviewing those studies, would not place great weight on the risks of excessive involvement in nuclear construction and generation. As discussed in Dr. Johnson's testimony, the studies provided by Mr. York did not consider the possibility that PVNGS could fail to obtain an operating license.

The studies did not consider the financial risk of EPEC's commitment to a 15.8 percent interest in PVNGS, given the massive amount of investment required.

The studies appear to be narrow analyses of the benefits of coal versus nuclear generation and particular levels of participation in PVNGS, which fail to take into account many relevant considerations. The record does not reflect that EPEC's management considered anything other than the studies presented by Mr. York in evaluating the prudence of its continued participation in PVNGS.

Other than the studies attached to his testimony, Mr. York offers no support for the prudence of EPEC's continued involvement in PVNGS at the initially subscribed level of 15.8 percent. Reliance upon these studies cannot possibly carry EPEC's burden of proof on this issue of the prudence of EPEC's continued full involvement in PVNGS in light of the very substantial testimony presented by the City raising innumerable doubts about the prudence of EPEC's management decisions in this regard. Many questions are raised by Dr. Johnson which cannot be answered from the studies presented by Mr. York, and EPEC presented no rebuttal testimony to answer those questions or to address doubts raised in the examiner's mind by the City regarding the prudence of EPEC's management in continuing to maintain a 15.8 percent interest in PVNGS.

(3) Efforts to Sell PVNGS. Mr. York testified that, although EPEC still believes that the Company's full 15.8 percent level of participation in PVNGS is in the long-term interests of EPEC's ratepayers, the Company has attempted to sell a portion of PVNGS, because of the completion of the Eastern Interconnection with SPS, because of the short-term benefits of such a sale to EPEC's financial position and its ratepayers, and because EPEC's full participation in PVNGS has been questioned by regulatory authorities.

In Mr. York's prefiled testimony, he provides the following summary regarding regulatory concerns:

Q. What have the regulatory authorities indicated about EPEC's participation?

A. A discussion of the need for full participation in PVNGS first appeared in the testimony of PUCT Witness Sweatman in PUCT Case No. 1981. This case involved the certification of PVNGS, and the final order was issued November 9, 1978. Primary consideration in Witness Sweatman's testimony was given to projections of load growth and fuel diversification. Although EPE was not ordered to divest itself of any portion of the PVNGS facility, it was clear in the Hearing Examiner's report that concern for the financial impacts on the ratepayer also played a vitally important part.

In PUCT Docket No. 2641, the City Council of El Paso recommended that EPE divest itself of twenty-five percent (25%) of the PVNGS project. Although this was a settled case, the recommendation was made part of the case. Specific reasons for the recommendation were reduced load growth and ratepayer impacts. The final order in this case was issued September 13, 1979.

In PUCT Docket No. 3254, another settled case, the City Council ordered EPE to divest itself of fifty percent (50%) of its PVNGS participation citing load growth and ratepayer impacts. The final order in this proceeding was issued September 30, 1980.

EPE appealed the divestiture order in PUCT Docket No. 3382. Although no hearings were ever held in this proceeding, an earlier separate proceeding before the EL Paso Public Utility Regulatory Board in April 1980 yielded the same results based on load growth and financial agreements.

PUCT Docket No. 3382 was settled by stipulation. An "off-system sales credit" tariff was implemented in exchange for the City's decision not to proceed further.

In both PUCT Docket Nos. 4620 (final order issued January 5, 1983) and 5700 (final order issued October 26, 1984), the City of El Paso, though not ordering a reduction in EPE's PVNGS involvement, has consistently failed to authorize inclusion in rate base of greater than 50% PVNGS-related CWIP.

Mr. York goes on to state that EPEC has over the past several years solicited interest from electric utilities regarding the sale of a portion of PVNGS and has contacted 42 utilities during that period, either by general solicitation letters, telephone conversations and/or personal contacts. According to Mr. York, EPEC has also expressed interest in pursuing other off-system sales arrangements and has considered such possibilities as purchase options, generation/capacity trades, sale/buy-back arrangements and system/unit contingent power with the goal of stimulating interest in possible purchases.

According to Mr. York, EPEC's sales efforts resulted in an agreement with M-S-R Power Agency in December, 1981 for the sale of 150 MW of PVNGS entitlement which was subsequently defeated in a Modesto Irrigation District referendum, execution of a letter of intent with Sacramento Municipal Utility District (SMUD) in July, 1982 for a sale identical to the M-S-R Power Agency proposal which was subsequently rejected by SMUD's Board of Directors, execution of a long-term power sales agreement in September, 1982 with Imperial Irrigation

District (IID), and execution of a long-term supplemental power sales agreement in December, 1981 with TNP.

Mr. York testified that EPEC's sales efforts are continuing, but that the following conditions are impacting upon the success of EPEC's efforts:

1) Most utilities have consummated arrangements to meet their load demands this decade and beyond.

2) Softening of regional/national electric demands.

3) Transmission limitations, given the 3-6 year lead time for new transmission lines

4) PVNGS start-up date uncertainties and impact on construction costs.

5) Diminishing confidence in the nuclear industry.

According to Mr. York, EPEC is continuing its efforts to obtain a purchaser for PVNGS ownership pursuant to its agreement to do so in Docket No. 3382 despite the difficulties EPEC has encountered to date.

Dr. Johnson has testified that EPEC's efforts to sell PVNGS are best characterized as "too little, too late" noting that although the Company was provided warnings from regulatory bodies as early as 1978, EPEC made no effort to divest itself of any interest in PVNGS prior to the Spring of 1981 and Mr. York admitted that fact on cross-examination. It is interesting that, although EPEC was first directed to sell a portion of PVNGS in September, 1979 by the El Paso City Council, it made no effort to do so until 1 1/2 years later. Dr. Johnson points out in his testimony that when the Company did begin to make efforts to sell, it never offered to sell more than 25 percent of its share in PVNGS until June 16, 1985, at which time it offered 33 percent for sale. According to Dr. Johnson, his examination of EPEC's documentation regarding sales efforts reflects that the Company did not attempt to sell with much effort or enthusiasm, noting that many of the letters sent by EPEC were boilerplate, merely indicating that up to 25 percent of EPEC's share of PVNGS was available for purchase.

While conceding that by early 1981 it was likely becoming more difficult for EPEC to sell an interest in PVNGS on very favorable terms, due to more obvious regulatory risks of nuclear power and less clearcut potential cost savings, Dr. Johnson indicates that EPEC's effort to sell 25 percent of PVNGS in 1981 met with almost immediate success, noting that the proposed sale to M-S-R was on favorable terms. Dr. Johnson concludes that it is reasonable to assume that EPEC could have readily sold 50 percent of PVNGS at any time during the 1978-1981 time frame, although the Company may have had to accept a price below book value.

EPEC argues in its brief that Dr. Johnson's analysis of EPEC's sales efforts constitutes no more than a second guess as to whether or not EPEC could have sold 50 percent of PVNGS. The examiner agrees that the record does not show whether EPEC could have sold an interest in PVNGS prior to the Spring of 1981, but as EPEC never made any effort to sell prior to the Spring of 1981 even though it had twice been ordered to do so, it would seem that the burden is on the Company to show that it could not have sold an interest in PVNGS rather than on the City to show that it could. EPEC did not offer any evidence reflecting that it could not have sold any interest in PVNGS between 1978 and 1981. Given that other participants in PVNGS, such as Tucson Gas & Electric Company, Arizona Electric Power Cooperative, Inc. and Salt River Project, were able to divest themselves of various interests in PVNGS, and given that EPEC was able to execute a letter of intent to sell a portion of PVNGS to SMUD as late as 1982, the examiner finds Dr. Johnson's assumption to be reasonable.

(4) Efforts to Reduce Capacity. Mr. York testified that, due to lower growth rates since 1977 than earlier predicted in EPEC load forecasts, EPEC has delayed or cancelled several construction projects and planned purchases of power in order to respond to this problem. Mr. York cites the following cancelled capacity:

San Juan Short-Term Purchase	100 MW
PVNGS Units 4 and 5	100 MW
New Mexico Project	75 MW
1981 Combustion Turbine	80 MW
	355 MW

San Juan short-term purchase was a proposed agreement with Tucson Gas & Electric Company to purchase power from San Juan Unit No. 3 from 1979 through 1983. This purchase was apparently cancelled sometime prior to 1979. PVNGS Units 4 and 5 were cost free options provided by Construction Engineering, Inc. which were cancelled in 1979 after withdrawal of certain California utilities. It does not appear that cancellation of Units 4 and 5 was initiated by EPEC. The 1981 Combustion Turbine Option was an option obtained when EPEC purchased the Copper 1 combustion turbine. The New Mexico Project was a joint venture with Public Service Company of New Mexico (PNM) to build four 500 MW coal-fired units in Bisti, New Mexico. While Mr. York characterizes this cancellation as EPEC's response to lower than expected load growth in his prefiled testimony, on cross-examination he stated that EPEC withdrew from the New Mexico project because it was extraordinarily expensive and lacked a secure water supply.

Reviewing Mr. York's testimony regarding EPEC's response to declining growth in demand, it appears to the examiner that that response was fairly minimal. Mr. York also references the Imperial Irrigation District and TNP long-term power sales, but those sales should properly be reviewed as efforts to mitigate excess capacity problems as a consequence of EPEC's failure to acknowledge its over-commitment to PVNGS.

[illegible] 10 percent of [illegible] than another [illegible] could have [illegible] 1981. But as EPNG never made any effort [illegible] the Company to show that it could not [illegible] in the [illegible] to show that [illegible] EPEC did not offer any evidence that it could not have sold any interest in PVNGS between 1978 and 19[illegible] that other participants in PVNGS, such as Tucson Gas & Electric Compan[y] Electric Power Cooperative, Inc. and Salt River Project, were able themselves of various interests in PVNGS, and given that EPEC wa[s] execute a letter of intent to sell a portion of PVNGS to SDGE as lat[e] the examiner finds Dr. Johnson's assumption to be reasonable.

(4) Efforts to Reduce Capacity. Mr. York testified that, due growth rates since 1977 than earlier predicted in EPEC load forecasts, delayed or cancelled several construction projects and planned out power in order to respond to this problem. Mr. York cites the cancelled capacity:

San Juan Short-Term Purchase	100 MW
PVNGS Units 4 and 5	100 MW
New Mexico Project	75 MW
1981 Combustion Turbine	30 MW
	305 MW

San Juan short-term purchase was a proposed agreement with Tu[cson] Electric Company to purchase power from San Juan Unit No. 3 from 19[illegible] 1983. This purchase was apparently cancelled sometime prior to 197[illegible] Units 4 and 5 were cost free options provided by Construction Enginee[rs] which were cancelled in 1979 after withdrawal of certain California [illegible] It does not appear that cancellation of Units 4 and 5 was initiate[d] The 1981 Combustion Turbine Option was an option obtained when EPEC [illegible] the Copper I combustion turbine. The New Mexico Project was a joi[nt] with Public Service Company of New Mexico (PNM) to build four 500 MW units in dist[illegible] New Mexico. While Mr. York characterizes this cance[llation as] EPEC's response to lower than expected load growth in his prefiled tes[timony, on] cross-examination he stated that EPEC withdrew from the New Mexi[co Project] because it was extraordinarily expensive and lacked a secure water supp[ly].

Reviewing Mr. York's testimony regarding EPEC's response to growth in demand, it appears to the examiner that that response minimal. Mr. York also references the reported Imperial Irrigation District long-term power sales, but those sales should properly be reviewed as mitigate excess capacity problems as a consequence of EPEC's [illegible] acknowledge its over-commitment to PVNGS.

Mr. Mentrup's recommendations result in a decrease in EPEC projected native system demand for the years 1986 through 1994 ranging from 8 MW to 27 MW.

With respect to EPEC's reserve margin, Mr. York testified that EPEC's reserve requirements are calculated using EPEC's largest hazard plus 5 percent of total peak demand, which is EPEC's planning criterion for installed reserve capacity. Total peak demand to the loads and resources is made up of firm native customer load and firm off-system sales. First sales in 1985 through 1992 are to IID and TNP.

Mr. York defends the use of this reserve margin criterion the basis that it is recommended by the Western System Coordinating Council. The examiner will not engage in lengthy discussion of this issue but simply note Mr. York's admission on cross-examination that use of the largest single hazard plus 5 percent criterion produces a reserve margin in 1986 in excess of 26 percent over native system and off-system sales demand. The examiner submits that that reserve margin is patently excessive and therefore recommends that EPEC's reserve margin be limited to 20 percent, as suggested by Dr. Johnson.

With regard to the loads and resources utilized by EPEC in reaching its projected net resource margins, Dr. Johnson has argued that EPEC's contingent obligation to make power and energy available to PNM during the 1985-1994 time frame should not be included in load calculations as a 100 percent certainty due to the fact that PNM currently has excess generating capacity, and it is therefore unlikely that PNM would request that power in the foreseeable future. Additionally, the PNM contingent power is unit specific. Dr. Johnson also argues that power purchases from SPS should be included as a capacity resource because, although the power is technically classified as interruptible, it has the characteristics of firm or at least unit-contingent purchases. Given the contingencies associated with both the PNM contingent sales and the SPS purchases, and the fact that the amounts of the annual SPS purchases roughly parallel the amounts of the annual PNM contingency sales, the examiner would support deletion of both the PNM and SPS transactions from calculation of EPEC's net resources for demand total.

Dr. Johnson has challenged EPEC's scheduled retirement of Rio Grande Units 3, 4, and 5 for late 1987 given that as of 1983 EPEC had scheduled Unit No. 3 for retirement on January 1, 1989, Unit No. 4 for January 1, 1992 and Unit No. 5 for 1992 or thereafter. As Mr. York has not explained in his prefiled testimony or on cross-examination the reason for the change in scheduled retirement dates, the examiner concurs with Dr. Johnson's assessment that it is inappropriate to delete that capacity from net capacity resource calculations.

Finally, Dr. Johnson has argued that for purposes of determining EPEC's need for PVNGS capacity for regulatory purposes, off-system sales should be eliminated from net capacity margin determinations since PVNGS was intended to meet native demand rather than to provide a source for power exports. The examiner concurs with Dr. Johnson's proposal to exclude off-system sales for determining excess capacity generated by EPEC's failure to reduce its PVNGS ownership interest.

The examiner has not recalculated net capacity margins for EPEC during the 1986-1994 based upon all of the adjustments recommended above. However, on page 4 of Dr. Johnson's Schedule 29, Dr. Johnson's calculation of excess capacity excluding scheduled retirements, firm sales, contingent sales and SPS purchases is a very close but understated approximation of the examiner's recommendation, failing only to consider Mr. Mentrup's downward adjustments to EPEC native system demand projections. Dr. Johnson's calculation reflects that EPEC's excess capacity would be in the vicinity of 370 MW in 1986, 334 MW in 1987, 436 MW in 1988, 402 MW in 1989, 445 MW in 1990, 415 MW in 1991, 260 MW in 1992, 305 MW in 1993, and 254 MW in 1994. Based on these calculations, it appears that approximately 50 percent of EPEC's interest in PVNGS will not be needed for many years to meet EPEC's native system demand.

[2] (6) Conclusion. In the examiner's opinion, EPEC has failed to prove that EPEC's decision to participate in PVNGS was predicated by the type of reasoned analysis one would expect prudent management to undertake before committing a business to a financial venture of such magnitude as PVNGS. Further, the examiner finds EPEC has failed to demonstrate in this docket that the Company's continued involvement in PVNGS at a 15.8 percent level was prudent.

To the extent that EPEC has failed to meet its burden of proof with respect to the prudence and efficiency of EPEC's initial and ongoing management decisions regarding participation in PVNGS, there is some basis in Commission precedent for disallowance of the entirety of PVNGS-related CWIP. However, in EPEC's last rate proceeding, the Commission utilized the estimated excess capacity attributable to PVNGS as a means of quantifying the amount of CWIP to be excluded under the prudence and efficiency standard. In the absence of any direct means for quantifying imprudence, the examiner finds the approach taken by the Commission in Docket No. 5700 to be appropriate in light of the record in this docket. Based upon the examiner's determination that approximately 50 percent of EPEC's interest in PVNGS will not be needed for many years to meet EPEC's native system demand and based further upon the evidence discussed herein regarding the prudence and efficiency of EPEC's planning and management of PVNGS, the examiner recommends that 50 percent of PVNGS related CWIP, including CWIP attributable to PVNGS transmission lines, be excluded from rate base.

b. Prudence and efficiency of the planning and management at the project. EPEC witness Edwin E. Van Brunt, Jr., Executive Vice President of the Arizona Nuclear Power Project (ANPP) is the only witness who testified regarding prudence and efficiency of planning and management at the project. Mr. Van Brunt's testimony includes a description of ANPP, which was organized to construct and operate PVNGS, a description of PVNGS and its site, including the site selection process, explanations of the precepts that controlled the development of the project, including the project-type of organization, objectives of safety, quality and reliability, and procurement methods, the status of the project as of the end of May 1985, current schedules for bringing the three units to commercial operation, and estimates of "brick and mortar" capitalized costs. For brevity's sake, the examiner has refrained from summarizing the testimony presented by Mr. Van Brunt. The text of Mr. Van Brunt's testimony can be found in Volume 3, tabs 19-20 of EPEC's Rate Filing Package. The intent of Mr. Van Brunt's testimony is to establish a prima facie case regarding the lack of imprudence or inefficiency regarding the planning and management of PVNGS on the part of ANPP.

As Mr. Van Brunt stated on cross-examination,

> What we're trying to demonstrate is that certainly the delays that we've been subject to were beyond our control first; and secondly, that we have dealt with those delays in a manner that in the end--the end result, we have still performed very well when you compare us against similar projects in a similar time frame.

As additional support for his testimony, Mr. Van Brunt included in his presentation a study prepared for ANPP by Pickard, Lowe and Garrick, Inc., entitled Cost and Controls Study of Palo Verde Nuclear Generating Station. The study purports, among other things, to compare PVNGS' schedule, cost, and construction productivity to other nuclear power plants constructed in the same period. As EPEC did not produce the authors of that study for cross-examination, it was not possible to evaluate the accuracy or objectivity of the study. In any event, Mr. Van Brunt admitted on cross-examination that one could not judge from the study whether delays and cost overruns experienced by the nuclear plants used for comparison purposes were reasonable or unreasonable or prudent or imprudent. In summary, the study did not add any weight to the credibility of Mr. Van Brunt's testimony.

No other party presented direct testimony on the prudence and efficiency of the planning and management of the construction project itself, although Mr. Van Brunt was cross-examined at length. To the extent that the parties have raised specific construction prudence issues in their briefs as a consequence of their cross-examination of Mr. Van Brunt, the examiner discusses those issues below.

(1) 1979 rescheduling of Unit 1 fuel load date. Staff counsel makes a passing reference in his brief to ANPP's deferral in 1979 of the scheduled fuel load date for Unit No. 1 from November 1981 to November 1982 and references Mr. Van Brunt's testimony on cross-examination that that delay increased the cost of the project by $262,000,000, exclusive of AFUDC. However, staff counsel does not specifically allege imprudence with regard to this delay in his brief nor have any other parties suggested in their briefs that this delay is attributable to imprudence or inefficiency. The examiner notes that Mr. Van Brunt addresses in detail the reasons for the 1979 deferral of the Unit No. 1 fuel loading date, nature of the problems causing the delay and the steps taken by ANPP and Bechtel to overcome those problems on pages 45-50 of his prefiled testimony. The examiner finds Mr. Van Brunt's testimony to be

generally credible and in the absence of any other evidence on this point or allegations of imprudence, the examiner does not, for purposes of this case, find the 1979 deferral of the Unit No. 1 fuel loading date to result from imprudent or inefficient management or planning of the project.

(2) <u>Selection of nuclear steam supply system (NSSS) contractor</u>. Counsel for the City cites the overall conduct of ANPP in its selection process and its relationship to the NSSS contractor as an issue that should be looked at in terms of prudence and efficiency in the management and planning of PVNGS. PVNGS' NSSS is supplied by Construction Engineering, Inc. (CE). PVNGS will be the first completed nuclear project to utilize a Combustion Engineering System-80 (CES-80) NSSS. There is no question but that this fact has caused PVNGS to experience additional delays and cost overruns that could likely have been avoided through the use of a proven NSSS. Mr. Van Brunt acknowledges in his testimony that PVNGS Unit No. 1 has had to undergo additional instrumental testing as a consequence of being the first CES-80 NSSS to be placed in operation, requiring the scheduled testing period for Unit No. 1 to be extended. The CES-80 NSSS is also one of several reasons cited by Mr. Van Brunt for the 1979 deferral of fuel loading for PVNGS Unit No. 1.

In light of the fact that PVNGS is the first and probably the last nuclear power plant to utilize a CES-80 NSSS, counsel for the City poses the following questions in his brief:

a) Should this have been a consideration at the time the supplier was selected?

b) Should the project in estimating its costs in the early years have taken this into account?

c) Was the decision to build a first of a kind plant one which has caused and will cause the ratepayers to incur additional costs which were foreseeable and avoidable?

There are no easy answers to these questions. From the evidence of record it appears to the examiner that when CE was selected to supply the NSSS to PVNGS, ANPP could not have known or foreseen that PVNGS would be the first nuclear project utilizing a CES-80 to go on line because Duke Power had ordered six CES-80 units and Washington Public Power Supply System (WPPSS) had ordered one CES-80 unit prior to the time CE was selected by ANPP in August, 1973. Mr. Van Brunt testified that at the time the CES-80s were ordered, ANPP believed that PVNGS would be the second or third project to be constructed utilizing CES-80s.

However, counsel for the City correctly notes that data compiled by the Atomic Industrial Forum, Inc. (AIF) reflects that the construction permits for PVNGS Units No. 1, 2 and 3 were issued in May of 1976, approximate 1 1/2 years before the first construction permits were issued to Duke Power for its plants using CES-80 units and almost two years before WPPSS received a construction permit for WPPSS 3, which utilizes a CES-80 NSSS. It therefore appears that even if the fact that PVNGS would be the first nuclear plant to use a CES-80 unit were not apparent in 1973, ANPP should have been aware of it in 1976. One can find without the use of hindsight that ANPP should have considered this development in its cost projections formulated after 1976. Such consideration would not have served to reduce any additional costs which occurred as a consequence of being the first nuclear project with a CES-80 unit, but the PVNGS participating utilities would have had better insight into the extent of their financial commitment to PVNGS.

As to whether the additional costs associated with proceeding with PVNGS as the first nuclear plant to use a CES-80 NSSS were foreseeable and avoidable, it would seem that the costs were to some extent foreseeable but the cost of avoidance, through cancellation of the plant, may well have far outweighed the cost of proceeding with construction, based upon data available to ANPP at that time. The examiner submits that the record in this docket is insufficiently developed to answer that question.

To the extent that those costs were avoidable, the record in this docket does not permit quantification. Mr. Van Brunt testified on cross-examination that he could not quantify the additional costs of Unit No. 1 as an consequence of being the first nuclear plant to use a CES-80 unit, nor has ANPP attempted to quantify those costs.

(3) Problems resulting from hot functional test. The City points in its brief to the problems associated with the delays announced in the fall of 1983 as definite issues concerning the prudency of PVNGS' management; specifically, the defects in the Reactor Coolant Pumps (RCP) and the Low Pressure Safety Injection Pumps (LPSI) as well as the violations arising from a NRC Construction Assessment Team (CAT) inspection.

During inspections in the summer of 1983 following the pre-core hot functional testing of Unit No. 1, a combination of design and manufacturing defects were uncovered with regard to the RCPs. Shortly thereafter, while testing the LPSIs on Unit No. 2, a design defect was discovered which had to be corrected on both Unit No. 1 and Unit No. 2. Both the RCPs and LPSIs, as part of the NSSS, were the responsibility of CE.

In September, 1983, a CAT comprised of 15 NRC inspectors spent two weeks at the PVNGS plant site and during the inspection found a number of violations of NRC rules, resulting in the assessment of an $40,000 fine against ANPP, although the amount of the fine was later reduced to $20,000. According to Mr. Van Brunt the delays caused by the CAT inspection and the problems with the RCPs and LPSIs caused combined additional costs to the project of $368,000,000.

Counsel for the City has questioned why ANPP has not made any claim against CE for the additional costs to the project caused by the RCP and LPSI problems, which have not been reimbursed by CE. Mr. Van Brunt has stated that no decision had been made to seek recourse against CE for the incidental damages caused to the project, nor had the possibility of making a claim been raised by the project's Administration Committee. When asked if the contract with CE limited CE's liability to the project for problems such as those that arose with the RCPs and the LPSIs, Mr. Van Brunt indicated that although he had read the contract, he refused to answer on the basis that the terms of the contract were confidential.

Clearly, counsel for the City has raised serious questions as to whether the project management's failure to pursue any claims to date against CE for incidental damages constitutes a basis for a finding of imprudence. EPEC has certainly failed to show in this docket that the project management's actions were prudent in this regard.

(4) Sewerage effluent line. The City notes in its brief that there may be excessive costs associated with construction of the sewerage effluent line which provides cooling water for PVNGS. A 28 mile gravity flow section of the line was designed and built to accommodate five nuclear plants at the PVNGS site. The remaining eight miles of line is sized for only three reactors. According to Mr. Van Brunt, because of right-of-way difficulties and the fact that the gravity flow line covered significant land areas, the project partners agreed to size the line such that they would not have to redo the line if five units were in fact built. It appears that had PVNGS Units No. 4 and 5 been built, part of the cost of the gravity flow line would have been assigned to those units. The City raises an interesting question regarding the prudence, at the time the line was built, of sizing the sewerage effluent line to accommodate five units when the project was committed to build only three. Again, the record does not answer this question.

(5) Conclusion. From the above discussion it is clear that, although many legitimate questions have been raised through cross-examination regarding the prudence and efficiency of the management and planning at the PVNGS project, the record does not provide an answer to these questions. In Docket No. 5700, the examiners correctly held that a utility is not entitled to the inclusion of CWIP in rate base to the extent that doubt or uncertainty exists regarding whether or not a major project has been imprudently or inefficiently planned or managed and the utility fails to dispel this uncertainty by a showing of prudence and efficiency. The parties' cross-examination of Mr. Van Brunt definitely raised doubts and uncertainties in the examiner's mind concerning prudence and efficiency of management and planning at PVNGS with respect to certain problems which arose during the construction phase of PVNGS. The examiner would point out that EPEC did not attempt to dispel the examiner's uncertainties on these issues at the hearing through redirect examination of Mr. Van Brunt, or through rebutal testimony although, in the examiner's opinion, issues were raised on cross-examination which warranted further examination.

EPEC took the position in its brief that prudence and efficiency questions pertain only to construction aspects of major projects. As discussed earlier, that position is contrary to the Commission's holdings in Docket Nos. 5700 and 5779. Nonetheless, given EPEC's position on this matter, it is curious that EPEC's brief contained virtually no discussion of the construction aspects of PVNGS.

In light of the very tough burden of proof a utility must meet to be entitled to extraordinary rate relief in the form of CWIP, the examiner believes EPEC's case would have been aided by the inclusion of persuasive argument on this issue in its brief. The examiner finds that EPEC has failed to meet its burden of proof with regard to the prudence test as it relates to the construction aspects of PVNGS. This determination further supports the position of the City and the examiner that no more than 50 percent of the CWIP related to PVNGS should be allowed in rate base.

3. Non-PVNGS CWIP

EPEC has requested that 100 percent of EPEC's non-PVNGS related CWIP be included in total Company rate base. EPEC's non-PVNGS CWIP totals $9,428,078. The examiner finds that inclusion of this CWIP is necessary to the financial integrity of EPEC, given that the examiner has recommended that less CWIP be included in EPEC's rate base than is required under a financial integrity test. Further there has been no showing by any party of imprudent or inefficient planning or management with regard to non-PVNGS projects associated with this CWIP, and no doubt or uncertainty exists in the examiner's mind regarding whether or not the projects associated with this CWIP have been imprudently or inefficiently planned or managed. Therefore, the examiner recommends that all non-PVNGS CWIP requested by EPEC be included in rate base.

4. Adjustments to Total CWIP

Three deductions to the total amount of CWIP recorded by EPEC have been proposed. First, City witness DeWard proposed that $76,277 in AFUDC associated with PVNGS Units 4 and 5 should be deducted from CWIP, based upon EPEC's response to a data request in which EPEC conceded that the AFUDC associated with PVNGS Units 4 and 5 should be removed from CWIP. It does not appear that this adjustment is opposed by any party and the examiner recommends its adoption by the Commission.

Second, Mr. DeWard recommended that $1.00 be removed from CWIP balances, symbolically representing costs which have been incurred to correct problems resulting from the hot functional test which will ultimately be recovered from other parties. EPEC has addressed this adjustment at some length in its brief. The examiner finds, based upon the questions raised in docket regarding possible claims against CE and other parties for hot functional test damages, that the adjustment is appropriate and should be adopted by the Commission.

Third, Mr. DeWard has recommended that EPEC's December 31, 1984, CWIP balance be reduced by $2,054,000 to reflect a settlement of overcharges of administrative and general expenses by APS. According to Mr. DeWard, the settlement was reached on February 11, 1985 in a document entitled "Palo Verde A&G Letter of Understanding." Although EPEC does not deny that its December 31, 1984 CWIP balance is overstated in light of that settlement, EPEC argues in its brief that this adjustment should not be made because of the Commission's policy of prohibiting known and measurable changes to rate base. The examiner finds EPEC's argument to be without merit. Although the Commission has adopted a policy prohibiting reclassification of post test year-end CWIP to plant-in-service, that policy does not prohibit recognition of known and measurable changes to a utility's test year-end CWIP balance as necessary to correct overstatements of that balance. The examiner recommends adoption of this adjustment as proposed by Mr. DeWard.

In addition to the three adjustments addressed above, the examiner has increased EPEC's total CWIP balance by $18,382,131 to reflect the examiner's previously discussed recommendation that the PVNGS transmission line be reclassified from plant-in-service to CWIP.

5. CWIP Summary

Based upon the examiner's CWIP recommendations herein, the examiner finds that EPEC is entitled to inclusion of CWIP in the amount of $557,579,256 in rate base. This represents a reduction of $325,699,773 from the level of CWIP requested by EPEC.

C. Working Capital

EPEC has requested working capital in the amount of $14,352,241 in rate base, composed of the following items:

Fuel Stock	$ 83,358
Material & Supplies	5,019,548
Prepayments	3,186,317
Cash Working Capital	6,063,018

1. Fuel Stock

EPEC's proposed fuel stock component of working capital constitutes EPEC's thirteen-month average balance for coal inventory. No party to this proceeding challenged EPEC's proposed fuel stock working capital number and the examiner finds the same to be reasonable and appropriate.

2. Materials and Supplies (M&S)

As with fuel stock, EPEC requested an M&S working capital requirement based upon EPEC's thirteen-month average balance of M&S inventory. Again none of the parties to this proceeding challenged the amount of M&S working capital requested by EPEC and the examiner finds the amount requested to be reasonable.

3. Prepayments

EPEC's requested working capital allowance for prepayments is based upon EPEC's thirteen-month average balance of prepayments. The prepayments component of EPEC's requested working capital requirement was challenged by both the City and the Commission staff.

a. Interest or commercial paper. City witness Hugh Larkin and staff witness Janet Simpson both opposed EPEC's inclusion of prepaid interest on commercial paper in the calculation of the average balance of prepayments. As pointed out by Mr. Larkin, commercial paper is not a part of the Company's capital structure, and therefore does not require a return through rates. Neither the Company nor any of the other parties included commercial paper as other short-term debt in their proposed capital structure. As interest on commercial paper is a "below the line" item for purposes of this rate case, the examiner concurs with the positions of Mr. Larkin and Ms. Simpson that such prepaid interest on commercial paper must be excluded from working capital requirements. Consequently, EPEC's requested working cash allowance for prepayments should be reduced by $53,798 to reflect this adjustment.

b. Occupational and street rental charges. In addition to the above adjustment, Ms. Simpson has proposed that the following prepayments for occupational and street rental charges be removed from the total working capital allowance requested by EPEC:

El Paso	$2,062,584
Clint	3,168
Vinton	51,316
Total	$2,117,088

Ms. Simpson takes the position that occupational and street rental charges are not prepayments from a regulatory perspective. According to Ms. Simpson, although the charges benefit a future period, they are calculated based upon revenues in a prior period. Through her cost of service treatment of these charges, Ms. Simpson asserts that the Company has the opportunity to recover amounts relating to these charges before they are paid. Ms. Simpson feels that it is inappropriate to allow the Company to earn a return on such payments simply because they benefit a future period if the revenue to pay the charges has been supplied by ratepayers rather than stockholders. The examiner agrees with that general statement, but such facts do not appear to exist in this instance.

EPEC witness William Johnson correctly notes in his rebuttal testimony that Ms. Simpson's cost of service treatment of these taxes does not allow EPEC the opportunity to recover the taxes before they are paid nor does it change the fact that the tax is paid for the privilege of using the public ways, streets and highways for the following year. Mr. Johnson also points out that EPEC pays the tax in advance for the following year but collects through rates only the tax already paid for the current year.

After review of relevant testimony and cross-examination, the examiner is persuaded that prepaid occupational and street rental charges should appropriately be considered prepayments and included as part of a utility's total working capital requirement. The examiner notes that the Commission has recently confirmed this point of view in Docket Nos. 5640, 5700 and 5779. However, in Docket No. 5700, the examiners determined that, although El Paso occupational and street rental charges were prepayments, the occupational and street rental charges assessed by Clint and Vinton were not. The record in this case is devoid of any evidence regarding the character of Clint and Vinton occupational and street rental charges, although EPEC's rebuttal testimony provides proof of the prepaid nature of the El Paso charge. Given the examiners' determination in Docket No. 5700 that the Clint and Vinton charges were not prepayments, this examiner believes that EPEC had the affirmative burden in this case of showing that the Clint and Vinton charges are prepayments, if they wished them to be so treated. Since EPEC failed to present evidence on that issue, the examiner finds that the Vinton and Clint occupational and street rental charges, totalling $54,484, should be deleted from the total amount of prepayments requested by EPEC for purposes of calculating EPEC's working capital requirement.

Based upon the above adjustments, the examiner finds EPEC to be entitled to inclusion of $3,078,035 in prepayments in rate base.

4. Cash Working Capital

EPEC performed a lead-lag study to calculate the amount of cash working capital needed by the Company. The study, performed under the supervision of Mr. Richard Treich with Coopers & Lybrand, produced a total cash working capital requirement of $6,094,612. However, the Company reduced its requested cash working capital component to $5,925,301 to comply with the one-eighth of operation and maintenance expense limitation imposed by P.U.C. SUBST. R. 23.21(c)(2)(B)(iii).

Mr. Treich's study measures the difference between the date the utility received goods and services and the date it paid for them. This is referred to as expense lag. The study also measures the difference between the date the utility renders service and the date of payment by the utility's customers for those services. This is referred to as revenue lag. Revenue lag is comprised of three sub-categories: service lag, billing lag and collection lag.

The lead-lag study performed by Mr. Treich was reviewed by Staff witness Bernard Uffelman and City witness Hugh Larkin, both of whom offered serious criticisms of the study and made such corrections to the study as they felt were appropriate. Mr. Uffelman's modifications of the study result in his recommended cash working capital allowance of $3,280,258 for EPEC. Mr. Larkin's adjustments result in a cash working capital recommendation of ($108,120).

a. Adjustments to revenue lag. Mr. Treich's study utilizes a composite revenue lag of 47.9 days. This lag is the sum of a 5.8 day meter reading to billing lag, a 5.3 day service lag and a 26.8 day collection lag. Both the City and the Commission staff challenged the 47.9 day composite revenue lag utilized by Mr. Treich. Mr. Uffelman noted that EPEC's total revenue lag of 47.9 days is from 8.16 to 10.9 days longer than the revenue lags of HL&P, CP&L, WTU and TUEC. As EPEC's service lag should be approximately the same as for other Texas utilities, it is apparent that EPEC must take longer to perform billing and/or collection functions than other utilities. According to Mr. Uffelman, the recently completed management audit of EPEC performed by Touche-Ross & Co. reflects that opportunities exist for improvement in EPEC's billing cycle, payment processing and collection policies.

According to Mr. Treich, EPEC bills its customers four business days after the meter is read, which converts to 5.8 calendar days. Staff witness Uffelman testified that a reduction of EPEC's billing cycle by one business day is appropriate. The one business day reduction in the billing cycle converts to a reduction of 1.5 calendar days. City witness Larkin, however, testified that he agrees with Mr. Treich's use of a 5.8 day billing cycle lag. The examiner finds that there is insufficient evidence to support the staff's adjustment. The only factual support behind Mr. Uffelman's recommendation is his comparison of EPEC's total revenue lag period with those of other Texas utilities, and the comparison does not provide a breakdown of the total revenue lag of those utilities into billing lag, service lag and collection lag components. Mr. Uffelman's reliance upon findings in the Touche Ross & Co. audit does not assist the examiner, as that audit is not a part of the record. While the examiner believes that cash working capital should be calculated on the basis of how much the utility needs, assuming that it is managing its affairs efficiently, the examiner cannot in this instance determine that EPEC's billing cycle is excessive.

Mr. Uffelman has also suggested that EPEC's collection lag of 26.8 days be reduced by 1.5 calendar days. Mr. Uffelman believes that if EPEC is more aggressive in its credit and collection policies and procedures, such a reduction in lag time can be achieved. Mr. Larkin has proposed a similar adjustment, advocating that collection lag be reduced from 26.8 days to 25 days. Again, the examiner believes there is insufficient evidence of record to support this adjustment. Mr. Uffelman's testimony does not specify how or in what ways collection procedures can be improved, nor does the record contain such information. No one has pointed to instances where EPEC has not been aggressive in its collections policies. Further, Mr. Larkin's testimony on this issue was successfully impeached by the Company. On cross-examination by counsel for EPEC, Mr. Larkin testified that his suggested 25 day collection lag is based upon common sense, rather than upon any type of statistical sampling or other procedure. Mr. Larkin testified that he simply looked at the delinquency date and the service cut-off date and then picked a day which he felt would be reasonable, keeping in mind EPEC's disconnect date. However, Mr. Larkin admitted that he believed that EPEC's disconnect date was 26 calendar days, when in fact it is 26 working days or approximately 37 calendar days. Therefore, the examiner cannot place much faith in this aspect of Mr. Larkin's testimony. Absent concrete evidence reflecting that EPEC's collection lag is excessive, the examiner cannot accept the proposed reduction in collection lag calculated by Mr. Treich.

In summary, the examiner finds the total revenue lag of 47.9 days utilized in the lead-lag study to be appropriate.

b. Expense lag adjustments. Mr. Larkin and Mr. Uffelman both testified that the lead-lag study performed by Mr. Treich included some inappropriate items and failed to properly analyze the expense lag associated with other items. Therefore, a number of adjustments have been proposed in order to reflect the proper amount of cash working capital required by EPEC.

Mr. Larkin testified that deficiencies exist in the Company's proposed calculation of expense lag days in the following areas:

1. Payment dates established for certain expenses
2. Inclusion of inappropriate items in the determination of cash working capital
3. Inclusion of payments that are not a part of the cost of service
4. Failure to recognize certain payments that require use of ratepayer-supplied funds.

A discussion of each of Mr. Larkin's proposed adjustments follows below. As the expense lag adjustments made by Mr. Uffelman have also been made by Mr. Larkin, Mr. Uffelman's adjustments will not be addressed separately.

(1) Payment dates. According to Mr. Larkin, the lead-lag study fails to consider the lag from the time the Company issues a check in payment of an expense to the time the check clears the bank. Consideration of this float time would increase the lag time on each expense item included in the study with the possible exception of Federal income taxes and withholding taxes. Mr. Larkin has proposed an adjustment to account for this additional period of cash use by the Company. Finding that fuel and purchased power expenses comprise 76 percent of EPEC's adjusted total operation and maintenance expense, Mr. Larkin adjusted the expense lags that the Company computed for each payment of fuel and purchased power expense to reflect the actual date on which each check cleared the bank. Mr. Larkin adjusted the lag days for each payment by adding the

number of days at the mid-point of the service period to the number of days between the end of the service period and the check-clearing date of each payment of fuel and purchased power expense made during the test year. As a consequence of this adjustment, Mr. Larkin determined that the expense payment lag for fuel expense should be increased from 37.3 days to 40.2 days and that the lag for purchased power should be increased from 36.7 days to 43.3 days.

EPEC opposes this adjustment on the basis that the Company should be prepared to honor its checks on the date they are written, and that reliance upon float time is somehow improper. EPEC's rationale for opposing this adjustment is unpersuasive. The purpose of including a cash working capital allowance in the rate base is to provide a return on operating funds advanced by a company's stockholders during the lag period between the time a utility expends funds and such time as the ratepayer provides the Company with funds to replace those advanced. When analyzing this expense lag adjustment, it appears to the examiner that when a check is issued, although the funds are committed at that time, the utility continues to draw interest on the funds which will be used to cover the check, until such time as the check actually clears the bank. Therefore, the examiner believes it is appropriate to include float time in the calculation of expense lag days in order to reflect the utility's opportunity to draw interest on funds until checks clear the utility's account.

(2) <u>Inclusion of inappropriate items</u>. Mr. Larkin and Mr. Uffelman both testified that the lead-lag study performed by Mr. Treich inappropriately included certain items which should not be considered in the determination of cash working capital. Specifically, non-cash items such as depreciation, amortization and uncollectible expense should not be included because they do not require current outlays of cash. Additionally, prepayments and materials and supplies charged to expenses are already included in the rate base as working capital, and as such should be deleted. Mr. Larkin and Mr. Uffelman proposed removal of the following expenses from the lead-lag study:

Amortization of Property Insurance	$ 960,469
Amortization of Prepaid Insurance (injuries and damages)	648,663
Amortization of Prepaid Taxes	5,353,239
Uncollectibles	1,038,653
Materials & Supplies Charged to Expenses	1,189,264
Total	$9,190,288

According to Mr. Larkin and Mr. Uffelman, the dollars associated with prepayment items and materials and supplies charged to expenses which were included in the lead-lag study by Mr. Treich cause EPEC's cash requirement to be overstated by a double-count. The double-count arises from inclusion of these items as part of the asset balance of prepayments and materials and supplies, and again, as a part of the lead-lag study determination of cash working capital.

EPEC, through cross-examination of Mr. Larkin, argued that if materials and supplies are expensed and EPEC has to expend additional funds to replenish materials and supplies during the year, EPEC will have revenue and collection lags for the purchased materials. Mr. Larkin admitted that that was true but correctly pointed out that if one includes cash outlays for materials and supplies in the determination of a cash working capital allowance, there is no need to include the average balance of materials and supplies elsewhere in the determination of working capital. Mr. Larkin testified that this is a theoretical truism of lead-lag studies and he references the Commission requirement that materials and supplies expense, fuel and prepayments be excluded from calculation of cash working capital under the one-eighth rule as theoretical support for the adjustment. The examiner fully accepts the reasoning behind these adjustments, as set forth by Mr. Larkin and Mr. Uffelman and concurs that the above enumerated expense items should not be included in the determination of cash working capital for EPEC.

In addition to the above adjustments, Mr. Larkin proposed that the balances of working funds and special deposits be excluded from the calculation of cash working capital because EPEC stated in an RFI response that the funds are invested in interest bearing accounts. Mr. Larkin indicates that under those circumstances, it is inappropriate to provide EPEC with a second duplicative return on those amounts. EPEC argues that only some of the funds in question are in interest bearing accounts. However, in the absence of evidence as to how much of the funds are earning interest, the examiner believes it necessary to exclude those amounts in their entirety.

(3) Inclusion of non-cost of service payments. Mr. Larkin testified that his firm reviewed copies of all EPEC vouchers and invoices used on Mr. Treich's analysis of Account 923, Outside Services, and all vouchers and invoices representing payments that yielded dollar days greater than negative $1,000,000 used in Mr. Treich's analysis of Operating Rents. As a consequence of that review, Mr. Larkin has identified several payments which he believes are inappropriately included in Mr. Treich's computation of expense lags for Outside Services and Operating Rents.

First, Mr. Larkin deleted a payment of $9,333 to First City National Bank of El Paso with associated negative lag days of 222 and dollar days of negative $2,071,926. According to Mr. Larkin the payment, representing a pledge to Renaissance 400/American Cities Corporation, had been inadvertently charged to EPEC's Outside Services Account rather than to Account 426, Contributions and Donations. Removal of the payment changes the expense lag for Account 923, Outside Services, from 48.7 days to 52.3 days. The examiner concurs in the appropriateness of this adjustment.

Second, Mr. Larkin found three payments associated with the lease on an aircraft, which had been included in Mr. Treich's analysis of the Operating Rents account. As the costs associated with aircraft expense have been deleted from the cost of service, Mr. Larkin removed the three payments from the calculation of the expense lag for Operating Rents. The examiner concurs with this adjustment.

Third, Mr. Larkin testified that there were deficiencies in payment dates and service periods used in the calculation of the individual lag days for certain payments included in Mr. Treich's analysis of operating rents. The specific payments are reflected on revised Schedule 5.7 of Mr. Larkin's testimony. Mr. Larkin, taking the position that ratepayers should not have to pay the Company a return on cash working capital requirements necessitated by the Company's decision to make payments earlier than necessary, adjusted the expense lag for each of the payments he questioned to reflect the due date of the invoice.

EPEC opposes this adjustment on the basis that, if the Company waits until the due date of the bill to make the payment, the payment will not be received by the party who rendered the bill until after the due date. The examiner would share EPEC's concern were it not for the fact that Mr. Larkin's adjustments applied only to payments which did not have an early payment discount or late payment penalty associated with the payment. The checks for the payments which Mr. Larkin challenged were issued as early as twelve days prior to the due date of the bill. It is therefore inappropriate to use the check date for calculating the expense lags associated with those payments. Under such circumstances, the examiner finds it reasonable to calculate the expense lag associated with those payments based upon the due dates.

Fourth, Mr. Larkin found a series of invoices for Computer Associates International, covering a service period of three years. Although payment of only one-fourth of the total invoice amount was made, Mr. Treich used the entire three-year term as the service period to compute an expense lag of negative 474.5 days. Mr. Larkin adjusted the service period to cover one-fourth of the three year term to correspond with the amount paid, thereby reducing the expense lag associated with those invoices to negative 156.5 days. The examiner believes this adjustment to be appropriate.

(4) <u>Cash expenses requiring ratepayer-supplied funds</u>. According to Mr. Larkin, the payment lag associated with interest expense on long-term debt has not been recognized in Mr. Treich's lead-lag study. Mr. Larkin notes that the source of funds for interest payments are the ratepayers, through revenues collected, and as lead-lag studies analyze the timing of the receipt and use of funds, an analysis of this item is necessary.

Mr. Larkin computed the amount necessary to reflect the expense lag time associated with interest expense on long-term debt, resulting in a net lag of negative 28.9 days. The appropriateness of this adjustment was not disproved by EPEC and the examiner believes that inclusion of this item in the lead-lag study is warranted.

c. Cash working capital summary. The results of EPEC's lead-lag study as modified by the recommendations outlined above reflect that EPEC has a cash working capital requirement of ($1,047,979). Attached to this report as Examiner's Exhibit No. 1 is a summary sheet reflecting the cash working capital calculations used by the examiner in deriving that figure.

In calculating this cash working capital number, the examiner has applied the adjusted net revenue/expense lag to adjusted O&M and other expenses found herein in an attempt to coordinate EPEC's cash working capital requirement with the level of cash expenses. The examiner notes that incorporation of the numbers herein to the lead-lag study has produced a working cash requirement substantially lower than any number recommended by the parties.

As the examiner's recommendations result in a negative working cash allowance, the examiner recommends that EPEC be assigned a cash working capital allowance of zero. Imputation of a zero working cash allowance when a negative requirement is found is in keeping with prior Commission precedent in Docket No. 5779, Application of Houston Lighting and Power Company for a Rate Increase and Docket No. 5640, Application of Texas Utilities Electric Company for a Rate Increase. However, the policy reasons underlying that precedent, to wit: recognition of the utility's good cash management techniques and provision of an incentive to continue such management practices, are not necessarily applicable to this docket, and the Commission may therefore wish to offset EPEC's level of invested capital by the negative level of cash working capital found by the examiner herein. Because the parties have not had an opportunity to review the examiner's calculations, the parties are urged to comment on the calculations by exceptions to this report should they perceive any serious deficiencies in the attached exhibit.

5. Working Capital Summary

The examiner recommends approval of working capital for EPEC of $8,180,941 composed of the following amounts:

Fuel Stock	$ 83,358
Materials & Supplies	5,019,548
Prepayments	3,078,035
Cash Working Capital	-0-
Total Working Capital Requirement	$8,180,941

The examiner's recommendation constitutes a $6,171,300 decrease to EPEC's requested working capital allowance.

D. Rate Base Deductions

1. Deferred Federal Income Taxes (FIT)

EPEC made a number of adjustments affecting accumulated deferred FIT which were challenged by the City and the Commission staff. Schedule 6-7.4 of the Rate Filing Package itemizes the additions, reductions and adjustments to accumulated FIT proposed by EPEC. EPEC witness Johnson testified that he reconciled the FIT eliminations made on the income statement with the accumulated FIT, indicating that these were timing differences on non-recurring items and other items not included in the overall cost of service. Mr. Johnson testified that he then restated deferred taxes on allowance for borrowed funds (ABFUDC) as a reduction from rate base to equate to the percentage of Palo Verde CWIP included in rate base.

Staff witness Simpson and City witness DeWard proposed several adjustments intended to reverse certain reductions to accumulated deferred FIT proposed by Mr. Johnson. A discussion of each of those adjustments follows below.

a. Reversal of EPEC's ABFUDC adjustment. Mr. Johnson eliminated $13,668,604 in deferred FIT on ABFUDC from EPEC's balance of accumulated deferred FIT, indicating that the adjustment is required because EPEC has not requested inclusion of 100 percent of CWIP in rate base. The deferred FIT which Mr. Johnson proposes to eliminate from accumulated deferred FIT is attributable to that portion of CWIP not included in rate base.

EPEC capitalizes AFUDC to CWIP on a gross basis (without adjusting for the tax effects of ABFUDC) as opposed to a net basis, and records accumulated deferred FIT to account for the tax effects of ABFUDC. According to Ms. Simpson, the objective of EPEC's proposed adjustment is to make invested capital equal to what it would be if EPEC were a net company and to eliminate the disadvantage of a theoretically lower return earned by a gross company as a result of the mismatch of CWIP and accumulated deferred FIT in rate base. Mr. Johnson sets out a hypothetical illustration of the difference in accounting treatment between a gross company and a net company on pages 29-30 of his prefiled testimony.

Ms. Simpson and Mr. DeWard have vigorously argued that this adjustment is inappropriate. According to Ms. Simpson, EPEC's rationale for the proposed adjustment is flawed because it fails to consider the fact that a gross company will receive more depreciation through rates than will a net company once the plant becomes commercially operable and is included in invested capital, because the CWIP and, therefore, the plant in service balances of a gross company are greater by the tax effect of ABFUDC than are the CWIP and plant in service balances of a company which capitalizes AFUDC net of tax. Ms. Simpson believes that, because the depreciation expense to be recovered by EPEC over the life of PVNGS is greater than would be recovered by a net company, the adjustment proposed by Mr. Johnson is not justified.

Mr. DeWard testified that, in addition to Ms. Simpson's reasoning, the Company's rationale for the adjustment is flawed because FERC has indicated that accumulated deferred FIT should not be considered in the computation of AFUDC, EPEC computes AFUDC without taking into consideration the deferred FIT balances and because EPEC's argument fails to consider that ratepayers are being charged on a current basis the deferred FIT expense associated with all interest being capitalized in the AFUDC computation.

Although EPEC did not cross-examine Mr. DeWard on this adjustment, EPEC engaged in substantial cross-examination of Ms. Simpson on this issue. EPEC unsuccessfully attempted to show that a gross company would receive less FIT expense than would a net company as a consequence of amortization of accumulated deferred FIT. The examiner finds Ms. Simpson's analysis to be credible. EPEC's cross-examination of Ms. Simpson demonstrated, at best, that were it not for the fact that a gross company receives additional depreciation expense through cost of service than does a net company, EPEC's proposed adjustment would be appropriate. EPEC did not file rebuttal testimony on this issue nor did it address the issue in its brief. After consideration of all of the evidence, the examiner believes that the $13,668,604 reduction in accumulated deferred FIT contained in EPEC's rate base calculation should be reversed, as recommended by Ms. Simpson and Mr. DeWard.

b. Reversal of EPEC's adjustments for non-recurring items. EPEC witness Johnson eliminated accumulated deferred FIT on the following items on the basis that they are non-recurring:

Deferred Rate Case Expense	$ 169,027
Research and Development	(29,623)
Preliminary Survey Charges	65,139
Fuel Enrichment Cost	34,373

Ms. Simpson has proposed that each of the above adjustments be reversed. According to Ms. Simpson, accumulated deferred FIT represents cost free capital supplied by the IRS, which is used in lieu of obtaining additional capital from investors or through borrowing. Ms. Simpson therefore believes that the balance of invested capital on which return is calculated should be reduced by the amount of capital which the company is supporting at no cost. The fact that the expenses are non-recurring does not in Ms. Simpson's opinion contradict the presence of cost free capital supporting investment at test year end. The examiner concurs fully with Ms. Simpson's reasoning and notes that EPEC did not attempt to refute her position on this issue through rebuttal or through its brief. The examiner recommends that the adjustments made by EPEC to accumulated deferred FIT pertaining to the above expense items be reversed as recommended by Ms. Simpson.

c. Elimination of TRASOP/PAYSOP charges. EPEC has included a total of $2,283,742 in deferred charges related to the Company's TRASOP/PAYSOP plans, comprised of the following components:

1981 TRASOP Amortization	$ 921,858
1982 TRASOP Funding	$1,300,998
1983 TRASOP/PAYSOP	$ 60,886

Ms. Simpson and Mr. DeWard have both recommended that, since they believe it is incorrect to include those costs relating to TRASOP/PAYSOP in EPEC's cost of service, it is inappropriate to recognize accumulated deferred FIT related to TRASOP/PAYSOP in invested capital. As TRASOP/PAYSOP expense is funded through utilization of payroll-based and investment tax credits (ITCs), Mr. DeWard states that ratepayers should not be asked to pay a rate of return on a charge which will be ultimately funded through special provisions in the tax code at no cost to the Company. The examiner has accepted the adjustment to cost of service proposed by Mr. DeWard and Ms. Simpson concerning TRASOP/PAYSOP. Therefore, the examiner must concur in the elimination of deferred debits associated with TRASOP/PAYSOP included in accumulated deferred FIT.

d. Pension window plan. EPEC's accumulated deferred FIT Schedule (6-7.4) reflects a deferred debit of $238,022 related to EPEC's pension window plan. Mr. DeWard has proposed that the deferred charge should be removed because this expense is being funded over a period of years and the obligation which EPEC recorded on its books was merely a book liability which did not reflect the requirements for an immediate cash payment. Mr. DeWard indicates in his prefiled testimony that as of the end of the test year, EPEC has recorded in Account 253--Other Deferred Credits, a liability for the pension window plan of $517,440. As Mr. DeWard does not recommend that this liability be used to offset rate base, he believes it is appropriate to remove the deferred debit from accumulated deferred FIT. The examiner fully concurs with this recommendation.

e. Deferred FIT summary. Based upon the examiner's recommendations regarding the above discussed adjustments to accumulated deferred FIT, the examiner finds EPEC's invested capital should be reduced by accumulated deferred FIT in the amount of $110,982,319. The examiner's recommendations increase EPEC's deferred taxes offset to rate base by $16,429,284.

2. Pre-1971 Investment Tax Credits

EPEC has proposed to reduce invested capital by $757,940 for pre-1971 investment tax credits. No party to this proceeding has challenged the amount of this rate base deduction and the examiner finds the amount to be reasonable and appropriate.

3. Customer Deposits

EPEC has deducted $2,966,146 from rate base, representing the amount of customer deposits held by EPEC. The examiner finds this amount, which has not been challenged by any party, to be appropriate.

4. Injuries and Damages Reserve

No party has challenged EPEC's proposed reduction to rate base of $100,000 for an injuries and damages reserve and the examiner recommends adoption of that figure.

5. Customer Advances for Construction

EPEC has deducted from total invested capital $992,940 for customer advances for construction. This figure has not been challenged and the examiner recommends that EPEC's proposed amount be adopted.

6. Other Rate Base Deductions

City witness DeWard has proposed two additional rate base deductions totaling $3,193,409 which were not advocated by either EPEC or the Commission staff. A discussion of those adjustments follows.

a. Unamortized gain on sale of turbine. Mr. DeWard has recommended that the unamortized gain on the sale of a turbine by EPEC be recorded as a rate base offset. According to Mr. DeWard, the sale of the turbine resulted in a gain on the Company's books and when the lease of the turbine was recorded as a capital lease the higher cost was included in plant in service. Mr. DeWard testified that the recording of the unamortized gain, as he proposes, will serve to reduce the plant in service amount to a level which would have existed had the sale and gain not been recognized.

EPEC cross-examined Mr. DeWard on this adjustment and secured Mr. DeWard's admission that the FERC System of Accounts provides for booking the gain or loss on the sale of a piece of equipment below the line. However, Mr. DeWard suggested that there is not necessarily any support in the FERC System of Accounts for selling equipment at a profit and then leasing it back under a capital lease for a higher cost, causing increased depreciation expense and a higher dollar return requirement. Certainly this type of transaction is unusual.

This particular issue is not well developed in the record and additional evidence regarding the facts surrounding this transaction would have been useful. Be that as it may, this adjustment can be readily evaluated on policy grounds. Regardless of the purpose of the transaction, a utility should not, as a matter of policy, be permitted to inflate rate base by selling assets for a profit and then reacquiring those assets at higher cost while recording the gain on the transaction below the line. Even though there may be no accounting rule or practice which specifically addresses the adjustment proposed by Mr. DeWard, the examiner believes that equity requires that an adjustment along the lines of that proposed by Mr. DeWard be made to offset the inflation of rate base caused by the sale and lease back of the turbine. Therefore, the examiner concurs in

Mr. DeWard's proposed $1,808,615 offset to rate base to recognize the unamortized gain on EPEC's sale of the turbine.

b. Accumulated sick time bond and accrued vacation pay. Mr. DeWard has proposed that accumulated sick time bond and accrued vacation pay be utilized as an offset to EPEC's rate base. This adjustment, if granted, would reduce EPEC's total invested capital by $1,384,794. Mr. DeWard cites two reasons for proposing this adjustment. First, Mr. DeWard indicates that Mr. Treich's lead-lag study assumes that all payroll is paid on specific dates. Those lead days are then subtracted from EPEC's revenue lag and applied to an average daily payroll expense amount. According to Mr. DeWard, the payroll expense includes vacation time which has a significant lead time and no consideration of that additional lead time is incorporated in Mr. Treich's lead-lag study.

Secondly, Mr. DeWard testified that EPEC accrues on its books at December 31, the estimated liability for all vacation earned as of that date and consequently, rates have been established on expense levels which include vacation accruals. Mr. DeWard concludes that it is therefore appropriate to offset rate base by these cost-free liabilities. According to Mr. DeWard, this adjustment pertains equally to sick time bond.

EPEC presented rebuttal testimony on this issue, wherein Mr. Johnson indicated that the recognition by EPEC of an accrued expenditure only indicates that EPEC has an obligation to make a future payment. Mr. Johnson states that no cash has been collected to make the payments and that annualization of the payroll at December 31 will match the collection of the salaries and wages with revenues during the term the rates will be in effect.

While concurring with Mr. DeWard's observation that there is probably a significant lead time associated with vacation and sick time, the examiner believes that Mr. Larkin' should have proposed an adjustment to Mr. Treich's lead-lag study to account for that fact. Mr. DeWard's proposal for a separate offset to rate base to account for accumulated sick time bond and accrued vacation pay does not appear to the examiner to be an appropriate vehicle for compensating for the failure to incorporate certain additional lead time in the lead-lag study. Additionally, the examiner is unsure as to whether use of a discrete rate base offset to address this matter would have the same rate base effect as would be the case if the additional lead days were flowed through the lead-lag study and the subsequently determined cash working capital allowance. The examiner is unconvinced of the propriety of Mr. DeWard's rate base offset for sick time bond and accrued vacation time and consequently recommends that the proposed offset to rate base not be effectuated.

E. Total Invested Capital

Based upon the discussion and examiner's recommendations outlined above in Section VI.A.-D., the examiner urges that the Commission find EPEC to have proven a total invested capital of $757,508,444 in this case, comprised of the following components:

Plant in Service	$ 439,731,601
Less Accumulated Depreciation	128,552,989
Net Plant	$ 311,178,612
Construction Work in Progress	557,579,256
Working Cash Allowance	-0-
Materials and Supplies	5,019,548
Prepayments	3,078,035
Fuel Inventory	83,358
Deferred Taxes	(110,982,319)
Pre 1971 Investment Tax Credits	(757,940)
Customer Deposits	(2,966,146)
Injuries and Damages Reserve	(100,000)
Customer Advances for Construction	(992,940)
Unamortized Gain on Sale of Turbine	(1,808,615)
Total Invested Capital	$ 759,330,849

Attached to this report as Examiner's Exhibit No. 2 is a summary of the Examiner's adjustments to EPEC's invested capital request.

VII. Return

EPEC, the City, DOD and the Commission staff each presented expert witnesses who testified regarding an appropriate capital structure for EPEC as well as EPEC's cost of long-term debt, preferred stock and common equity. A discussion of the parties' positions and the examiner's recommendation on each of these issues follows below.

A. Capital Structure

The following chart sets forth the capital structure recommendations in dollars and percentages exclusive of ITCs, recommended by the parties:

	EPEC	CITY	STAFF
Long-Term Debt	$686,650,000	$730,037,000	$748,037,000
	% 51.34	% 53.29	% 52.60
Preferred Stock	$151,273,000	$150,873,000	$150,873,000
	% 11.31	% 11.01	% 10.61
Common Equity	$499,467,000	$489,133,000	$523,098,000
	% 37.35	% 35.70	% 36.79

The examiner has not included DOD in the above chart because DOD's capital structure recommendation is identical to that proposed by the Commission staff. Further, the examiner notes that the difference between the staff's and EPEC's proposals is due to the staff's use of EPEC's actual capital structure as of July 31, 1985, rather than the adjusted test year capital structure. The City also utilized EPEC's updated capital structure as the starting point of its proposed adjustments. EPEC argues in its brief that the test year capital structure should be used, based on EPEC's belief that it is patently unfair to refuse to recognize post test year additions of generating plant in rate base and then proceed to adjust the capital structure that supports that rate base. The examiner finds that argument unpersuasive and agrees with the City, the staff and DOD that the July 31, 1985 data should be used since it is a more accurate reflection of EPEC's likely capital structure during the time the rates set in this docket will be in effect.

The City is the only party which proposed adjustments to EPEC's capital structure aside from the parties' use of July 31, 1985, data. City witness Basil Copeland recommended removal of two $9,000,000 notes from EPEC's total long-term debt on the basis that since those notes expire on December 2, 1985, they will not be a part of the capital structure during the period that rates set in this docket are in effect. The examiner rejects this adjustment, noting staff witness Reilley's testimony on cross-examination that although those notes will be retired in December, 1985, they have been replaced with a slightly larger amount of debt. In the examiner's opinion, it is inappropriate to recognize the debt retirement without also recognizing the incurrance of new debt. The examiner therefore recommends that the two $9,000,000 notes be replaced with the recently secured replacement debt. The record reflects the amount of that replacement debt to be $20,000,000.

The City, through Mr. DeWard, has also proposed that $33,965,336 in common equity associated with EPEC's transactions with FL&R be deleted from EPEC's capital structure. The components of this proposed adjustment are as follows:

1. Undistributed Earnings of FL&R	$ 8,875,552
2. FL&R ITC Tax Leases	6,889,446
3. Amounts paid to FL&R in Excess of Tax Saving Realized	18,200,338
Total Common Equity Deduction	$33,965,336

With regard to the proposed adjustment for undistributed earnings of FL&R, the City argues that since FL&R's earnings are recorded below the line, EPEC's ratepayers have not received the benefit of those earnings through cost of service. Therefore, it is inappropriate to include undistributed earnings of FL&R in the common equity of EPEC thereby resulting in a higher rate of return on invested capital than would be the case if FL&R did not exist. This argument, although attractive, does not appear to the examiner to be appropriate under the circumstances of this case. The capital structure of EPEC embraces both the utility and non-utility aspects of the Company. While inclusion of FL&R equity in the capital structure increases the percent of EPEC's total capital attributable to common equity, which carries a higher capital cost than debt or preferred stock, the examiner notes that investors, in making investment decisions, look at EPEC as a whole, rather than solely to EPEC's regulated activities. It would seem then that the appropriateness of this adjustment would turn on whether the existence of FL&R provides a benefit to EPEC in terms of reducing the perceived risk of EPEC in the eyes of investors, thereby having a beneficial effect upon EPEC's cost of common equity. The evidence on this point is not abundant, but the examiner notes that Touche Ross & Company indicated in the management audit it performed on EPEC that it was possible that FL&R has had a positive effect on EPEC's cost of capital. Additionally, staff witness Reilley pointed out in his direct testimony that the April 27, 1984 Value Line investment publication discussed EPEC's involvement with FL&R in favorable terms. In the examiner's opinion, it is inappropriate to remove undistributed earnings of FL&R from the common equity portion of EPEC's capital structure on the basis that inclusion of those earnings increases the return on equity without also considering that FL&R may well serve to reduce EPEC's cost of common equity to some extent. Therefore, the examiner declines to recommend this adjustment.

With regard to the City's proposed reductions to EPEC's common equity to account for monies paid by EPEC to FL&R for ITCs which are not of use to EPEC at present, the City argues that EPEC's payments to FL&R for ITCs which cannot at present be used constitutes in effect, an interest free loan to FL&R. City witness DeWard testified that EPEC paid FL&R $7,787,412 in 1982 for ITCs in the same amount generated in 1981 and 1982 by FL&R and that, based upon an RFI response by EPEC, it appears that only $897,966 in ITCs purchased from FL&R were utilized as of December 31, 1984, leaving a balance of $6,889,446 in unused ITCs attributable to FL&R. The examiner agrees with the City that through the purchase of those ITCs, the Company in essence provided cost free capital to FL&R. In the examiner's opinion, that transaction was clearly not in the best interests of EPEC's ratepayers given EPEC's inability to utilize those ITCs in a timely manner. The purchase of those ITC's before they could be used by EPEC also appears to violate the terms of the joint tax allocation agreement entered into by FL&R and EPEC. However, the examiner is uncertain of the propriety of remedying this matter through adjustment of EPEC's capital structure. The examiner has a similar problem with the City's proposal to reduce common equity by the amount of the ITCs that EPEC has failed to utilize on its tax return by virtue of including the taxable losses of FL&R in its income tax computation. Adjustment of the common equity portion of EPEC's capital structure seems a rather indirect means of remedying the disadvantage to EPEC's ratepayers caused by EPEC's purchase of FL&R ITCs which cannot be utilized in the near term. Assessment of a company charge against FL&R for prefunded tax benefits, as suggested in the Touche Ross & Company audit, would seem to be a much more direct method for remedying this problem.

Mr. DeWard fails to address in detail the consequences to EPEC of adjusting EPEC's capital structure as opposed to use of some form of accounting adjustment to correct any inequities caused to EPEC's ratepayers as a consequence of the

ITC purchases. The examiner has some concern regarding the effect of such an adjustment on EPEC's financial ratios, and hesitates to recommend the adjustments without being certain that an equally effective adjustment could not be made which would avoid a direct impact on EPEC's perceived financial integrity. Therefore, the examiner does not recommend that these two proposed adjustments to EPEC's capital structure be accepted by the Commission.

Based upon the above discussion and recommendations the examiner finds EPEC's capital structure to be as follows, for purposes of this rate proceeding.

Long-Term Debt	$ 750,037,000	52.67%
Preferred Stock	150,873,000	10.59%
Common Equity	523,098,000	36.73%
Total	$1,424,008,000	100%

B. Cost of Debt & Preferred Stock

Although cost of debt is generally a readily determinable item, the parties to this proceeding are in disagreement as to the appropriate cost of long-term debt for EPEC. The effective cost proposed by each party is as follows:

	Debt	Preferred
EPEC	11.25%	9.80%
City	10.49%	9.80%
DOD	10.82%	9.80%
Staff	10.92%	9.80%

The difference between the cost of debt proposed by the staff and that proposed by EPEC results from the staff's use of EPEC's July 31, 1985 data concerning costs of long-term debt and preferred stock. As discussed previously, the examiner finds use of that updated data to be appropriate. The difference between the effective costs of long-term debt proposed by the City, DOD and the staff is attributable to the City's proposed deletion of $18,000,000 in long-term debt which the examiner rejects, as previously discussed, and to adjustments to the interest rate applicable to certain long-term debt proposed by the City and DOD.

The City proposed that the cost of two $75,000,000 unsecured floating rate notes held by Bank of New York which mature in 1987 and 1988 be adjusted to reflect the interest rate in effect at the end of the test year, rather than the "weighted lifetime" cost calculated by EPEC. According to City witness Copeland, the "weighted lifetime" cost is biased upward by unusually high interest rates which are not indicative of current debt costs. It appears that the staff and DOD concur in the necessity of adjusting the interest rates on EPEC's floating rate debt, and the Company has put forward no argument in opposition to such an adjustment other than its contention that if post test year additions to rate base are not permitted, post test year adjustments to cost of debt and preferred stock should not be permitted. The examiner concurs with the cost of debt adjustment proposed by Mr. Copeland with regard to the Bank of New York debt.

In addition to the above adjustment DOD witness Winter proposed a reduction to the floating rates on two $9,000,000 notes to be retired in December. As discussed previously, although that debt is being retired shortly, EPEC has recently incurred additional debt for a slightly larger amount. It appears from cross-examination of Mr. Reilley that the amount of the replacement debt is $20,000,000. The interest rate on the new debt is a flat rate of 10.365 percent, according to staff witness Reilley. The examiner therefore recommends that the replacement debt be substituted for the two $9,000,000 notes and that the interest rate be adjusted to 10.365 percent to correspond with the cost of the replacement debt.

On the basis of the above recommendations, the examiner finds EPEC's long-term debt to have an effective cost of 10.39 percent.

With regard to EPEC's cost of preferred stock, there is no dispute concerning the appropriateness of the 9.80 percent effective cost of that component of the capital structure, as indicated in Schedule F of the rate filing package.

C. Return on Common Equity

1. EPEC's Position

EPEC presented the testimony of Mr. Robert Jackson, Senior Vice-President of Stone & Webster Management Consultants, Inc., in support of its requested return on equity of 16.90 percent. Mr. Jackson evaluated EPEC's required return on common equity on the basis of two discounted cash flow (DCF) analyses. The first DCF analysis attempts to formulate EPEC's cost of equity based upon yield and growth projections of comparable utilities. The second DCF analysis utilizes EPEC-specific data. On the basis of those two analyses, Mr. Jackson concludes that EPEC's current cost of equity is fairly stated at 16.90 percent.

A DCF analysis attempts to quantify the return on equity capital required by investors by calculating the dividend yield and adding to that yield anticipated growth in dividends. The DCF theory assumes that the price of a share of common stock is equal to the present value of all its future dividends. By looking to the market to determine what investors think a share of EPEC's common stock is worth, the rate of return required by investors can be imputed by approximating their expectations of future dividend growth. The DCF formula is expressed as follows:

$$K = D_1/P_0 + g$$

where K = required return
D_1 = anticipated dividends
P_0 = current price
g = expected growth

a. Surrogate companies DCF analysis. Mr. Jackson's first DCF analysis evaluates the cost of common equity for a group of comparison utilities and then translates that cost to its equivalent for EPEC. According to Mr. Jackson, as EPEC must compete for funds in the marketplace, its cost of equity capital can be ascertained through a market-oriented DCF study of comparison companies.

Mr. Jackson developed three comparison groups of utilities from Standard & Poor's Utility Compustat listing of electric utilities. The first group constitutes electric utilities with revenues ranging between \$150 million and \$600 million in 1983, being not less than one-half or more than twice the size of EPEC in terms of revenues. The second comparison group constitutes those electric utilities which had reported AFUDC over 75 percent of reported earnings during the last five years. The third group comprises all 60 companies listed by S&P's Utility Compustat as electric utilities. Mr. Jackson calculated the cost of equity for each group through use of a DCF analysis.

Annual growth rates for each of the comparison companies were calculated by Mr. Jackson for per share earnings, dividends and book value for the years 1974 through 1984. Because the standard deviations were high for growth rates in per share earnings and per share book values, Mr. Jackson utilized solely per share dividends in developing a growth expectation for his DCF study. His calculations reflect anticipated growth rates of 5.35 percent for Group 1, 2.25 percent for Group 2 and 4.65 percent for Group 3.

Based on dividends paid and average market prices in calendar year 1984, Mr. Jackson calculated yields of 11.65 percent for Group 1, 12.76 percent for Group 2 and 10.69 percent for Group 3. For the four quarters ended March, 1985, the yields were 11.45 percent, 12.92 percent and 10.8 percent, respectively. Mr. Jackson averaged the yields for these two periods to derive the following yields for use in his DCF study: 11.51 percent for Group 1, 12.84 percent for Group 2 and 10.75 percent for Group 3.

Summing the growth rates and yields for the three groups produces required returns of 16.86 percent for Group 1, 15.09 percent for Group 2, and 15.40 percent for Group 3.

Having made the above determination, Mr. Jackson indicated that those results lead to a market-to-book ratio of 1.00, which he believes is insufficient because costs associated with public offerings of stock require that the cost of EPEC's common equity be calculated at a market-to-book range of 1.05 to 1.10 to enable stock to be issued on non-dilutive terms. Through use of a market-to-book adjustment, Mr. Jackson increased the return requirement for each group of comparable utilities. Mr. Jackson concluded that the required return on common equity for each group falls within the following ranges, depending upon whether the return is calculated on a market-to-book ratio of 1.05 or 1.10:

Group 1	17.47% - 18.14%
Group 2	15.77% - 16.52%
Group 3	15.97% - 16.59%
Average	16.40% - 17.08%

b. <u>EPEC-specific DCF analysis</u>. Mr. Jackson's second DCF analysis is specific to EPEC. Mr. Jackson determined a yield of 11.74 percent for EPEC based upon the average of EPEC's actual 1984 and 1985 yields on common stock. The growth component of the DCF formula was developed by Mr. Jackson through use of EPEC's growth in dividends per share from 1974 through 1984. Mr. Jackson determined that EPEC's dividends per share have grown at an average compound annual rate of 5.35 percent. According to Mr. Jackson, the sum of this growth and adjusted yield data produces an indicated cost rate of 17.71 percent at a market-to-book ratio of 1.05, and 18.39 percent at a market-to-book ratio of 1.10.

Mr. Jackson also testified regarding an alternative methodology for incorporating the costs of common stock sales into the required return. Mr. Jackson's yield and growth numbers of 11.74 and 5.35, respectively, result in a total return requirement of 17.09 percent based upon a market-to-book ratio of 1.00. Mr. Jackson determined that EPEC's historic "net proceeds" from stock sales equates to $97.98 per $100.00 of gross investment. Therefore, multiplication of the calculated return of 17.09 percent by the differential between gross and net sales proceeds (.9798) results in a required return for EPEC of 17.44 percent.

On the basis of the above discussed DCF analyses, Mr. Jackson concluded that a required return of 16.90 percent fairly states EPEC's cost of common equity.

2. Staff's Position

Mr. Robert Reilley testified on behalf of the Commission staff regarding EPEC's cost of equity. Mr. Reilley utilized both a DCF analysis specific to EPEC and a DCF analysis of comparable utilities. Additionally, Mr. Reilley performed a risk premium analysis. On the basis of those analyses, Mr. Reilley has concluded that the best point estimate of the cost of equity to EPEC is 15.5 percent.

a. <u>Surrogate companies DCF analysis</u>. In selecting a group of utilities comparable to EPEC, Mr. Reilley utilized several screening criteria. Each comparable utility had to meet the following criteria:

1. Involvement in ongoing nuclear construction.
2. More than 85 percent of revenues obtained from electric sales.
3. Percentage of long term debt in capital structure of between 40 percent and 55 percent.
4. CWIP as a percentage of common equity of 90 percent or above.
5. Capitalization greater than $100 million and less than $10 billion.
6. Bond rating falling within the range of BBB and A.
7. No omitted or reduced dividends.

Utilizing the above criteria, Mr. Reilley developed a group of eight utilities which he believes are comparable to EPEC.

In order to estimate the growth component of the DCF formula, Mr. Reilley relied upon four distinct methodologies for each sample utility. First, Mr. Reilley looked at the actual historical growth of earnings per share, dividends per share, and book value per share for each sample utility. The growth estimates were then "smoothed" using a linear regression model. The results for five, ten and fifteen year periods are as follows:

	Average	1979-1984	1974-1984	1969-1984
EPS	3.83%	5.22%	3.53%	2.74%
DPS	4.63	4.48	4.89	4.51
BVPS	.98	.44	.77	1.73
Average	3.15%	3.38%	3.06%	2.99%

Second, Mr. Reilley estimated growth for the sample utilities through use of an implied future growth methodology (bxr) whereby the sum of each utility's historical retained earnings ratio (b) and historical returns on book equity (r) are utilized as representations of expected growth. Application of this methodology to the sample utilities for the 1980-1984 time period produced a projected growth ranging from 1.07 percent to 4.33 percent.

Third, Mr. Reilley reviewed the dividend growth rates projected by Value Line, Salomon Brothers and Merrill Lynch for each sample utility. Based upon those growth projections, Mr. Reilley determined that dividend growth during the next five years is expected by those firms to average approximately 3.6 percent. For purposes of establishing a range of expected growth for this analysis of the sample companies, Mr. Reilley used 3.11 percent and 4.07 percent, being the lowest and highest growth projections, as reasonable and upper and lower limits.

Fourth, by combining each of the three previously mentioned growth calculations into one estimate, Mr. Reilley hoped to capture the growth expectations of those investors who do not depend exclusively on one calculation methodology. The results of this combination of growth measures are as follows:

Actual Historical Growth	2.99%-3.38%
Implied Growth (bxr)	1.07%-4.33%
Projected Dividend Growth	3.11%-4.07%
AVERAGE	2.39%-3.93%

In order to determine the appropriate yield for each sample utility, Mr. Reilley utilized the current quarterly dividend for each utility as reported in the October 7, 1985 Wall Street Journal and the average price of common stock for each utility during the period of August 2, 1985 through October 4, 1985. The average yield for the sample utilities was found by Mr. Reilley to be 11.44 percent. The results of Mr. Reilley's surrogate company DCF analyses is as follows:

	Yield + Growth = Cost of Equity
Historical Growth	11.44 + 2.99 - 3.38 = 14.43 - 14.82%
Implied Growth	11.44 + 1.07 - 4.33 = 12.51 - 15.77%
Projected Growth	11.44 + 3.11 - 4.07 = 14.55 - 15.51%
Combined Growth	11.44 + 2.39 - 3.93 = 13.83 - 15.37%

b. EPEC-specific DCF analysis. In addition to the surrogate companies DCF analysis, Mr. Reilley performed a company specific DCF analysis. EPEC's current common dividend is $1.52 annually. Noting that EPEC has traditionally increased its dividends in the third quarter over the last several years, and that EPEC's 1985 quarterly dividend was 4.5 percent larger than the previous year's dividend, Mr. Reilley assumed that EPEC would increase its current dividend by 4.5 percent in the third quarter of 1986 and projected a 1986 dividend of $1.54 for purposes of his DCF analysis. Noting that in September and October, 1985, EPEC's common stock traded in the price range of $13.25 to $14.38 per share, Mr. Reilley assumed a representative price of $14.00 for EPEC stock. Based on these dividend and stock price assumptions, Mr. Reilley calculated a dividend yield of approximately 11.0 percent for EPEC common stock.

For purposes of determining expected dividend growth, Mr. Reilley utilized an implied growth analysis (bxr) and an historical growth analysis. Additionally, Mr. Reilley reviewed the growth projections of several investment advisory services.

On the basis of his implied growth analysis, Mr. Reilley projected that investors would expect EPEC to have short-term growth of 7.6 to 10.0 percent. Although failing to state a long-term growth projection, Mr. Reilley noted that investors would likely have lower expectations for long-term growth. On the basis of an historical growth analysis performed in the same fashion as for his surrogate company analysis, Mr. Reilley found EPEC to have an annual growth of 5.88 percent in net book value, 7.77 percent in earnings per share and 4.80 percent in dividends per share. Mr. Reilley testified that dividends per share is probably the most meaningful indicator of future growth for EPEC because it is not inflated by AFUDC earnings. Due to accounting convention, AFUDC is counted as earnings on a utility's financial records even though there is no cash flow associated with AFUDC until plant is included in rate base.

Reviewing recent publications by Value Line and Salomon Brothers, as well as other investment advisory services, Mr. Reilley determined that investment analysts anticipate EPEC to experience short-term growth in earnings and dividends of 4.7 percent to 5.5 percent.

Mr. Reilley concluded from his analyses that a growth estimate of 4.0 to 5.0 percent best reflects investors' perceptions of EPEC's growth potential.

Using the dividend yield of 11.0 percent and a growth estimate of 5.0 percent, Mr. Reilley derived an estimated cost of equity for EPEC in the range of 15.0 percent to 16.0 percent. Mr. Reilley did not include a market-to-book adjustment in his DCF analysis because EPEC does not plan any major issues of stock during the time that rates set in this docket are in effect.

c. Risk premium analysis. In addition to his surrogate and company specific DCF analyses, Mr. Reilley performed a risk premium analysis. According to Mr. Reilley, because the Federal Reserve is attempting to hold interest rates stable at least for the near term, thereby reducing bond volatility, a risk premium approach can currently be viewed as a legitimate cost of equity estimation tool.

In developing his risk premium, Mr. Reilley utilized an investor survey performed by Paine Webber during March and April of 1985. The survey polled 356 institutional electric utility security analysts for their expected return on electric utility common stocks versus a double A bond yield of 12.5 percent. According to Mr. Reilley, the poll reflected that investors required a return of from 256 basis points to 459 basis points more than the bond alternative, depending upon whether and to what extent a utility was engaged in nuclear construction. Therefore, Mr. Reilley assumed that an appropriate risk premium for EPEC would fall between 250 and 450 basis points.

Mr. Reilley noted that during September 1985, Moody's Bond Survey reported that BBB rated bonds yielded an average of 12.72 percent while single A bonds yielded an average of 12.13 percent. Averaging the two to correspond to EPEC's split rating produces a yield of 12.43 percent which Mr. Reilley believes is appropriate. Addition of the 250-450 risk premium range to the yield provides a cost of equity estimate of between 14.93 percent and 16.93 percent.

On the basis of the above discussed DCF and risk premium analyses, Mr. Reilley concluded that EPEC should be found to have a cost of equity of 15.5 percent. In making this recommendation, Mr. Reilley relied most heavily upon his company specific DCF analysis, believing that that analysis most closely reflects the specific risks inherent in the ownership of EPEC common stock at this time.

3. DOD's Position

Mr. Philip Winter testified on behalf of DOD regarding EPEC's cost of equity. Based upon his use of a two-stage DCF analysis specific to EPEC, a risk premium analysis, and a market-to-book ratio analysis, Mr. Winter recommends that EPEC be found to have a cost of equity of 14.85 percent, being the mid-point of his projected cost of equity range of 14.5 percent to 15.2 percent.

a. <u>DCF analysis</u>. Mr. Winter has used a two-stage non-constant DCF model in performing his DCF analysis. A two-stage model allows consideration of varying dividend growth rates over time whereas a single stage model assumes a constant rate of dividend growth into infinity. According to Mr. Winter, the traditional DCF model assumes that market price, earnings and book value of common stock each grow at the same constant rate as dividends, even though the rate of utility company dividend and price growth has varied widely over past time periods. Mr. Winter believes that the investment community expects variation in price and dividend growth over future holding periods. A multistage DCF model allows explicit consideration of varying growth rates. According to Mr. Winter, the two-stage DCF model has been accepted in the investment and academic communities. Mr. Winter's two-stage model utilizes a four year forecast period for short-term growth which constitutes the initial stage of the model.

For purposes of projecting short-term and long-term growth, Mr. Winter has relied upon investment advisory service growth forecasts. Data obtained from publications put out by <u>Value Line</u>, Prudential-Bache, Merrill Lynch, Salomon Brother, Duff and Phelps and Dean Witter, reflect near-term dividend growth rate projections ranging from 4.0 percent to 6.3 percent. According to Mr. Winter, the average of these forecasts falls near the upper end of the 3 percent to 5 percent growth rate range forecast for electric utilities in general by E. F. Hutton in its July-August 1985 <u>Equity Research</u> report.

Mr. Winter testified that short-term historical growth rates for EPEC range from 3.4 percent to 6.1 percent. Mr. Winter concluded that a short-term growth rate of 4.5 percent to 5.0 percent is most representative of investors' growth expectations for EPEC.

For purposes of long-term growth, which constitutes the second stage of Mr. Winter's DCF model, Mr. Winter relied upon Merrill Lynch's long-term growth forecast for EPEC of 4.4 percent as well as historical growth rates for both regulated utilities and unregulated firms in general. Using data from Moody's Utility Index and the DOW Industrial Index, Mr. Winter found historical growth rates for regulated utilities and unregulated firms to range from 3.0 percent to 4.2 percent. Mr. Winter used the mid-point of the lowest historical growth rate and the projected future long-term growth rate of EPEC, being 3.7 percent, as the appropriate long-term growth rate for his DCF model.

For purposes of determining the current dividend yield, Mr. Winter used the average of the quotients of end-of-week stock prices and effective annual dividend rates for a sixteen week period running from June 14, 1985, through September 27, 1985. Mr. Winter's calculations result in a yield of 10.1 percent. Under Mr. Winter's two-stage DCF model, a cost of equity range of 14.5 percent to 15.2 percent is projected.

b. Risk premium analysis. Mr. Winter performed a risk premium analysis as a check on the validity of his DCF results. For purposes of a risk premium analysis, Mr. Winter used the historical spread between utility stocks and long-term government bonds for the period 1929 to 1984 to calculate an appropriate risk premium.

Based upon geometric mean returns, Mr. Winter determined that a portfolio of Moody's 24 Utilities during the period 1929 to 1984 provided a return of approximately 182 basis points more than long-term government bonds. Calculating the average of the premiums that would have been realized over all whole-year holding periods of one year to ten years during 1929 to 1984 produced an average premium of 359 basis points. Citing the recent volatility in the bond market, Mr. Winter believes a risk premium at the lower end of the above historical risk premium range is appropriate. Using the average yield on long-term treasury securities over the period of June 14, 1985 through September 27, 1985, being 10.7 percent, as the base upon which to add a risk premium, Mr. Winter finds that his recommended return range of 14.5 percent to 15.2 percent offers a return well in excess of what could be justified by his risk premium analysis.

c. Market-to-book ratio analysis. As a final check on the reasonableness of his DCF results, Mr. Winter performed an analysis of the statistical relationship between current market-to-book ratios for electric utilities and the corresponding expected returns on book equity. Mr. Winter utilized a *Value Line* survey published in July 1985 to obtain current market-to-book ratios and expected returns for 47 regulated electric utilities. Through the use of regression analysis, Mr. Winter determined that a return on equity of 12.81 percent corresponds to a market-to-book ratio of 1.0 for companies with EPEC's *Value Line* safety ranking. Finding this figure to be well below the cost of equity which he calculates using the two-stage DCF methodology, Mr. Winter concludes that his recommend cost of equity of 14.85 percent for EPEC is reasonable.

4. City's Position

Mr. Basil Copeland testified on behalf of the City regarding EPEC's cost of equity. Utilizing a surrogate companies DCF analysis, Mr. Copeland has found EPEC's cost of equity to be 15.0 percent.

In compiling a sample of companies comparable to EPEC, Mr. Copeland utilized those companies with a Value Line safety ranking of three which are involved in nuclear construction and which are reported on by Value Line in its July 16, 1985 Central Edition. Additionally, he used two utilities which are reported in Value Line's Western Edition because of the fact that they are PVNGS participants. A total of ten utilities are included on Mr. Copeland's sample, one of which is in fact EPEC.

Mr. Copeland relied upon an implied growth methodology (bxr) to determine expected growth for each of the utilities in his sample. The earnings, dividend and book value forecasts published by Value Line were used to develop forecasts for each utility's earnings retention rate (b) and expected return on book equity (r). Additionally, Mr. Copeland testified that he supplemented his analysis by deriving estimates of b and r for each company using earnings per share and dividends per share forecasts projected by Merrill Lynch in its investor publication Quantitative Analysis.

Mr. Copeland indicated that he utilized a two-stage non-constant DCF model as well as a single stage constant DCF model in projecting growth. He presented the results of both DCF models in his analyses and relies equally on the results of both.

For purposes of determining the dividend yield, Mr. Copeland used the current dividend per share for each utility. Unfortunately, his analysis does not provide his rationale for choosing the representative stock prices he utilizes. Using a constant DCF model, Mr. Copeland's surrogate DCF analysis reflects mean and median return requirements of 15.3 percent and 15.2 percent, respectively, using Merrill Lynch projections and 15.1 percent and 15.2 percent, respectively, using Value Line projections. Using a two-stage DCF model, Mr. Copeland's analysis reflects mean and median return requirements of 14.5 percent and 14.9 percent, respectively, with Merrill Lynch projections and 14.6 percent with both Value Line projections. On the basis of these results, Mr. Copeland recommends that the Commission find EPEC to have a cost of equity of 15.0 percent.

5. Examiner's Recommendation

As a beginning point, the examiner notes that all of the rate of return witness in this proceeding have to some extent incorporated questionable assumptions in formulating their DCF analyses. Notwithstanding that fact the examiner finds that the DCF analyses presented in this docket are the most reliable measures for determination of the return on EPEC common equity required by investors. The examiner believes that each of the other methodologies utilized by the parties is flawed in some respect and therefore is of limited probative value.

First, the examiner rejects the market-to-book ratios analyses performed by Mr. Winter. Mr. Winter failed to adequately explain the regression analysis he performed and his analysis appears to incorporate a number of assumptions which are questionable and which cannot be validated by the examiner. The fact that the results of that analysis are far out of line with other analyses performed by witnesses in this proceeding casts further doubt on that methodology.

Second, the examiner rejects Mr. Jackson's "net proceeds" analysis which is only cursorily addressed in his prefiled testimony. That methodology appears to constitute some form of market-to-book adjustment and risk premium analysis rolled into one methodology. As is discussed below, a market-to-book adjustment is not warranted by the evidence and this methodology is not supportable by Mr. Jackson's testimony or by the record.

Third, the examiner rejects the risk premium analyses performed by Mr. Reilley and Mr. Winter. Mr. Winter's concerns regarding volatility in the bond market leads the examiner to question Mr. Reilley's conclusion that risk premium analyses appear at present to be legitimate tools for determining cost of equity. Mr. Winter compared the coefficients of variation for stock and bond prices in his prefiled testimony and noted that stock and bond prices were more volatile in 1984 and early 1985 than in 1983. Mr. Winter also makes reference to a April 1985 Merrill Lynch publication entitled "Valuation Perspectives" which Mr. Winter relies upon to show that bond price volatility continues to exceed that of stocks in general. Finally, Mr. Winter stated on cross-examination that a November 11, 1985 report by Salomon Brothers indicates that volatility in the bond market is continuing and that it once again appears that bonds may be at least equally as risky as common stocks. The examiner has sufficient concern regarding the probative value of such analyses at present to recommend that both Mr. Reilley's and Mr. Winter's analyses be disregarded for purposes of this docket. The examiner believes that EPEC's cost of equity can adequately be determined in this docket on the basis of the DCF analyses presented herein, and that the DCF methodology will, when questionable assumptions are eliminated, most closely approximate EPEC's cost of equity during the period when rates set in this docket will be in effect.

a. Surrogate companies DCF analysis. Mr. Copeland, Mr. Reilley and Mr. Jackson each performed a surrogate companies DCF analysis. In the examiner's opinion, the results of such analyses must be evaluated on the basis of the comparability of the utilities selected to EPEC.

Mr. Jackson's set of comparable companies is flawed because of his failure to remove utilities which have been forced to cut or omit dividends. Additionally, Mr. Jackson does not limit his sample groups to utilities which are involved in nuclear construction.

Mr. Copeland limited his pool of utilities from which to select comparables to those utilities listed in Value Line's Central Edition, thereby removing from consideration utilities in other parts of the country which may be more comparable to EPEC than the utilities he actually selected. The only screen Mr. Copeland used, other than a requirement that the utilities be involved in on-going nuclear construction, was that the utilities have the same Value Line safety ranking as EPEC. According to Mr. Copeland, Value Line's safety ranking is a general ranking of investors' perceptions of the overall safety of stocks. In the examiner's opinion Value Line safety rankings constitute a very loose screen for filtering out non-comparable utilities. Mr. Copeland did not screen his sample by size of the utility, by percentage of AFUDC to net income or by any other such criteria which might help assemble a truly comparable set of utilities.

On the other hand, Mr. Reilley looked at all utilities in the country with nuclear exposure and screened them by percent of electric revenues, financial risk, size of construction program, capitalization, bond rating and dividend history. In the examiner's opinion, Mr. Reilley utilized the most thorough and accurate procedure for selecting a set of utilities comparable to EPEC. Based upon application of DCF analysis to this sample of comparable utilities, Mr. Reilley found EPEC to have a return requirement of from 13.80 percent to 15.37 percent. However, Mr. Reilley states in his testimony that his comparable companies may be somewhat less risky than EPEC and that in his opinion it is most appropriate to rely on data specific to EPEC in determining an appropriate cost of equity for that company. The examiner is inclined to agree with Mr. Reilley's judgment. Given that EPEC has the highest nuclear exposure of any utility in the country, relative to size of the company, it would appear difficult to select utilities which are truly in a position comparable to that of EPEC. Therefore, the examiner finds that a DCF analysis using data specific to EPEC will likely produce the most accurate estimation of return on EPEC common equity required by investors and the examiner recommends that the return on equity set by the Commission be based upon EPEC-specific data.

b. EPEC-specific DCF analysis.

(1) EPEC Dividend Yield

The following dividend yields specific to EPEC have been put forth by the parties for use in the DCF formula:

	EPEC
EPEC	11.74%
Staff	11.00%
City	9.73%
DOD	10.10%

Of the above yields, the examiner finds that the staff's proposed yield best approximates the dividend yield to be expected in 1986. This conclusion is based on Mr. Reilley's use of the most realistic dividend and stock price figures. The examiner notes that Mr. Reilley and Mr. Copeland were the only witnesses who actually set forth in their testimony or exhibits the actual EPEC stock prices and dividends which they assumed in calculating yields. Although Mr. Copeland utilized a surrogate DCF methodology rather than a company specific methodology, he did include EPEC in his list of comparables and in that context applied the DCF methodology to data specific to EPEC. Therefore, the examiner has used that data for purposes of this discussion. Although Mr. Winter and Mr. Jackson stated how they calculated their assumed dividend yields, they never expressly stated the dollar stock prices and dollar dividend numbers used. In the absence of that data, the examiner cannot evaluate the appropriateness of their proposed dividend yields.

With regard to stock price, Mr. Reilley testified that during September and October 1985, the two months immediately preceding the hearing in this docket, EPEC's common stock traded in the price range of $13.25 to $14.38 per share. Mr. Reilley indicated that he felt that $14.00 was a representative market price. While Mr. Reilley's choice of $14.00 is not based upon any mathematical calculation, it does appear reasonable given recent trading prices for EPEC common stock. In choosing the $14.00 figure Mr. Reilley noted that a recent representative price is a better indication of investors' present requirements than is an historical point estimate or a long run average, since cost of equity is a current and forward looking concept. The examiner agrees. Although Mr. Jackson did not specify the stock price he assumed for DCF purposes, he indicated that he utilized an historical average price. Use of an historical average would appear to understate the present value of EPEC common stock, thereby increasing the yield component of the DCF calculation. With regard to Mr. Copeland's use of a $15.00 price per share of common stock, Mr. Copeland never offered any explanation of why he used that particular price. Although not unreasonable, $15.00 appears to be a somewhat excessive price in light of EPEC's stock prices over the last two months.

As to annual dividends, Mr. Reilley stated that he calculated 1986 dividends based upon three quarters of the current EPEC quarterly dividend of $.38 per share and one quarter at a projected dividend of $.40 per share since EPEC usually raises its dividend in the third quarter of each year and the amount of the 1986 third quarter dividend increase is likely to be 4.5 percent, or $.02 per share. On an annual basis, Mr. Reilley's projected dividend is $1.54 per share. Mr. Copeland uses an annual dividend of $1.46 per share which equates to use of EPEC's dividend prior to the dividend increase implemented by EPEC in August 1985. Of the two dividend projections, Mr. Reilley's is clearly more current and more appropriate for use in calculating EPEC's current dividend yield. It is not clear from Mr. Jackson's or Mr. Winter's testimony what dollar dividend figure they use to calculate EPEC's yield, although it appears from cross-examination that Mr. Jackson used the four quarters of dividends preceding March 31, 1985.

Division of Mr. Reilley's assumed annual dividend of $1.54 by his assumed stock price of $14.00 produces a current dividend yield of 11.00 percent. The examiner recommends that that yield be used for purposes of an EPEC-specific DCF analysis.

(2) Expected growth. The following growth expectations were utilized by the parties in their EPEC-specific DCF calculations:

EPEC	5.35%	
Staff	4.0% - 5.0%	
City	5.1% - 8.8%	
DOD	4.5% - 5.0%	(short-term)
	3.7% - 4.4%	(long-term)

Mr. Jackson's projection is limited to analysis of historical dividend growth, without resort to other methodologies to substantiate his projection. Mr. Reilley's projected growth rate is based upon review of historical trends in net book value per share, earnings per share and dividends per share, as well as review of investment advisory service projections and use of an implied growth methodology. Mr. Copeland's growth projections are based solely upon an implied growth methodology and his results reflect an unacceptably wide range in expected growth. Mr. Winter's short-term growth projection is based upon review of investment advisory service forecasts and historical short-term growth history. His long-term growth projection is based upon historical growth data for regulated utilities and unregulated businesses gleaned from Moody's Utility Index and the Dow Industrial Index. Additionally, he relies upon a long-term growth projection of 4.4 percent made by Merrill Lynch. With the exception of the Merrill Lynch projection, the basis for Mr. Winter's long-term forecast is highly suspect.

Mr. Reilley and Mr. Winter are the only witnesses who used multiple methodologies to verify the accuracy of their growth projections. If Mr. Winter's questionable use of Moody's Utility Index and Dow Industrial Index historical data is rejected, then it appears that Mr. Reilley and Mr. Winter both propose growth projections falling within the 4.0 percent to 5.0 percent range. The examiner finds this range to be most appropriate and best capable of being suggested by the record. Therefore, the examiner proposes that the mid-point of that projected growth range be utilized for DCF purposes. Combining a current dividend yield of 11.0 percent with an expected growth of 4.5 percent produces an required return on equity of 15.5 percent when using EPEC-specific data.

(3) Market-to-book adjustment. EPEC witness Jackson has recommended that a market-to-book adjustment be utilized to insure that EPEC stock issues are sold on a non-dilutive basis. The examiner strongly disagrees with the propriety of this adjustment. Clearly, a market-to-book adjustment is warranted, if ever, only in such instances where major stock offerings are

contemplated within the near future. The evidence is this record reveals that EPEC anticipates no new stock offering in 1986, and based upon representations in EPEC's brief, it is fair to conclude that EPEC intends to initiate another rate increase request within the next year. There is therefore no basis for considering a market-to-book adjustment in this docket.

c. Conclusion. The examiner finds EPEC to have a cost of equity of 15.5 percent, although a range of 15.0 percent to 16.0 percent is fully supportable from the evidence of record.

D. Overall Rate of Return

The examiner proposes an overall rate of return on invested capital of 12.21 percent (rounded) for EPEC, calculated as follows:

Source	Amount	Ratio	Cost	Weighted Cost
Long-term Debt	$ 750,037,000	52.67%	10.39%	5.473%
Preferred Stock	150,873,000	10.59%	9.80%	1.038%
Common Equity	523,098,000	36.73%	15.5%	5.694%
Total	$1,424,008,000	100%		12.21%

VIII. Annualization and Other Revenue Adjustments

Mr. McClellan Harris testified on behalf of EPEC regarding revenue adjustments made by EPEC as a consequence of annualization of test year kw and kwh sales and customers. Staff witness Kim Oswald has recommended that the Company's annualization methodology and revenue adjustments be accepted by the Commission without modification. However, the City has taken issue with EPEC on the appropriate methodology to be used for annualizing test year kwh sales to account for customer growth as well as on EPEC's reduction to kw and kwh sales to account for reduced energy usage by Southwest Portland Cement. Additionally, the City has proposed an adjustment for unbilled revenues and an adjustment to fuel revenues to match the City's proposed kwh annualization adjustments. A discussion of each of these issues follows below.

A. Customer Growth Adjustment

The customer adjustment to test year kwh sales is made to account for changes in the number of customers during the test year. The adjustment brings test year kwh sales to the level that would have been achieved had the same number of customers been on the system throughout the test year as were on the system at the end of the test year. For purposes of annualizing kwh sales, EPEC divided the Texas Retail Jurisdiction into four groups. Group I consists of Rate 01, with Subrates 05, 06 and 21; Rates 11, 22, 23, and 24 with Subrate 02; and Rates 25, 26, 41 and 54. It is EPEC's methodology for annualizing kwh usage for the rate classes included in Group I which the City opposes. Under EPEC's methodology, average kwh sales per month is computed by dividing per book kwh sales for each month by the number of customers at the end of the month. This average is multiplied by the difference between the number of customers at the end of each month. These monthly adjustments are totaled to yield the kwh adjustment for year-end number of customers.

City witness Hugh Larkin has taken issue with EPEC regarding the accuracy of this methodology. According to Mr. Larkin, the Company's calculation incorrectly assumes that all new customers added during each month entered the system on the first day of each month and, therefore, consumed the same average amount of energy as those customers who had in fact been on-line for the entire month. The effect of assuming that all new customers enter the system on the first of the month is to understate the average kwh usage per customer per month. Mr. Larkin has proposed that EPEC's methodology be modified such that customers are assumed to come on line ratably during the month, rather than on the first day of the month, and that the average number of customers be used to compute average usage per customer.

EPEC opposes implementation of this modification to the year end customer adjustment calculation on the basis that the City's proposal has been rejected in past dockets and that appeasement of the City's preference is not a justifiable basis for altering the current annualization procedure. EPEC also implies that refinement of the current annualization procedure would in some way violate the rate design and revenue distribution stipulation entered in this docket.

With regard to EPEC's contention that the Commission has considered and rejected the City's proposal in past dockets, the examiner notes that the record in this docket is not identical to the record in prior dockets on this issue. In Docket No. 5700, the examiners stated that the City's proposal was rejected in large part because the record was unclear as to how the "average" number of customers was to be computed under the City's proposal, and because the City's witness did not demonstrate in his testimony that the use of average figures would be more accurate than the current annualization methodology. In this docket, Mr. Larkin's prefiled testimony illustrated in detail his contention that his proposed methodology is more accurate than EPEC's methodology and he demonstrated the exact manner in which the "average" number of customers is to be calculated. In other words, the City cured the deficiencies in its testimony on this issue which existed in Docket No. 5700, and thereby eliminated the major arguments used by the examiners in Docket No. 5700 to reject this proposal.

With regard to EPEC's contention that refinement of the current annualization would contravene the terms of the cost allocation and rate design stipulation, the examiner notes that paragraph 5 of that agreement expressly provides that the annualized adjusted kw demand and kwh sales <u>as found by the Commission</u> in this proceeding shall be used for rate design purposes. Clearly, EPEC's contention that acceptance of the City's proposed annualization methodology would violate the stipulation of the parties is meritless.

The examiner finds that Mr. Larkin's proposed modification of the current annualization methodology used by EPEC is necessary, reasonable, and fully supported by the evidence of record. Accordingly, the examiner recommends that new customers be assumed to enter the system ratably during the month, and that the average kwh usage per customer for each month be determined by dividing monthly per book kwh by the average number of customers in service for each respective month. The effect of this adjustment is to increase EPEC's adjusted test year kwh sales by 3,548,180 kwh.

B. Reduced Load Adjustment

EPEC witness Harris testified that he adjusted test year kwh sales and billing kw in order to reflect Southwest Portland Cement Company's (SPC) reduction in service requirements which commenced in January, 1985. The adjustment is based upon EPEC's best estimate of SPC's anticipated usage in 1985. The City, although recognizing that SPC has in fact reduced its load from the test year level, has opposed this adjustment on the basis that it is inappropriate to recognize a post test year decrease in consumption without also recognizing post test year increases in sales due to the addition of new customers under the general service and large power service classifications.

Mr. Larkin testified that thirteen new general service and large power service customers have been added to the system or are projected to be added to the system during 1985. Using data obtained from EPEC, Mr. Larkin compiled a schedule reflecting the effect of the addition of those new customers on billing determinants and revenues and comparing those effects to EPEC's adjustment for SPC. The results of Mr. Larkin's comparison reflect that the increase in consumption resulting from the addition of new customers in the general service and large power service classifications in 1985 more than offsets SPC's decreased consumption. Mr. Larkin therefore recommends that EPEC's adjustment to reflect reduced consumption by SPC be reversed.

EPEC opposes this recommendation on the basis that the SPC reduction constitutes a known and measurable change, whereas increases due to anticipated load additions are speculative and cannot constitute known and measurable changes. In the examiner's opinion, Mr. Larkin's proposal to reverse the SPC adjustment is appropriate. As the Commission uses an historic test year, known and measurable changes should be recognized only where there is little doubt as to their appropriateness. In this instance, it appears that there have been post test year customer additions which offset the reduction in usage by SPC. Under the circumstances, the examiner questions the need to make an adjustment to account for SPC's reduced load. The examiner would also note that, although there are undoubtedly reduced expenses which would result from reduced SPC load, EPEC has not proposed any expense reduction which corresponds to this revenue adjustment.

As the examiner has doubts regarding the propriety of EPEC's adjustment of kw and kwh sales to reflect SPC's reduced load, the examiner concurs with the City's position that EPEC's adjustment should be reversed. Reversal of EPEC's SPC adjustment results in an increase in adjusted kwh sales of 22,764,924 kwh.

C. Unbilled Revenues

City witness DeWard proposed an upward adjustment of $816,391 to adjusted test year revenues to reflect unbilled revenues. According to Mr. DeWard, an unbilled period is created due to the processing time involved between the time a meter is read and the date the billing is rendered and/or that revenue is recorded on the books such that, at any given time, there are unbilled revenues that EPEC has not recorded on its books. Mr. DeWard testified that in order to properly match revenues and expenses, it is necessary to determine the amount of unbilled revenue at December 31, 1984 and December 31, 1983, and to reflect the change in the amount of unbilled revenues in operating revenues. According to Mr. DeWard, this change in unbilled revenues from 1983 to 1984 totals $816,391 on a total company basis.

EPEC witness Johnson testified on rebuttal regarding this proposed adjustment. According to Mr. Johnson, the annualization of revenues calculates the expected revenues which will be produced from all kwh expected to be sold. Therefore, as annualization is based on total kwh sales, the effect of cycle billings is eliminated.

The examiner concurs fully with EPEC's refutation of the necessity of adjusting revenues to account for unbilled revenues and recommends that Mr. DeWard's adjustment be rejected for want of merit.

IX. Cost of Service

EPEC has proposed a total cost of service of $461,121,408 in its CWIP filing. A breakdown of the components comprising the requested revenue requirement, taken from Revised Schedule I of Staff Exhibit No. 4A, is as follows:

Fuel	$ 84,605,476
Purchased Power	62,408,599
Operations & Maintenance	49,909,648
Depreciation & Amortization	16,480,207
Other Taxes	20,861,851
Interest on Customers Deposits	183,640
State Income Taxes	3,330,037
Federal Income Taxes	74,462,282
Return	148,879,668
Total	$461,121,408

The staff accountant and EPEC each categorize expenses in a somewhat different manner, which makes it difficult to cross-reference between the Rate Filing Package and the staff accounting testimony. Due to the examiner's familiarity with staff cost of service presentations, the examiner has utilized the staff's accounting format in the cost of service discussion which follows below.

Additionally, EPEC, the staff and the City each presented the examiner with extensive corrections to their original accounting testimony. The original and corrected accounting testimony presented by the City and the staff refer to the original Rate Filing Package numbers. It is therefore difficult to compare EPEC's corrected accounting data to the staff's and the City's corrected numbers. Although recognizing that EPEC has corrected certain accounting numbers in its filing, the examiner refers herein solely to EPEC's original filing in order to avoid confusion and the necessity of recalculating the dollar amount of each adjustment made by the City or the staff.

Finally, in the interest of brevity, the examiner has not addressed herein each accounting adjustment proposed by EPEC. The examiner had addressed only those adjustments proposed or questioned by the City and the Commission staff. To the extent that the examiner does not address an adjustment proposed by EPEC, it is appropriate to assume that the examiner concurs in the propriety of that adjustment.

A. Fuel and Purchased Power

1. Natural Gas Costs

EPEC purchases its natural gas requirements from two suppliers. El Paso Natural Gas Company (EPNG) supplies interstate natural gas to the Rio Grande generating station and serves as an alternate supply source for the Newman generating station under the terms of an existing interstate natural gas sales agreement. El Paso Hydrocarbons Company (EPHC) of Odessa, Texas, supplies intrastate natural gas to the Newman and Copper generating stations, through its subsidiary El Paso Gas Transportation Company, Inc. (EPGT).

The following chart reflects the natural gas prices per MMBtu proposed by the Company, the City and the staff for each of EPEC's generating stations:

	Newman (EPGT)	Copper (EPGT)	Rio Grande (EPNG)	Four Corners (EPNG)
EPEC	3.50	3.52	4.02	2.70
City	3.19	3.14	3.75	3.58
Staff	2.83	2.83	3.55	3.35

EPEC and the City have both recommended in their posthearing briefs that the staff's proposed natural gas prices be adopted. As the cost of gas is therefore uncontested, the examiner concurs with the City and EPEC that the staff's proposed gas prices be adopted in this proceeding. The examiner notes that staff witness Michael Still has recommended that EPEC continue to work closely with EPGT in attempting to take advantage of the currently soft natural gas market. Additionally, Mr. Still has recommended that EPEC aggressively seek to arrange third party transport of gas by either EPGT and EPNG in the future. The examiner concurs with these recommendations.

2. Coal Costs

The entirety of EPEC's coal fired generation is supplied by the Four Corners generating station in New Mexico. EPEC owns 110 MW of Four Corners Units 4 and 5. The remaining 1,368 MW of Units 4 and 5 are owned by five other utilities, including Arizona Public Service (APS). APS owns all of Units 1, 2, and 3 and is the managing partner for Units 4 and 5. The Four Corners generating station is a mine mouth plant. Coal is supplied to the Four Corners generating station exclusively by Utah International, Inc. under a 35 year fuel supply agreement. In addition to the coal supply agreement, EPEC and the other Four Corners Units 4 and 5 partners contract with Utah International for the disposal of ash from the plant.

In its rate filing package, EPEC requested that the Commission find EPEC to have an adjusted test year cost of coal of \$0.94 per MMBtu. Staff witness Stan Kaplan noted that the price requested by EPEC was obviously inadequate, given that the price of Four Corners coal had already reached a level of \$0.968 per MMBtu as of April 1985. It appears that EPEC actually projected a 1986 cost of Four Corners coal of \$0.994 per MMBtu, exclusive of ash disposal and coal handling charges, but by apparent oversight, EPEC failed to request that coal price in its CWIP rate filing package in this docket. Nonetheless, the parties' posthearing briefs reflect that no one opposes the \$0.994 per MMBtu cost of coal, exclusive of ash disposal and coal handling charges, which EPEC included in its plant in service filing and which Mr. Kaplan believes should be adopted given historical coal price escalation at the Four Corners station. According to Mr. Kaplan, the \$0.994 estimated adjusted test year coal price is based upon the output of a computer model of the Four Corners coal contract maintained by APS. As no one contests Mr. Kaplan's 1986 projected coal price of \$0.994 per MMBtu exclusive of coal handling and ash disposal costs, and as Mr. Kaplan has provided ample justification for that coal price in his prefiled testimony, the examiner recommends adoption of that estimate.

Although the cost of coal was not contested by the parties, the Commission staff contested EPEC's methodology for determining an appropriate adjustment to that base coal price to account for coal handling and ash disposal costs. In order to determine an appropriate coal price adjustment for coal handling and ash disposal costs, EPEC determined the average ratio of total coal costs (fuel cost plus handling and ash disposal cost) to the fuel cost alone for the period 1982 through 1984. Finding that the ratio of total cost to fuel cost has averaged approximately 105 percent over that period, EPEC added five percent to the monthly coal prices generated by the APS model, resulting in a projected \$1.045 per MMBtu weighted average 1986 price of coal. According to Mr. Kaplan, it is inappropriate to express ash disposal and coal handling costs as a function of coal price. Mr. Kaplan testified that only the overhead portion of ash disposal cost, which accounts for one-third or less of ash disposal cost, is tied to changes in a portion of the coal price. The remainder of the ash disposal and coal handling costs are apparently based upon labor and investment cost calculations unrelated to the coal price.

Mr. Kaplan proposed an alternative methodology for accounting for ash disposal and coal handling costs, suggesting that test year ash disposal costs should be stated as a cost per MMBtu and then added to the APS monthly coal price projections. Using this methodology, Mr. Kaplan determined that test year coal handling and ash disposal costs equate to \$0.038 per MMBtu, based upon 1984 coal burn.

Mr. Kaplan's methodology produces an estimated 1986 coal cost, inclusive of coal handling and ash disposal charges, of \$1.032 per MMBtu as opposed to \$1.045/MMBtu under the Company's methodology.

EPEC attempted to demonstrate through cross-examination and in its brief that Mr. Kaplan's methodology runs the risk of understating 1986 coal handling and ash disposal costs since his calculation is based on test year costs and does not take into consideration higher costs which occurred in prior years, as does EPEC's methodology. However, Mr. Kaplan noted that, as those costs declined from 1982 to 1983 and then remained constant at \$0.38 per MMBtu from 1983 to 1984, it is reasonable to use test year costs.

The examiner finds Mr. Kaplan's methodology for adjusting coal prices for the cost of coal handling and ash disposal to be preferable to EPEC's methodology. The examiner therefore recommends that the \$1.032 price per MMBtu resulting from that methodology be adopted by the Commission. The examiner notes that Mr. Kaplan treats ash disposal and coal handling costs as variable costs as opposed to fixed costs, due to the uncertainty of the costs and the recent history of wide downward swings in coal consumption at the Four Corners plant, which would tend to reduce the ash disposal and coal handling costs. As variable costs, those costs are appropriately included in EPEC's fuel factor. No party to this proceeding has opposed Mr. Kaplan's recommendations in that regard.

Mr. Kaplan has recommended that, given the history of large coal price escalations under the existing coal supply contract with Utah International, Inc., EPEC should request renegotiation of coal prices under that contract in 1986. Under the terms of that contract, the Four Corners partners can request adjustment of the coal price in 1986 if they believe Utah International is earning an excessive return on investment under the Four Corners contract. While Utah International, Inc. coal is currently the least-cost possible coal to the Four Corners plant, Mr. Kaplan points out that in another five or ten years, the coal provided by Utah International, Inc. may look expensive rather than cheap compared to other delivered coal prices. The examiner concurs in Mr. Kaplan's recommendation that EPEC be directed to exercise the renegotiation option available to it in 1986.

3. Generation Efficiency & Productivity

P.U.C. SUBST. R. 23.23(b)(2)(I)(i) requires that a utility demonstrate that it has operated plant and generated electricity efficiently.

EPEC witness York addressed the issue of EPEC's generating efficiency and productivity in his prefiled testimony. Additionally, Mr. York attached to his testimony as exhibit REY-17, an EPEC study entitled "Optimizing Capacity Factors of Large Gas Generating Unit" which was ordered by the Commission in Docket No. 5700. In the interest of brevity the examiner has not summarized Mr. York's testimony on this issue. The examiner notes, however, that Mr. York addresses a number of specific steps which EPEC has taken to improve the efficiency and productivity of EPEC's power generation. EPEC witness Mattson testified regarding the prudency of EPEC's expenditures on fuel.

The only witness to this proceeding who addressed the issue of generation efficiency and productivity in a comprehensive fashion was staff witness Norwood.

According to Mr. Norwood, the two key indicators of generating unit performance are efficiency and productivity. The measure for generating unit efficiency is "net heat rate," which is the amount of fuel a unit consumes per kilowatt-hour supplied (measured at the plant busbar). Mr. Norwood measures generating unit productivity in terms of annual average of 1) equivalent availability, 2) equivalent unplanned unavailability and 3) capacity factor. "Capacity factor" is the percentage of maximum potential kilowatt-hours that a unit has generated in a given period, and as such, defines unit productivity in its strictest sense.

Mr. Norwood testified that in evaluating and forecasting the performance of a utility's generating units one cannot rely exclusively upon test year data because one must consider external factors which effect generating unit performance and system dispatch on a daily basis. Some of these factors are fixed or somewhat controllable by the utility, for example, generating unit design, the scheduling of routine unit maintenance and utility system reliance on firm-purchased power. However, many factors such as the weather, fuel cost and quality, system loads and load factor, availability and cost of non-firm energy, and to some extent, unit availability, are dynamic and somewhat unpredictable. Mr. Norwood testified that, to account for these external factors he focused his evaluation on those generating units which have supplied 80 percent of EPEC's generation in the recent past.

In reviewing the performance of those units, he made three comparisons of major plant groups: 1) EPEC to national averages, 2) EPEC to Texas averages and 3) EPEC historical to EPEC test year performance.

According to Mr. Norwood, the performance of EPEC's two western coal-fired units at the Four Corners Plant in New Mexico, has compared favorably to the performance of other similar units both nationally and in Texas. Mr. Norwood testified that during the last three years, these units have averaged annual capacity factors of approximately 74 percent, net heat rates of 9.8 MMBtu/MWH and equivalent availability factors some 11 percent better than the national average for similar units. During the test year (calendar year 1984), the Four Corners units had a combined average capacity factor of 75.6 percent and a heat rate of 9.71 MMBtu/MWH.

Mr. Norwood notes that although the Four Corners units have typically provided only 15 percent of EPEC's generation requirements, their performance has a significant impact on the fuel costs of the EPEC system. For example, a 5 percent decrease in the annual productivity of these units would result in an additional $1,000,000 in annual replacement fuel costs.

EPEC's gas-fired units are used primarily to supply its system intermediate and peak load requirements. According to Mr. Norwood, the overall performance of these units has been average in comparison to national and state averages during the last three years. Their efficiency has been relatively poor. Mr. Norwood testified that this problem is related to increased cycling of these gas units to accommodate EPEC's heavy utilization of lower cost non-firm energy purchases in meeting system loads. Mr. Norwood testified that the net effect of this shift in operations has been lower generation costs for EPEC's customers. Therefore, although he believes EPEC should pursue cost-effective operations and maintenance solutions to improve the efficiency of its gas-fired units, he does not recommend any adjustment to allowable fuel costs to reflect this individual aspect of their system performance. On the basis of Mr. York's testimony and Mr. Norwood's testimony, the examiner finds that EPEC has met its burden of demonstrating that it has operated plant and generated electricity efficiently, for purposes of this docket. The examiner specifically concurs with Mr. Norwood's recommendation that, although fuel costs should not be adjusted to reflect the performance of EPEC's gas-fired units, EPEC should further pursue ways to improve the efficiency of its gas-fired units.

4. Generation Mix & Fuel Requirements

EPEC witness Johnson testified regarding generation mix and overall fuel costs for the rate year. A rate year is the twelve month period immediately following the anticipated implementation of a utility's new rates. His testimony can best be described as sparse on this issue.

According to Mr. Johnson, EPEC's annualized net generation reflected a 1.9 percent decrease from the test year. Since EPEC expects its fuel mix to remain relatively constant until PVNGS Unit 1 comes on line, Mr. Johnson testified that he prorated the 1.9 percent difference to the Newman and Rio Grande Power Stations based on their actual test year ratios relative to each other. Mr. Johnson kept Four Corners and Copper 1 at the actual test year generation level. Using test year station heat rates, EPEC's projected gas and coal costs per MMBtu and the above described allocation of generation between units, Mr. Johnson projected a rate year fuel expense of $84,605,476, constituting a decrease of $600,065 from test year fuel expense.

With regard to purchased power, Mr. Johnson testified that due to the continued availability of economy purchases, EPEC anticipates that test year economy purchases will be repeated. Mr. Johnson's adjusted test year purchased power expense proposal is comprised of actual test year net purchased power excluding SPS interruptible power purchase, annualized SPS interruptible power expense and MWH based on the actual five-month average monthly expense for October 1984 through February 1985, annualized contract demand charges for SPS and annualized contract transmission capacity costs per the Public Service Company of New Mexico (PNM) wheeling agreement. Mr. Johnson's projected purchase power expense totals $62,408,599.

Staff witness Norwood testified at some length regarding generation mix, purchased power quantities and costs and total projected rate year fuel costs. Mr. Norwood testified that his generation mix forecast was developed with fuel cost forecasts provided by staff witnesses Mike Still and Stan Kaplan and a system sales forecast provided by staff witness Kim Oswald.

Mr. Norwood testified that in developing his projected generation mix for EPEC's system he relied on the fundamental concept of economic dispatch (scheduling generation based on availability and relative costs of each source). In the case of EPEC's generation units, Mr. Norwood multiplied projected unit heat rates (MMBtu/MWH) by projected unit fuel costs ($/MMBtu) to determine average per unit costs of generation ($/MWH). These were compared to the projected average costs of purchased power ($/MWH) available to the EPEC system, to determine the appropriate contribution from each potential generation source.

Because unit heat rates vary with the amount of cycling and the level of generation, Mr. Norwood indicated that it was necessary to make some initial assumptions on the capacity factor for each generating unit. Base load coal units are operated at relatively continuous output levels because of their low generation costs. For this reason, unit heat rates for the coal-fired Four Corners units were determined by Mr. Norwood from recent historical performance. Mr. Norwood projected a 73.8 percent capacity factor for the Four Corners units based upon his analysis of the amount of planned maintenance scheduled for the units during the rate year. Mr. Norwood testified that the amount of planned maintenance projected by EPEC is reasonable.

Mr. Norwood developed his proposed capacity factors for EPEC's intermediate and peaking gas units based upon projected unit fuel costs and contract requirements provided by staff witness Still, historical unit heat rate data, and system demand requirements.

Based upon the results of his projected generation mix, Mr. Norwood recommended that the Commission find EPEC's total fuel costs to be $66,142,165 and total purchased power costs to be $59,124,787. The examiner finds that Mr. Norwood presented a very persuasive justification for his fuel and purchased power projections, whereas the Company addressed the issue in a very cursory fashion. The City has endorsed Mr. Norwood's forecasts and calculations and the examiner finds that Mr. Norwood's recommendations should be adopted in their entirety. However, the examiner's recommendations herein regarding kwh sales necessitates a slight change in Mr. Norwood's recommended purchased power costs. The examiner's kwh sales recommendation increases Mr. Norwood's projected purchased power costs from $59,124,787 to $59,888,808.

5. Fuel Factor

According to EPEC witness Johnson, EPEC calculated its proposed fuel factor by dividing the Texas allocated adjusted fuel and purchased power expense by the Texas retail annualized kwh sales at meter. EPEC's proposed factors are as follows:

Texas System Fuel Factor	$0.03305/kwh
Voltage Level Fuel Factors:	
Transmission	$0.03122/kwh
Primary	$0.03263/kwh
Second	$0.03361/kwh

Staff witness Jeff Rudolph testified that he calculated the staff's proposed fuel factor by dividing total Texas reconcilable fuel costs by total adjusted Texas retail sales. To derive voltage level factors, Mr. Rudolph multiplied the Texas system fuel factor by the loss multiplier associated with each given voltage level. The staff's proposed fuel factors are as follows:

Texas System Fuel Factor	$0.028489
Voltage Level Fuel Factor:	
Transmission	$0.026916
Primary	$0.028124
Secondary	$0.028968

The recommendations made by the examiner regarding fuel and purchased power costs cause a slight change in the fuel factors recommended by the staff.

The examiner therefore recommends adoption of the following fuel factors:

Texas System Fuel Factor	$0.028513
Voltage Level Fuel Factor:	
Transmission	$0.026938
Primary	$0.028147
Secondary	$0.028992

6. Non-Reconcilable Purchased Power Costs

Staff witness Simpson notes in her testimony that Mr. Norwood's purchased power recommendation does not include SPS demand charges of $8,041,200 per year or $1,800,000 in annual wheeling charges assessed by PNM. According to Ms. Simpson, as these charges are fixed by contract and do not vary on a monthly basis, they should be considered non-reconcilable and should not be included in the fixed fuel factor. The examiner concurs in this recommendation, and these amounts are not included in the examiner's proposed fixed fuel factors. Ms. Simpson did however add these expenses to Mr. Norwood's purchased power expense recommendation as non-reconcilable fuel costs.

City witness DeWard proposed in his testimony that O&M be adjusted to remove the PNM wheeling charge on the basis that the charge is directly related to providing transmission service from PVNGS. As PVNGS is not yet in service, Mr. DeWard argues that the charges should not be included in O&M. The examiner concurs with Mr. DeWard's recommendation. The examiner has accomplished this adjustment by not including the $1,800,000 charge in the total purchased power number recommended by the examiner.

7. Summary of Fuel and Purchased Power Expense

Based upon the above discussion, the examiner finds EPEC's appropriate fuel expense to be $66,142,165 and the appropriate purchased power expense to be $67,930,008.

B. Operations and Maintenance Expenses (O&M)

EPEC has requested total O&M expenses of $49,909,648. The City and the staff have each proposed numerous adjustments to EPEC's requested level of O&M expense. A discussion of each O&M adjustment, together with the examiner's recommendation thereon, follows below.

1. Salaries and Wages

Staff witness Janet Simpson has proposed to reduce EPEC's requested salaries and wages expense by $243,704, to correct EPEC's failure to deduct miscellaneous fees relating to FL&R from EPEC's annualized payroll expense. The Company acknowledged this error and indicated that the payroll for FL&R security guard services and the payroll associated with the FL&R management fee were inadvertently included in requested salaries and wages expense. The examiner notes that EPEC witness Johnson proposed to correct this error in the errata to his testimony. However, his adjustment to correct this error totals $160,962, which is substantially less than Ms. Simpson's adjustment. Absent an explanation of this discrepancy, and given the fact that EPEC's RFI response, upon which the adjustment is based, cites a figure of $243,704, the examiner recommends that Ms. Simpson's downward adjustment of $243,704 to EPEC's requested salaries and wages expense be accepted by the Commission.

2. Employee Benefits

a. <u>TRASOP expense</u>. Both Ms. Simpson and City witness DeWard have proposed that EPEC's requested expense of $132,709 for TRASOP be disallowed. TRASOP is a tax credit program which allows companies to take additional ITCs in order to fund an employee stock ownership plan. According to Ms. Simpson, because EPEC is currently in an ITC carry forward position, the Company has not been able to reduce taxes by the total amount of the ITCs taken to fund the stock plan and therefore, the expense incurred to fund the plan has not been offset by an equal amount of tax savings. EPEC is seeking to recover this expense from ratepayers currently, although there will be no actual expense to EPEC once the ITCs are used. Both Mr. DeWard and Ms. Simpson believe it is inappropriate to require ratepayers to pay an amount which will ultimately be funded by payroll based ITCs, and the examiner concurs. The examiner recommends that this $132,709 downward adjustment to EPEC's requested employee benefits expense be accepted.

b. <u>Billed reimbursements</u>. Mr. DeWard testified that EPEC received $176,138 in billed reimbursements of insurance costs during the test year and that there was no basis for determining that the billed reimbursements would not continue past 1984 at the same level that existed in 1984. Therefore, Mr. DeWard has proposed that EPEC's requested employee benefits expense be reduced by $176,138. In the examiner's opinion, Mr. DeWard's adjustment is reasonable. EPEC has not challenged the propriety of this adjustment through rebuttal or in its brief and the examiner recommends approval of this adjustment.

c. <u>Pension contributions</u>. EPEC requested pension expense of $1,630,050, constituting an increase of $451,334 over actual test year pension cost of $1,178,716, as reflected on Schedule A-3 of the rate filing package. EPEC has admitted that its proposed pension expense is inflated because it does not take into consideration zero personnel growth, frozen wage increases and a change in plan year. Ms. Simpson testified that, absent an actuarial report which includes assumptions consistent with EPEC's cash containment program, pension expense should be held to the test year level. Mr. DeWard has recommended use of the 1984 level plus a 10 percent increase to account for wage increases and the funding of the pension window plan. However, Mr. DeWard's calculation assumes EPEC's actual 1984 pension cost was $1,064,000 based upon a response to an RFI propounded by the City. Mr. DeWard's recommended expense is $1,170,400.

EPEC states in its brief that the question of general pension expense is speculation, no matter whose figure is selected. In a spirit of compromise, EPEC has suggested that the Commission adopt Mr. DeWard's assumed test year expense of $1,064,000 plus 15 percent.

The examiner finds the record to be somewhat confused on this issue and the briefs are of little assistance. No explanation has provided as to why Mr. DeWard's and Ms. Simpson's test year expense levels differ. Also, EPEC's contention that its requested expense level is no more than test year expense plus 20 percent appears to be erroneous.

All things considered, the staff's approach is the most reasonable. The examiner prefers to recommend adoption of the test year expense level as shown in the Rate Filing Package, rather than to choose between the speculative numbers offered by the City and EPEC. This recommendation results in a $451,334 downward adjustment to EPEC's requested pension expense.

d. Pension window plan expense. Ms. Simpson has recommended reduction of EPEC's employee benefits expense by $85,064 on the basis that the pension window plan is actually being funded through EPEC's minimum pension contributions as determined by actuarial studies, and that it is therefore inappropriate for EPEC to propose an increase in pension expense for the cost of separately funding the window plan. According to Ms. Simpson, allowance of EPEC's request in this area would result in double-counting the expense. EPEC has not countered Ms. Simpson's recommendation through rebuttal testimony or through its brief. It appears from the errata sheet tendered by EPEC witness Johnson that EPEC concurs with Ms. Simpson's conclusion that this item should be removed from employee benefits expense. Finding Ms. Simpson's adjustment to be reasonable, the examiner recommends that it be adopted by the Commission.

e. Vacation accrual. Mr. DeWard has recommended removal of $267,141 in vacation accrual from employee benefits expense on the basis that the amount is already included in EPEC's payroll annualization adjustment. It does not appear that EPEC contests this adjustment and the examiner accordingly recommends its approval.

f. Sick time bond and payroll charges. Mr. DeWard has recommended that 14.06 percent of sick time bond and payroll charges be allocated to construction and removed from employee benefits expense. This adjustment is only cursorily addressed by Mr. DeWard and neither his testimony nor the City's brief offers any explanation of the merit of accepting this adjustment. Absent some explanation, the examiner declines to recommend approval of this adjustment.

g. Supplemental retirement program. Mr. DeWard has recommended that the Commission disallow $192,695 in requested expenses related to EPEC's supplemental retirement program. According to Mr. DeWard, EPEC's Supplemental Retirement and Survivor Income Plan was initiated in July, 1984, for the purpose of attracting and retaining key personnel in mid-career. Mr. DeWard testified that the plan is inconsistent with the Company's cash containment program, hiring freeze and other policies aimed at maintaining financial viability. Mr. DeWard alludes in his testimony to the finding by Touche Ross & Co. that EPEC provides many more benefit plans than other employers within the El Paso area. In its brief, the City has argued that this program constitutes an effort to increase salaries and benefits for top management while maintaining a posture of austerity for the rank and file.

According to EPEC witness Johnson, the supplemental retirement program is applicable to 35 to 40 employees within EPEC's senior management. To be eligible for supplemental pension benefits, an employee has to have been with EPEC for 20 years or more. EPEC argues in its brief that the attraction or retention of key managerial employees is important enough for EPEC to make an expenditure for supplemental pension benefits even during a temporary cash crunch. Given the current salary freeze and hiring freeze, EPEC argues that supplemental pension benefits is a means of keeping senior personnel from departing for greener pastures.

It appears to the examiner that the supplemental pension plan cannot reasonably be viewed as a tool for attracting management talent from outside of the Company since one must be employed by EPEC for 20 years before being eligible for supplemental benefits under the plan. Other short term incentives would seem to the examiner to be a more appropriate recruiting tool than a supplemental pension program. Further, it appears that EPEC has not suffered in the past or currently from chronic loss of top management personnel. EPEC's employee benefits appear to be more than sufficient to retain existing personnel without resort to additional pension programs.

As it does not appear to the examiner that the supplemental retirement program is in fact necessary to retain key EPEC personnel, the examiner does not believe the expense associated with that program to be reasonable or necessary for the provision of service the public. Therefore, the examiner recommends that the entirety of the expenses requested by EPEC to support the supplemental pension plan be disallowed by the Commission.

h. Disability insurance. Mr. DeWard has recommended that EPEC's requested allowance for disability insurance premiums be reduced by $102,925 to $49,602, being the level of the last three years paid losses plus 25 percent to cover the cost of administering a self-insurance plan or to seek an alternate insurance carrier with lower premiums. Mr. DeWard relies upon the Touche Ross & Co. management audit to support this adjustment. EPEC opposes this adjustment, arguing that the concept of insurance is to have protection, provided by premiums, which one hopes never has to be used. As the Touche Ross & Co. audit is not a part of the record, the examiner is not aware of the recommendations made in that audit regarding disability insurance. If the disability insurance premiums paid by EPEC are excessive, the Company should take immediate steps to obtain less expensive coverage. However, the examiner finds that the record does not demonstrate that the premiums are excessive. Further, disability insurance is a reasonable expense to be incurred by EPEC. The examiner recommends that no adjustment be made in this proceeding to EPEC's requested allowance for disability insurance premiums.

i. Aircraft lease expense. Mr. DeWard has proposed that $9,571 in employee benefits charges associated with the aircraft lease be disallowed. The examiner concurs with this recommendation, which is opposed by EPEC.

j. Employee benefits summary. The examiner recommends that EPEC's requested allowance for employee benefits expense be reduced by a total of $1,292,666 to account for the adjustments recommended above.

3. Advertising, Contributions and Dues Expense

a. Salute to teenagers. Both Ms. Simpson and Mr. DeWard have recommended that $15,520 in expense attributable to the Salute to Teenagers program be disallowed. This adjustment has been proposed because the program will be discontinued after the 1984-1985 school year and because it does not conform to EPEC's professed criteria for determining the need for an advertisement. EPEC witness Johnson testified that the ultimate question is whether an ad campaign will further the Company's goal of providing reliable and efficient service at the lowest possible cost. Clearly, Salute to Teenagers advertising does not meet that goal.

The examiner concurs in the assessments of Ms. Simpson and Mr. DeWard that this advertising expense is unnecessary to the provision of service within the meaning of P.U.C. SUBST. R. 23.21(5) and Section 41(3)(D) of the Act.

b. The electric guide. Mr. DeWard has proposed that 25 percent, or $25,379, of the EPEC's requested expenses for the Electric Guide be disallowed from cost of service. The Electric Guide is a monthly billing insert. According to Mr. DeWard, his review of previous inserts revealed that each month a community calendar is presented, together with occasional recipes. Mr. DeWard also notes that the March, 1984 issue contained information about FL&R. On the basis of his review of certain of these billing inserts, Mr. DeWard concludes that the cost of one-fourth of each insert should be excluded because it is not a legitimate utility expense.

The examiner rejects Mr. DeWard's adjustment. On cross-examination, Mr. DeWard admitted that three-fourths of The Electric Guide contained useful consumer information, and Mr. DeWard further admitted that he was unaware that the insert was a single piece of paper folded into four sections. Apparently, Mr. DeWard had reviewed photo-copies of past electric guides, wherein each section was photo-copied on a separate piece of paper. The examiner agrees with EPEC that the one-quarter of the electric guide containing the community calendar and recipes could not be deleted except by leaving that portion of the folded page blank. Mr. DeWard's proposed adjustment is unreasonable and the examiner recommends that the Commission permit EPEC to recover the full cost of these billing inserts in EPEC's cost of service.

c. Charitable contributions. EPEC has requested a total of $117,768 in expenses for the following charitable contributions:

El Paso Rehabilitation Center	$ 5,000
U.T. El Paso	9,000
New Mexico State University	7,173
United Way	96,595

Ms. Simpson has recommended that all expenses relating to charitable contributions be disallowed on the basis that, although the contributions may be to worthy organizations, ratepayers should not be required to contribute to charities involuntarily through electric rates. As the expenditures are not necessary in providing electrical service to the public, Ms. Simpson urges disallowances of these expenses in cost of service.

EPEC argues that P.U.C. SUBST. R. 23.21(b)(1)(e) permits the inclusion of charitable contributions in cost of service and that the substantive rule does not require ratepayer approval of such contributions. However, EPEC fails to point out that that rule permits charitable contributions only to the extent that they are reasonable and necessary. The examiner finds the amounts donated by EPEC in 1984 to be reasonable. The question then, is whether they are necessary. An argument can be made that charitable contributions are never necessary to the provision of utility service to the public. Therefore, such contributions should never be permitted in cost of service for any utility. However, the fact remains that the Commission's Substantive Rules do permit classification of contributions as allowable expenses.

Absent a Commission policy that no charitable contributions can be included in cost of service, the examiner believes that the decision to include or exclude those expenses should turn on the reasonableness of the amounts donated, provided that the donations are not of the type prohibited under P.U.C. SUBST. R. 23.21(b)(2).

P.U.C. SUBST. R. 23.21(b)(1)(E) places a ceiling of 3/10 of 1.0 percent of the gross receipts of a utility on the amount of advertising, contributions and donations which can be included in cost of service. EPEC's expenses in those categories are well below the ceiling. $117,768 in charitable contributions appears to be a reasonable level of expenditure by EPEC for charitable contributions, given the size of the Company. The recipients of the contributions certainly appear to be worthy organizations. Therefore, absent a determination by the Commission that charitable contributions are not legitimate utility expenses, the examiner recommends that Ms. Simpson's proposed disallowance of charitable contributions expense be rejected.

d. Trade association dues. Mr. DeWard has recommended that all dues/contributions paid to Edison Electric Institute (EEI), U.S. Committee for

Energy Awareness and the Atomic Industrial Forum, to the extent that they have not already been removed from cost of service by EPEC, be disallowed. The amounts in question are as follows:

Edison Electric Institute	$101,187
U.S. Committee for Energy Awareness	190,829
Atomic Industrial Forum	12,840

(1) EEI

According to EPEC witness Johnson, EPEC excluded 20 percent of test year EEI dues from its requested EEI dues expense based upon a letter from EEI, attached to Mr. Johnson's prefiled testimony, which identifies 20 percent of EEI's activities as possibly being related to influencing legislation. According to Mr. DeWard, the entirety of EPEC's EEI dues should be disallowed on the basis that EEI provides no real or direct benefits to the ratepayers of Texas. Based upon the evidence of record, the examiner cannot agree with that conclusion. EPEC provided direct testimony regarding the benefits provided to EPEC and the consumer from membership in EEI. No party presented any evidence to contradict EPEC's testimony on this issue. EPEC made a prima facie case which was not successfully countered. The City's entire direct testimony on the benefits to the ratepayer is as follows:

> . . .Despite the testimony of Mr. William J. Johnson, I see no real or direct benefits to the ratepayers of Texas for membership in the Edison Electric Institute. . .

In the examiner's opinion, the above statement by Mr. DeWard fails to support his proposed adjustment. No party questioned in direct testimony EPEC's assertion that no more than 20 percent of EEI's dues could be attributed to lobbying efforts and no party asserted in its direct testimony that the 20 percent allocation was inappropriate. On cross-examination of staff witnesses Uffelman and Simpson, the City attempted to show that there are still outstanding concerns regarding what percentage of EEI dues is used to influence legislation, but those witnesses had limited knowledge of the issue and could not verify that EPEC's 20 percent allocation was appropriate or inappropriate.

The examiner recommends that Mr. DeWard's proposed disallowance of EEI dues be rejected.

(2) U.S. Committee for Energy Awareness (CEA)

Mr. DeWard has proposed disallowance of EEI's CEA dues on grounds that the organization's purpose is to promote nuclear power. EPEC Witness Johnson addresses the merits of CEA membership in his direct testimony. According to Mr. Johnson, the organization conducts public discussions and provides media coverage on the importance of electric energy and the need for diversity of energy sources to lessen America's dependence on foreign oil.

Mr. Johnson further states that the committee's emphasis is on education and information for the formulation of sound energy policies. The educational efforts of CEA are aimed at ratepayers, regulators, legislators and the industry itself.

On cross-examination of Mr. Johnson, the City introduced into evidence a CEA advertisement which, in the examiner's opinion, confirms Mr. DeWard's assessment that the primary purpose of CEA is to promote nuclear power. Based upon the record in this docket, the examiner cannot find that EPEC's CEA dues are reasonable or necessary to the provision of utility service to the public. Further, the evidence of record does not reflect that CEA dues contribute toward the professionalism of CEA members within the meaning of P.U.C. SUBST. R. 23.21(b)(1)(E)(iv).

The examiner recommends that all CEA dues be disallowed from EPEC's cost of service.

(3) Atomic Industrial Forum (AIF)

According to Mr. Johnson, AIF's purpose is similar to that of EEI, except that its membership is limited to those companies with nuclear generation. In his direct testimony, Mr. Johnson elaborates on benefits obtained by EPEC from membership in AIF, in terms of training and information exchange. From Mr. Johnson's testimony, it appears that AIF dues are a legitimate expense. The only direct testimony provided by the City on this issue is as follows:

> . . . If, in fact, nuclear power is good for the ratepayers of Texas then actual operating results should eliminate the need to fund this organization.

The examiner finds the above statement by Mr. DeWard to be unpersuasive. P.U.C. SUBST. R. 23.21(b)(1)(E) permits inclusion of trade association dues. EPEC has established in its direct testimony that AIF dues are a legitimate expense and that EPEC and its ratepayers benefit from AIF membership in the same manner as with EEI membership. No party demonstrated on cross-examination that Mr. Johnson mischaracterized the benefits obtained from AIF membership or that he did not accurately characterize the purpose of the organization.

The examiner recommends that Mr. DeWard's proposed disallowance of AIF dues be rejected.

4. Uncollectible Expense

EPEC calculated its effective uncollectible expense rate by dividing test year uncollectible accounts written off by test year retail sales revenue. According to staff witness Simpson, the staff's accounting model calculates revenue related items such as uncollectible expense by multiplying an effective rate times total revenue requirement. The denominator in the staff's effective rate calculation is total operating revenues, including fuel under/over recoveries. According to Ms. Simpson, it is necessary to use a total revenue number in the effective rate calculation because the effective rate is multiplied by total revenue requirement to determine the appropriate level of uncollectible expense.

The examiner accepts the staff's methodology for calculating uncollectible expense. Based upon the examiner's recommendations herein, EPEC should be permitted to include $1,063,715 in uncollectible expense in its cost of service, based upon an uncollectible expense effective rate of .3033 percent.

5. Regulatory Expenses

EPEC has requested regulatory expense totaling $3,074,765 on a total company basis, of which amount EPEC has jurisdictionally allocated $2,081,152 to Texas.

The Commission staff and the City have both proposed a number of adjustments to EPEC's requested allowance for regulatory expense. A discussion of each proposed adjustment follows below.

a. Touche Ross management audit. EPEC is requesting recovery in this docket of $600,000 in expenses attributable to the Touche Ross Management Audit. EPEC has allocated all of this expense to the Texas jurisdiction on the basis that the audit was ordered by this Commission pursuant to Section 16(u) of the Act. Both Mr. DeWard and Ms. Simpson have recommended that the cost of the audit be amortized over a five-year period because savings attributable to the audit will benefit future periods. EPEC argues that requiring the Company to wait five years to recoup costs incurred as a consequence of direct Commission orders is arbitrary and tantamount to confiscation of EPEC's working capital, unless the Commission permits EPEC to earn a return on the unamortized balance of the funds expended for the audit.

In the examiner's opinion, it is clearly appropriate to amortize the Touche Ross audit expenses because if the recommendations contained in the audit are implemented by EPEC, EPEC ratepayers will benefit from the audit expenditures for a number of years. The examiner further believes that the costs of the audit should not be allocated solely to the Texas jurisdiction. Although the audit was ordered by this Commission, there is no question but that the audit will benefit all customers of EPEC, not just Texas customers. There is no reason for the examiner to believe that other jurisdictions will disallow costs allocated to those jurisdictions given the benefits that will flow to EPEC customers in those jurisdictions.

With regard to EPEC's contention that amortization of the expenses associated with the management audit results in confiscation of EPEC's working capital, absent the allowance of a return of the unamortized balance, the examiner flatly disagrees. If a return is allowed on the unamortized balance, the ratepayers will have borne the entire burden of the expense and the carrying charges associated with the expense. Stockholders as well as ratepayers benefit from improvements and efficiencies resulting from management audit recommendations. Therefore, it is appropriate that the stockholders bear some portion of the expense by foregoing a return on the unamortized balance of the expense.

The examiner recommends a five year amortization of the Touche Ross audit expenses.

b. Lead-lag and depreciation studies. Ms. Simpson has proposed that EPEC's expenses associated with the lead-lag study performed by Coopers & Lybrand and the depreciation study performed by Stone & Webster be amortized over a five year period. Finding that the studies can be used in future rate cases in Texas and in other jurisdictions, the examiner concurs that the expenses should be allocated to other jurisdictions as well as Texas and amortized over a five year period. The examiner rejects EPEC's request for a return allowance on the unamortized balances of those expenses.

c. Ernst & Whinney PVNGS audit. Ms. Simpson has proposed that Ernst & Whinney audit expenses be disallowed in this proceeding on the basis that the costs are not at this point known and measurable. According to Ms. Simpson, EPEC does not have a contract or a fixed schedule specifying when over the next three years the $500,000 in authorized funds is to be spent. As only $10,949 was expended by EPEC through July 1985, Ms. Simpson feels it appropriate to disallow any of the expense in this proceeding. The City has proposed that the Ernst & Whinney audit expenses be amortized over a five year period commencing with this rate proceeding. EPEC believes that the expenses should be recovered over the three year period during which they are to be incurred but in any event opposes disallowance of a portion of this expense in this case, given that EPEC has expended substantial sums for the audit during 1985. After consideration of the testimony of record on this issue, the examiner believes that it is equitable to the Company and the ratepayers to amortize this expense over a five year period commencing with this rate proceeding as proposed by Mr. DeWard.

d. FERC & New Mexico regulatory expenses. Ms. Simpson has proposed that $250,000 in rate case expenses requested by EPEC for the New Mexico and FERC jurisdictions be reduced to test year levels. According to Schedule II of Ms. Simpson's prefiled testimony, New Mexico test year rate case expenses totaled $60,705 and FERC expenses totaled $44,911. EPEC has requested $250,000 in expenses for each of those jurisdictions, indicating that those amounts represent broad estimates respecting future filings which are currently under consideration. According to Ms. Simpson, broad estimates concerning future filings under consideration are not known and measurable changes in rate case expense and should not be included in cost of service. Ms. Simpson has therefore proposed that those expense requests be reduced to test year levels. Although the examiner is uncertain as to the necessity of adjusting non-Texas regulatory expenses, the examiner recommends adoption of these adjustments.

e. City rate case expense. EPEC included $329,000 in its requested level of regulatory expense for rate case expenses incurred by the City of El Paso. That expense level is based upon the expenses incurred by the City in EPEC's last general rate case. Mr. DeWard has proposed that that requested amount be adjusted upward by $84,000 for a total city rate case expense allowance of $413,000. The City has requested this adjustment due to the increased complexity of this proceeding as compared to EPEC's last rate case. Mr. DeWard cites the depreciation study, the lead-lag study, the dual rate filing and the rate moderation task force as reasons for the increase in the City's rate case expenses. After review of the evidence of record, the examiner is satisfied that the rate case expenses requested by the City are reasonable and the examiner therefore recommends that Mr. DeWard's proposed upward adjustment of $84,000 to EPEC's requested city rate case expense be accepted by the Commission.

6. Outside Services

Ms. Simpson and Mr. DeWard both proposed a number of adjustments to outside services. A discussion of each proposed adjustment follows below:

a. Chapman & Cutter expense. Both Ms. Simpson and Mr. DeWard proposed that $25,684 attributable to legal fees paid to Chapman & Cutter in conjunction with a long-term debt issuance be removed from outside services. The Company has conceded that this amount was charged to the wrong account. The examiner therefore urges adoption of this downward adjustment.

b. Renaissance 400/American Cities Corporation. Ms. Simpson has proposed a $9,333 reduction to outside services expense to eliminate a payment to Renaissance 400/American Cities Corporation which EPEC concedes should have been classified as charitable contributions. The examiner recommends adoption of this adjustment.

c. TBA management audit expense. Both Ms. Simpson and Mr. DeWard have recommended that $220,618 in expense attributable to an audit performed by Theodore Barry & Associates (TBA) at EPEC's request be amortized over a five year period. Ms. Simpson asserts that amortization of this audit expense is consistent with staff's proposed treatment of the Touche Ross audit. In its post-hearing brief, the City changed its recommendation on this issue and now argues that the entire cost of the audit should be excluded from cost of service. The City's position arises from EPEC witness Harris' statement on cross-examination that the TBA audit was a "preaudit audit" undertaken by EPEC in anticipation of the upcoming Commission ordered audit. The City argues that the ratepayers derive no benefit from having a preliminary audit performed in order to permit EPEC to prepare itself for the Commission ordered Touche Ross audit. The examiner fully concurs with the City's revised position on this issue. In reviewing the City's cross-examination of Mr. Harris, it is apparent that EPEC knew or suspected that this Commission would order a management audit, and as EPEC believed TBA would not be selected to undertake the audit, EPEC hired TBA to detect those areas of EPEC's operations which could be subjected to criticism by another auditing firm. Under the circumstances, the examiner agrees with the City that the ratepayers obtained no benefit from this preaudit audit. Given the stated purpose of the TBA audit, it is appropriate that the stockholder rather than the ratepayer shoulder the burden of this expense.

The examiner recommends that $220,618 in Outside Services expense attributable to the TBA audit be disallowed from cost of service.

d. Ogilvy & Mather expense. Mr. DeWard has proposed that $61,408 in expenses paid to Ogilvy & Mather Public Relations be disallowed. According to Mr. DeWard, this expense item is inappropriate because it is non-recurring and because the funds in question were spent planning media events which were ultimately cancelled. EPEC has not addressed this proposed adjustment in its brief or demonstrated the appropriateness of this expense in rebuttal testimony. Under the circumstances the examiner finds that EPEC has not met its burden of proof on this issue. The examiner recommends that Mr. DeWard's proposed $61,408 downward adjustment to outside services be approved.

e. Palo Verde pollution control bonds issuance. Mr. DeWard has proposed removal of $5,200 on the basis that the amount was improperly included on EPEC's Schedule G-4.6 workpaper. This adjustment is not addressed sufficiently by the City in its direct case or in its brief for the examiner to determine whether the expense should in fact be removed. Absent additional explanation, the examiner declines to recommend that the adjustment be adopted.

f. Legal fees. Mr. DeWard has proposed that $43,449 in legal fees paid in connection with the Fuel Oil Financing Trust be disallowed. Additionally, Mr. DeWard has challenged the propriety of allowing $18,963 in legal expenses associated with an employee termination in cost of service. The basis for Mr. DeWard's objection to these expenses is that they are non-recurring. Although Mr. DeWard indicates in his prefiled testimony that the fees associated with the Fuel Oil Trust are excessive, he repudiated that comment on cross-examination and stated that he did not challenge the amount of that expense. In the examiner's opinion, these two proposed adjustments should not be permitted. As pointed out by EPEC in its brief, legal expenses generally do not involve repetition of the same activity on a year-by-year basis, although a certain level of legal expense does recur. The examiner believes it is inappropriate to single out specific legal expenses for disallowance on the basis that the specific expense is non-recurring, given that a certain amount of legal expense is bound to recur, unless a showing can be made that EPEC's legal expenses as a whole are beyond what could be expected on a recurring basis or that one specific fee is beyond what could be expected on a recurring basis. The two fees discussed above do not appear to be out of line from the normal level of legal expense which might be expected. The examiner therefore rejects the above adjustments.

Mr. DeWard has additionally recommended disallowance of $375,740 in legal fees related to the issuance of Palo Verde Pollution Control Bonds. Mr. DeWard opposed these expenses on the basis that the expense was non-recurring, and additionally, on the basis that since EPEC records interest income related to funds from pollution control bonds below the line, the ratepayer should not be asked to support $375,740 in legal fees to obtain the bonds.

EPEC has indicated that the legal expenses were incurred in order to obtain a favorable ruling from the Internal Revenue Service regarding the tax exempt nature of the bonds. After considerable cross-examination by EPEC on this issue, Mr. DeWard conceded that he did not question the reasonableness or the prudence of the expense since the purpose of the expense was to secure tax-exempt status for the bonds. However, Mr. DeWard argued that the expense should be disallowed on the basis that it is a non-recurring legal expense. In this instance the examiner must question whether the expense should be permitted, given that the expense constitutes more than one-half of EPEC's expenditure level of outside legal services during the test year. The examiner believes that an outside services legal expense of this magnitude is beyond the norm of what might be expected on a yearly basis. Absent a showing that an expense of that magnitude is likely to recur, the examiner recommends that the expense be deleted from EPEC's cost of service.

g. FL&R expenses. Mr. DeWard has proposed disallowance of $2,300 in expenses paid to Peat, Marwick, Mitchell & Co. for services rendered on behalf of FL&R on the basis that the expense clearly should have been removed by EPEC. The examiner concurs in the propriety of this adjustment.

7. Other O&M Expense

Mr. DeWard has proposed a number of additional O&M adjustments which the examiner has included under this heading for purposes of organizational convenience. A discussion of each proposed adjustment follows below.

a. Customer assistance expense. Mr. DeWard has proposed that $152,500 in expenses paid to Energy Resource Group, Inc. to develop a strategic marketing plan and an energy management plan be amortized over a five-year period, given that EPEC has asserted that the benefits to ratepayers derived from this expenditure will be realized over a fifteen-year period. EPEC did not cross-examine Mr. DeWard on this issue nor did the Company address it on rebuttal or by brief. Therefore the proposed adjustment appears reasonable; the examiner recommends its adoption.

b. Office supplies & expense. Mr. DeWard has proposed the following adjustments, totaling $94,422, to this account:

1)	Removal of loss on sale of residence of former employee	$46,949
2)	Removal of miscellaneous expenses associated with short-term debt issuance costs	7,946
3)	Marriott Hotel hors d'oeuvres	4,259
4)	Renaissance 400 Workshop registration fees	160
5)	Bankers tour of Palo Verde	4,298
6)	Marlene Schmidt, Inc. Renaissance 400 fees	29,667
7)	Marlene Schmidt, Inc. expenses	1,143
	Total	$94,422

Of the adjustments, EPEC cross-examined Mr. DeWard solely with regard to the loss of $46,949 on the sale of a residence of a former employee. EPEC met with no success in countering Mr. DeWard's assertion that the loss was a non-recurring item and additionally, that the loss should have been recorded below the line.

Mr. DeWard proposed the adjustments because the remaining expenses were non-recurring, misclassified or inappropriate. EPEC did not cross-examine Mr. DeWard or address these issues in brief. The expenses were put in issue by the City and EPEC failed to persuade the examiner that the proposed adjustments are inappropriate. Therefore, the examiner recommends that each of the above adjustments, totaling $94,422, be adopted by the Commission.

c. Other adjustments. Mr. DeWard has proposed the following miscellaneous O&M adjustments which the examiner has not previously addressed:

1) Automobile expense - Remove from operating expense $117,338 attributable to the value of personal use of Company owned vehicles. According to Mr. DeWard, IRS regulations require that EPEC employees be charged for this use, or that the value be included as additional taxable income to the employee.

2) Payroll taxes - Remove $3,405 of payroll taxes associated with the corporate aircraft which EPEC failed to consider in its corporate aircraft adjustment.

3) Amortization of easement - Remove $12,156, or 8/9ths of the payment to the Texas General Land Office for a nine year easement.

4) Additional depreciation expense - Remove $116,688 in depreciation expense associated with the adjustment by Mr. DeWard for the amortization of gain on the sale and lease back of turbine.

5) Energy and Man's Environment - Remove $34,782 in charges payable to Energy and Man's Environment on the basis that a Company RFI reflects that the expenses are non-recurring.

6) Cash containment program - Remove $19,000 in expense for eliminating duplicate mailing labels and $141,000 for savings from EPEC's new meter policy.

Each of the above proposed adjustments is only fleetingly addressed in this docket. Of the above adjustments, EPEC appears to oppose the adjustment for additional depreciation expense and the Energy and Man's Environment adjustment.

With regard to the adjustment for additional depreciation expense, the Company opposition to the adjustment stems from its disagreement with the City regarding the City's proposal to amortize the gain on the sale and lease back of a turbine. This issue has already been addressed by the examiner in the invested capital section of this report. As the examiner has accepted the City's amortization proposal, it is necessary for the examiner to recommend approval of this adjustment to additional depreciation expense.

With regard to the Energy and Man's Environment adjustment, EPEC argues in its brief that Mr. DeWard has not demonstrated that the expense is non-recurring. In the examiner's opinion, EPEC had the burden of demonstrating that expense was in fact a recurring expense. As Mr. DeWard alluded to a specific RFI response to show that the expense was non-recurring, EPEC could easily have demonstrated that the response did not reflect what Mr. DeWard said it did if the Company had desired to do so.

The examiner finds that EPEC has failed to demonstrate the inappropriateness of the above adjustments. Therefore, the examiner recommends that the adjustments be adopted.

8. New Mexico Project

Although the City did not propose in its direct case any adjustments to EPEC's requested allowance of $552,349 in expense representing amortization of the costs of the New Mexico Project, the City has urged in its brief that the requested expense should not be allowed. The New Mexico Project was a proposed coal-fired generation station at Bisti, New Mexico which EPEC cancelled in 1981. According to EPEC witness Johnson, the site selection studies as well as other studies performed by EPEC in connection with that project were considered potentially applicable to other projects until 1984, when EPEC determined that the Company would not further pursue the possibility of constructing a coal-fired generating plant.

The City argues that, since the project was cancelled in 1981 and no application was made for a certificate of convenience or necessity, the expenses associated with the New Mexico Project are no different from the expenses associated with PVNGS Units 4 and 5 for which EPEC did not request amortization.

The examiner agrees with EPEC's position that the New Mexico Project progressed significantly beyond the preliminary stages at which PVNGS Units 4 and 5 were cancelled. Those units were no more than options provided by Combustion Engineering for additional CES-80 units. The examiner also agrees that amortization is generally considered the appropriate regulatory treatment for cancelled plant. Absent testimony regarding the inappropriateness of amortization of New Mexico Project costs, the examiner does not recommend exclusion of this requested expense item. The examiner would note that, unlike the expenses for PVNGS Units 4 and 5 which were not expressly addressed by EPEC in its testimony in Docket No. 5700, EPEC witness Johnson clearly and expressly proposed amortization of these expenses in his direct testimony in this docket. Any party wishing to challenge the request had ample opportunity to file testimony on the issue. The examiner would also note that there was no particular set of facts which was developed on cross-examination, previously unknown, which would justify the failure to raise this objection to the expense in direct testimony.

The examiner therefore rejects the City's request for disallowance of this expense item.

9. Summary of O&M Adjustments

Based upon the above discussion of proposed adjustments, and the examiner's recommendations thereon, the examiner finds that EPEC's requested O&M expenses of $49,909,648 should be adjusted downward by $4,324,958 for total allowable O&M expense of $45,584,690. Attached to this report as Examiner's Exhibit No. 4 is a summary of the examiner's O&M adjustments.

C. Depreciation & Amortization Expense

Pursuant to the Commission's directive in the Final Order in EPEC's last general rate case, EPEC presented a depreciation study in this docket, performed by Stone & Webster Management Consultants, Inc. The study was sponsored by Mr. William K. Strand, Vice-President of Stone & Webster, who testified on this issue on behalf of EPEC. Based upon the revised depreciation rates formulated in the study, EPEC has requested an upward adjustment of $4,034,940 to test year depreciation expense of $11,849,819. In addition to Mr. Strand's testimony, staff witness Frank McRae and City witness Thomas DeWard testified regarding this issue and challenged the appropriateness of several of the rates formulated by Mr. Strand.

1. Salvage Values for Newman and Rio Grande

Mr. McRae opposed EPEC's use of -10 percent and -9 percent net salvage rates for the Rio Grande and Newman generating station primary accounts in developing recommended depreciation rates. Mr. McRae testified that in response to a data request, EPEC furnished him with a study used to support EPEC's estimated salvage and replacement costs. However, Mr. McRae indicated that the study failed to provide enough detail to validate the assumptions, methods and overall basis for the salvage/replacement costs proposed by EPEC. The study provided by EPEC indicated that the estimated cost of removal was based on previous studies. Those studies were not furnished by EPEC. Accordingly, Mr. McRae testified that he rejected the net salvage rates proposed by Mr. Strand and relied upon the Commission's Engineering Division data base on depreciation rates and upon engineering judgment to arrive at his proposed net salvage value of -5 percent. This salvage value is identical to the net salvage values utilized in EPEC's previous depreciation study.

On cross-examination, Mr. McRae admitted that the Company had recently furnished him with the underlying data supporting Mr. Strand's estimated salvage and replacement costs, and that the data appeared to be the type of information that would be needed to verify Mr. Strand's estimates of net salvage value. However, Mr. McRae indicated that he had not had sufficient time to review the data and evaluate it in detail.

In addition to Mr. McRae's testimony on this issue, City witness DeWard testified in opposition to EPEC's proposed net salvage values for Rio Grande Units 3, 4 and 5. Mr. DeWard has proposed that there be no negative salvage associated with those units, based upon the following statement made by EPEC in a response to a data request:

> The Company "retired in place" Rio Grande Units 1 and 2 because of their proximity to the other units and the dangers inherent in the demolition of the two units. Therefore, the actual negative salvage impact has not been sustained but is being deferred.

In the examiner's opinion, the above statement does not indicate that the Rio Grande units will not be demolished. Rather, it seems clear that demolition is being deferred until it can be accomplished without endangering the remaining Rio Grande units. The examiner finds that there is a negative salvage value associated with the Newman and Rio Grande generating stations, and therefore the examiner rejects Mr. DeWard's proposal that negative salvage associated with Rio Grande Units 3, 4 and 5 be removed. However, given the inability of the staff to verify the validity of the salvage values proposed by Mr. Strand based upon EPEC's apparent failure to respond timely completely to data requests, the examiner believes it is appropriate to reduce the negative salvage values to a level of -5 percent as proposed by Mr. McRae.

2. Primary Account 353, Station Equipment in Transmission Plant

Mr. McRae testified that in his opinion, EPEC, in proposing an average service life of 18 years and a net salvage value of zero, underestimated the average service life and net salvage value of this account. Mr. McRae has proposed that 30 years and a +10 percent net salvage be adopted by the Commission as a more characteristic service life for Primary Account 353. The examiner rejects this proposed adjustment. Mr. McRae provided no information to support this assertion, nor did he offer any explanation of why he felt that the results of Mr. Strand's depreciation study were inappropriate as to this account. On the other hand, Mr. Strand was specifically cross-examined on this issue and gave a credible explanation for his determination of an appropriate service life for this account.

The examiner finds that there is no support in the record for Mr. McRae's proposed adjustment to this account.

3. Reversal of Depreciation Expense

As discussed previously in this report, the examiner recommends that plant in service be reduced by the costs of the SPS Transmission Line penalties and the Palo Verde Transmission Line, which has been reclassified as CWIP. As a consequence of those rate base adjustments, the examiner recommends that depreciation be adjusted to reflect those recommendations.

4. Summary

Based upon the above recommendations the examiner finds that EPEC is entitled to a depreciation and amortization expense level of $15,188,851, being $1,291,356 less than the expense level requested by EPEC.

D. <u>Other Taxes</u>

EPEC requested a total other taxes allowance of $20,861,851. The Company's other tax calculations were sponsored by Mr. Johnson.

The staff reduced EPEC's request by $1,453,029 for a total recommended allowance of $19,408,822. Staff witness Simpson explained that adjustments were necessary to Payroll Taxes, Franchise Taxes and Revenue Related Taxes. Ms. Simpson calculated her recommended payroll tax adjustment by multiplying the FICA rate times the staff's proposed reduction in payroll expense. Texas franchise tax expense is calculated using the percent of business in Texas. Ms. Simpson rejected the allocators used by EPEC and recalculated franchise tax expense using the percentage of business in Texas shown on EPEC's December 31, 1984 franchise tax return and the staff's proposed capital structure. EPEC did not challenge her methodology for calculating franchise tax expense.

EPEC divided revenue related taxes by retail revenues to determine effective tax rates for revenue related taxes. Because the staff's accounting model multiplies effective rates times total revenue requirement, Ms. Simpson calculated effective tax rates by dividing test year taxes by total 1984 operating revenues, unadjusted for fuel over-recovery. Ms. Simpson has determined and recommended use of the following effective tax rates:

Texas PUC Assessment	.128%
New Mexico PUC Assessment	.081%
Texas Gross Receipts Tax	1.339%
Texas Occupational and Street Rental	1.269%
New Mexico Occupational and Street Rental Tax	.157%

The examiner concurs with the methodologies proposed by the staff for calculating Payroll Taxes, Franchise Taxes and Revenue Related Taxes. Based upon those methodologies, the examiner's recommendations herein result in total other taxes for EPEC of $18,620,910. A summary of the examiner's adjustments for other taxes is attached hereto as Examiner's Exhibit No. 5.

E. Interest on Customer Deposits

EPEC proposed a total allowance of $183,640 for interest on customer deposits. The staff decreased the requested amount by $19,558 based upon Ms. Simpson's application of the Commission's minimum required interest rate of 6 percent to the test year end balance of customer deposits. This adjustment was not opposed by any party. However, the examiner notes that on December 2, 1985, the Commission established an interest rate for customer deposits for all utilities of 7.29 percent to be effective during calendar year 1986. In light of this post-hearing development, the examiner believes it is necessary to recalculate EPEC's allowance for interest on customer deposits based upon the new interest rate set by the Commission. The examiner therefore recommends a total expense of $199,360 for interest in customer deposits.

F. State Income Taxes

EPEC witness Johnson testified that EPEC's requested New Mexico and Arizona income tax expense incorporates the effects of all accounting adjustments made to test year operating results. EPEC requested total state income tax expense of $3,330,037.

Both the Commission staff and the City took issue with EPEC regarding an appropriate level of state income tax expense. Ms. Simpson rejected EPEC's state allocator and utilized state allocators based upon test year end numbers. Based upon the staff's recommended revenue increase in this docket, Ms. Simpson's calculations result in a staff recommended state income tax expense of $655,263, or a decrease of $2,674,744 from the amount requested by EPEC.

City witness DeWard testified to a different state income tax expense level, based upon his review of EPEC's Arizona and New Mexico state income tax returns. Mr. DeWard testified that EPEC's 1984 Arizona corporation income tax return indicates a loss carry forward at December 31, 1984, of $142,063,065.75. He therefore concludes that EPEC will have no Arizona state income tax expense for the foreseeable future.

With regard to New Mexico state income taxes, Mr. DeWard proposed that that expense request be reduced to the level actually due and payable in 1984. Mr. DeWard testified that EPEC's 1984 New Mexico income tax has been impacted by the losses of FL&R, while in 1983 there was no such impact. According to Mr. DeWard, this likely results from the acquisition from EPEC by FL&R of New Mexico farmland associated with the cancelled New Mexico Project. Mr. DeWard testified that it is appropriate to offset the taxable income of EPEC by the losses of FL&R since there is a question of when, if ever, FL&R will generate taxable income and further, when PVNGS comes on line, the three part allocator in New Mexico will change dramatically. Less property and payroll will be allocated to New Mexico than is now the case. Therefore, Mr. DeWard concludes that there will be less income tax payable in New Mexico. Mr. DeWard proposes that EPEC's state income tax expense be set at the actual New Mexico income tax paid in 1984, being $349,944.

EPEC did not challenge Mr. DeWard's state income tax recommendations at the hearing. In its brief, EPEC offers no counter to Mr. DeWard's recommendation regarding New Mexico taxes, and simply indicates in regard to Arizona taxes that if the Commission considers the operating expenses and revenues related to Arizona in calculating the Arizona income tax, the Company's request is appropriate.

In the examiner's opinion, Mr. DeWard's recommendations regarding state income tax expense are the most well reasoned of any of the proposals made by the parties. EPEC has failed to demonstrate that Mr. DeWard's recommendation is not appropriate. The examiner recommends that EPEC be found to have state income tax expense of $349,944.

G. Federal Income Tax

EPEC witness Johnson computed the Company's requested Federal Income Tax (FIT) allowance of $74,462,282. According to Mr. Johnson, he adjusted FIT to incorporate the following:

1. Recognize cost of service adjustments made to test year.

2. Include only taxable items and tax deductions included in the overall cost of service.

3. Synchronize interest with rate base. EPEC's computation of the weighted cost of debt includes accumulated deferred ITCs in the capital structure.

4. Eliminate prior years' adjustments and intercorporate tax effects.

5. Restate the timing difference on tax depreciation based upon actual 1984 tax depreciation and annualized book depreciation.

6. Recognize the effect of additional depreciation on non-normalized timing differences.

Mr. Johnson testified that EPEC's recognition of the above adjustments insures that EPEC's rates are designed only to collect FIT associated with the income and expenses includable in the adjusted test year overall cost of service.

Staff witness Simpson and City witness DeWard proposed a number of adjustments to EPEC's FIT calculations. Each of those adjustments is discussed below.

1. Interest Deduction on Fuel Trust

The record reflects that the Rio Grande Resource Trust borrows funds to purchase nuclear fuel, resulting in the incurrence of interest expense. The interest expense is capitalized into the cost of the fuel and is recovered by the trust when the fuel is burned. EPEC deducts interest expense associated with nuclear fuel from its federal tax return each year since EPEC is a beneficial owner of the trust. Staff witness Simpson testified that the tax timing difference caused by this transaction would normally result in accumulated deferred taxes but, because the asset is not recorded on EPEC's books, EPEC asserts that no accumulated deferred taxes can be provided. Ms. Simpson argues that EPEC's failure to provide accumulated deferred FIT on nuclear fuel interest precludes ratepayers from benefitting from this source of cost free capital. Ms. Simpson feels that this is inappropriate because, in her opinion, the ratepayers will ultimately bear the cost of the nuclear fuel interest. Ms. Simpson asserts that EPEC is in effect treating this item as a non-normalized timing difference for book purposes and that it is therefore appropriate to treat it as such for ratemaking purposes by deducting the 1984 trust interest incurred from return in calculating FIT, thereby flowing the benefit of the tax deduction to current ratepayers. According to Ms. Simpson, when EPEC begins leasing heat from the trust it will incur fuel expense which will include interest which has previously been deducted for tax purposes. As the Company will then have a deduction for book purposes which it cannot take for tax purposes, it will be necessary to deduct interest expensed through fuel during the test year from the interest expense incurred by the trust in order to calculate FIT. On the basis of her analysis, Ms. Simpson proposes deduction of the total 1984 trust interest expense of $8,694,064 from return, since no nuclear fuel was expensed during 1984.

EPEC has vigorously opposed this adjustment through rebuttal testimony and by brief. EPEC notes that if the transaction were to be normalized in the usual fashion, an increase in deferred FIT would have to be made to EPEC's rate base. EPEC asserts that flowing the interest deduction into current cost of service without providing for deferred FIT violates tax normalization rules. According to Mr. Johnson, EPEC has not adjusted deferred FIT because, for accounting purposes, the arrangement with the trust is an operating lease which EPEC's outside auditors require not be recorded on the Company's books. Consequently, no entry is present. Mr. Johnson indicates that the transaction reverses itself when fuel is burned and the Company pays the trust for fuel expense. The deduction will be at that point, but due to the reduction in the tax basis of the fuel by the current interest deduction, tax expense in the future rate case will not be reduced by the deduction and the transaction reverses itself with no effect on cost of service at any time.

This issue is extensively discussed in the parties' briefs and the issue was also raised in Docket No. 5700. In that proceeding, the examiners noted that there were two alternative treatments of this expense: 1) adoption of the Company's treatment; or 2) adoption of the staff's adjustment together with a requirement that an adjustment for deferred taxes be made. Because nothing actually appeared on the Company's books requiring an offset, the examiners recommended in Docket No. 5700 that the Company's treatment of this expense be adopted. The Commission adopted the examiner's recommendation on this issue in Docket No. 5700. Given that EPEC's auditors do not permit deferred FIT from this transaction to be recorded on the Company's books, and given that the Commission concurred in EPEC's handling of this item in Docket No. 5700, the examiner finds that it is appropriate to accept EPEC's treatment of this item.

2. ITC Amortization

Mr. DeWard proposed that the ITC amortization amount proposed by EPEC be increased by $241,458. First, Mr. DeWard notes that EPEC's ITC level is identical to that used in EPEC's last rate case. Mr. DeWard determined from responses to data requests that EPEC should have reflected a higher revised ITC level, which increases ITC amortization by $16,580. The examiner recommends adoption of this adjustment.

Second, Mr. DeWard proposed an increase in the amount of ITCs available for amortization and urged the Commission to assume that all non-TRASOP and non-PVNGS ITCs had been taken, since EPEC carried forward ITCs which Mr. DeWard feels EPEC could have taken were it not for the ITCs taken for FL&R activities. Third, Mr. DeWard increased the amounts for ITCs taken on the 1984 tax return based on the above adjustment. In the examiner's opinion, Mr. DeWard's second and third adjustments should be rejected since they are premised on the assumption that EPEC can designate which ITC is in a carry forward position. On cross-examination by EPEC, Mr. DeWard conceded that the IRS code prohibits designation of ITCs, but indicated as follows:

> My treatment goes to a regulatory concept and says, "Ignore the IRS Code. Let's go on a regulatory basis and let's consider what's happened here and why we can't utilize these ITCs."

EPEC argues in its brief that, since the Company must adhere to IRS requirements, if the Company attempted to utilize the ITC on the basis suggested by Mr. DeWard, the IRS might disallow the ITC entirely. After considering the evidence of record, the examiner is persuaded that the adjustments are inappropriate given the IRS prohibition against designation of ITCs. It appears to the examiner that the Commission should not take a stance on this issue which contravenes IRS regulations concerning ITCs or subjects EPEC's ITCs to possible jeopardy.

3. Interest Synchronization

City witness Hugh Larkin proposed that an interest expense deduction related to the portion of rate base financed by the Job Development ITC (JDITC) be imputed in the computation of FIT expense. This imputation of interest is commonly referred to as interest synchronization. According to Mr. Larkin, inclusion of accumulated JDITCs in capital structure at the overall weighted cost of capital causes the ratepayer to be charged a higher cost than if the JDITC had not been available. This is because a tax expense is attributed to the return on rate base supported by accumulated deferred ITCs which the ratepayer would not have paid in the absence of the credit.

Since the IRS has in the past required that accumulated deferred ITCs be included in a company's capital structure at the overall cost of capital, the Commission has not permitted interest synchronization for fear that such action could threaten a utility's ratepayers with loss of ITCs. However, Mr. Larkin testified at length concerning the current permissibility of interest synchronization. Further, the City introduced into evidence an IRS private letter ruling to Texas Utilities Electric Company wherein the IRS indicated that neither the IRS code nor IRS regulations are violated if, in establishing the cost of service for ratemaking purposes, there occurs an imputation of an interest expense deduction related to the portion of rate base financed by the ITC in the computation of federal income tax expense.

Staff witness Simpson, who initially opposed the City's proposal, revised her testimony during the hearing and now agrees with the City's position on this issue. Further, EPEC does not oppose the adjustment, stating in its brief that the issuance of private letter rulings such at that to TUEC indicates interest synchronization is an idea whose time has arrived. The examiner urges the

Commission to adopt the City's proposal and impute a deduction for interest expense equivalent to the hypothetical portion of ITCs in the capital structure represented by debt in computing FIT expense.

4. Additional Depreciation

Staff witness Simpson proposed that EPEC's $1,793,852 request for additional depreciation for FIT calculation purposes be increased by $198,520, based upon her conclusion that a depreciation add-back adjustment is necessary to insure that EPEC has adequate revenues allotted to meet current tax liabilities.

According to general counsel's brief, the major factor influencing the need for the additional depreciation adjustment in the FIT expense calculation has to do with the permanent difference in the depreciable basis of assets for tax purposes as opposed to book purposes. The difference in basis is apparently caused by the fact that certain items such as allowance for equity funds used during construction (AEFUDC) and allowance for borrowed funds used during construction (ABFUDC), are treated differently in calculating FIT expense for book versus tax purposes.

Both Mr. DeWard and Ms. Simpson make a depreciation add-back adjustment to account for the permanent difference between book and tax for AEFUDC. Mr. DeWard explained that EPEC's calculation of FIT expense and deferred FIT expense fails to take into consideration that a portion of book depreciation is comprised of AEFUDC. That portion of depreciation expense representing AEFUDC is not deductible for tax purposes. Therefore, Mr. DeWard concludes that it is appropriate to add back that portion of depreciation expense which represents AEFUDC. The examiner concurs in the propriety of a depreciation add-back adjustment for AEFUDC.

According to testimony and briefs of EPEC and the staff, there is also a need for a depreciation add-back adjustment relating to the permanent difference in basis arising from timing differences for items such as ABFUDC, pensions and taxes. Ms. Simpson testified that prior to the implementation of comprehensive normalization requirements, tax benefits of accelerated depreciation were flowed through to ratepayers. No deferred taxes were provided on timing differences. Under current normalization requirements, FIT is normalized to book for ratemaking purposes. The revenue currently received from ratepayers is greater than the FIT actually payable to the IRS. However, once the timing differences begin to reverse, a company's income taxes payable to the IRS will be greater than the revenue received from ratepayers related to FIT. Because the benefits of a lower tax liability during construction of plant resulting from the deduction for tax purposes of construction interest, pensions and taxes were passed on to the ratepayers prior to full normalization requirements, EPEC and the staff argue that EPEC has never been provided with revenues to cover its tax liability as these timing differences reverse.

The Commission staff argues that, as with ABFUDC, it is necessary to adjust the FIT provided in cost of service so that EPEC will have sufficient revenue to meet its current actual tax obligation.

City witness DeWard opposed this adjustment, on the basis that EPEC failed to provide for reversals of items which were normalized in prior years and has not provided for the appropriate reversal of the deferred FIT liability and deferred FIT expense, that the adjustment could be viewed as retroactive ratemaking, and that EPEC has made no attempt to flow back additional tax collected when FIT rates were at higher levels. In its brief, the City raises additional arguments as to why this adjustment should not be permitted. Specifically, the City argues that EPEC has failed to demonstrate why it now proposes the adjustment when FERC Order No. 144 first required utilities to make this adjustment in 1982, that EPEC has not made any effort to quantify or account for other requirements of FERC Order No. 144 or to show that the order is binding upon the Commission, that the IRS Code does not seem to the City to require this adjustment and that Mr. Johnson's citations to other Commission cases in which this adjustment was made are misleading since the adjustment was never litigated in these dockets. Despite the objections to this adjustment raised by the City, the examiner is persuaded by the argument in general counsel's brief. As the examiner cannot hope to state the staff's position more eloquently than did general counsel in her brief the examiner will quote general counsel's argument in its entirety:

> . . .There is also a need for a depreciation addback adjustment relating to the permanent difference in basis given rise to by timing differences, i.e., allowance for borrowed funds used during construction, pensions, and taxes. If FIT for ratemaking purposes had always been fully normalized to book, this adjustment would not be necessary. Currently, with comprehensive tax normalization, deferred taxes are provided on timing differences. This is accomplished as described below.
>
> When interest, pensions and tax expenses are incurred, they are deducted currently for tax purposes and capitalized for book purposes. This causes taxes currently payable to the IRS to be less than the income tax expense calculated per book. The resulting difference in FIT for book versus tax purposes is accounted for on the Company's books by increasing the Deferred Taxes Expension account and increasing the Accumulated Deferred Taxes account. Because FIT is normalized to book for ratemaking purposes, the revenue currently received from ratepayers is greater than the FIT actually payable to the IRS. This gives rise to the concept of cost free capital and compensates for the fact that, once the timing differences begin to reverse, the Company's income taxes payable to the IRS will be greater than the revenue received from ratepayers related to FIT.
>
> Prior to the implementation of comprehensive normalization requirements, some of the benefits of a lowerr tax liability during construction of plant resulting from the deduction for tax purposes of construction interest, pensions, and taxes, were passed on to the ratepayers. Consequently, the Company has never been provided revenue related to its tax liability as these timing differences reverse. As with the adjustment for additional depreciation relating to the allowance for equity funds used during construction, it is necessary To adjust the FIT provided in the Cost of Service so that the Company will have sufficient revenue to meet its current actual tax obligation.

While it may be argued that this type of adjustment is retroactive ratemaking in disguise, such is simply not the case. The depreciation addback adjustment in docket #6350 does not attempt to obtain FIT revenue forgone in prior years as a result of a failure to make the depreciation addback adjustment in those years. Rather, it recognizes the fact that there have been insufficient tax revenues provided to meet the Company's current FIT obligation due to the allowance for equity funds used during construction which is a permanent book to tax difference and due to the fact that comprehensive normalization of tax timing differences was not previously practiced.

The City has recommended a depreciation addback adjustment to compensate for the portion of taxes relating to the allowance for equity funds used during construction. The Company has requested a depreciation addback adjustment to compensate for the portion of taxes relating to the non-normalized timing differences, i.e., the allowance for borrowed funds used during construction, taxes, and pensions. The general counsel submits that both of the adjustments are appropriate and necessary to provide sufficient revenues to enable a Company to cover its reasonable and necessary operating expenses would have the effect of eroding the Company's earned return. Therefore, the general counsel urges the ALJ to adopt Ms. Simpson's depreciation add-back adjustment. This adjustment results in an increase of $198,520 to the Company's request of $1,793,852 for additional depreciation. This results in a total adjustment to return for purposes of the Staff's FIT expense calculation of $1,992,372.

Based upon general counsel's arguments as set forth above, the examiner recommends that the depreciation add-back adjustments for both AEFUDC and ABFUDC, as proposed by Ms. Simpson, be incorporated into the calculation of EPEC's FIT expense.

5. Consolidated Return Adjustment

The City has proposed in its brief that the Commission consider reducing EPEC's cost of service by the amount of the tax savings resulting from EPEC's filing of consolidated tax returns with FL&R, on the basis that the tax savings realized from filing consolidated returns is the only benefit to the ratepayers provided by FL&R activities. It appears that a similar adjustment was made by the Commission in Docket No. 5700. The examiner notes that none of the witnesses to this proceeding have proposed such an adjustment in prefiled testimony or through cross-examination. In the examiner's opinion, the record in this docket is not sufficiently developed on this issue for the examiner to recommend that such an adjustment be adopted or rejected by the Commission.

6. FIT Summary

The examiner's recommendations herein result in a total FIT allowance for EPEC of $44,293,871 as opposed to the Company requested allowance of $74,462,282. A summary of the examiner's adjustments to FIT expense is attached hereto as Examiner's Exhibit No. 6.

H. Return

EPEC requested total return dollars of $148,879,668. Application of the examiner's recommended composite rate of return of 12.21% to the examiner's recommended invested capital amount of $759,330,849 yields a total recommended return of $92,714,297.

I. Other Revenue

Ms. Simpson decreased EPEC's requested other revenue amount of $2,162,701 by $12,636 for a total staff recommended other revenue figure of $2,150,065. This decrease reflects staff witness Jeff Rudolph's proposal to decrease EPEC's proposed returned check charge. That adjustment, which the examiner has accepted, is discussed later in this report in connection with EPEC's service rules. The examiner recommends adoption of the staff's determination of EPEC's other revenues.

J. Total Revenue Requirement and Revenue Deficiency

The examiner's recommendations herein result in a total company revenue requirement of $351,024,096 constituting a $110,097,312 reduction in the revenue requirement requested by EPEC in this filing.

The components of this recommendation are as follows:

Fuel	$ 66,142,165
Purchased Power	67,930,008
Operations and Maintenance	45,584,690
Depreciation and Amortization	15,188,851
Other Taxes	18,620,910
Interest on Customer Deposits	199,360
State Income Taxes	349,944
Federal Income Taxes	44,293,871
Return	92,714,297
Revenue Requirement	$351,024,096

The revenue requirement translates into a Texas retail revenue surplus of $4,162,486 which is $71,650,408 less than the amount requested by the Company.

A summary of the examiner's adjustments to EPEC's requested revenue requirement is attached hereto as Examiner's Exhibit No. 7. The examiner's revenue deficiency calculation is set forth in Examiner's Exhibit No. 8.

X. Cost Allocation, Revenue Distribution and Rate Design

A stipulation on revenue distribution and rate design (the Stipulation) was entered into evidence at the hearing on November 21, 1985. A copy is attached to the examiner's report as Examiner's Exhibit No. 9. By agreement of the signatories to the Stipulation, various prefiled testimonies and exhibits were admitted into evidence. Evidence concerning cost allocation, revenue distribution, and rate design otherwise was not taken. Most such issues which are raised in prefiled testimony were resolved in the Stipulation. The examiner indicated at the hearing that if a party wished the examiner to address an issue which was not determined in the Stipulation, the issue should be raised specifically in that party's brief. Only two such issues were raised in brief: the jurisdictional allocation of PVNGS costs, raised by TNP, and the appropriateness of an economic recovery rider (ERR), raised by Border Steel and ASARCO. Miscellaneous service charges are not mentioned in the Stipulation. The examiner has assumed that such charges were not intended to be covered by the parties' agreement, and thus has included a recommended resolution of those issues based upon the evidence in the record.

The issues resolved in the Stipulation, as well as those which are still contested, are discussed below. The parties' original positions as reflected by testimony in the record are also summarized.

The examiner recommends adoption in full of the Stipulation. The Stipulation was signed by parties representing a broad spectrum of interests, is reasonable, and has adequate support in the record. The examiner recommends use of EPEC's proposed jurisdictional allocation. The examiner further recommends that an ERR not be adopted in this case. Finally, the examiner recommends adoption of EPEC's miscellaneous service charges, with two exceptions. First, the staff's proposed $10 returned check charge should be approved instead of EPEC's proposed $13 charge. Second, EPEC's tariff should specify the Commission approved 1986 interest rate of 7.29 percent.

Attached to the examiner's report as Examiner's Exhibit Nos. 10 through 13 are three jurisdictional separation schedules and one revenue distribution schedule which incorporate the examiner's overall recommendations.

A. Cost Allocation

EPEC provides retail and wholesale electric service in Texas and New Mexico. Its electric sales for resale are regulated by FERC. EPEC thus is subject to three jurisdictions: FERC and the States of Texas and New Mexico. Because of this, allocation of EPEC's costs requires a jurisdictional cost of service study and a customer class cost of service study.

Allocation of the costs of providing service involves three processes: functionalization, classification, and allocation. Functionalization involves grouping costs into five functions: production, transmission, distribution, customer, and administrative and general. Classification involves grouping costs into three cost areas: demand, energy and customer. Demand costs are related to the customer's capacity requirements; energy costs are related to the customer's usage; and customer costs are related to neither capacity nor usage. Allocation involves assigning classified costs to different jurisdictions (in the jurisdictional cost of service study) and customer classes (in the class cost of service study).

1. Jurisdictional Separation

a. Original positions of the parties. EPEC witness Harris testified as follows concerning EPEC's jurisdictional separation study. In that study, where identification of cost causation could be attributed to a specific jurisdiction, it was directly assigned to that jurisdiction. Otherwise, each function was classified using demand, energy and customer allocators. EPEC's demand allocator is the average of the twelve month retail jurisdictional and wholesale class customer peaks at the time of system peak. This method, known as the 12 CP method, was approved for the jurisdictional cost allocation in EPEC's last Texas rate case, Docket No. 5700. The energy allocator is annualized mwh adjusted to recognize energy losses. The customer allocators are the retail customer counts as of test year end.

ASARCO did not actually recommend an adjustment to EPEC's proposed jurisdictional separation. However, ASARCO witness Moore observed that in mid-September 1985, ASARCO indefinitely suspended lead smelting operations at its El Paso plant. (This suspension is discussed in greater detail in connection with the proposed ERR in Section X.D.1.d. of the examiner's report.) Mr. Moore testified that if the resulting load reduction is considered a known and measurable change, the jurisdictional separation, class cost of service and rate design will all need to be adjusted.

TNP presented no direct testimony concerning jurisdictional separation. However, TNP Attorney Mark Zeppa asked questions of EPEC witness Harris during the revenue part of the hearing. In response to an objection by counsel for EPEC that Mr. Zeppa's cross-examination was not relevant to the revenue requirement part of Mr. Harris' testimony, Mr. Zeppa stated: "I understand, Your Honor, that there are some elements of rate design involved, but I am specifically concerned about the revenue aspects and not the cost of operations. I believe they are relevant to this gentleman's testimony at this portion of the proceedings." EPEC's objection was overruled. In its brief, TNP cites this cross-examination as grounds for rejecting EPEC's proposed jurisdictional separation of PVNGS costs, and concludes: "Again EPEC has failed its burden of proof on such a critical rate design issue that its entire proposal must fail." In its reply brief, EPEC complained that TNP had signed the Stipulation and could not now be heard to complain on this issue.

In its brief, TNP stated that EPEC has not shown that its allocation of PVNGS costs among the three regulatory jurisdictions is just and reasonable and has not shown that its proposal does not "establish or maintain unreasonable differences as to rates of service either as between localities or as between classes of service" as required in PURA Section 45. TNP argued that its cross-examination of Mr. Harris clearly demonstrates that EPEC has no intention of seeking equal treatment of PVNGS costs by its three rate regulatory jurisdictions.

The referenced cross-examination indicates that in October 1985, EPEC filed an application with FERC concerning the treatment of the costs relating to the operation of PVNGS during the testing period. The filing was to amend the tariffs applicable to EPEC's wholesale customers to exclude test energy produced by PVNGS from inclusion in the fuel adjustment clause and instead charge the customers at a replacement cost rate and credit their CWIP balances. The replacement cost would be the fuel or purchased power EPEC would need if PVNGS test energy were not available. Only fuel costs, and not, for instance, labor costs or return, were included in the FERC filing. New Mexico allows immediate pass-through of fuel costs. In Texas, there would not be current recovery of fuel costs because of the fixed fuel factor. Recovery of such costs probably would be postponed until a future reconciliation hearing or rate case. EPEC has not and is not intending to file an application at the Texas Commission which is similar to that it has filed at FERC.

b. Examiner's recommended resolution. Under the Stipulation, each customer class would receive a base rate revenue increase or decrease that is equal to "the total Texas jurisdictional base rate revenue increase or decrease, as the case may be, found by the Commission herein." Apparently, most of the parties did not consider jurisdictional separation to be still contested after the Stipulation. Only TNP raised it in brief, and the City's brief states that the only cost allocation or rate design issue not resolved by the Stipulation is the ERR.

TNP did not recommend a specific jurisdictional separation or adjustment to that proposed by any other party. Its requested relief appears to be denying the requested rate increase on the grounds that EPEC has not sustained its burden of proof concerning jurisdictional separation of PVNGS costs. Although TNP's arguments may raise some questions, these issues were not explored in this record to an extent sufficient to enable the examiner to conclude that EPEC has failed to meet its burden of proof concerning jurisdictional separation. Moreover, the examiner has recommended a rate decrease. If the Commission decides to change EPEC's rates upward or downward, a jurisdictional separation must be decided on in order to set rates. EPEC's proposed jurisdictional separation is the most credible evidence on this point in the record.

With respect to the point brought up by ASARCO witness Moore, the examiner notes that the Stipulation, which was signed by ASARCO, contemplates no change in class cost of service or rate design due to the September 1985 suspension of the lead smelting part of the operations at ASARCO's El Paso plant. It would be inconsistent to take a different approach with respect to the jurisdictional separation. Accordingly, the examiner recommends that this suspension of operations not be viewed as a known and measurable change requiring an adjustment in the jurisdictional separation.

The examiner recommends that EPEC's proposed jurisdictional separation methodology be utilized in this proceeding.

2. Texas Retail Customer Class Allocation

a. Original positions of the parties. The prefiled testimony reflects that originally the parties took widely divergent positions respecting the appropriate Texas retail customer class allocation. Since the parties eventually agreed upon a result different from that testified to by any, their original positions are only summarized in this report, and some originally contested issues are not discussed.

EPEC used an allocator of average and excess (A&E) for production and transmission items. This allocation is based on the following formula: A&E = (load factor) (average demand) + (1-load factor) (excess demand). Average demand was based on the rate classes' annual energy sales divided by 8760 hours. Excess demand was based on the difference between average demand and the average of the four coincident peaks (4CP) for the months of June, July, August and September. The load factor used was the overall jurisdictional load factor. EPEC witness Harris testified that in EPEC's last two Texas rate cases, Docket Nos. 4620 and 5700, the final class allocator of production and transmission costs, including allowed PVNGS costs, was based on this methodology, except that the CP portion was based on 1CP rather than 4CP. EPEC allocated distribution plant and related items using rate class noncoincident peak (NCP) demand and customer factors.

TIEC witness Jeffry Pollock testified that all production and transmission capital costs should be classified to demand and allocated using the 4CP method. He concluded, however, that EPEC's proposed A&E/4CP is a reasonable proxy of the 4CP method, and should be adopted. DOD witness Suhas P. Patwardhan testified similarly. Mr. Pollock further testified that all production plant investment should be allocated relative to demand.

ASARCO witness Michael K. Moore testified that production plant and PVNGS CWIP should be allocated using a 4CP demand allocator, but that EPEC's proposed A&E/4CP is a reasonable facsimile. He recommended that transmission plant be allocated on the basis of 4CP.

W. Silver witness Raymond J. Stanley for the most part agreed with EPEC's proposed allocation of distribution costs, but concluded that distribution poles should be classified as 40 percent customer- and 60 percent demand-related. He agreed with EPEC that uncollectible accounts expense should be apportioned to the customer classes which historically contributed to that expense.

City witness Dr. Ben Johnson recommended an allocation of production plant and comparable costs similar to that which he proposed in Docket No. 5700. His formula gives approximately 47.5 percent weight to peak kws and 52.5 percent weight to kwh usage. Dr. Johnson allocated approximately 50.5 percent of the investment in PVNGS using his recommended production plant factor, and 49.5 percent using a kwh factor. He allocated approximately 65 percent of transmission plant and related expenses to CP demand and 35 percent to energy sales. Finally, Dr. Johnson allocated distribution plant on the basis of demand, energy and customer statistics. This methodology had been approved in Docket No. 5700.

OPC witness Dr. Steven Andersen proposed a capital substitution method of cost allocation.

Staff witness Kol recommended that EPEC's proposed allocation of production costs on the basis of A&E/4CP be adopted, but that transmission costs be allocated on the basis of a 12CP demand allocator, that regulatory commission expense be allocated on the basis of the revenue cost of service, and that uncollectible expenses be allocated on the basis of revenue to all customer classes.

b. Resolution in the Stipulation. The Stipulation does not specifically allocate costs, but proceeds directly to revenue distribution. Since adoption of the Stipulation is recommended, no resolution of the disputes over cost allocation is attempted in this report.

B. Revenue Distribution

1. Positions of the Parties

EPEC witness Harris testified that EPEC developed rates based on the total class cost of service, tempered by other considerations.

TIEC witness Pollock testified that primary emphasis should be on the cost of service to each class and each customer within a class. He believed that EPEC's proposed class revenue allocation would move the rates of each class closer to cost, and recommended its adoption, except that no class should receive a base rate percent increase in excess of 1.5 times the system average. This constraint would affect the street lighting rate.

ASARCO witness Moore stated that no class should receive an increase of less than 50 percent or more than 150 percent of the system average increase and that no class should receive an increase of more than five percentage points above the system average percentage increase.

DOD witness Patwardhan testified that the class revenue distribution should result in uniform class rates of return.

W. Silver witness Stanley testified similarly, and was supportive of EPEC's proposed revenue distribution.

City witness Johnson testified that factors important in developing a revenue distribution include cost of service, value of service, historic rate relationships, ability to pay, relative risk, relative growth rates, economic conditions, rate simplicity, embedded and marginal cost, and demand characteristics. Dr. Johnson argued that EPEC's proposed revenue distribution places far too much emphasis on the results of EPEC's cost study. Dr. Johnson's approach was to give a uniform average percentage increase or decrease to each customer class which produces returns within a reasonable percentage of the system average. The other classes (municipal street lighting, irrigation service and private security lighting) would receive an increase or decrease limited to a specific percentage.

Using his cost of service study, OPC witness Andersen concluded that the only classes for which larger than system average increases are clearly indicated are street lighting, Phelps Dodge, water heating, ASARCO and cotton gins. He proposed that OPC's recommended base rate increase be allocated across customer classes in proportion to class contribution to energy sales, and that irrigation and area lighting customers be excluded in recognition of the excess revenues they currently contribute.

Using the staff recommended base rate revenue increase and cost allocation, staff witness Kol recommended that classes which experience a cost of service revenue decrease receive no increase, that classes which experience more than a four percent increase receive an increase limited to 2.5 times the Texas retail average increase, that the class which incurs a 42.85 percent increase (El Paso municipal street lighting and traffic signal) receive a 12.99 percent increase and that all other classes be assigned cost of service results.

2. Resolution in the Stipulation

The Stipulation provides that any base rate revenue increase or decrease found by the Commission be allocated to the customer classes proposed by EPEC on an equalized percentage basis. Thus, each class would receive a base rate revenue increase or decrease equal to the total Texas jurisdictional base rate revenue increase or decrease.

The Stipulation provides that the assignment of customers to classes proposed by EPEC in its proposed tariffs is accepted. The examiner assumes that this means that the parties agreed to the rate schedule numbers and titles and provisions prescribing which customers each rate schedule applies to contained in EPEC's proposed tariff. EPEC proposed certain changes in these items from those reflected in its present tariff. As explained in the prefiled direct testimony of EPEC witness Harris, EPEC proposed to change the minimum billing demand for Rate 25, large power service, from 300 kw to 600 kw per month, which will require the transfer from Rate 25 to Rate 24, general service, of 110 former Rate 25 customers who averaged less than 600 kw per month during the test year. EPEC also proposed to consolidate Rate 23, small master-metered apartments, into Rate 24 and eliminate the tariff for Rate 26, large master-metered apartments. Of the seven current customers on Rate 26, two average in excess of 600 billing kw per month during the test year. These two customers will be consolidated under the new Rate 25. The remaining five customers on Rate 26 will be consolidated under Rate 24, general service. EPEC proposed establishing a new rate schedule, 31, for Fort Bliss, which has been billed under Rate 29-A, Fort Bliss, a transmission voltage rate. EPEC proposed eliminating its Rate 97, off-system sales credit, which sprang from the Stipulation and Order in Docket No. 3382. Mr. Harris testified that Rate 97 applies to refunds made from off-system sales for which there are no contractual arrangements existing or contemplated.

The stipulated revenue distribution methodology was not originally proposed by any of the parties. However, it is conservative in that it would have little impact on the class revenue distribution incorporated in the present rates. This is especially appropriate since these issues were fully litigated and decided by the Commission for EPEC only a year ago in Docket No. 5700. In addition, under the Stipulation each customer class would tend to see a similar drop in rates. This would mitigate the customer confusion which could result if an overall rate decrease were ordered but rates were increased to some customer classes due to a change in revenue distribution. The examiner concludes that the stipulated revenue distribution is appropriate for use in this case, and recommends its adoption.

C. Rate Design

1. Design of Base Rates

a. Positions of the parties. EPEC proposed three general revisions in its rates. First, it proposed a revision in its peak and off-peak hours, which was not contested. Second, it proposed increasing the ratchet from 60 to 75 percent of the highest measured demand established during the immediately preceding months of May through October. The ratchet applies to seven customer classes, including general service and large power and other large user classes. This proposal was contested with respect to the general service class by the City. Third, EPEC proposed a customer charge which it considered to include all specific capital and operating costs which vary only with the number of customers. EPEC's proposed customer charge for specific classes was contested, as discussed below.

In addition to these general changes, EPEC proposed certain revisions in specific rates. First, it proposed to reduce the boundary for the seasonal energy block in the residential tariff for qualified space heating customers from 800 kwh to 500 kwh. This was contested by City witness Johnson and OPC witness Andersen. Dr. Johnson recommended a rate differential of 2.5 cents per kwh for usage above 800 kwh during November through April for qualified space heating customers and separately metered water heating usage. Second, EPEC proposed collecting the horsepower charge in the irrigation rate only during the irrigation season. This change was not contested. Third, as discussed previously, EPEC proposed consolidating its master metered apartment rate with its general service rate and consolidating its large master metered apartment rate with its large power rate. It also proposed changing the applicability provisions in the general service and large power rates, so that the general service rate would include customers whose highest thirty minute kw average load does not exceed 599 kw, and the large power rate would apply to customers whose load is 600 kw or more. These changes were not contested. Fourth, EPEC proposed a new rate schedule for Fort Bliss, which had been billed under a transmission voltage rate. This was not contested. Fifth, EPEC proposed eliminating its schedule for off system sales credits. This was not contested.

The City, OPC and the staff contested EPEC's proposed increase in the residential customer charge from $6.50 to $10.00 and in the water heating customer charge from $1.50 to $2.00. Mr. Andersen recommended a residential customer charge of $6.00. Dr. Johnson recommended a $6.00 residential customer charge if a rate reduction is ordered.

Dr. Johnson also made the following recommendations concerning the general service rate. First, the customer charge for the general service class should be reduced to $18.50. Second, the rate discount for off-peak water heating and space heating in the general service rate should be reduced below the current level, approximately 4.701 cents per kwh for customers with 0-3,000 kwhs of usage, to 3.5 cents below the rate in the 0-3,000 usage block. Third, the tail-block rate for usage exceeding 3,000 kwh should be increased from 1.0 cent per kwh to 1.25 cents per kwh, rather than reduced, as EPEC proposed. Fourth, the energy rate implicit in the first block (0-3,000 kwhs) should also be raised to 1.25 cents per kwh, consistent with the rate in the tail-block. Fifth, after determination of the revenues generated by the $18.50 customer charge and the kwh rate of 1.25 cents in both blocks, the remaining portion of the general service revenue requirement should be uniformly recovered through the kw charge for demand above 15 kw and the implicit demand charge in the 0-3,000 usage block.

Staff witness Jeff Rudolph recommended that a seasonal rate structure be developed for both the regular and space heating residential customers. With respect to the general service class, he testified that the customer charge should be $18.00 and the existing tail block price should not be reduced from the current level of $.01 per kwh, but instead should be increased by a modest amount.

Border Steel witness Lupia expressed interest in an interruptible rate being made available to Border Steel.

b. Resolution in the Stipulation. The examiner interprets the Stipulation to mean that, unless expressly stated therein, none of the proposals concerning rate design described above are adopted for use in this case. As noted previously, the Stipulation incorporates EPEC's proposed changes in customer classes.

The Stipulation provides that any base rate increases or decreases found by the Commission be recovered as follows: (a) for rate classes other than rate class 24, general service, which have demand charges, any increase or decrease shall be applied to the demand charge; (b) for rate classes which do not have demand charges, any increase or decrease shall be applied to the energy charge on a uniform cents per kwh basis; and (c) for rate class 24, any increase or decrease shall be applied to the demand charge on a percentage basis; however, the implicit demand charge in the first 3,000 kwh block shall be calculated by subtracting $0.01 per kwh from the total revenues derived from the first 3,000 kwh block. This proposal results from agreement by parties representing a diverse array of utility and customer interests. It appears reasonable, and the examiner recommends its adoption.

2. Other Provisions in the Stipulation

As described in Subsection X.B.2. of this report, EPEC proposed certain changes in its customer classes. The Stipulation provides that the assignment of customers to classes proposed by EPEC in its proposed tariffs is accepted. The examiner recommends adoption of this provision of the Stipulation.

The Stipulation also provides that the annualized adjusted kw demand and kwh sales found by the Commission in this proceeding is to be used for rate design purposes. The examiner's recommended resolution of these issues has been previously discussed.

Under the Stipulation, fixed fuel factors would be developed by multiplying the Texas system fixed fuel factor, calculated to reflect the adjusted annual fuel costs found by the Commission, by the following energy loss factors: 0.944768 for transmission voltage, 0.987162 for primary voltage and 1.01681 for secondary voltage. The examiner recommends adoption of this provision.

D. The Proposed Economic Recovery Rider

The ERR is the principal rate design issue which the parties generally agreed remains unresolved by the Stipulation. The argument over the ERR concerns two main questions. First, should an ERR be adopted? Three parties expressly took a position concerning this: Border Steel, ASARCO and DOD, each of which supported the ERR. Second, who should bear the burden of unrecovered revenues resulting from an ERR if adopted? The City proposed that the Commission consider spreading this burden between EPEC customers and shareholders, and EPEC argued that the burden should be borne by the other EPEC customers. Other parties in testimony or briefs offered comments but took no express position concerning the questions set out above.

The ERR issue arose in an unusual way. EPEC originally proposed an ERR, as well as an incremental productivity rider, but subsequently withdrew both proposals. As mentioned previously, only the ERR is still being pushed by the parties at this time. However, the prefiled testimony of the City, Border Steel, ASARCO, DOD and the staff which discusses EPEC's ERR proposal was admitted into evidence. In its reply brief EPEC argued that any references in parties' briefs to EPEC's withdrawn proposal concerning the ERR is inappropriate. Since the withdrawn EPEC testimony was not admitted into evidence, the examiner has not considered such testimony or references thereto. However, the examiner considered descriptions and evaluations of EPEC's original proposal which are in testimony which was admitted into evidence, as well as references to such testimony in parties' briefs.

1. Positions of the Parties Concerning Adoption of an ERR

a. EPEC. In its reply brief EPEC concurred with the City and other intervenors that approval of the concept of an ERR is a policy decision for the Commission. EPEC indicated that it had withdrawn its own proposal.

b. The City. City witness Johnson described the ERR EPEC originally proposed as follows. The ERR would apply to rate schedules serving three of EPEC's largest industrial customers: Rate 15-Phelps Dodge, Rate 29-ASARCO, and Rate 30-Border Steel. Under the rider, these customers would receive a 25 percent discount on their monthly kw charge, if their highest maximum demand during the month occurred during the off-peak billing hours. Dr. Johnson testified that according to EPEC witness Harris, the proposed ERR recognizes two factors: the importance of maintaining an industrial base in EPEC's Texas service area and the importance of reducing peak demand growth.

Dr. Johnson stated that the Commission faces a policy decision with regard to the ERR. He testified that in making this decision, the Commission should answer four questions: Are such discounts necessary to keep the industrial customers on the system? If so, do they benefit EPEC's ratepayers and the El Paso community as a whole? Assuming that they do, what discount level is needed, and is the ERR the most appropriate method of implementing such a discount? Who should bear the resulting revenue shortfalls?

Dr. Johnson expressed two concerns about the particular ERR originally proposed by EPEC. He testified that there is no indication that the ERR would benefit other customer classes by reducing overall system load growth, reasoning as follows. At least two of the customers, ASARCO and Border Steel, would receive the discount with virtually no alteration in their monthly load patterns, particularly if the Commission approved EPEC's proposal to narrow the designated on-peak period to the hours from 10:00 a.m. to 8:00 p.m. The maximum kw demand of Phelps Dodge occurred more often during the peak period. However, given potential savings of almost $730,000 per year, this customer would have a very strong incentive to shift its highest demand to an off-peak hour each month. Similar incentives would apply to other eligible customers. Dr. Johnson concluded that there is no assurance that any steps taken by customers in order to qualify for the discount would have any beneficial impact on EPEC's growth in peak demand. The proposed ERR does not provide an incentive for customers to reduce their peak load; it simply encourages them to have a slightly higher maximum load during the off-peak period than they have during the peak period. Accordingly, the Commission should view the ERR not as a means of reducing peak demand for the benefit of the system, but simply as a price discount for large industrial customers.

Dr. Johnson further testified that the ERR is not necessarily the optimal means of implementing such a discount. He is particularly concerned that EPEC's original proposal tends to mask the true purpose, by obscuring the fact that the rate classes eligible for the ERR are not being asked to pay their full share of the total cost of service, while the remaining classes are.

In its brief, the City referenced the report and recommendations of its Public Utility Regulation Board which is attached to EPEC's appeal to the Commission from the City Council's action on EPEC's rate request. The examiner notes that such report was not admitted into evidence. However, the November 1, 1985 resolution of the El Paso City Council indicates that the report was adopted and made a part of the resolution. Thus, the report is legal authority, in that it is indicative of the decision reached by this local regulatory authority. The Report states:

> The Board is concerned about the downslide of the industrial section brought about by the softening of the metals market and competition from outside forces. Because a reduction in electric revenues is recommended for all classes in the instant case, the Board, with Mr. Ward dissenting, declined to recommend adoption of either or both industrial incentives at this time. Once again the Board wishes to alert the Council about the need for consideration of such relief when an increase in electric rates may become necessary due to the inclusion of in-service Palo Verde units in the rate base. Should such relief fail to materialize, and the current depressed state of the local metals industry remain or deteriorate further, our community may well experience additional unemployment as well as an additional rise in electric rates caused by the shrinking load demand by the local industrial sector.

c. Border Steel. Border Steel submitted detailed testimony concerning its economic condition and the effect the ERR would have on Border Steel, which is summarized below.

Border Steel witness Lupia provided the following description of Border Steel and its subsidiaries. EPIM, which is wholly-owned by Border Steel, purchases scrap metal from local businesses and recycles it. The iron and steel portion of the scrap is sold to Border Steel. EPIM's future is heavily dependent upon that of Border Steel, as well as of the El Paso economy. Border Steel is a steel "mini-mill," meaning that it has an annual maximum production capacity of less than 500,000 tons. Border Steel has been in operation since

1962. Metal Processing, Inc. was acquired in 1976, and the EnerSteel plant, which manufactures oil field sucker rods, was built in 1982. The steel mill is located in Vinton, Texas, approximately 17 miles north of the City of El Paso. The Metal Processing division of Metal Processing, Inc. is located adjacent to the steel mill. EPIM is located in downtown El Paso. EnerSteel Products Company is located in Santa Teresa, New Mexico, about 10 miles northwest of the City of El Paso.

Mr. Lupia described Border Steel's contributions to the local economy as follows. Border Steel employs approximately 500 people, down from 600 last year, and has an annual payroll of over $8,700,000, down from $10,000,000 last year. Currently, the average wage paid to non-management personnel is approximately $14,000 per year. Border Steel is not a minimum wage employer. During the past fiscal year, Border Steel paid $192,634 in state and local taxes, $623,713 for health care, and $2,186,869 for natural gas. In addition, Border Steel purchased services such as welding and motor repair maintenance from a number of El Paso companies.

Mr. Lupia also described Border Steel's use of electricity. Steel mini-mills characteristically recycle ferrous scrap by melting it in electric arc furnaces as the first step in making steel. The greatest part of Border Steel's electric consumption is in the electric arc furnaces. Other uses are to drive the electric motors in the rolling mill, and to operate the pollution control system, auxiliary motors, thermal energy recovery systems, lights, computers and other equipment.

According to Mr. Lupia, Border Steel's electricity rates have increased dramatically. In 1972, Border Steel paid an average price of 1.09¢/kwh. In 1984, Border Steel paid approximately 6.2¢/kwh. Electricity is now approximately 15 percent of Border Steel's total costs. For calendar year 1984, this amounted to approximately $6,317,000.

Mr. Lupia offered the following opinions concerning the effect of this increase in power costs on Border Steel's ability to compete. Border Steel sells its products basically in the western United States. Border Steel's electricity rates are about 2¢/kwh higher than those of its competitors, which translates into about $2 million per year at Border Steel's level of consumption. The difference is greater in some cases, and Mr. Lupia knows of no competitor that pays higher rates than Border Steel. This leads Mr. Lupia to draw the following conclusions. First, it shows that Border Steel cannot pass any increased electricity costs on to its customers, and that existing rates give Border Steel's competitors the ability to put Border Steel out of business over the long-term. Second, it explains why industry, other than the most labor intensive kinds that pay at or near the minimum wage, cannot be attracted to El Paso. Third, it indicates that other businesses in the El Paso area besides Border Steel will probably shut down as a result of electric rates.

Mr. Lupia provided the following explanation of why he believes that Border Steel cannot pass on increased costs of electricity to its customers. Prices for Border Steel's products are a function of the national steel market. Price and prompt delivery are about the only factors in a customer's buying decision, with price being by far the most important. Thus, Border Steel must sell at the market price in the western United States if it wishes to sell at all. Any increase in Border Steel's costs lowers its profit or increases its loss. Since Border Steel's competitors enjoy dramatically lower electricity costs, then all else being equal, they can afford to cut their price much more before losing money than can Border Steel. Labor costs are lower in El Paso than in the rest of the United States, but have become a much smaller percentage of total costs than was once the case at Border Steel and throughout the mini-mill industry. Mr. Lupia does not believe that labor cost differentials offset the electric rate disadvantage suffered by Border Steel.

According to Mr. Lupia, Border Steel has made many plant improvements to reduce its consumption of electrical energy on a kwh per ton basis. Border Steel's average consumption is 455 kwh per ton, compared to an industry average of 500 kwh per ton. Most of these changes increased Border Steel's usage of other commodities such as oxygen and natural gas.

Mr. Lupia stated that Border Steel is paying about 2¢/kwh more for electricity than its competitors, or, at 455 kwh per ton, $9.10 per ton more for electricity than its competitors. A competitor can sell to Border Steel's customers by cutting Border Steel's price by only $1.00 per ton. If that competitor can afford to sell at a price that causes Border Steel to lose money indefinitely, Border Steel's fate is sealed. Border Steel has lost approximately $14,000,000 in the past three years. The reduced demand for steel products associated with the recession has played a role in those losses. Nevertheless, if Border Steel's electric rates were as low as some of its competitors, Border Steel would have made a profit in those years.

Mr. Lupia testified that those businesses that are energy intensive and compete on a regional or national basis must be faced with the same competitive disadvantages as Border Steel. If this competitive disadvantage continues, the companies that are presently in El Paso will have to consider shutting down their operations. The impact on El Paso's economy, and on the electric rates for the ratepayers left behind, would be staggering.

Mr. Lupia urged the adoption of the ERR, which he testified has two advantages for industrial customers, most other customers, and the utility. First, if an industrial customer can regulate its peak demands so as to qualify for the ERR discount, it can achieve a lower cost per kw of demand and thus reduce its cost of electricity. This will help offset the competitive disadvantage imposed on industrial customers by EPEC's high electric rates. Second, the utility's generation plant will be more efficiently utilized, which in the long run should result in lower overall costs and lower rates for all customers. Mr. Lupia believes that most people would conclude that it is worth the tiny amount that would actually flow through to a typical residential bill to save the jobs that companies like Border Steel provide to the community.

In its brief, Border Steel argued that the ERR should be adopted now, because delay will result in idle plants and a deteriorating industrial economy. Border Steel acknowledged that customers who presently practice careful load management, or whose loads are inherently very stable, may need to do little more in the way of load management to qualify for the ERR. Border Steel argued, however, as follows. Such customers should not be criticized for their past efficiency. A crisis exists in the El Paso metals industry. If the crisis passes, the ERR can be modified to require greater load management results on the part of a customer before the demand charge reductions become applicable.

d. <u>ASARCO</u>. Like Border Steel, ASARCO presented detailed testimony about its economic condition and the impact upon ASARCO if the ERR is adopted.

ASARCO witness Hank A. Schlieper testified that the customers in the three major industrial classes to which EPEC's originally proposed ERR would be applicable are among the largest on the EPEC system and are in the economically troubled ferrous (in the case of Border Steel) or nonferrous (in the case of Phelps Dodge and ASARCO) metals industries. For each of these companies, electric power cost is a major component of their total costs, and can significantly affect their ability to compete.

Both Mr. Schlieper and ASARCO witness Moore testified that the advantage from an ERR of reducing growth in peak demand is less relevant in the short-term than is the advantage of maintaining an industrial base in EPEC's service area. This is because EPEC is currently on the verge of bringing PVNGS on-line, which arguably will constitute excess generating capacity for a period of time. They testified, however, that PVNGS is a testament to the continuing need to employ load management incentives and other tools to avoid or postpone further potentially risky plant construction, and that this advantage also would be more important if EPEC is ordered to divest itself of part of PVNGS.

Mr. Schlieper described ASARCO's impact on the community as follows. During the one-year period ending August 1985, the total budget for ASARCO's El Paso plant totaled approximately $91,000,000. Of these expenditures, over $82,000,000 were paid into the local economy, including salaries and wages of over $26,000,000 ($35,500,000 if one includes pension benefits), local property taxes of $990,000, power purchases of $8,135,000, fuel purchases (gas, oil and oxygen) of $15,000,000, locally purchased materials and supplies of $10,500,000, transportation charges of $10,000,000, and medically related expenditures of $2,500,000. In August 1985 ASARCO's El Paso plant employed 808 full-time equivalent employees, making ASARCO one of the largest industrial employers in the City. These represent high quality, union-wage jobs held in many cases by workers who would find it exceedingly difficult, if not impossible, to find equivalent employment elsewhere in El Paso. Moreover, there is a "multiplier effect" for dollars injected into the local economy. For example, if one assumes a five-to-one multiplier for jobs, as has been found to be the case with heavy industrial operations like ASARCO's, then these over 800 jobs have been responsible for creating perhaps another 3,200 jobs in the El Paso economy.

Mr. Schlieper testified that since 1979, there have been over 20,000 layoffs in the domestic nonferrous metals industry, as approximately 55 percent of the country's total mining, smelting, and refining capacity has been idled. ASARCO has operated a plant, comprised of a lead smelter and a copper smelter, at its present site in El Paso since 1887. On September 15, 1985, the Company announced the indefinite suspension of its lead smelting operations at El Paso, which has resulted in the layoff to date of 330, including 60 managerial employees, of the El Paso plant's 808 total employees. Similar economic factors place continued operation of the copper plant in jeopardy.

Mr. Schlieper testified that lead and copper are traded internationally on terminal commodities markets such as the London Metal Exchange and the New York Commodity Exchange. ASARCO's competition therefore is truly worldwide.

Mr. Schlieper described the economic forces affecting the copper market as follows. The control of productive capacity and marketing philosophy for copper largely resides with countries rather than companies, since Third World governments in countries such as Chile, Zaire, Zambia, and Peru make business decisions in order to further political and social objectives rather than in accordance with traditional principles of supply and demand economics. This strategy is encouraged by subsidies provided to Third World nations by the World Bank whenever the price falls below artificially established levels. Thus, unlike domestic producers, Third World producers have no incentive to curtail production in the face of declining demand, which has resulted in the current prolonged period of artificially depressed worldwide copper prices.

Mr. Schlieper testified that the economic forces affecting ASARCO's lead operations are somewhat different than for copper. He explained this as follows. Lead has an ever-declining real demand. In terms of constant 1900 dollars, the current low price of lead has only been reached once before, during the Great Depression of the 1930's. Many lead mining companies worldwide have found current prices to be insufficient to cover basic costs, and have therefore curtailed, suspended, or ceased mining operations. Consequently, the supply of lead concentrates has decreased dramatically, and the few remaining suppliers of available lead concentrates have been able to negotiate very low treatment or smelting charges from domestic smelters such as ASARCO's El Paso lead plant. As a result, a smelter's ability to bid for lead concentrates has become heavily dependent on its ability to contain its total smelting costs. One of the major components of those total costs is the cost of electricity. ASARCO's East Helena lead smelter has been able to obtain concentrates and remain operating in large part because its per kwh electric rate is only one-third that of the El Paso plant. Since the El Paso lead plant can no longer afford to bid for sufficient concentrates for smelting on a break-even basis, plant operations have been suspended indefinitely.

Other relevant economic factors include the following. First, labor costs in the emerging nations are only a fraction of those paid by American producers. Second, pollution control devices are virtually nonexistent in Third World industrial applications. In stark contrast, ASARCO has invested over $120 million in capital expenditures since 1970 at the El Paso plant alone on pollution abatement equipment and associated control measures. Furthermore, approximately forty-eight percent of the El Paso plant's total consumption of electrical energy is devoted to the operation of the plant's numerous baghouses, electrostatic precipitators, metallurgical scavenger acid plants, and associated ventilation equipment. Third, the cost of energy itself is generally higher for most domestic producers than for their subsidized Third World competitors.

Mr. Schlieper testified that ASARCO had taken several steps to cut costs in an effort to respond to these concerns. First, in response to rising labor costs, ASARCO in 1983 negotiated concessionary labor contracts with affected unions, freezing employee wages and benefits at 1983 levels. A company-wide hiring freeze was instituted at that time and remains in effect today. In 1985, a progressive salary reduction program was implemented for all ASARCO management personnel. Second, earlier in 1985, all vendors selling supplies and goods to ASARCO were requested to provide ASARCO with a hardship discount on all of its future purchases. Most suppliers have agreed to do so. Third, ASARCO's direct sale arrangements were renegotiated earlier in 1985 with El Paso Natural Gas Company for deliveries to both the El Paso plant and ASARCO's Hayden, Arizona plant, resulting in fuel cost savings in the range of 15 to 20 percent. Fourth, in order to minimize electric power costs, demand control measures have been implemented at the El Paso plant in the form of computerized monitoring and control of in-house generating capacity and revised work schedules designed to shift peak demand usage to off-peak periods. Fifth, and of greater significance, ASARCO consolidated operations in a number of areas. To date this has resulted in the permanent closure of the ASARCO's Tacoma, Washington, copper smelter, the indefinite suspension of operations at the Corpus Christi, Texas, zinc refinery, the indefinite suspension of the Globe, Colorado, cadmium by-products plant, the permanent closure of the Silver Bell, Arizona, copper mine, the indefinite suspension of operations at the Sacaton, Arizona, copper mine, and the indefinite suspension of lead smelting operations at the El Paso plant.

Mr. Schlieper also expressed the following opinions concerning ASARCO's energy costs. Mr. Schlieper believed that the total cost of production is the key to whether or not the El Paso plant can remain competitive. In terms of domestic competition, one of the most, if not the most, significant variables is the cost of energy, including electric power, because labor contracts are generally negotiated on a national basis and plants having similar productive capabilities must meet generally comparable environmental standards. ASARCO's most recent in-house survey of the electric rates paid by its smelting and refining facilities nationwide as of January 1985 shows that the El Paso plant has the highest electric rates, in total cost per kwh, as indicated by the following summary:

Plant	Rate in $/kwh
East Helena, Montana (Pb Smelter)	0.021
Omaha, Nebraska (Pb Refinery)	0.022
Glover, Missouri (Pb Smelter)	0.031
Amarillo, Texas (Cu Refinery)	0.039
Hayden, Arizona (Cu Smelter)	0.043
Hillsboro, Illinois (Zn Plant)	0.050
Corpus Christi, Texas (Zn Plant)	0.051
Columbus, Ohio (Zn Plant)	0.055
El Paso, Texas (Cu & Pb Smelters)	0.058

Mr. Schlieper favored adoption of EPEC's originally proposed ERR. However, he testified that it is unclear from the tariff language originally proposed by EPEC how the proposed ratchet provision in Schedule 29, ASARCO, dovetails with the ERR proposed in that schedule. ASARCO would immediately benefit from the ERR if the ERR provision is interpreted as overriding the ratchet provision, so that the ERR is applied to the greater of the ratchet level or the actual peak demand for the billing month. If instead the ratchet takes priority, ASARCO's minimum payment on its demand charge for any given month can be no less than 75 percent of its peak demand in the preceding May through October billing months. Due to the current lead plant suspension, ASARCO's demand will decrease by more than 25 percent. Accordingly, if the ratchet provision supersedes the ERR, no benefits would accrue to ASARCO under the ERR for an initial period of twelve months. In any case (either immediately if the ERR supersedes the ratchet or after October 1986 if the ratchet overrides the ERR) ASARCO estimates that with optimal load management the El Paso plant could achieve approximately a ten percent savings in its total cost per kwh under the ERR. Given the El Paso plant's present precarious financial position, ASARCO would view savings of this magnitude as significant.

According to Mr. Schlieper, perhaps even more significant would be the signal that adoption of the ERR would provide that the City and community of El Paso and the State of Texas appreciate their existing industrial base and the crisis it is facing. Such a signal would be particularly meaningful to the officers and directors of a nationwide corporation, like ASARCO, which has the option of shifting production from one facility to another, especially since other jurisdictions have approved economic incentive and recovery rates to attract and retain major industrial facilities.

Mr. Schlieper testified that excluding the electrical demand of those portions of the lead plant which are no longer operating, ASARCO has projected a peak demand in most months of 17,000 kw and energy requirements of 9,500,000 kwh. ASARCO estimates that out of these figures, approximately 2,000 kw and 1,500,000 kwh would be provided by self-generation, with 15,000 kw and 8,000,000 kwh being provided by EPEC. These projections have been confirmed by actual figures. During the period from September 20, 1985, through October 15, 1985, ASARCO's peak demand purchases were 14,898 kw, and its average demand purchases were 11,307 kw per hour, which yields energy purchases of 8,254,000 kwh per month.

Mr. Schlieper testified that because under the EPEC proposal any savings experienced as a result of the ERR would be capitalized and recovered from all customer classes in the next EPEC rate case, the net effect on the cost per kwh of other customers would be almost negligible. In ASARCO's case, if one assumes the maximum possible annual savings under the ERR of $1,129,892 (based upon ASARCO's off-peak usage during 1984 when the lead plant was operating), and dividing that figure by the total Texas adjusted kwh sales figure used by EPEC in its rate filing package, the maximum potential impact upon the system average cost per kwh for EPEC's Texas jurisdiction customers would be merely $0.0003814 per kwh, or less than four-tenths of one mill.

In its brief ASARCO pointed out that while the ERR is not covered by the Stipulation, no party in testimony opposed its adoption. It also provided additional argument for the proposition that even if the revenue deferrals resulting from the ERR were spread among all customer classes, the impact upon other ratepayers would be minimal, reasoning as follows. Mr. Schlieper's $0.0003814 figure is based upon EPEC's in-service filing and the most conservative assumptions possible. (Schlieper testimony at 19 and Exhibit HAS-1.) However, substituting the City's dollar figures (Johnson testimony at 86) into Mr. Schlieper's calculation, the impact figure under current rates falls to $0.0002801 per kwh for applying the ERR to ASARCO and $0.0007506 per kwh for applying it to all three companies. The $0.0007506 figure represents less than one percent of EPEC's system average cost per kwh of 8.19 cents. (Total adjusted revenues under current rates of $242,685,131, from Schedule Q-1 at 2 ÷ total Texas sales of 2,962,737 mwh, from Schedule Q-7 at 1.) Its impact on the average EPEC residential ratepayer would be only 33 cents per month, and that is assuming all three companies are able to take advantage of the ERR. (Total residential kwh of 769,481,969 ÷ total customer months of 1,770,876/12 months = 435/kwh mo. for average residential customer; 435 kwh times $0.0007506 per kwh = 33 cents per mo.; <u>see</u> Schedule Q-7 at 2.) ASARCO further observed in its brief that if the Commission finds that EPEC should receive no rate increase or a rate decrease, someone may argue that the ERR should not be adopted. In response to such an argument, ASARCO contends that the adverse economic forces and competitive disadvantages will not disappear simply because EPEC's rates do not increase in this particular rate case.

Finally, in its brief, ASARCO disagreed with application of the ERR to Fort Bliss, as proposed by DOD. ASARCO pointed to the distinction between a private enterprise which must make a profit to survive and a tax-funded governmental entity that can apparently withstand even the largest of operational and cumulative financial deficits.

e. DOD. DOD witness Patwardhan testified that since Fort Bliss is one of EPEC's larger commercial and industrial customers, the ERR should also apply to Fort Bliss. He stated that EPEC should not narrow the applicability of the ERR by arbitrarily classifying loads as commercial, industrial, etc. Rather it should look at the size of the loads it is trying to impact and what effect the maintenance or loss of such loads has on the areawide economy and on EPEC operations. Mr. Patwardhan testified that Fort Bliss employs a large number of people and incurs large expenditures. Fort Bliss employs 7,400 civilians on base, making it perhaps the largest single civilian employer on the EPEC system. In addition, there are 23,000 active-duty soldiers and their families. Mr. Patwardhan further testified that out of Phelps-Dodge, ASARCO, Border Steel and Fort Bliss, during the test year Fort Bliss received service at the highest voltage (115 kv), contracted for the highest minimum capacity of 10,000 kw, and had the highest number of billing demand units and the second highest number of billing energy units (with the recent significant reduction in the operation of ASARCO, Fort Bliss' billing energy units will be the highest). EPEC's proposed revenue from Fort Bliss is the largest from these four customers. Fort Bliss has the highest coincidence factor. This indicates that Fort Bliss follows EPEC's load pattern. For Fort Bliss to receive any benefit from the ERR it would have to change its load profile and shift usage from on-peak to off-peak or increase the usage during off-peak. This may not be true for the other three customers who already have some diversity between their individual peaks and the EPEC system peaks. Mr. Patwardhan recommends that the Commission adopt the ERR proposed by EPEC, and that this ERR be made applicable to Fort Bliss, in addition to other rate schedules proposed by EPEC.

f. Staff. Staff rate design witness Rudolph testified that the rate design staff neither opposes nor endorses EPEC's proposed ERR, but is assuming an information support role with respect to this issue. He stated that the primary reason for the ERR proposal is that EPEC is concerned about maintaining its customer base. As a result, it is offering price discounts to specific customer classes.

The rate design staff conducted an informal telephone survey of twenty commissions to determine how other commissions are handling economic recovery/incentive issues. The survey indicated that two factors, unemployment and capacity availability, frequently assume a prominent role in the decision process. Mr. Rudolph presented unemployment statistics which led him to conclude that most of EPEC's Texas service area is characterized by a relatively high level of unemployment.

Mr. Rudolph's schedules indicate that in June 1985 Texas had the nineteenth highest unemployment rate, 7.7 percent, of the fifty states plus the District of Columbia. In June 1984 it had the thirty-sixth highest unemployment rate, 5.50 percent. Out of twenty-eight Texas Metropolitan Statistical Areas, in June 1985, El Paso was fifth highest with an unemployment rate of 12.40 percent. This is thirteenth out of a national sample of 253 metropolitan statistical areas. The June 1985 unemployment rate in EPEC's service area by county was: Culbertson, 8.90 percent; El Paso, 10.50 percent; and Hudspeth, 3.10 percent. Mr. Rudolph also presented EPEC-specific excess capacity figures by month for 1979 to 1984 and estimated by year for 1985 to 1994. These numbers indicate excess capacity in 1985 of 5.78 percent, increasing to 43.05 percent in 1986 when PVNGS comes on line, and decreasing to 29.71 percent in 1994.

2. Positions of the Parties Concerning Recovery of the Underrecovery of Revenues Resulting from an ERR, if Adopted

a. EPEC. EPEC proposed that in its next rate case, underrecovery of revenues resulting from adoption of an ERR in this case should be recovered in full from EPEC's other customers, as opposed to EPEC's shareholders, for two reasons. First, EPEC's position is that to the extent possible, each customer group should bear the burden of its costs to the system. However, according to EPEC, for certain customer groups such as municipal lighting and the residential class, the pure cost of service analysis has traditionally been skewed in favor of social considerations such as gradualism and customer impact. In such situations, EPEC contends, the unrecovered revenues have been shifted to other customer groups such as the industrial and commercial customer classes. EPEC concluded that the recommendation by the industrial intervenors is no different in this case. Second, EPEC argued that the City's approach would violate the constitutional prohibitions precluding the confiscation of a utility's property, citing Bluefield Water Works v. Public Service Commission, 262 U.S. 679 (1923) and Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944). EPEC stated that all ratepayers benefit from having industrial customers on the system, not only because of the contributions these customers make to the El Paso economy, but also because a utility with industrial customers on its system can more effectively allocate the costs associated with its base load generation plant and can better use its available capacity. EPEC further argued that when considering the financial condition of three heavy industrial employers, the Commission cannot ignore the financial condition of EPEC. EPEC concluded that in view of inappropriate levels of rate relief awarded to date, EPEC cannot shoulder the burden of carrying unrecovered revenues in the name of social responsibility.

b. The City. City witness Johnson estimated the annual test-year revenue impact of the ERR, assuming that the maximum monthly demands for each of the three affected customers occurs off peak. Under current rates, the proposed rider would reduce the annual demand charges for Rate 15 by approximately $730,000, for Rate 29 by $830,000, and for Rate 30 by $664,000. Thus the total annual revenue effect under current rates would be about $2.2 million. Under EPEC's proposed CWIP rates, the ERR would result in an annual revenue shortfall of about $2.9 million.

Dr. Johnson testified that if special price cuts are necessary to keep the industrial customers, it is not clear that the other customer classes should bear the entire burden of financing them. He believed that it would be reasonable for EPEC's stockholders to share this burden, reasoning as follows. EPEC's high electric rates are largely a result of management decisions outside the control of the other customer classes, in particular, EPEC's commitment to PVNGS. While disallowance of 50 percent of PVNGS would ameliorate some of the impact on ratepayers, it would not remove the full effect of these management decisions.

In brief the City argued that if the economic situation is such that industrial customers are about to leave the system because of market conditions or overall electric rate conditions, such a rider could benefit both the ratepayers and EPEC. The ratepayers would benefit from the continued employment and contribution of the industrial users to the El Paso economy. EPEC would benefit by continuing to have the customers on the system. Thus, if the Commission decides to adopt the rider, the City recommends that consideration be given to spreading the burden of the nonrecovered revenues between EPEC customers and EPEC shareholders.

c. Border Steel. In its brief, Border Steel argued that high load factor industrial customers in the El Paso area have for many years subsidized other classes in the name of gradualism, social considerations, and customer impact. Thus, Border Steel concluded, the Commission should not hesitate to approve the ERR merely because other customers will share in the cost. If, however, the Commission considers it more appropriate that part of the cost of the ERR be borne by EPEC's shareholders, Border Steel does not oppose that treatment. Border Steel stated that maintaining the existing industrial base is critical to EPEC's survival of the crisis created by EPEC's participation in PVNGS.

d. ASARCO. In its brief, ASARCO stated that since rate base adjustments, while ameliorative, are not likely to remove the full effect that PVNGS and related management decisions have had in driving up the price of electricity in El Paso, ASARCO believes that the City's suggestion that underrecovery due to the ERR be shared between EPEC's customers and shareholders has merit. However, ASARCO argued that the ERR should be adopted even if this suggestion by the City is rejected.

3. Examiner's Conclusions and Recommendations Concerning the ERR

The examiner agrees with several of the parties that adoption of the ERR is a policy question for the Commission. To the examiner's knowledge, the issue has not been fully litigated in a previous Commission case. Thus, while the examiner has offered recommendations, the examiner has tried to present arguments and evidence favoring each side of the question. By way of summary, the examiner recommends that an ERR not be adopted in this docket. In the event that the Commission wants to approve an ERR now, the examiner recommends that the ERR originally proposed by EPEC be the ERR adopted, that it be applied only to the Border Steel, ASARCO and Phelps Dodge rate classes, and not to Fort Bliss, and that the clarification requested by ASARCO that the ERR override the ratchet provisions in the schedules to which the ERR applies be made. The examiner further recommends that the issue of recovery of underrecovered revenues resulting from an ERR, if adopted in this docket, be deferred until EPEC's next general rate case.

a. Should an ERR be adopted in this docket? In the examiner's opinion, in considering the issues associated with an ERR, it is critical to decide the specific purposes it is intended to serve. This is necessary to determine in the initial and future rate cases whether or not an ERR should be initiated or continued, and if so, to which rate schedules it should apply. The discussion in the present docket centered around the two advantages EPEC originally claimed for the ERR: maintaining an industrial base in EPEC's Texas service area, and reducing peak demand growth.

The need to conserve energy and resources is clearly an important goal of rate design generally. (P.U.C. SUBST. R. 23.23(b)(1).) Thus, reducing peak demand growth may influence the design of EPEC's rates, including those to which an ERR is sought to be applied. However, the examiner does not believe that reducing peak demand growth should be the justification for adopting an ERR. In his opinion, it would be more appropriate to address the objective of reducing peak demand through a unified approach that considers the possibilities for all customer classes. However, if an ERR is adopted, it may be desirable to consider its impact on peak demand growth and on other rate design objectives in choosing a particular ERR or designing other aspects of the rates. Even if reducing peak demand growth is viewed as an appropriate justification for adopting an ERR, the evidence concerning the advent of PVNGS and the need to reduce EPEC's peak demand growth at this time does not appear to warrant adoption of the ERR in this docket. The examiner therefore concludes that the justification, if any, for adopting an ERR in this case must come from a need to maintain an industrial base in EPEC's service area.

PURA Section 38 provides in part: "Rates shall not be unreasonably preferential, prejudicial, or discriminatory, but shall be sufficient, equitable, and consistent in application to each class of consumers." PURA Section 45 states:

> No public utility may, as to rates or services, make or grant any unreasonable preference or advantage to any corporation or person within any classification, or subject any corporation or person within any classification to any unreasonable prejudice or disadvantage. No public utility may establish and maintain any unreasonable differences

as to rates of service either as between localities or as between classes of service.

As with other issues in rate design, the ERR must be evaluated in light of these requirements. Applying an ERR which provides for a possible rate discount to some customer classes and not others constitutes a difference in treatment. The question is, would it be unreasonable?

The definition of unreasonable distinctions between customer classes has been fleshed out through expert opinion and case law. It is clear, for example, that distinctions between customer classes are not necessarily unreasonable if they are based on a balancing of criteria such as the following:

1. Simplicity, understandability, public acceptability, and feasibility of application;

2. Freedom from controversies as to proper interpretation;

3. Effectiveness in yielding total revenue requirements;

4. Revenue stability from year to year;

5. Minimizing unexpected changes in rates seriously adverse to existing customers;

6. Fairness in apportioning total costs of service among customers;

7. Avoidance of undue discrimination;

8. Efficiency in discouraging wasteful use of service while promoting all justified types and amounts of use.

(See, e.g., Docket No. 6380, Application of Upshur-Rural Electric Cooperative Corporation for Authority to Change Rates, ____ P.U.C. BULL. ___ (December 20, 1985).)

Thus, in the examiner's opinion, an ERR discount available only to some customer classes might not constitute unreasonable discrimination if: (1) it is necessary to prevent a loss of all or a significant portion of a utility's industrial load and that load contributes to an efficient use of the utility's facilities (criterion number 8); or (2) it is necessary to minimize an unexpected change in rates seriously adverse to the customer classes to whom the ERR would be applied (criterion number 5). In situation (1) described above, the examiner would recommend requiring a showing that the loss of load is likely, and that the ERR is likely to prevent it. In situation (2), the examiner would recommend requiring a showing that the change in rates is more adverse, or that the ERR would be a more appropriate vehicle for ameliorating this problem, for the customer classes who are eligible for the ERR than for those which are not.

The examiner does not feel that either situation has been shown to warrant adoption of an ERR in this docket. First, the evidence does not show that Fort Bliss is likely to reduce or eliminate its power purchases from EPEC. The examiner accordingly believes that DOD's suggestion that an ERR be applied to Fort Bliss is not justified by this objective. Second, the record does support a conclusion that Border Steel and ASARCO might significantly reduce or eliminate electricity purchases from EPEC. There is also evidence that Phelps Dodge is similar to the other two large industrial customers. However, the record does not show how likely either event is to occur or how likely it is that if the ERR is adopted, Border Steel and ASARCO will as a result fail to reduce or eliminate electricity purchases or will increase such purchases. This is a critical question. If the Commission were to adopt the ERR without achieving the desired effect on EPEC's customer base, it would have accomplished no more than redistributing income from EPEC's other customers (and, under the City's proposal, EPEC's shareholders as well) to EPEC's large industrial customers and their shareholders. The record indicates that while high electric rates are part of the large industrial customers' problems, other market forces also have played and will continue to play a major role. This leads to considerable uncertainty as to whether or not the ERR would accomplish its desired purpose of preserving EPEC's industrial base. In addition, the extent to which EPEC's electric rates contribute to or ameliorate the large industrial users' economic problems is a function of what the total rates for those users are, not whether they are lower because of reductions in the requested revenue requirement or because of approval of an ERR. In this report the examiner recommends a rate decrease for EPEC, of which, under the Stipulation, the large industrial customers would receive their proportionate share. The examiner is unwilling to recommend that an ERR be approved in this docket, further reducing the large industrial customers' rates, with some or all of the underrecovery having to be collected from other customers after the next general rate case in which PVNGS Unit 1 may be being considered for inclusion in rate base as plant-in-service, with the possible implications that might have for all customers' rates.

It is clear from the evidence that at least some parties viewed the goal of maintaining an industrial base in EPEC's Texas service area as broader than that described above. Specifically, they viewed it as encompassing preservation not only of the utility's industrial customer base, but also of the benefits to the community which large industrial plants can bring. The examiner finds both persuasive and undisputed the evidence in this docket of the adverse impact on the El Paso area which elimination or curtailment of operations there by the three large industrial customers might have. The policy question for the Commission is, are community problems such as unemployment matters which the Commission should try to ameliorate through rate discounts to customers who expend large amounts or employ numerous persons in the community, or would they be more appropriately addressed by a different local, state or federal agency or program? Questions which might impact on this policy question include the following. First, do large users of electricity in each customer class receive a greater community benefit from the existence of large industrial plants than small users, and if not, should they have to pay more for this benefit simply because utility rates are the mechanism used to address the problem? Second, do customers of a utility located far from the community receive any (or the same amount of) benefit from large industrial operations in that community as those customers located in the community, and if not, if community benefits are the justification for the ERR, should the Commission surcharge the particular community instead of all ratepayers in order to recoup the revenues lost because of the ERR discount? Obviously, the larger and more diverse a utility's service territory, the more of a problem this would be. Third, should the Commission consider only the advantages to the community of a large industrial plant and not any disadvantages? How would the Commission deal with claims, for example, by a potential intervenor that a community would receive a net benefit if an industrial plant shut down because it constitutes a hazard to public health or the environment? Fourth, do not other customer classes, such as small commercial or residential customers, also benefit the community? Are the benefits a customer provides to the community a proper criterion for allocating revenue requirement among customer classes? Although valid arguments to the contrary certainly can be made, these and other questions would induce the examiner to be hesitant about trying to tackle community problems through a utility rate discount to isolated customer classes.

If the Commission concludes that community problems are a proper separate rationale for approving an ERR, the examiner nonetheless would not recommend that the ERR be adopted in this docket. First, as with the objective of maintaining EPEC's industrial customer base, it is unclear how likely it is that the large industrial customers will further curtail their operations, or that the ERR will prevent this or result in operations being expanded. Again, if the desired benefits for the community are not achieved, approving the ERR would only shift funds from EPEC's other ratepayers to the shareholders of its large industrial customers, many of whom doubtless are not located in the community. Second, where evaluation of a proposed ERR's effect on the community is in question, the examiner believes that it is especially appropriate to pay considerable deference to the local regulatory authority. For reasons which it clearly explained (see Section X.D.1.b. of this report), the City of El Paso declined to approve the ERR at this time. The examiner recommends that the Commission do the same.

b. <u>If an ERR is adopted, what characteristics should it have?</u> The examiner recommends that if the Commission decides to adopt an ERR in this case, that it order EPEC to file new tariff sheets for Border Steel, ASARCO and Phelps Dodge which would implement the ERR as originally proposed by EPEC. The only exception is the clarification requested by ASARCO, and described in Section X.D.1.d. of this report. No one contested ASARCO's suggested interpretation that the ERR be read as overriding the ratchet provision rather than the other way around. The record indicates that unless ASARCO's interpretation is adopted, ASARCO will be unable to benefit from the ERR for nearly a year. If the Commission decides to adopt the ERR, presumably it would intend that ASARCO have an opportunity immediately to take advantage of the ERR so as to achieve the claimed benefits. The examiner recommends that if the Commission decides to adopt an ERR, that EPEC be required to submit tariff schedules for all three eligible classes reflecting ASARCO's requested clarification.

c. If an ERR is adopted, who should bear the burden of the resulting underrecovery? The examiner recommends that the above issue not be addressed in this rate case. It concerns a proposal which EPEC states that it will make in its next rate case if the ERR is adopted in this docket. At that time more data should be available concerning factors which the Commission might wish to consider, such as the magnitude of the underrecovery resulting from the ERR, the correctness of EPEC's application of the ERR and the size of EPEC's revenue requirement at that time.

E. Miscellaneous Service Charges

Miscellaneous service charges were not mentioned in the Stipulation. The examiner has assumed that they were not intended to be covered by the Stipulation.

EPEC proposed three changes in its miscellaneous service charges. Only one, the returned check charge, was contested. EPEC proposed that the charge for a returned check or bank draft be increased from $8 to $13. EPEC witness Harris testified that this charge has been $8 since 1980 and that $13 is more reflective of the charge that El Paso area banks are now charging. EPEC averages 351 returned checks per month. Staff witness Rudolph recommended that the returned check charge be increased only to $10, for two reasons. First, the $13 proposal is 62.5 percent higher than the existing charge, and such an extreme increase is not in conformance with rate moderation objectives. Second, $13 is higher than the returned check charges being imposed by twelve other large Texas utilities Mr. Rudolph surveyed. EPEC did not respond to Mr. Rudolph's recommendation in rebuttal testimony or brief. The examiner finds Mr. Rudolph's proposal to be reasonable, and recommends that EPEC's returned check charge be increased only to $10.

EPEC also proposed two new charges--a field collection charge of $7 and a meter seal replacement charge of $10. These charges were not disputed and are supported by Mr. Harris' testimony. The examiner recommends their approval.

XI. Service Rules and Regulations

EPEC proposed several clarifying changes in its rules and regulations regarding electric service and the line extension policy, which are described in Mr. Harris' testimony and in Schedule L-2. Only one witness, staff witness Irish, proposed changes in such language or proposed language. Except as described below, the examiner recommends approval of EPEC's service rules and regulations.

Mr. Irish's testimony stating his recommended changes is as follows:

1. In line 2 of the Discontinuance of Use By Customer section of Schedule No. 22, the words "after issuance of disconnect notice" should be added after the word "time" to make the section conform with P.U.C. SUBST. R. 23.46(a).

2. In line 4 of the Terms and Conditions section of Schedule No. 28, words "after issuance of disconnect notice" should be added after the word "schedule" to make the section conform with P.U.C. SUBST. R. 23.46(a).

3. In Schedule No. 99, I recommend that the New Service Charge and Non-Pay Reconnect Charge be combined and called "Reconnect Fee" for simplicity.

4. In Schedule No. 99, I recommend adding the following sentences to the company's explanation of the Energy Diversion charge: "Company will maintain evidence as required by P.U.C. SUBST. R. 23.46(c). A notice will be left at customer premises when possible."

5. On Page 14, Item C, Line 2 of the Rules and Regulations Regarding Electric Service, I recommend deleting the words "equal to 6.0%" and adding the words "determined by the Public Utility Commission." This would bring the tariff into compliance with Senate Bill 1034 which was passed in the 69th Legislature. Under this bill, the PUC is to calculate the interest rate each December.

6. On Page 15, Item B, Paragraph 3, Line 1 of the Rules and Regulations Regarding Electric Service, I recommend deleting the words "six (6) percent simple interest" and adding the words "a rate of interest determined by the Public Utility Commission." See Recommendation No. 5 for explanation.

In its reply brief, EPEC disputed only item 3 above, stating that with the current separation between the charges, there is a distinction between new customers and former customers who have been cut off for nonpayment which assists EPEC in its system operations when dealing with the customer groups. The examiner is of the opinion that EPEC has expressed a valid reason for maintaining separate charges which outweighs the objective of simplicity. The examiner thus recommends that the new service charge and non-pay reconnect charge not be combined in the tariff.

In open meeting on December 2, 1985, the Commission established an interest rate of 7.29 percent for calendar year 1986. The Commission also directed that all utilities file tariff sheets containing the interest rate of 7.29 percent. In light of this direction, Mr. Irish's recommended changes 5 and 6 should be modified to require that the 7.29 percent rate be specified in EPEC's tariff. Except as described above, Mr. Irish's recommended changes should be adopted.

XII. Reconciliation

Staff witness Janet Simpson testified that she reviewed EPEC's monthly over/underrecovery of fuel expense and notes that the most recent cumulative overrecovery balance available (July 1985) totals $3,814,381. Ms. Simpson testified that she calculated interest on the cumulative monthly over/underrecovery balance since March 1984, in accordance with P.U.C. SUBST. R. 23.23, using the composite cost of capital approved in Docket No. 5700. Ms. Simpson calculated interest of $1,387,206 on the $3,814,331 for a total reconcilable amount of $5,201,537.

The City challenged Ms. Simpson's calculation in its post hearing brief. The City takes the position that, as Ms. Simpson recommended that the SPS demand charge (which totals $8,041,200 on an annual basis) be considered a non-reconcilable purchased power cost in the future, due to the fact that the charge is fixed by contract and does not vary on a monthly basis, Ms. Simpson should have made a corresponding adjustment to the current reconciliation amount to remove $2,516,852 in payments previously made by EPEC to SPS thereby increasing the overrecovery balance by that amount. The City believes the charge should be treated consistently. The examiner rejects this argument. Although agreeing that the SPS demand charge should be treated as a non-reconcilable expense prospectively, the examiner believes it is inequitable to disallow recovery of past payments to SPS when those payments were necessary elements of EPEC's purchased power costs and the record reflects that EPEC's economy power purchases have been beneficial to the ratepayer. The examiner therefore recommends that EPEC be permitted to include prior SPS demand charge expense in the reconciliation balance, as proposed by Ms. Simpson. To do otherwise would be to penalize EPEC for attempting to minimize the cost of power to its customers.

With regard to the methodology for accomplishing a refund, the examiner would first note that the reconciliation issue was almost entirely ignored by the parties. Staff witness Jeff Rudolph was the only witness who addressed refund methodologies and Mr. Rudolph did not recommend any particular methodology. Rather he testified regarding three possible methodologies which could be adopted. As neither the Company nor the City nor any other party cross-examined Mr. Rudolph or expressed any preference on the refund issue, the examiner assumes that none of the parties have a preference.

According to Mr. Rudolph, an overrecovery can be refunded in one of two ways; that is, the refund methodology can either assume a prospective or retrospective approach. With a prospective refund, customers are reimbursed on the basis of current or future kilowatt-hour usage. A prospective refund can be advantageous in the sense that it avoids the problems associated with historical tracking (e.g., data availability, retrieval, and verification). Conversely, the main disadvantage associated with this approach is that it is likely to attain less accuracy in matching customer overpayments with company refunds. More specifically, when customer bills are credited on the basis of current or future consumption, there is little guarantee that reimbursements will match historical billings. This is especially true when a seasonal customer is involved and the prospective refund fails to reflect the temporal nature of the customer's energy usage patterns.

In comparison, a retrospective approach determines a customer's refund on the basis of the historical kilowatt-hour consumption which transpired during the overrecovery period. This approach is more likely to achieve a better overpayment/refund match because of the verification process entailed. In return, the attainment of a more precise refund is likely to promote a situation where intraclass subsidies are minimized. If true, a higher level of customer acceptance and satisfaction should be achieved when refunds are made on a historical basis. On the other hand, a clear disadvantage of the retrospective approach is that it requires considerable data verification; hence, it might prove costly to administer and implement. Of course, the magnitude of this disadvantage is not certain as it will fluctuate with a given company's level of computer sophistication. Another potential problem is that the size and measurability of a customer class is apt to affect the degree to which a particular customer's refund matches previous overpayment. That is, the designated kilowatt-hour tracking period for different customer classes might vary because of problems related to data availability and customer turnover. Uniform treatment might therefore only be approached and not completely achieved if such problems do arise.

According to Mr. Rudolph, in recognition of the fact that no single refund methodology is inherently correct, the Commission's Rate Design Section has established an order of preference with respect to how an overrecovery should be refunded.

According to Mr. Rudolph, the Rate Design Section prefers the full retrospective approach first, the modified retrospective approach second and the retrospective/prospective approach third. A discussion of Mr. Rudolph's testimony pertaining to each approach follows below.

A. Full Retrospective Approach

Mr. Rudolph testified that, in that an overrecovery is linked to historical generation, it is reasonable to conclude that a refund should be allocated in accordance with a customer's level of overpayment. In other words, Rate Design favors the implementation of a retrospective refund approach on a systemwide basis. Given knowledge of each customer's refund amount, the proper payback procedure would be to either issue a one-time check or grant a one-time credit on the customer's electric bill. The adoption of a check or credit would be based on the relative costs of each approach; that is, the least costly approach should be implemented in order to minimize refund-related costs. Also, a one-time check or credit is recommended by the Rate Design Section simply because of the time value of money. If a bill credit procedure is adopted and if the credit exceeds a given bill, then two approaches might be pursued with respect to refunding the remaining amount. The first approach is to spread the credit over subsequent billings until the entire refund is completed. The second approach is to issue a check in conjunction with the one-time credit so that the repayment process is confined to a single reimbursement. As an aside, it should be noted that the preceding guidelines are also applicable with respect to customers residing in master-metered dwellings. The only difference is that the refund would be administered by the affected housing manager or operator. Finally, according to Mr. Rudolph the Rate Design Staff recommends that returned checks or unused credits be applied against future fuel costs in order to bestow equal benefit upon all customers within the utility's system.

B. Modified Retrospective Approach

According to Mr. Rudolph two arguments frequently directed against a retrospective refund are (1) some customer classes experience significant turnover; and (2) high administrative expenses are often associated with historical verification. If such criticisms prove accurate, Mr. Rudolph believes it is possible to mitigate their effect by measuring kilowatt-hour usage for only a portion of the overrecovery period. For example, if the overrecovery occurred over twelve months, one could determine individual refunds by averaging a segment, say two or three months, of a period in question. The only specification would be that the selected sample reflect both peak and off-peak usage patterns. Mr. Rudolph testified that the chief benefits of this approach are that (1) it results in lower verification expenses; (2) it expedites the review process; and (3) it permits usage of the retrospective approach on a modified basis. With respect to actual refunds and assignment of unused credits/checks, the Modified Retrospective Approach would operate in the same manner as the Full Retrospective Approach.

C. Retrospective/Prospective Approach

According to Mr. Rudolph, if customer class turnover and administrative expense constraints prove too strong, it might be necessary to adopt a retrospective/prospective approach whereby large and small customer classes are treated differently. Under this approach, refunds are dispensed to historically verifiable customer classes on the basis of past usage patterns. Here the main question centers on whether to measure historic kilowatt-hour usage on a full retrospective or modified retrospective basis. In contrast, ratepayers in classes with relatively many customers would be afforded refunds according to some measure of non-test-year usage. With respect to these customers, Mr. Rudolph indicates that the main design problem focuses on how to select a future period representative of the energy usage patterns experienced during the overrecovery. According to Mr. Rudolph, opponents of this approach are likely to criticize the non-uniform refund application between customer classes. Mr. Rudolph believes that such a criticism, however, is not warranted if refund-related costs vary substantially by customer class. Finally, the Retrospective/Prospective Approach would treat actual disbursements and unused credits/checks in the same fashion as specified in the Full Retrospective Approach.

D. Examiner's Recommendation

Given that Mr. Rudolph's testimony is unchallenged and that no parties have expressed any preference whatsoever regarding an appropriate refund methodology, the examiner recommends adoption of the methodology preferred by the Commission's Rate Design Section, although the record supports all of the above methodologies.

The examiner recommends that the full retrospective approach be adopted. EPEC should grant a one-time credit to each customer's electric bill based on each customer's prior usage. In the event the credit exceeds the customer's bill, the balance of the refund should be paid by check. Further, the examiner recommends that returned checks and unused credits be applied against future EPEC fuel costs.

The examiner recommends that the refund be accomplished during the first full billing cycle following Commission approval of EPEC's revised tariffs resulting from this docket.

XIII. Deferral of PVNGS Expenses

[3] During the pendency of the hearing on the merits in this docket, EPEC requested and received permission to amend its petition to include a request that the Commission incorporate the following language in its final Order in this docket:

> The Commission orders that EPEC defer those costs currently being capitalized and the depreciation which would be recorded for Palo Verde Unit No. 1, effective with the commercial in-service date of this unit. The recovery of these deferred costs will be included in the rate order at the time the unit is placed in-service for ratemaking purposes.

The specific costs embraced by this request include the O&M expenses, taxes, insurance, depreciation and AFUDC applicable to PVNGS Unit No. 1 from the date of commercial operation to the date that PVNGS Unit No. 1 is included in EPEC's rate base.

This issue was addressed by staff witnesses Uffelman and Reilley as well as by EPEC witness J. Donald Warren, Jr., each of whom supports deferral through capitalization of the expense items enumerated above.

The reason for EPEC's request is that, although this Commission does not recognize or permit reclassification of post test year-end CWIP to plant in service, current generally accepted accounting principles (GAAP) require that O&M expenses, taxes, insurance, depreciation and similar expenses be expensed as period costs after a plant is placed in-service. According to staff witness Uffelman, EPEC must at some point classify PVNGS Unit No. 1 as plant in service for financial reporting purposes. At that time the Company will be booking depreciation without offsetting revenues to recover such expenses. The effect of this development is to reduce EPEC's reported net income and cash flow. According to staff witness Reilley, EPEC's failure to defer depreciation, O&M and property taxes on PVNGS Unit No. 1 would reduce EPEC's 1986 operating income by $44,182,428. Mr. Reilley concludes that if EPEC booked PVNGS Unit No. 1 expenses for one year without receiving offsetting revenues its financial viability would be seriously impacted. EPEC witness Bostic testified on rebuttal that long term capital would be unavailable to EPEC without significant capitalization of carrying charges and expenses beyond PVNGS' in-service date. In summary, due to the magnitude of EPEC's investment in PVNGS, the lag between PVNGS' in-service date and rate base treatment of PVNGS by this Commission may cause serious harm to EPEC's financial integrity. It is in an effort to prevent the Company's financial indicators from seriously deteriorating that EPEC has proposed that PVNGS Unit No. 1 expenses be capitalized.

According to EPEC witness Warren, Statement of Financial Accounting Standards No. 71 (FAS 71) issued by the Financial Accounting Standards Board (FASB) sets forth the standards for accounting for most public utilities. Paragraph 9 of FAS 71 permits a regulatory authority to create the existence of an asset under certain circumstances. The relevant language is as follows:

> Rate actions of a regulator can provide reasonable assurance of the existence of an asset. An enterprise shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met:
>
> a. It is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for ratemaking purposes.
>
> b. Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost.

Based upon the above language, Mr. Warren believes that an order from this Commission permitting deferral of PVNGS Unit No. 1 costs currently being capitalized as well as depreciation which would otherwise be recorded, would permit EPEC to avoid the problems addressed by Mr. Reilley, Mr. Uffelman and Mr. Bostic pending a final Order in EPEC's next general rate case.

The City notes in its brief that the Commission must address two issues before deciding to incorporate language such as the language requested by EPEC in a final Order in this proceeding. First, the Commission must determine whether such language in an Order is appropriate for EPEC. Second, should the Commission decide that such language is appropriate, the Commission must determine the proper language to be included in the Order.

The answer to the first question posed by the City is clearly, in the examiner's opinion, "Yes." The size of EPEC's commitment to PVNGS is so massive when compared to the size of the Company that the examiner is persuaded that the lag between regulatory recognition of PVNGS Unit No. 1 and the PVNGS Unit 1 in-service date may have a very detrimental impact on EPEC's financial integrity. The examiner believes that this development is a direct result of poor management of EPEC, but the problem nonetheless exists and must be recognized.

EPEC's request for deferral of PVNGS Unit No. 1 expenses will not in any way affect the dollar impact of this rate case, but the request would increase the total book cost of PVNGS Unit No. 1, if granted. This point is raised by the City and it is a valid consideration. However, EPEC witness Warren indicated that the inclusion of language such as that requested by EPEC in a final Order would not place any limitations on the Commission's ability to evaluate the prudency of the expenses capitalized, the prudency of the plant construction and excess capacity. Mr. Warren also indicated that if the specific language to that effect were deemed to be necessary, it could be included. Under the circumstances, the examiner agrees with EPEC's position that the proposed request for capitalization of PVNGS Unit No. 1 expenses will do no more than preserve the Company's financial position until the rate case in which PVNG Unit No. 1 is considered for in-service treatment by the Commission.

It appears to the examiner that the Commission can prevent some financial difficulties for EPEC without harming the ratepayer or circumscribing the Commission's freedom of action concerning future rate base treatment of PVNGS Unit No. 1, by permitting deferral of PVNGS Unit No. 1 expenses. The worst that could happen by such action is that the accounting community would not consider the Commission's order to satisfy the criteria set forth in paragraph 9 of FAS 71.

As to the City's contention that the Commission should modify the language requested by EPEC in the event the Commission accepts EPEC's proposal, the examiner fully agrees. The language proposed by EPEC does not, in the examiner's opinion, clearly reflect that the Commission reserves the right to treat PVNGS Unit No. 1 costs in such manner as it deems appropriate in a future rate case. Therefore, the examiner recommends that the following language be inserted in the final Order issued in this docket:

> The Commission orders that EPEC defer those costs currently being capitalized and the depreciation which would be recorded for PVNGS Unit No. 1, effective with the commercial in-service date of this unit. The recovery of those deferred costs will be included in the rate order at the time the unit is placed in-service for ratemaking purposes. However, the Commission reserves the right to exclude from rate base or other recovery any portion of the expenditures for the plant, AFUDC, capitalized expenses, capitalized depreciation or other capitalized costs which the Commission determines to be related to plant that is not used and useful or to have been imprudently spent or incurred. The Commission further reserves the right to consider the reasonableness and prudence of any deferred expenses in the rate order in which rate base treatement for plant is requested.

XIV. Franklin Land & Resources

Although FL&R, as a wholly owned subsidiary of EPEC, was not a primary focus on attention in this proceeding, the City did propose a number of adjustments, the rationale for which were based upon perceived problems with FL&R activities. In the course of the hearing, the examiner received into evidence the entirety of that portion of the Touche Ross & Company management audit pertaining to FL&R.

Based upon the discussion contained in that audit report, the examiner cannot conclude that FL&R is at this time a detriment to EPEC. However, the audit report does contain some analysis which gives the examiner some cause for concern about FL&R's effect upon EPEC in the future. For instance FL&R's participation in the renovation and operation of the Paso del Norte Hotel is discussed with some reservation by Touche Ross. The audit report notes that FL&R's investment in that project exceeds 50 percent of FL&R's total asset value as of the end of 1984. The report notes that the magnitude of the investment combined with FL&R's relative inexperience in an industry that is subject to cyclical operating risks results in an investment that is riskier than most ventures FL&R has chosen to participate in. The report notes that the hotel will impose a tremendous cash drain on FL&R and its possible future partner in the project and warns that FL&R should monitor the cash flow situation carefully and be prepared to allocate additional resources should the original assumptions pertaining to the hotel not materialize. Additionally, the audit report notes that FL&R has not updated the financial scenario for the hotel project since 1983. Given the size of FL&R's investment in the hotel project and its relationship to FL&R's total financial structure, Touche Ross believes that FL&R should update the project to reflect the impact of increases in construction costs, delays in construction completion date, entry of potential competitors and changes in the cost structure for hotel operations. Further, Touche Ross indicates that FL&R should perform sensitivity analyses to assess the extent of the impact of major variations in key variables on the hotel project.

The examiner cannot help but notice the similarity between EPEC's participation in PVNGS and FL&R's participation in the Paso del Norte renovation. The criticisms which Touche Ross level at Paso del Norte are identical to criticisms which have been leveled at PVNGS in prior years. The examiner urges the management of FL&R to carefully evaluate the level of its participation in Paso del Norte and to monitor the appropriateness of its investment on an ongoing basis so that FL&R can avoid the sort of financial detriment which has befallen EPEC as a consequence of EPEC's failure to critically evaluate on an ongoing basis its financial exposure in PVNGS.

In the City's post-hearing brief, the City urges that the Commission require EPEC to address the Touche Ross recommendations regarding FL&R in EPEC's next rate filing. The examiner concurs with the appropriateness of that recommendation.

XV. Findings of Fact and Conclusions of Law

The examiner recommends that the Commission adopt the following Findings of Fact and Conclusions of Law.

A. Findings of Fact

1. On June 24, 1985, El Paso Electric Company (EPEC) filed an application to increase its rates within the unincorporated areas of El Paso, Culberson and Hudspeth Counties served by it.

2. EPEC's filing seeks to increase rates by $61,222,878 or 25 percent over total Texas adjusted test year revenues, assuming Commission recognition of Palo Verde (PVNGS) Unit No. 1 as a commercially operating unit. Alternatively, should PVNGS Unit No. 1 be excluded from EPEC's plant in service, EPEC seeks authorization to increase its rates by $67,487,922, or 27.63 percent over total Texas adjusted test year revenues.

3. All Texas customers and classes of customers are affected by the proposed changes.

4. By order dated June 17, 1985, EPEC's proposed rate increase was suspended for 150 days beyond the otherwise effective date of July 30, 1985, until December 27, 1985. On July 16, 1985, EPEC extended the effective date of the proposed increase to August 6, 1985, and the examiner resuspended the effective date until January 3, 1986. On August 12, 1985, EPEC again extended the effective date of the proposed increase from August 6, 1985, to August 27, 1985, and the examiner accordingly resuspended the effective date, by Order dated August 13, 1985, for 150 days until January 24, 1986. On October 25, 1985, EPEC extended the effective date from August 27, 1985 to September 3, 1985, and by Order dated October 30, 1985, the effective date was again resuspended by the examiner for the full 150 day statutory period of suspension, until January 31, 1986.

5. EPEC published notice of its proposed rate increase and provided individual customer notice and notice to affected municipalities in compliance with Commission requirements.

6. EPEC appealed the ratemaking ordinances of the City of El Paso, the Town of Vinton, the Town of Clint and the Town of Antony on November 22, 1985, and by Order dated December 10, 1985, the examiner consolidated those appeals with this docket without opposition.

7. Prehearing conferences were conducted on July 16, 1985 and October 14, 1985, for the purpose of establishing procedural schedules and addressing discovery matters.

8. The hearing on the merits was convened on November 4, 1985. The hearing was concluded on November 22, 1985.

9. On November 6, 1985, after taking oral argument from the parties, the Commission dismissed EPEC's PVNGS plant in service filing. A written order to the same effect, was issued by the Commission on November 18, 1985.

10. On November 13, 1985, EPEC requested permission to amend its petition in order to reflect that EPEC is seeking to defer depreciation and costs currently being capitalized which would otherwise necessarily be recorded for PVNGS Unit No. 1 on its commercial in-service date. The examiner granted EPEC's request on November 20, 1985.

11. EPEC provides electric utility service to more than 200,000 customers residing in several areas within the states of Texas and New Mexico.

12. EPEC's quality of service is adequate and not such that it should be considered either favorably or adversely in fixing a return on invested capital in this proceeding.

13. EPEC's energy efficiency plan and its conservation efforts in general are woefully lacking.

14. Because this is the first proceeding in which the Commission has reviewed EPEC's energy efficiency plan and energy efficiency programs, the Commission should give no consideration to EPEC's conservation and load management activities in setting a reasonable return on invested capital.

15. EPEC has a total invested capital of $759,330,849 as illustrated below, for the reasons set out in Section VI of the Examiner's Report:

Plant in Service	$439,731,601
Accumulated Depreciation	(128,552,989)
Net Plant	$311,178,612
Construction work in Progress	557,579,256
Working Cash Allowance	-0-
Materials & Supplies	5,019,548
Prepayments	3,078,035
Fuel Inventory	83,358
Deferred Taxes	(110,982,319)
Pre 1971 Investment Tax Credits	(757,940)
Customer Deposits	(2,966,146)
Injuries & Damages Reserve	(100,000)
Other Cost Free Capital	(992,940)
Unamortized Gain on Sale of Turbine	(1,808,615)
Total Invested Capital	$759,330,849

16. From a financial integrity standpoint, inclusion in rate base of CWIP in the amount of $653,641,094 is necessary to the financial integrity of EPEC during 1986.

17. The record in this docket does not demonstrate that EPEC's initial decision to become involved with PVNGS was the result of prudent and efficient planning and management on that part of EPEC.

18. EPEC has failed to demonstrate that the Company's continued involvement in PVNGS at a 15.8 percent level was prudent.

19. Approximately 50 percent of EPEC's interest in PVNGS will not be needed for many years to meet EPEC's native system demand.

20. EPEC has failed to meet its burden of proof with regard to the prudence test as it relates to the construction aspects of PVNGS.

21. For the reasons explained in Section VI.B. of the report as discussed in Section VI.B. of this report, EPEC is entitled to inclusion of no more than 50 percent of PVNGS related CWIP in rate base.

22. Given the overall recommendations of the Examiner's Report, inclusion of 100 percent of non-PVNGS test year-end CWIP in rate base is necessary for EPEC's financial integrity.

23. A return on equity of 15.5 percent is reasonable for EPEC for the reasons set out in Section VII of the report.

24. EPEC's long-term debt has an effective cost of 10.39 percent.

25. EPEC's preferred stock has an effective cost of 9.80 percent.

26. For the reasons discussed in Section VII of the report, EPEC has a capital structure and weighted average cost of capital as follows:

Source	Amount	Ratio	Cost	Weighted Cost
Long-term Debt	$ 750,037,000	52.67%	10.39%	5.473%
Preferred Stock	150,873,000	10.59%	9.80%	1.038%
Common Equity	523,098,000	36.73%	15.5%	5.694%
Total	$1,424,008,000	100%		12.21%(Rounded)

27. Application of the weighted average cost of capital of 12.21 percent to EPEC's total invested capital of $759,330,849 results in a return of $92,714,297.

28. The City's proposed methodology for calculating a customer growth adjustment for kwh sales is more accurate than the methodology utilized by the Company and should be adopted. The City's methodology results in an increase in kwh sales of 3,548,180 kwh over the kwh sales figure proposed by EPEC.

29. It is inappropriate to adjust kw and kwh sales to reflected the reduction in service requirements of Southwest Portland Cement Company because the increase in consumption resulting from the addition of new customers in the general service and large power service classifications in 1985 more than offsets Southwest Portland Cement Company's decreased consumption. Reversal of EPEC's reduced load adjustment increases kwh sales by 22,764,924 kwh.

30. EPEC has a total Company revenue requirement of $351,024,096, composed of the following:

Fuel	$ 66,142,165
Purchased Power	67,930,008
Operations and Maintenance	45,584,690
Depreciation and Amortization	15,188,851
Other Taxes	18,620,910
Interest on Customers Deposits	199,360
State Income Taxes	349,944
Federal Income Taxes	44,293,871
Return	92,714,297
Revenue Requirement	$351,024,096

31. EPEC has other revenue in the amount of $2,150,065. Subtraction of that other revenue amount from EPEC's total revenue requirement of $351,024,096 yields a total base rate revenue requirement of $348,874,031 for EPEC.

32. The cost of service components and amounts set forth in Finding of Fact No. 30 are reasonable and necessary for the reasons discussed in Section IX of the report.

33. On a Texas jurisdiction basis, EPEC's revenue requirement is $241,534,662 Including fuel, EPEC's Texas retail revenue deficiency, calculated in accordance with all recommendations in this report is ($4,162,486) as compared to the amount requested by the Company of $67,487,922.

34. EPEC had a cumulative fuel expense overrecovery of $3,814,381 as of July 1985, plus accrued interest on that balance in the amount of $1,387,206, for a reconcilable total of $5,201,587.

35. EPEC's Texas system fixed fuel factor should be set at 0.028513 per kwh. Adjustment of the Texas system factor to reflect the effects of line losses for the transmission, primary, and secondary voltage customer yields the following fuel factors:

Transmission Voltage	$0.026938
Primary Voltage	$0.028147
Secondary Voltage	$0.028992

36. EPEC should be required to refund to its Texas customers the cummulative balance of EPEC's fuel overrecovery as of July, 1985, plus interest, in the amounts set forth in Finding of Fact No. 33, in the form and manner recommended in Section XII.D. of the report.

37. The depreciation rates set forth in the depreciation study performed by Stone & Webster Management Consultants, Inc. are proper and adequate with the exception of the net salvage values for Rio Grande Units 3, 4, and 5, which should be reduced to the level of -5 percent as discussed in Section IX.C. of the report.

38. The Commission should permit EPEC to defer those costs currently being capitalized and the depreciation which would be recorded for PVNGS Unit No. 1, effective with the commercial in-service date of that unit until such time as PVNGS Unit No. 1 is considered for in-service treatment by the Commission.

39. EPEC should be required to address the recommendations made by Touche Ross and Company regarding FL&R in EPEC's next rate filing.

40. The parties reached agreement as to issues pertaining to cost allocation, revenue distribution and rate design. This agreement is evidenced by a signed written document, a copy of which is attached to this report as Examiner's Exhibit No. 9 (the Stipulation).

41. The jurisdictional separation should not be adjusted to account for loss of load due to ASARCO's suspension of lead smelting operations at its El paso plant. The Stipulation, to which ASARCO was a signatory, provides for no such adjustment to rate design. To adjust jurisdictional separation only would be inconsistent.

42. EPEC's jurisdictional separation methodology was contested only by TNP. It constitutes the best evidence on the issue in this docket and should be adopted.

43. As reflected by their prefiled testimony, the parties originally took widely divergent positions as to the appropriate Texas retail customer class allocation, revenue distribution and rate design.

44. Since the Stipulation does not specifically allocate costs but proceeds directly to revenue distribution, and since the Stipulation should be adopted, no resolution of disputes as to customer class allocation is necessary in this docket.

45. The parties' disputes as to the appropriate revenue distribution and, except for the ERR, as to rate design would be resolved if the proposed Stipulation is adopted.

46. EPEC's proposed assignment of customers to classes is reasonable, is supported by the record, was agreed to in the Stipulation by parties representing a diverse array of interests, and should be adopted.

47. The revenue distribution proposed in the Stipulation would have little impact on the class revenue distribution incorporated in the present rates. This is appropriate in that it would minimize unexpected changes in rates seriously adverse to existing customers and minimize customer confusion. It is also appropriate because these issues were fully litigated and decided by the Commission for EPEC only a year ago in Docket No. 5700.

48. The revenue distribution proposed in the Stipulation is reasonable, was agreed to by parties representing a diverse array of interests, and should be adopted.

49. The rate design proposed in the Stipulation is reasonable, was agreed to by parties representing a diverse array of interests, and should be adopted.

50. EPEC originally proposed an ERR, but subsequently withdrew testimony concerning it. However, the prefiled testimony of the City, Border Steel, ASARCO, DOD and the staff which describes and evaluates EPEC's original proposal was admitted into evidence.

51. As originally proposed by EPEC, the ERR would apply to rate schedules serving three of EPEC's largest industrial customers: Phelps Dodge, ASARCO and Border Steel. Under the rider, these customers would receive a 25 percent discount on their monthly kw charge, if their highest maximum demand during the month occurred during off-peak billing hours.

52. None of the parties proposed a different ERR than EPEC. However, DOD proposed that it be made applicable also to DOD. ASARCO opposed this. ASARCO

requested a clarification as to whether the ERR would override the ratchet provision in the rate schedules to which the ERR applied or vice versa. No party opposed this.

53. Border Steel, ASARCO and DOD supported adoption of the ERR. The other parties took no express position.

54. EPEC proposed that in its next rate case, underrecovery of revenues resulting from adoption of an ERR in this case should be recovered in full from EPEC's other customers. The City argued that this burden should be shared by EPEC's customers and shareholders.

55. Whether or not the ERR should be adopted is a policy question for the Commission.

56. The parties supporting adoption of the ERR claimed two advantages for it: maintaining an industrial base in EPEC's Texas service area and reducing peak demand growth.

57. Reducing peak demand growth should not be a principal justification for adopting an ERR.

58. The evidence does not show that an ERR is presently justified in order to reduce EPEC's peak demand growth.

59. An ERR available only to some customer classes might not constitute unreasonable discrimination if it is necessary to prevent a loss of all or a significant portion of a utility's industrial load and that load contributes to an efficient use of the utility's facilities. In such a situation, for the ERR to be adopted it should be shown that the loss of load is likely and the ERR is likely to prevent it.

60. An ERR available only to some customer classes might not constitute unreasonable discrimination if it is necessary to minimize an unexpected change in rates seriously adverse to the customer classes to whom the ERR would be applied. In such a situation, for the ERR to be adopted it should be shown that the change in rates is more adverse, or that the ERR would be a more appropriate vehicle for ameliorating this problem, for the customer classes who are eligible for the ERR than for those which are not.

61. An EER should not be applied to Fort Bliss since the evidence does not show that Fort Bliss is likely to reduce or eliminate its power purchases from EPEC or to eliminate or curtail its operations in the El Paso area.

62. The record supports a conclusion that Border Steel or ASARCO might significantly reduce or eliminate their electricity purchases from EPEC or their operations in the El Paso area. However, it does not show how likely it is

either that this will happen, or that the ERR could prevent this or reverse this trend.

63. The ERR should not be adopted in this docket because there is too much uncertainty as to whether or not the ERR would accomplish its objectives and because the customers to whom it would be applied will already be receiving a rate reduction.

64. Where community problems are the alleged justification for an ERR, special deference to the local regulatory authority's decision respecting the ERR is appropriate.

65. The most appropriate ERR based on its record is that described as having been originally proposed by EPEC.

66. If an ERR is adopted in this docket, it should be interpreted as overriding the ratchet provision in the rate schedules to which the ERR applies.

67. It is unnecessary to address in this rate case who should bear the burden of the resulting underrecovery if an ERR is adopted in this docket.

68. EPEC's proposed service charges should be approved, except that the returned check charge should be increased only to $10.

69. The rates established in this docket are just and reasonable and are not unreasonably preferential, prejudicial or discriminatory. They neither establish nor maintain any unreasonable difference between localities or between classes of service.

70. EPEC's proposed service rules as revised by staff witness Irish should be adopted, with two exceptions. First, the new service charge and non-pay reconnect charge should not be combined. Second, EPEC's tariff should specify the 7.29 percent interest rate approved by the Commission for 1986.

71. The service rules recommended herein are reasonable terms and conditions of service and are not unreasonably discriminatory.

B. Conclusions of Law

1. EPEC is a public utility as defined by Section 3(c)(1) of the Public Utility Regulatory Act (the Act), Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. 1985).

2. The Commission has ratemaking jurisdiction in this docket, regarding customers not subject to the original jurisdiction of any municipality, pursuant to Section 17(e) of the Act. It also has jurisdiction over the rates in the cities from which timely appeals were taken and which appeals were consolidated

with this docket. The Commission has jurisdiction over the rates in the Town of Van Horn as a consequence of that municipality's relinquishment of original ratemaking jurisdiction for purposes of this docket.

3. Section 27(b) of the Act requires the Commission to fix proper and adequate rates and methods of depreciation, amortization, or depletion of the several classes of property of each utility. EPEC'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 Section 40 of the Act, EPEC has the burden of proving its proposed rates are just and reasonable. To the extent recommended by the report, EPEC has met its burden of persuasion.

5. The recommendations of the Examiner's Report will allow EPEC to recover its reasonable and proper operating expenses, together with a reasonable return on its invested capital pursuant to Section 39 of the Act.

6. Section 41(a) of the Act sets forth the statutory test to be applied in determining the amount of CWIP to be included in rate base.

7. P.U.C. SUBST. R. 23.21(c)(2)(D), enacted pursuant to the Commission's general rulemaking authority under Section 16 of the Act, implements the statutory mandate of Section 41(a) of the Act.

8. P.U.C. SUBST. R. 23.21(c)(2)(D) requires that two tests be met before CWIP may be included in rate base. The projects under construction must be shown to be prudently and efficiently planned and managed, and inclusion of CWIP must be necessary to the Company's financial integrity.

9. The lower quantification of the two tests set forth in P.U.C. SUBST. R. 23.21(c)(2)(D) may be included in the utility's rate base. Application of El Paso Electric Company, Docket No. 5700 (October 26, 1984), Application of Houston Lighting and Power Company, Docket No. 5779 (January 11, 1985).

10. The high percentage of EPEC'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. 23.21(c)(2)(D).

11. Inclusion of 60 percent of CWIP is necessary to EPEC's financial integrity, within the meaning of Section 41(a) of the Act. However, EPEC has not met its burden of proof under Section 41(a) of the Act and P.U.C. SUBST. R. 23.21(c)(2)(D) of demonstrating that PVNGS has been efficiently and prudently planned and managed. Under the standards set forth in those provisions, inclusion of rate base of no more than 50 percent of adjusted test year end PVNGS CWIP is warranted.

12. The rates proposed herein are just and reasonable within the meaning of PURA Sections 38 and 40.

13. The rates proposed herein are not unreasonably preferential, prejudicial or discriminatory, but are sufficient and equitable, as required by Section 38 of the Act.

14. The rates proposed herein make or grant no unreasonable preference or advantage, and subject no corporation or person to any unreasonable prejudice or disadvantage. They neither establish nor maintain any unreasonable differences as to rates for service between localities or classes of service, as required by PURA Section 45.

15. The rates proposed herein are those which the municipalities which are parties to this docket should have fixed in the ordinances from which EPEC's appeals were taken, as required by PURA Section 26(e).

16. The rates proposed herein comply with the ratemaking mandates of PURA and the Commission's substantive rules.

17. The service rules proposed herein comply with the PURA and the Commission's substantive rules.

18. EPEC has fulfilled the notice requirements of P.U.C. PROC. R. 21.22 and Section 43(a) of the Act.

19. EPEC's proposed rates have been suspended until January 31, 1986, in full accordance with Section 43(d) of the Act.

20. The fuel and purchased power expenses recommended by the examiner are appropriate for purposes of setting base rates and establishing fuel factors for EPEC, satifying the standards of Sections 39(a) and 41 of the Act, and P.U.C. SUBST. R. 23.23.

21. The fixed fuel factors recommended by the examiner have been calculated in accordance with P.U.C. SUBST. R. 23.23.

Respectfully submitted,

Mark W. Smith

MARK W. SMITH
ADMINISTRATIVE LAW JUDGE

APPROVED on this the 9th day of January, 1986.

Rhonda Colbert Ryan

RHONDA COLBERT RYAN
DIRECTOR OF HEARINGS

mmk

PUBLIC UTILITY COMMISSION OF TEXAS
EL PASO ELECTRIC COMPANY
DOCKET #6350 - CWIP CA
LEAD LAG STUDY

REVISED EXAMINER'S EXHIBIT NO. 1

Description	Expense Per Books	Recommended Adjustments	Expense as Adjusted	Average Daily Amount	Expense Lag	Revenue Lag	Net Lag	Dollar Days
Fuel	85,184,106	(19,041,941)	66,142,165	$180,716	40.2	47.9	7.7	1,391,515
Purchased Power	43,329,297	24,600,711	67,930,008	$185,601	43.3	47.9	4.6	853,765
Subtotal Fuel & Purchased Power	128,513,403	5,558,770	134,072,173					2,245,281
Payroll	22,983,007	(565,646)	22,417,361	$61,250	13.0	47.9	34.9	2,137,612
Outside Services	1,521,603	(695,083)	826,520	$2,258	52.3	47.9	-4.4	(9,936)
Property Insurance	985,835	(960,469)	25,366	$69	28.9	47.9	19.0	1,317
Injuries & Damages	814,540	(648,663)	165,877	$453	55.5	47.9	-7.6	(3,444)
Pensions and Benefits	4,102,771	(645,545)	3,457,226	$9,446	7.0	47.9	40.9	386,340
Regulatory Commission Expenses	509,069	921,973	1,431,042	$3,910	24.0	47.9	23.9	93,448
Rents	3,704,303	(212,229)	3,492,074	$9,541	-2.4	47.9	50.3	479,922
Other O&M	13,475,122	(3,547,515)	9,927,607	$27,125	28.9	47.9	19.0	515,368
M&S Charged to Expense	1,189,264	(1,189,264)	0	$0				0
Uncollectible Expense	1,016,243	(1,016,243)	0	$0				0
Total O&M Expenses	178,815,160		175,815,246	$480,370				5,845,906
Depreciation & Amortization	12,445,267	2,743,584	15,188,851					
Other Taxes	17,364,240	(3,746,625)	13,617,615	$37,207	126.3	47.9	-78.4	(2,916,997)
FIT - Current	11,356,195	3,072,208	14,428,403	$39,422	59.5	47.9	-11.6	(457,294)
FIT - Deferred	23,912,031	6,468,966	30,380,997					
Investment Tax Credit	6,316,840	0	6,316,840					
Total Operating Expense	250,209,733		255,747,951	$698,765				2,471,615
Interest on Customer Deposits	183,640		183,640	$502	183.0	47.9	-135.1	(67,786)
Sales Tax	4,855,546		4,855,546	$13,267	35.4	26.8	-8.6	(114,092)
Cash Requirement				$0				0
Working Funds & Special Deposits				$0				0
Interest on Long Term Debt	42,270,034		42,270,034	$115,492	76.8	47.9	-28.9	(3,337,716)
Total Cash Working Capital Allowance								(1,047,979)

1254

EXAMINER'S EXHIBIT NO. 2

PUBLIC UTILITY COMMISSION OF TEXAS
EL PASO ELECTRIC COMPANY
DOCKET #6350 - CWIP CASE
INVESTED CAPITAL AND RETURN

	COMPANY AMOUNT (1)	RECOMMENDED ADJUSTMENTS (2)	RECOMMENDED AMOUNT (3)
PLANT IN SERVICE	$458,813,732	($19,082,131)	$439,731,601
ACCUMULATED DEPRECIATION	($129,198,667)	$645,678	($128,552,989)
NET PLANT	$329,615,065	($18,436,453)	$311,178,612
CONSTRUCTION WORK IN PROGRESS	$883,279,029	($325,699,773)	$557,579,256
WORKING CASH ALLOWANCE	$6,063,018	($6,063,018)	$0
MATERIALS AND SUPPLIES	$5,019,548	$0	$5,019,548
PREPAYMENTS	$3,186,317	($108,282)	$3,078,035
FUEL INVENTORY	$83,358	$0	$83,358
DEFERRED TAXES	($94,553,035)	($16,429,284)	($110,982,319)
PRE 1971 INVESTMENT TAX CREDITS	($757,940)	$0	($757,940)
CUSTOMER DEPOSITS	($2,966,146)	$0	($2,966,146)
INJURIES AND DAMAGES RESERVE	($100,000)	$0	($100,000)
OTHER COST FREE CAPITAL	($992,940)	$0	($992,940)
UNAMORTIZED GAIN ON TURBINE SALE	$0	($1,808,615)	($1,808,615)
TOTAL INVESTED CAPITAL	$1,127,876,274	($368,545,425)	$759,330,849
* RATE OF RETURN	13.20%	-0.99%	12.21%
RETURN	$148,879,668	($56,165,372)	$92,714,297

1255

EXAMINER'S EXHIBIT NO. 3

PUBLIC UTILITY COMMISSION OF TEXAS

DOCKET 6350
El Paso Electric Company
Rate Year Reconcilable Fuel and Purchased Power Costs

	GROUP	MW	CF	HR	MWH	FUEL COST	COST/MWH
NET GENERATION:							
COAL:	Four Corners 4	55	75.30	9.85	362,795	$3,693,022	$10.18
	Four Corners 5	55	72.30	9.85	348,341	$3,530,815	$10.14
	TOTAL COAL:	110	73.80	9.85	711,137	$7,223,837	$10.16
GAS:	Rio Grande 8	150	3.96	12.16	52,000	$2,216,436	$42.62
	Newman 3	103	40.00	11.10	360,912	$11,339,137	$31.42
	Newman 4	211	45.00	9.90	831,762	$23,392,857	$28.12
	Balance of Plants	415	18.00	12.00	654,372	$21,969,898	$33.57
	TOTAL GAS:	879	24.66	10.91	1,899,046	$58,918,328	$31.03
	TOTAL NET GENERATION:	989	30.13	10.62	2,610,183	$66,142,165	$25.34
PURCHASES:							
	Firm				189,900	$5,659,020	$29.80
	Non-Firm				2,008,511	$54,229,788	$27.00
	TOTAL PURCHASES:				2,198,411	$59,888,808	$27.24
SALES:							
	Total Company				4,808,594	$126,030,973	$26.21

Notes:

1) Generating unit Capacity Factors (% CF), Heat Rates (HR) and Cost/Mwh are based on annual average performance.

2) Heat Rates are expressed in terms of MMBtu/Mwh.

3) Total Company sales are measured at the source.

4) Values shown are for calendar year 1986.

REVISED EXAMINER'S EXHIBIT NO. 4

PUBLIC UTILITY COMMISSION OF TEXAS
****
EL PASO ELECTRIC COMPANY
****
DOCKET #6350 - CWIP CASE
****
OPERATIONS AND MAINTENANCE
****

	COMPANY ADJUSTMENT TO TEST YEAR (1)	RECOMMENDED ADJUSTMENT TO TEST YEAR (2)	RECOMMENDED ADJUSTMENT (3)
SALARIES AND WAGES	($321,942)	($565,646)	($243,704)
EMPLOYEE BENEFITS	$647,121	($645,545)	($1,292,666)
ADVERTISING, CONTRIB., AND DUES	($29,190)	($235,539)	($206,349)
UNCOLLECTIBLE EXPENSE	$349,994	$48,413	($301,581)
RATE CASE EXPENSE	$1,846,757	$921,973	($924,784)
OUTSIDE SERVICES	$0	($695,083)	($695,083)
AIRPLANE EXPENSE	($372,050)	($372,050)	$0
ABNORMAL MAINTENANCE	$47,554	$47,554	$0
NEW MEXICO PROJECT	($2,209,398)	($2,209,398)	$0
OTHER O&M EXPENSE	($329,520)	($990,311)	($660,791)
TOTAL	($370,674)	($4,695,632)	($4,324,958)

REVISED EXAMINER'S EXHIBIT NO. 5

PUBLIC UTILITY COMMISSION OF TEXAS
****
EL PASO ELECTRIC COMPANY
****
DOCKET #6350 - CWIP CASE
****
OTHER TAXES
****

	TEST YEAR PER BOOKS (1)	COMPANY ADJUSTMENTS (2)	COMPANY TEST YEAR (3)	RECOMMENDED ADJUSTMENTS (4)	RECOMMENDED TEST YEAR (5)
AD VALOREM TAXES	$3,662,059	$562,514	$4,224,573	($189,929)	$4,034,644
PAYROLL TAXES	$1,864,916	($97,015)	$1,767,901	($17,181)	$1,750,720
FRANCHISE TAXES	$1,539,153	$574,700	$2,113,853	$138,055	$2,251,908
OTHER TAXES	$144,180	$0	$144,180	$0	$144,180
NON REVENUE RELATED TAXES	$7,210,308	$1,040,199	$8,250,507	($69,055)	$8,181,452
TEXAS PUC ASSESSMENT	$425,710	$92,684	$518,394	($69,083)	$449,311
NEW MEXICO PUC ASSESMENT	$270,630	$311,404	$582,034	($297,704)	$284,330
TEXAS STATE GROSS RECEIPTS	$4,460,008	$923,581	$5,383,589	($683,376)	$4,700,213
TEXAS OCCUPATIONAL AND STREET RENTAL	$3,864,765	$1,237,703	$5,102,468	($647,972)	$4,454,496
NEW MEXICO OCCUPATIONAL AND STREET RENTAL	$529,768	$495,091	$1,024,859	($473,751)	$551,108
REVENUE RELATED TAXES	$9,550,881	$3,060,463	$12,611,344	($2,171,886)	$10,439,458

SUMMARY OF OTHER TAXES
****

	(1)	(2)	(3)	(4)	(5)
NON REVENUE RELATED TAXES	$7,210,308	$1,040,199	$8,250,507	($69,055)	$8,181,452
REVENUE RELATED TAXES	$9,550,881	$3,060,463	$12,611,344	($2,171,886)	$10,439,458
TOTAL OTHER TAXES	$16,761,189	$4,100,662	$20,861,851	($2,240,941)	$18,620,910

EXAMINER'S EXHIBIT NO. 6

PUBLIC UTILITY COMMISSION OF TEXAS

EL PASO ELECTRIC COMPANY

DOCKET #6350 - CWIP CASE

FEDERAL INCOME TAXES

	COMPANY AMOUNT (1)	RECOMMENDED ADJUSTMENTS (2)	RECOMMENDED AMOUNT (3)
RETURN	$148,879,668	($56,165,372)	$92,714,297
ADJUSTMENTS TO RETURN			
INTEREST EXPENSE	($62,145,982)	$20,587,805	($41,558,177)
AMORTIZATION OF ITC	($498,948)	($16,580)	($515,528)
PLUS OR MINUS NON-NORMALIZED DIFFERENCES			
RATE DIFFERENTIAL	($10,081)	$0	($10,081)
PREFERRED DIVIDENDS	($20,544)	$0	($20,544)
ADDITIONAL DEPRECIATION	$1,793,852	$198,520	$1,992,372
NUCLEAR FUEL INTEREST	$0	$0	$0
TOTAL ADJUSTMENTS TO RETURN	($60,881,703)	$20,769,745	($40,111,958)
TAXABLE COMPONENT OF RETURN	$87,997,965		$52,602,338
TAX FACTOR (1/.54)(.46)	0.851851852		0.851851852
FEDERAL INCOME TAXES BEFORE CREDITS	$74,961,230		$44,809,399
AMORTIZATION OF INVESTMENT TAX CREDITS	($498,948)		($515,528)
TOTAL FEDERAL INCOME TAXES	$74,462,282	($30,168,410)	$44,293,871

1259

REVISED EXAMINER'S EXHIBIT NO. 7

PUBLIC UTILITY COMMISSION OF TEXAS
EL PASO ELECTRIC COMPANY
DOCKET #6350 - CWIP CASE
REVENUE REQUIREMENT

	TEST YEAR PER BOOKS (1)	COMPANY ADJUSTMENTS (2)	COMPANY TEST YEAR (3)	RECOMMENDED ADJUSTMENTS (4)	RECOMMENDED TEST YEAR (5)
FUEL	$85,205,541	($600,065)	$84,605,476	($18,463,311)	$66,142,165
PURCHASED POWER	$43,329,297	$19,079,302	$62,408,599	$5,521,409	$67,930,008
OPERATIONS AND MAINTENANCE	$50,280,322	($370,674)	$49,909,648	($4,324,958)	$45,584,690
DEPRECIATION AND AMORTIZATION	$12,445,267	$4,034,940	$16,480,207	($1,291,356)	$15,188,851
OTHER TAXES	$16,761,189	$4,100,662	$20,861,851	($2,240,941)	$18,620,910
INTEREST ON CUSTOMERS DEPOSITS	$183,640	$0	$183,640	$15,720	$199,360
STATE INCOME TAXES	$603,051	$2,726,986	$3,330,037	($2,980,093)	$349,944
FEDERAL INCOME TAXES	$41,585,066	$32,877,216	$74,462,282	($30,168,410)	$44,293,871
RETURN	$78,621,974	$70,257,694	$148,879,668	($56,165,372)	$92,714,297
REVENUE REQUIREMENT	$329,015,347	$132,106,061	$461,121,408	($110,097,312)	$351,024,096
OTHER REVENUE	$1,188,842	$973,859	$2,162,701	($12,636)	$2,150,065
FUEL REVENUE	$127,915,552	$17,298,523	$145,214,075	($19,183,102)	$126,030,973
BASE REVENUE	$199,910,953	$113,833,679	$313,744,632	($90,901,574)	$222,843,058
REVENUE REQUIREMENT	$329,015,347	$132,106,061	$461,121,408	($110,097,312)	$351,024,096

1260

REVISED EXAMINER'S EXHIBIT NO. 8

PUBLIC UTILITY COMMISSION OF TEXAS
****
EL PASO ELECTRIC COMPANY
****
DOCKET #6350 - CWIP CASE
****
TEXAS RETAIL REVENUE DEFICIENCY
****

	COMPANY TEST YEAR (1)	RECOMMENDED ADJUSTMENTS (2)	RECOMMENDED TEST YEAR (3)
PROPOSED FUEL REVENUE	$97,916,341	($12,722,932)	$85,193,409
PROPOSED BASE REVENUE	$212,256,712	($57,475,758)	$154,780,954
PROPOSED OTHER REVENUE	$1,572,935	($12,636)	$1,560,299
TOTAL REVENUE REQUIREMENT	$311,745,988	($70,211,326)	$241,534,662
LESS			
TEST YEAR ADJUSTED FUEL REVENUE	$84,089,410	$693,344	$84,782,754
TEST YEAR ADJUSTED BASE REVENUE	$158,595,721	$745,738	$159,341,459
TEST YEAR ADJUSTED OTHER REVENUE	$1,572,935	$0	$1,572,935
TOTAL ADJUSTED TEST YEAR REVENUES	$244,258,066	$1,439,082	$245,697,148
FUEL REVENUE DEFICIENCY	$13,826,931	($13,416,276)	$410,655
BASE REVENUE DEFICIENCY	$53,660,991	($58,221,496)	($4,560,505)
OTHER REVENUE DEFICIENCY	$0	($12,636)	($12,636)
TOTAL REVENUE DEFICIENCY	$67,487,922	($71,650,408)	($4,162,486)

1261

EXAMINER'S EXHIBIT NO. 9

DOCKET NO. 6350

APPLICATION OF EL PASO ELECTRIC COMPANY FOR AUTHORITY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

STIPULATION
ON
COST ALLOCATION AND RATE DESIGN

The undersigned hereby state that they each have full authority to enter into and bind the entities they represent to the terms of this Stipulation on Cost Allocation and Rate Design as set forth below. This Stipulation is entered into in the interests of reaching an agreed settlement of certain matters previously placed at issue by the pleadings and prefiled direct testimony of the parties, is entered into for purposes of this proceeding only, shall not bind the parties to the positions or results agreed to herein in subsequent proceedings before this Commission, and shall thus be subject to further order of the Commission in any such subsequent proceedings.

1. The undersigned hereby agree and stipulate that any base rate revenue increase or decrease found by the Commission in this docket shall be allocated to the various customer classes proposed herein by El Paso Electric Company ("EPEC") on an equalized percentage basis so that each such class receives a base rate revenue increase or decrease that is equal to the total Texas jurisdictional base rate revenue increase or decrease, as the case may be, found by the Commission herein.

5-6350 11/21/85 5330-13

2. The undersigned hereby agree and stipulate that fixed fuel factors shall be developed by multiplying the Texas system fixed fuel factor, as calculated to reflect the adjusted annual fuel costs found by the Commission in this proceeding, by the following energy loss factors: 0.987162 for primary voltage, 1.01681 for secondary voltage, and 0.944768 for transmission voltage.

3. The undersigned hereby agree and stipulate that the assignment of customers to classes as proposed by EPEC in its proposed tariffs is accepted.

4. The undersigned hereby agree and stipulate that any base rate increases or decreases found by the Commission herein shall be recovered as follows: (a) For rate classes other than rate class 24 which have demand charges, any increase or decrease shall be applied to the demand charge; (b) for rate classes which do not have demand charges, any increase or decrease shall be applied to the energy charge on a uniform cents per kWh basis; and (c) for rate class 24, any increase or decrease shall be applied to the demand charge on a percentage basis; however, the implicit demand charge in the first 3,000 kWh block shall be calculated by subtracting $0.01 per kWh from the total revenues derived from the first 3,000 kWh block.

5. The undersigned hereby agree and stipulate that the annualized adjusted kW demand and kWh sales as found by the Commission in this proceeding shall be used for rate design purposes.

6. The undersigned agree and stipulate that their respective prefiled testimony and exhibits, if any, pertaining to the matters covered by this Stipulation should be admitted into evidence in this docket, without cross-examination by any of the other signatories hereto. All signatories hereto preserve any rights they otherwise have in the event and to the extent that the Public Utility Commission of Texas does not incorporate the terms of this Stipulation into its final order as ultimately entered in this Docket No. 6350. In addition, all parties to this Stipulation reserve their rights to file written exceptions, present oral arguments, and otherwise advance and defend the terms of this Stipulation in the event and to the extent the Hearings Examiner should in his Examiner's Report fail to endorse any of the terms hereof.

7. The agreement of any party to the terms of this Stipulation may be withdrawn in the event that one or more parties submitting prefiled direct testimony on any of the issues addressed by this Stipulation fails to agree to the terms hereof. However, such right of withdrawal of assent to

this Stipulation must be exercised, in any event, by written notice delivered to the Commission's General Counsel by 5:00 p.m., Tuesday, November 19, 1985.

8. This Stipulation can be signed in counterparts, each of which shall be deemed to be an original, but all of which shall be deemed one and the same document.

EL PASO ELECTRIC COMPANY

THE CITY OF EL PASO Norman J. Gordon, Attorney

OFFICE OF THE GENERAL COUNSEL,
PUBLIC UTILITY COMMISSION OF TEXAS

OFFICE OF PUBLIC UTILITY COUNSEL

ASARCO INCORPORATED

BORDER STEEL ROLLING MILLS, INC./
EL PASO IRON & METAL COMPANY

TEXAS INDUSTRIAL ENERGY CONSUMERS/
PHELPS DODGE

for UNITED STATES DEPT. OF DEFENSE

W. SILVER, INC., ET AL.

TEXAS-NEW MEXICO POWER COMPANY

EL PASO COUNTY

UNITED STEELWORKERS OF AMERICA

7021E

MR. R. BRIAN JONES

this Stipulation must be exercised, in any event, by written notice delivered to the Commission's General Counsel by 5:00 p.m., Tuesday, November 19, 1985.

8. This Stipulation can be signed in counterparts, each of which shall be deemed to be an original, but all of which shall be deemed one and the same document.

EL PASO ELECTRIC COMPANY

THE CITY OF EL PASO

OFFICE OF THE GENERAL COUNSEL,
PUBLIC UTILITY COMMISSION OF TEXAS

OFFICE OF PUBLIC UTILITY COUNSEL

ASARCO INCORPORATED

C. Michael [illegible]

BORDER STEEL ROLLING MILLS, INC./
EL PASO IRON & METAL COMPANY

TEXAS INDUSTRIAL ENERGY CONSUMERS/
PHELPS DODGE

UNITED STATES DEPT. OF DEFENSE

W. SILVER, INC., ET AL.

REVISED EXAMINER'S EXHIBIT NO. 10

PUBLIC UTILITY COMMISSION OF TEXAS
EL PASO ELECTRIC COMPANY
DOCKET NO. 6350
JURISDICTIONAL COST OF SERVICE STUDY
RECOMMENDED REVENUE REQUIREMENT
CWIP CASE

Jurisdiction	EPEC Adj.Current Revenue	EPEC Request	EPEC Increase (Decrease) Request	Percent	Adjusted Current Revenue	Examiner Recommendation	Revenue Deficiency	Percent
Texas Retail	($)	($)	($)	(%)	($)	($)	($)	(%)
a.Base Rate Revenue	158,595,721	212,256,712	53,660,991	33.84	159,341,459	154,780,954	(4,560,505)	(2.86)
b.Fuel & Purchased Power	84,089,410	97,916,341	13,826,931	16.44	84,782,754	85,193,409	410,655	0.48
c.Misc.Revenues	1,572,935	1,572,935	0	0.00	1,572,935	1,560,299	(12,636)	(0.80)
Total	244,258,066	311,745,988	67,487,922	27.63	245,697,148	241,534,662	(4,162,486)	(1.69)

REVISED EXAMINER'S EXHIBIT NO. 11

PUBLIC UTILITY COMMISSION OF TEXAS
EL PASO ELECTRIC COMPANY
DOCKET NO. 6350
JURISDICTIONAL COST OF SERVICE STUDY
SUMMARY OF REVENUE REQUIREMENT ALLOCATION
CWIP CASE

Description	Total System ($)	Texas Retail ($)	Other Jurisdictions ($)
Fuel	66,142,165	44,710,253	21,431,912
Purchased Power	67,930,008	45,913,521	22,016,487
Operation & Maintenance	45,584,689	33,530,881	12,053,808
Depreciation & Amortization	15,188,849	10,489,862	4,698,987
Decommissioning Cost	0	0	0
Other Taxes	18,620,910	15,888,780	2,732,130
Interest on Customer Deposit	199,360	157,739	41,621
State Income Taxes	349,944	157,696	192,248
Federal Income Taxes	44,293,871	28,682,700	15,611,171
Return on Rate Base	92,714,296	62,003,229	30,711,067
Revenue Requirement	351,024,092	241,534,662	109,489,430
Miscellaneous Revenue	(2,150,065)	(1,560,299)	(589,766)
Fuel Revenue	(126,030,973)	(85,193,409)	(40,837,564)
Base Rate Revenue	222,843,054	154,780,954	68,062,100
Percent (%)	100.0000	69.4574	30.5426

EXAMINER'S EXHIBIT NO. 12

PUBLIC UTILITY COMMISSION OF TEXAS
EL PASO ELECTRIC COMPANY
DOCKET NO. 6350
JURISDICTIONAL COST OF SERVICE STUDY
RATE BASE ALLOCATION
CWIP CASE

Description	Total System	Texas Retail	Other Jurisdictions
	($)	($)	($)
Plant In Service	439,731,594	306,110,996	133,620,598
Accumulated Depreciation	(128,552,986)	(89,657,306)	(38,895,680)
Accumulated Decommissioning	0	0	0
Net Plant	311,178,608	216,453,690	94,724,918
CWIP-Net	557,579,256	356,831,107	200,748,149
Working Capital Allowance	8,180,941	6,257,313	1,923,628
Accum. Deferred Income taxes	(110,982,319)	(67,424,128)	(43,558,191)
Injury & Damage Reserves	(100,000)	(74,002)	(25,998)
Customer Advance for Constr.	(992,941)	(144,782)	(848,159)
Customer Deposits	(2,966,146)	(2,346,901)	(619,245)
Unamortized Pre 1971 ITC	(757,940)	(527,626)	(230,314)
Unamort.gain on turbine sale	(1,808,615)	(1,217,714)	(590,901)
Total Rate Base	759,330,844	507,806,957	251,523,887
Percent (%)	100.0000	66.8756	33.1244

1269

REVISED EXAMINER'S EXHIBIT NO. 13

PUCT COST OF SERVICE STUDY
EL PASO ELECTRIC COMPANY
DOCKET NO.6350
RECOMMENDED BASE RATE REVENUE REQUIREMENT
CWIP CASE

Class		(1) Examiner Adj.Current Base Rate Revenue	(2) Recommended Increase (Decrease)	(3) Revenue Increase (Decrease)	(4) Recommended Base Rate Revenue
		($)	%	($)	(%)
01	Residential	55,367,001	(2.86)	(1,584,657)	53,782,344
08	E.P.St.Light & Sig	1,677,982	(2.86)	(48,025)	1,629,957
11	E.P.Mun.Pumping	4,948,568	(2.86)	(141,633)	4,806,935
15	Electrolyte Refin.	3,586,285	(2.86)	(102,643)	3,483,642
21	Off-Peak W.H.	1,627,623	(2.86)	(46,584)	1,581,039
22	Irrigation	63,771	(2.86)	(1,825)	61,946
24	General Service	48,922,001	(2.86)	(1,400,195)	47,521,806
25	Large Power	22,595,013	(2.86)	(646,691)	21,948,322
28	Area Lighting	755,118	(2.86)	(21,612)	733,506
29	Transm. Voltage	4,149,997	(2.86)	(118,777)	4,031,220
30	Electric Furnace	3,159,211	(2.86)	(90,420)	3,068,791
31	Military Service	5,392,789	(2.86)	(154,347)	5,238,442
34	Cotton Gin	126,481	(2.86)	(3,620)	122,861
41	City & County	6,816,416	(2.86)	(195,092)	6,621,324
54	Mun.Pumping	153,203	(2.86)	(4,385)	148,818
	Total	159,341,459	(2.86)	(4,560,506)	154,780,953

APPLICATION OF EL PASO ELECTRIC COMPANY FOR AUTHORITY TO CHANGE RATES	§	PUBLIC UTILITY COMMISSION
	§	
APPEAL OF EL PASO ELECTRIC COMPANY FROM THE RATEMAKING ORDINANCES OF THE CITY OF EL PASO AND THE TOWNS OF VINTON, CLINT AND ANTHONY	§	OF TEXAS

ORDER

In a public meeting at its offices in Austin, Texas, the Public Utility Commission of Texas finds that, after statutory notice was provided to the public and interested persons, the application in this case was processed by an examiner in accordance with Commission rules and all applicable statutes. An Examiner's Report containing Findings of Fact and Conclusions of Law was submitted, which report is hereby ADOPTED with the following modifications:

1. Finding of Fact No. 14 is STRICKEN and shall be replaced by the following finding:

    14. Although this is the first proceeding in which the Commission has reviewed EPEC's energy efficiency plan and energy efficiency programs, PURA Section 39(b) requires that the Commission consider EPEC's conservation and load management activities in setting a reasonable return on invested capital.

2. Finding of Fact No. 15 is STRICKEN and shall be replaced by the following finding:

    15. EPEC has a total invested capital of $767,255,652 as illustrated below, for the reasons set out in Section VI of the report, as modified by revised Findings of Fact Nos. 72, 79 and 80:

Plant in Service	$458,113,732
Accumulated Depreciation	(128,906,480)
Net Plant	$329,207,252
Construction Work in Progress	548,388,190
Working Cash Allowance	(912,771)
Materials & Supplies	5,019,548
Prepayments	3,078,035
Fuel Inventory	83,358
Deferred Taxes	(110,982,319)
Pre 1971 Investment Tax Credits	(757,940)
Customer Deposits	(2,966,146)
Injuries & Damages Reserve	(100,000)
Other Cost Free Capital	(992,940)
Unamortized Gain on Sale of Turbine	(1,808,615)
Total Invested Capital	$767,255,652

3. Finding of Fact No. 16 is STRICKEN and shall be replaced by the following finding:

16. From a financial integrity standpoint, inclusion in rate base of no more than 50 percent of EPEC's adjusted test year end CWIP balance is necessary to the financial integrity of EPEC during 1986.

4. Finding of Fact No. 23 is STRICKEN and shall be replaced by the following finding:

23. A return on equity of 15.0 percent is reasonable for EPEC in light of the testimony of the parties as summarized in Section VII of the report.

[4] 5. Finding of Fact No. 26 is STRICKEN and shall be replaced by the following finding:

26. EPEC has a capital structure and weighted average cost of capital as follows:

Source	Amount	Ratio	Cost	Weighted Cost
Long-term Debt	$ 750,037,000	53.9578%	10.39%	5.606%
Preferred Stock	150,873,000	10.8538%	9.80%	1.064%
Common Equity	489,133,000	35.1883%	15.0%	5.278%
Total	$1,390,043,000	100%		11.95%

6. Finding of Fact No. 27 is STRICKEN and shall be replaced with the following finding:

27. Application of the weighted average cost of capital of 11.95 percent to EPEC's total invested capital of $767,255,652 results in a return of $91,687,050.

7. Finding of Fact No. 30 is STRICKEN and replaced with the following finding:

30. EPEC has a total company revenue requirement of $337,515,663 composed of the following:

Fuel	$ 66,142,165
Purchased Power	$ 67,930,008
Operations and Maintenance	$ 44,839,575
Depreciation and Amortization	$ 15,895,832
Other Taxes	$ 18,406,667
Interest on Customers Deposits	$199,360
State Income Taxes	$349,944
Federal Income Taxes	$ 32,065,062
Return	$ 91,687,050
Revenue Requirement	$337,515,663

[illegible] would [illegible] of the Texas [illegible] fuel losses for [illegible] voltage [illegible]

[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]

The [illegible] fuel factors will be adjusted to [illegible] the amount of fuel over-recoveries and [illegible] finding of [illegible] in compliance with the final order in this docket.

(S) 13. Finding of Fact No. 59 is hereby AMENDED to read as follows:

59. An SRR available only to certain industrial classes does not unreasonably discriminate if the evidence demonstrates: (1) that the utility system and the general body of ratepayers are benefitted by maintaining the existing industrial load; (2) that such load is in serious danger of substantially shrinking or disappearing altogether; (3) that unusually high industrial [illegible] rates are a major economic factor which elevates the possibility of serious load loss; and (4) that approval of the SRR would increase the probability that this industrial load will continue operating on the utility's system.

14. Finding of Fact No. [illegible] is hereby AMENDED to read as follows:

[illegible] The record in this [illegible] conclusion (1) [illegible] faced with [illegible] when PWMCS [illegible] of EPEC [illegible] s of that [illegible] ratepayers [illegible] of ASARCO, [illegible] economic [illegible] operation [illegible] create a [illegible] enhances

12. Finding of Fact No. 35 is STRICKEN and shall be replaced with the following finding:

35. EPEC's unadjusted Texas system fixed fuel factor should be set at $0.028513 per kwh. Adjustment of the Texas system factor to reflect the effects of line losses for the transmission, primary, and secondary voltage customer yields the following fuel factors:

Transmission Voltage	$0.026938
Primary Voltage	$0.028147
Secondary Voltage	$0.028992

The secondary and primary voltage fuel factors will be adjusted to reflect the refund of fuel overrecoveries and associated interest set out in revised Finding of Fact 36 in the tariffs filed by EPEC in compliance with the final order in this docket.

[5] 13. Finding of Fact No. 59 is hereby AMENDED to read as follows:

59. An ERR available only to certain industrial classes does not unreasonably discriminate if the evidence demonstrates (1) that the utility system and the general body of ratepayers are benefited by maintaining the existing industrial load; (2) that such load is in serious danger of substantially shrinking or disappearing altogether; (3) that unusually high industrial electric rates are a major economic factor which elevate this possibility of serious load loss; and (4) that approval of the ERR would increase the probability that this needed industrial load will continue operating on the utility's system.

14. Finding of Fact No. 62 is hereby AMENDED to read as follows:

62. The record in this proceeding supports a conclusion (1) that EPEC and its ratepayers will be faced with considerable amounts of excess capacity when PVNGS comes on-line, and that the general body of EPEC ratepayers will benefit if the associated costs of that facility are ultimately spread among as many ratepayers as possible; (2) that the El Paso plants of ASARCO, Border Steel, and Phelps Dodge all face economic circumstances so adverse that their continued operation is in serious jeopardy; (3) that EPEC's rates create a significant competitive disadvantage which enhances

this possibility of load loss; and (4) that adoption of the ERR will make it more likely that the El Paso plants of these three heavy industrial customers remain in operation as major EPEC ratepayers. For these reasons, an ERR should be adopted on an experimental basis.

15. Finding of Fact No. 65 is hereby AMENDED to read as follows:

65. The ERR approved in this docket should be the ERR described as having been originally proposed by EPEC, except that under the ERR, Phelps Dodge, ASARCO and Border Steel should receive a 15 percent discount on their monthly kw charge, if their highest maximum demand during the month occurred during off-peak billing hours. The ERR should be designated as experimental.

16. Finding of Fact No. 66 is hereby AMENDED to read as follows:

66. The ERR should be interpreted as overriding the ratchet provision in the rate schedules to which the ERR applies.

17. Finding of Fact No. 68 is hereby AMENDED to read as follows:

68. EPEC's proposed service charges should be approved, except that the returned check charge of $8.00 should not be increased, since no increase has been shown to be justified on the basis of EPEC's costs.

18. The following Findings of Fact are hereby DELETED: 57, 58, 60, 63, 64, and 67.

19. The following Findings of Fact are ADDED:

72. In light of the use of the Palo Verde transmission line for off-system sales during the test year, the transmission line should be treated as plant in service as proposed by EPEC, rather than being reclassified as CWIP.

73. Finding the testimony of City witness Copeland to be most credible, the Commission concludes that allowance of no more than 50 percent of EPEC's adjusted test year end CWIP in rate base is necessary to prevent further deterioration of and commence the improvement of EPEC's financial integrity.

74. EPEC's federal income tax expense should be calculated incorporating the tax deductions from advertising, dues and charitable donations which have been disallowed from cost of service pursuant to the provisions of this Order.

[6] 75. EPEC's request for inclusion in cost of service of $552,349 of expenses associated with the cancelled New Mexico generation project is rejected because the record in this case does not contain any evidence supporting the reasonableness of EPEC's expenditures of the project.

76. Finding the testimony of City of El Paso to be the most persuasive with regard to the issue of the appropriateness of a depreciation add-back adjustment, federal income tax expense should not include additional depreciation on non-normalized timing differences.

[7] 77. Given the requirements of PURA Section 41(c)(2), it is in the public interest to include the tax savings resulting from EPEC's practice of filing a consolidated tax return in the calculation of EPEC's cost of service.

78. Finding the testimony of City witness DeWard to be most persuasive on the issue of unbilled revenues, the City's proposed adjustment for unbilled revenues should be adopted and those revenues should be reflected in the revenue deficiency calculation in this docket.

79. The recommendations contained in the Examiner's Report, as modified by this final Order, result in a cash working capital determination of $(912,771) for EPEC.

[8] 80. It is inappropriate to impute a zero working cash allowance for EPEC in lieu of the actual working cash determination made herein, because EPEC has not demonstrated that its cash working capital requirement is the result of good cash management techniques.

81. The Commission staff presented the most credible evidence regarding the appropriate treatment of the nuclear fuel trust interest deduction. Therefore, the staff's recommendations on this issue should be adopted.

82. EPEC has failed to meet its burden of proving that no
[9] portions of the EEI and AIF dues requested by EPEC to be included in its cost of service support, directly or indirectly, legislative advocacy or lobbying activities on the part of those organizations. Therefore, all EEI and AIF dues requested for inclusion in cost of service by EPEC should be disallowed. If any item requested for inclusion in cost of service could have legislative advocacy as a component part, the utility has the burden of proving that no part of that expense item can be attributed to legislative advocacy.

83. The rate case expenses incurred by the City of El Paso in connection with this rate proceeding, as set forth in the City's testimony, are reasonable.

84. The cost of the Touche Ross management audit of EPEC should be borne solely by Texas customers and should be amortized over a three year period.

85. It is not necessary or in the public interest, within
[10] the intended meaning of P.U.C. SUBST. R. 23.21(b)(1)(e), to permit the inclusion of charitable contributions in EPEC's cost of service given the current financial condition of EPEC and as such expenses are not necessary to provide service to the public.

86. EPEC's proposed revision to its definitions of on-peak and off-peak hours was not contested by any of the parties, was not addressed in the Stipulation, and, therefore, is adopted.

87. EPEC stipulated at the January 29, 1986 open meeting of the Commission that the Company has not paid in full the amounts due and owing to Touche Ross & Company for the August, 1985, management audit of EPEC and that the Company recognizes its obligation to pay such amounts in full.

20. Conclusion of Law No. 4 is amended as follows:

4. Pursuant to Section 40 of the Act, EPEC has the burden of proving its proposed rates are just and reasonable. EPEC has failed to meet its burden of proof to the extent that its proposals in this case have been rejected by the Examiner's Report as modified by this Order.

21. Conclusion of Law No. 5 is amended as follows:

5. The recommendations of the Examiner's Report as modified by this final Order, will allow EPEC to recover its reasonable and proper operating expenses, together with a reasonable return on its invested capital pursuant to Section 39 of the Act.

22. Conclusion of Law No. 11 is amended as follows:

11. Inclusion of no more than 50 percent of CWIP is necessary to EPEC's financial integrity within the meaning of Section 41(a) of the Act. EPEC has not met its burden of proof under Section 41(a) of the Act and P.U.C. SUBST. R. 23.21(c)(2)(D) of demonstrating that PVNGS has been efficiently and prudently planned and managed. Under the standards set forth in those provisions, inclusion of rate base of no more than 50 percent of adjusted test year end PVNGS CWIP is warranted.

23. Conclusion of Law No. 12 is amended as follows:

12. The rates proposed in this final Order are just and reasonable within the meaning of PURA Sections 38 and 40.

24. Conclusion of Law No. 13 is amended as follows:

13. The rates proposed in this final Order are not unreasonably preferential, prejudicial or discriminatory, but are sufficient and equitable, as required by Section 38 of the Act.

25. Conclusion of Law No. 14 is amended as follows:

14. The rates proposed in this final Order make or grant no unreasonable preference or advantage, and subject no corporation or person to any unreasonable prejudice or disadvantage. They neither establish nor maintain any unreasonable differences as to rates for service between localities or classes of service, as required by PURA Section 45.

26. Conclusion of Law No. 15 is amended as follows:

15. The rates proposed in this final Order are those which the municipalities which are parties to this docket should have fixed in the ordinances from which EPEC's appeals were taken, as required by PURA Section 26(e).

27. Conclusion of Law No. 16 is amended as follows:

16. The rates proposed in this final Order comply with the ratemaking mandates of PURA and the Commission's substantive rules.

28. Conclusion of Law No. 21 is amended as follows:

21. The fixed fuel factors recommended by the examiner as modified by this final Order to accommodate the refund of fuel overrecoveries are in accordance with P.U.C. SUBST. R. 23.23.

29. The following Conclusion of Law is added:

22. PURA Section 41(c)(2) clearly requires that consolidated tax savings be passed along to ratepayers.

The Commission further issues the following Order:

1. The first full paragraph on page 75 of the Examiner Report is NOT ADOPTED.

2. The last two paragraphs of Section IX.B.3.C. on page 91 of the Examiner's Report are NOT ADOPTED.

3. The last sentence contained in the second full paragraph on page 107 of the Examiner's Report is DELETED.

4. The application of El Paso Electric Company (EPEC) is hereby GRANTED in part and DENIED in part, as set out in the Examiner's Report and modified by this Order.

5. The Commission hereby orders that EPEC defer those costs currently being capitalized and the depreciation which would be recorded for PVNGS Unit No. 1, effective with the commercial in-service date of this unit as defined by the Commission. The recovery of those deferred costs will be included in the rate case at the time the unit is placed in-service for ratemaking purposes. However, the Commission reserves the right to exclude

from rate base or other recovery any portion of the expenditures from the plant, AFUDC, capitalized expenses, capitalized depreciation or other capitalized costs which the Commission determines to be related to plant that is not used and useful or to have been imprudently spent or incurred. The Commission further reserves the right to consider the reasonableness and prudence of any deferred expenses in the rate order in which rate base treatment for plant is requested.

6. EPEC is hereby directed to address the recommendations pertaining to FL&R contained in the Touche Ross & Company management audit report in EPEC's next rate filing.

7. EPEC shall refund the fuel overrecovery balance together with interest thereon, in the amounts and in the manner set forth in Finding of Fact No. 34 and revised Finding of Fact No. 36.

8. EPEC shall in its next general rate case present evidence regarding the amount of and appropriate treatment of return earned by EPEC on CWIP attributable to PVNGS Units 4 and 5.

9. EPEC is directed to retain Tariff No. 97 in effect until such time as the City of El Paso's Public Utility Regulatory Board declares PVNGS to be in service.

10. EPEC shall maintain records tracking the effect of the ERR approved in this case. The issue of who should bear the burden of any resulting underrecovery shall be addressed in EPEC's next general rate case.

11. EPEC shall continue to account for all Palo Verde related construction work in progress on a customer-by-customer basis. Such plans shall be similar to that approved or hereafter approved by the New Mexico Commission in Case #1539 involving the Company. The Company shall include with its revised schedule of rates and tariffs to be filed with the Commission, a plan for informing each customer of such amount, all subject to final approval of the Commission.

12. EPEC SHALL file revised rate schedules in accordance with the rates and guidelines set out in this Order sufficient to generate revenues not greater than those prescribed in this Order no later than twenty (20) days from the date of this Order. EPEC shall also file any other pages of its tariff that are being revised pursuant to this docket. The revised tariff sheets shall be filed in four (4) copies with the Commission filing clerk and shall comply with the requirements of P.U.C. SUBST. R. 23.24.

EPEC shall serve a copy of its revised tariff on all parties of record at the same time that it is filed with the Commission. The parties shall have ten (10) days from the date of filing to present their written objections to the revised tariff, if any, to the Commission staff for its review and consideration. The Commission staff shall have twenty (20) days from the date of the filing of the revised tariff to review it for approval or rejection. The tariff shall be deemed to be approved and shall become effective upon the expiration of twenty (20) days after filing or sooner upon notification by the examiner. In the event of rejection, EPEC shall be notified by the examiner, with a copy sent to all parties, and it shall have ten (10) additional days to file another revised tariff, with the same procedures then to be repeated.

13. The revised and approved rates shall be charged only for service rendered in areas over which this Commission was exercising its original or 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. Should the tariff approval date fall within the EPEC's billing period, EPEC shall be authorized to prorate each customer's bill to reflect that customer's customer charge, demand charge, and daily energy consumption at the appropriate new rates.

14. EPEC shall use the depreciation rates set out in the Examiner's Report for all regulatory purposes until further order of this Commission.

15. This Order is deemed effective on the date of signing. Approval of the revised tariff filed in compliance with this Order shall be deemed to be final on the date of its effectiveness either by operation of this Order or by notification by the examiner, whichever occurs first.

-continued-

16. All motions, applications, and requests for entry of specific Findings of Fact and Conclusions of Law and any other requests for relief, general or specific, if not expressly granted herein are DENIED for want of merit.

SIGNED AT AUSTIN, TEXAS on this the 31st day of January 1986.

PUBLIC UTILITY COMMISSION OF TEXAS

SIGNED: Peggy Rosson
PEGGY ROSSON

SIGNED: Dennis L. Thomas
DENNIS L. THOMAS

SIGNED: Jo Campbell
JO CAMPBELL

ATTEST:

Rhonda Colbert Ryan
RHONDA COLBERT RYAN
SECRETARY OF THE COMMISSION

tv

COMMISSION EXHIBIT NO. 1

PUBLIC UTILITY COMMISSION OF TEXAS

EL PASO ELECTRIC COMPANY

DOCKET #6350 - CWIP CASE

LEAD LAG STUDY

Description	Expense Per Books	Recommended Adjustments	Expense as Adjusted	Average Daily Amount	Expense Lag	Revenue Lag	Net Lag	Dollar Days
Fuel	85,184,106	(19,041,941)	66,142,165	$180,716	40.2	47.9	7.7	1,391,515
urchased Power	43,329,297	24,600,711	67,930,008	$185,601	43.3	47.9	4.6	853,765
Subtotal Fuel & Purchased Power	128,513,403	5,558,770	134,072,173					2,245,281
Payroll	22,983,007	(565,646)	22,417,361	$61,250	13.0	47.9	34.9	2,137,612
Outside Services	1,521,603	(695,083)	826,520	$2,258	52.3	47.9	-4.4	(9,936)
Property Insurance	985,835	(960,469)	25,366	$69	28.9	47.9	19.0	1,317
Injuries & Damages	814,540	(648,663)	165,877	$453	55.5	47.9	-7.6	(3,444)
Pensions and Benefits	4,102,771	(645,545)	3,457,226	$9,446	7.0	47.9	40.9	386,340
Regulatory Commission Expenses	509,069	1,001,973	1,511,042	$4,129	24.0	47.9	23.9	98,672
Rents	3,704,303	(212,229)	3,492,074	$9,541	-2.4	47.9	50.3	479,922
Other O&M	13,475,122	(4,331,659)	9,143,463	$24,982	28.9	47.9	19.0	474,661
M&S Charged to Expense	1,189,264	(1,189,264)	0	$0				0
Uncollectible Expense	1,016,243	(1,016,243)	0	$0				0
Total O&M Expenses	178,815,160		175,111,102	$478,446				5,810,423
Depreciation & Amortization	12,445,267	3,450,565	15,895,832					
)ther Taxes	17,364,240	(3,960,868)	13,403,372	$36,621	126.3	47.9	-78.4	(2,871,105)
´IT - Current	11,356,195	(865,408)	10,490,787	$28,663	59.5	47.9	-11.6	(332,495)
FIT - Deferred	23,912,031	(1,822,228)	22,089,803					
Investment Tax Credit	6,316,840	0	6,316,840					
Total Operating Expense	250,209,733		243,307,736	$664,775				2,606,823
Interest on Customer Deposits	183,640		183,640	$502	183.0	47.9	-135.1	(67,786)
Sales Tax	4,855,546		4,855,546	$13,267	35.4	26.8	-8.6	(114,092)
Cash Requirement				$0				0
Working Funds & Special Deposits				$0				0
Interest on Long Term Debt	42,270,034		42,270,034	$115,492	76.8	47.9	-28.9	(3,337,716)
Total Cash Working Capital Allowance								(912,771)

1283

COMMISSION EXHIBIT NO. 2

PUBLIC UTILITY COMMISSION OF TEXAS

EL PASO ELECTRIC COMPANY

DOCKET #6350 - CWIP CASE

INVESTED CAPITAL AND RETURN

	COMPANY AMOUNT (1)	RECOMMENDED ADJUSTMENTS (2)	RECOMMENDED AMOUNT (3)
PLANT IN SERVICE	$458,813,732	($700,000)	$458,113,732
ACCUMULATED DEPRECIATION	($129,198,667)	$292,187	($128,906,480)
NET PLANT	$329,615,065	($407,813)	$329,207,252
CONSTRUCTION WORK IN PROGRESS	$883,279,029	($334,890,839)	$548,388,190
WORKING CASH ALLOWANCE	$6,063,018	($6,975,789)	($912,771)
MATERIALS AND SUPPLIES	$5,019,548	$0	$5,019,548
PREPAYMENTS	$3,186,317	($108,282)	$3,078,035
FUEL INVENTORY	$83,358	$0	$83,358
DEFERRED TAXES	($94,553,035)	($16,429,284)	($110,982,319)
PRE 1971 INVESTMENT TAX CREDITS	($757,940)	$0	($757,940)
CUSTOMER DEPOSITS	($2,966,146)	$0	($2,966,146)
INJURIES AND DAMAGES RESERVE	($100,000)	$0	($100,000)
OTHER COST FREE CAPITAL	($992,940)	$0	($992,940)
UNAMORTIZED GAIN ON TURBINE SALE	$0	($1,808,615)	($1,808,615)
TOTAL INVESTED CAPITAL	$1,127,876,274	($360,620,622)	$767,255,652
* RATE OF RETURN	13.20%	-1.25%	11.95%
RETURN	$148,879,668	($57,192,618)	$91,687,050

1284

COMMISS'ON EXHIBIT NO. 4

PUBLIC UTILITY COMMISSION OF TEXAS
EL PASO ELECTRIC COMPANY
DOCKET #6350 - CWIP CASE
OPERATIONS AND MAINTENANCE

	COMPANY ADJUSTMENT TO TEST YEAR (1)	RECOMMENDED ADJUSTMENT TO TEST YEAR (2)	RECOMMENDED ADJUSTMENT (3)
'LARIES AND WAGES	($321,942)	($565,646)	($243,704)
EMPLOYEE BENEFITS	$647,121	($645,545)	($1,292,666)
ADVERTISING, CONTRIB., AND DUES	($29,190)	($467,334)	($438,144)
UNCOLLECTIBLE EXPENSE	$349,994	$7,442	($342,552)
RATE CASE EXPENSE	$1,846,757	$1,001,973	($844,784)
OUTSIDE SERVICES	$0	($695,083)	($695,083)
AIRPLANE EXPENSE	($372,050)	($372,050)	$0
ABNORMAL MAINTENANCE	$47,554	$47,554	$0
NEW MEXICO PROJECT	($2,209,398)	($2,761,747)	($552,349)
OTHER O&M EXPENSE	($329,520)	($990,311)	($660,791)
TOTAL	($370,674)	($5,440,747)	($5,070,073)

COMMISSION EXHIBIT NO. 5

PUBLIC UTILITY COMMISSION OF TEXAS

EL PASO ELECTRIC COMPANY

DOCKET #6350 - CWIP CASE

OTHER TAXES

	TEST YEAR PER BOOKS (1)	COMPANY ADJUSTMENTS (2)	COMPANY TEST YEAR (3)	RECOMMENDED ADJUSTMENTS (4)	RECOMMENDED TEST YEAR (5)
AD VALOREM TAXES	$3,662,059	$562,514	$4,224,573	($2,431)	$4,222,142
PAYROLL TAXES	$1,864,916	($97,015)	$1,767,901	($17,181)	$1,750,720
FRANCHISE TAXES	$1,539,153	$574,700	$2,113,853	$138,055	$2,251,908
OTHER TAXES	$144,180	$0	$144,180	$0	$144,180
NON REVENUE RELATED TAXES	$7,210,308	$1,040,199	$8,250,507	$118,443	$8,368,950
TEXAS PUC ASSESSMENT	$425,710	$92,684	$518,394	($86,374)	$432,020
NEW MEXICO PUC ASSESMENT	$270,630	$311,404	$582,034	($308,646)	$273,388
TEXAS STATE GROSS RECEIPTS	$4,460,008	$923,581	$5,383,589	($864,254)	$4,519,335
TEXAS OCCUPATIONAL AND STREET RENTAL	$3,864,765	$1,237,703	$5,102,468	($819,394)	$4,283,074
NEW MEXICO OCCUPATIONAL AND STREET RENTAL	$529,768	$495,091	$1,024,859	($494,959)	$529,900
REVENUE RELATED TAXES	$9,550,881	$3,060,463	$12,611,344	($2,573,627)	$10,037,717

SUMMARY OF OTHER TAXES

	(1)	(2)	(3)	(4)	(5)
NON REVENUE RELATED TAXES	$7,210,308	$1,040,199	$8,250,507	$118,443	$8,368,950
REVENUE RELATED TAXES	$9,550,881	$3,060,463	$12,611,344	($2,573,627)	$10,037,717
TOTAL OTHER TAXES	$16,761,189	$4,100,662	$20,861,851	($2,455,184)	$18,406,667

1286

COMMISSION EXHIBIT NO. 6

PUBLIC UTILITY COMMISSION OF TEXAS
################################
EL PASO ELECTRIC COMPANY
######################
DOCKET #6350 - CWIP CASE
######################
FEDERAL INCOME TAXES
##################

	COMPANY AMOUNT (1)	RECOMMENDED ADJUSTMENTS (2)	RECOMMENDED AMOUNT (3)
RETURN	$148,879,668	($57,192,618)	$91,687,050
ADJUSTMENTS TO RETURN			
INTEREST EXPENSE	($62,145,982)	$19,133,630	($43,012,352)
AMORTIZATION OF ITC	($498,948)	($16,580)	($515,528)
PLUS OR MINUS NON-NORMALIZED DIFFERENCES			
RATE DIFFERENTIAL	($10,081)	$0	($10,081)
PREFERRED DIVIDENDS	($20,544)	$0	($20,544)
ADDITIONAL DEPRECIATION	$1,793,852	($1,371,722)	$422,130
NUCLEAR FUEL INTEREST	$0	($8,694,064)	($8,694,064)
CONSOLIDATED TAX SAVINGS	$0	($1,171,688)	($1,171,688)
COMMISSION ADJUSTMENTS TO ADV., CONT. AND DUES	$0	($438,144)	($438,144)
TOTAL ADJUSTMENTS TO RETURN	($60,881,703)	$7,441,432	($53,440,271)
TAXABLE COMPONENT OF RETURN	$87,997,965		$38,246,780
TAX FACTOR (1/.54)(.46)	0.851851852		0.851851852
FEDERAL INCOME TAXES BEFORE CREDITS	$74,961,230		$32,580,590
AMORTIZATION OF INVESTMENT TAX CREDITS	($498,948)		($515,528)
TOTAL FEDERAL INCOME TAXES	$74,462,282	($42,397,220)	$32,065,062

COMMISSION EXHIBIT NO. 7

PUBLIC UTILITY COMMISSION OF TEXAS
****
EL PASO ELECTRIC COMPANY
****
DOCKET #6350 - CWIP CASE
****
REVENUE REQUIREMENT
****

	TEST YEAR PER BOOKS (1)	COMPANY ADJUSTMENTS (2)	COMPANY TEST YEAR (3)	RECOMMENDED ADJUSTMENTS (4)	RECOMMENDED TEST YEAR (5)
FUEL	$85,205,541	($600,065)	$84,605,476	($18,463,311)	$66,142,165
PURCHASED POWER	$43,329,297	$19,079,302	$62,408,599	$5,521,409	$67,930,008
OPERATIONS AND MAINTENANCE	$50,280,322	($370,674)	$49,909,648	($5,070,073)	$44,839,575
DEPRECIATION AND AMORTIZATION	$12,445,267	$4,034,940	$16,480,207	($584,375)	$15,895,832
OTHER TAXES	$16,761,189	$4,100,662	$20,861,851	($2,455,184)	$18,406,667
INTEREST ON CUSTOMERS DEPOSITS	$183,640	$0	$183,640	$15,720	$199,360
STATE INCOME TAXES	$603,051	$2,726,986	$3,330,037	($2,980,093)	$349,944
FEDERAL INCOME TAXES	$41,585,066	$32,877,216	$74,462,282	($42,397,220)	$32,065,062
RETURN	$78,621,974	$70,257,694	$148,879,668	($57,192,618)	$91,687,050
REVENUE REQUIREMENT	$329,015,347	$132,106,061	$461,121,408	($123,605,744)	$337,515,663
OTHER REVENUE	$1,188,842	$973,859	$2,162,701	($21,060)	$2,141,641
FUEL REVENUE	$127,915,552	$17,298,523	$145,214,075	($19,183,102)	$126,030,973
BASE REVENUE	$199,910,953	$113,833,679	$313,744,632	($104,401,582)	$209,343,049
REVENUE REQUIREMENT	$329,015,347	$132,106,061	$461,121,408	($123,605,744)	$337,515,663

1288

COMMISSION EXHIBIT NO. 8

PUBLIC UTILITY COMMISSION OF TEXAS
##################################
EL PASO ELECTRIC COMPANY
########################
DOCKET #6350 - CWIP CASE
########################
TEXAS RETAIL REVENUE DEFICIENCY
###############################

	COMPANY TEST YEAR (1)	RECOMMENDED ADJUSTMENTS (2)	RECOMMENDED TEST YEAR (3)
PROPOSED FUEL REVENUE	$97,916,341	($12,722,932)	$85,193,409
PROPOSED BASE REVENUE	$212,256,712	($66,644,976)	$145,611,736
PROPOSED OTHER REVENUE	$1,572,935	($21,060)	$1,551,875
TOTAL REVENUE REQUIREMENT	$311,745,988	($79,388,968)	$232,357,020
LESS			
TEST YEAR ADJUSTED FUEL REVENUE	$84,089,410	$693,344	$84,782,754
TEST YEAR ADJUSTED BASE REVENUE	$158,595,721	$1,333,213	$159,928,934
TEST YEAR ADJUSTED OTHER REVENUE	$1,572,935	$0	$1,572,935
TOTAL ADJUSTED TEST YEAR REVENUES	$244,258,066	$2,026,557	$246,284,623
FUEL REVENUE DEFICIENCY	$13,826,931	($13,416,276)	$410,655
BASE REVENUE DEFICIENCY	$53,660,991	($67,978,189)	($14,317,198)
OTHER REVENUE DEFICIENCY	$0	($21,060)	($21,060)
TOTAL REVENUE DEFICIENCY	$67,487,922	($81,415,525)	($13,927,603)

1289

COMMISSION EXHIBIT NO. 10

PUBLIC UTILITY COMMISSION OF TEXAS
EL PASO ELECTRIC COMPANY
DOCKET NO. 6350
JURISDICTIONAL COST OF SERVICE STUDY
RECOMMENDED REVENUE REQUIREMENT
CWIP CASE

Jurisdiction	EPEC Adj.Current Revenue	EPEC Request	EPEC Increase (Decrease) Request	Percent	Adjusted Current Revenue	Recommendation	Revenue Deficiency	Percent
Texas Retail	($)	($)	($)	(%)	($)	($)	($)	(%)
a.Base Rate Revenue	158,595,721	212,256,712	53,660,991	33.84	159,928,934	145,611,736	(14,317,198)	(8.95)
b.Fuel & Purchased Power	84,089,410	97,916,341	13,826,931	16.44	84,782,754	85,193,409	410,655	0.48
c.Misc.Revenues	1,572,935	1,572,935	0	0.00	1,572,935	1,551,875	(21,060)	(1.34)
Total	244,258,066	311,745,988	67,487,922	27.63	246,284,623	232,357,020	(13,927,603)	(5.66)

1290