BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UG-040640** **Docket No. UE-040641** **(*consolidated*)**
In the Matter of the Petition of **PUGET SOUND ENERGY, INC.** **For an Order Regarding the Accounting Treatment for Certain Costs of the Company's Power Cost Only Rate Filing.**	**Docket No. UE-031471 (*consolidated*)**
In the Matter of the Petition of **PUGET SOUND ENERGY, INC.** **For an Accounting Order Authorizing Deferral and Recovery of the Investment and Costs Related to the White River Hydroelectric Project.**	**Docket No. UE-032043 (*consolidated*)**

EXCERPTS OF NON-WASHINGTON AUTHORITIES
CITED IN THE REPLY BRIEF OF
PUGET SOUND ENERGY, INC.
(WAC 480-07-395(1)(c)(vi))

JANUARY 27, 2005

Administrative Decisions of Other Jurisdictions

Other Authorities

Tab A

ALJ/MFG/sid **Mailed 12/20/2004**

Decision 04-12-047 December 16, 2004

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) for Authorized Capital Structure, Rate of Return on Common Equity, Embedded Cost of Debt and Preferred Stock, and Overall Rate of Return for Utility Operations for 2005.	Application 04-05-021 (Filed May 10, 2004)
Application of Pacific Gas and Electric Company for Authority to True-up its Cost of Capital for 2004 and to Establish its Authorized Cost of Capital for 2005. (U 39 M)	Application 04-05-023 (Filed May 12, 2004)

William Harn, Attorney at Law, for Southern California Edison Company; and Shirley Woo, Attorney at Law, and Darcy Morrison, for Pacific Gas and Electric Company, applicants.

James Weil, for Aglet Consumer Alliance; Robert Finkelstein, Attorney at Law, for The Utility Reform Network; Norman J. Furuta, Attorney at Law, for the Department of the Navy; Jeffrey M. Parrott and James Ozenne, Attorneys at Law, for San Diego Gas & Electric Company; Alcantar & Kahl, LLP, by Rod Aoki and Donald Brookhyser, Attorneys at Law, for Cogeneration Association of California; and Davis Wright Tremaine LLP, by Steven F. Greenwald and Jeffrey P. Gray, Attorneys at Law, for Calpine Corporation, interested parties.

Laura J. Tudisco, Attorney at Law, for the Office of Ratepayer Advocates.

OPINION ON TEST YEAR 2005 RETURN ON EQUITY AND ON PACIFIC GAS AND ELECTRIC COMPANY'S TRUE UP YEAR 2004

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OPINION ON TEST YEAR 2005 RETURN ON EQUITY AND ON PACIFIC GAS AND ELECTRIC COMPANY'S TRUE UP YEAR 2004

I. Summary

This decision addresses the debt equivalence issue for Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E), adopts a test year 2005 return on equity (ROE) for SCE, and both a true up year 2004 and test year 2005 ROE for PG&E.

The test year 2005 ROE for SCE is 11.40%, which results in a corresponding 9.07% return on rate base and a $43.6 million revenue requirement reduction for 2005.[1]

The true up year 2004 and test year 2005 ROE for PG&E is 11.22%. That authorized ROE results in a corresponding return on rate base of 8.53% for true up year 2004 and 8.77% for test year 2005 resulting in a $1.2 million increase in electric and a $8.3 million reduction in gas revenue requirements for test year 2005.[2]

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1 SCE's projected revenue requirement reduction of $28.2 million at an 11.60% ROE plus $15.4 million ($7.7 million impact on each 10 basis points change in ROE per Exhibit 34) equals a $43.6 million revenue requirement reduction for test year 2005.

2 PG&E's projected $25.6 million electric and $0.9 million gas revenue requirement increase at a 11.60% ROE that includes estimated savings from the issuance of energy recovery bonds less $24.4 electric and $9.2 gas revenue requirement change ($8.7 million electric and $3.3 million gas impact for each 10 basis points change in authorized ROE as set forth in Exhibit 35) equals a $1.2 million electric increase and $8.3 million gas reduction in test year 2005 revenue requirements.

II. Jurisdiction and Background

Applicants are public utilities subject to the jurisdiction of this Commission as defined in Pub. Util. Code § 218.[3] SCE, a California corporation and wholly owned subsidiary of Edison International, provides electric service principally in southern California. PG&E, a California corporation, provides electric and gas services in northern and central California.

The utilities filed their respective test year 2005 ROE applications pursuant to Decision (D.) 89-01-040.[4] PG&E also filed its application pursuant to D.03-10-074, which required PG&E to file an application to true up its year 2004 capital structure and ROE upon its implementation of a financing plan approved by the Bankruptcy Court.

SCE seeks to maintain its 11.60% ROE, which would result in a $28.2 million reduction in its electric revenues. PG&E seeks authority to true up its 2004 capital structure in conformance with its adopted Chapter 11 exit financing plan while maintaining its interim 11.22% ROE for its true up year 2004. PG&E also seeks to increase its authorized ROE to 11.60% from 11.22% for test year 2005. Approval of PG&E's true up year 2004 capital structure and requested test year ROE would result in a net $2 million electric revenue decrease and a net $1 million gas revenue requirement increase for test year 2005.

SCE and PG&E included in their respective applications a request for the Commission's recognition and mitigation of debt equivalence, risk associated with long term (three years or more) non-debt obligations such as capacity

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3 All statutory references are to the Public Utilities Code unless otherwise stated.

4 30 CPUC2d 576 at 610 (1989).

payments for purchased power contracts. This issue was included in their applications pursuant to the Commission's direction in the procurement proceeding (R.01-10-024) that the appropriate forum to address debt equivalence is the cost of capital proceeding for each utility.[5]

On June 29, 2004, the applications were consolidated into one proceeding, pursuant to Rule 55 of the Commission's Rules of Practice and Procedure. The consolidation of these applications does not necessarily mean that a uniform ROE should be applied to each of the utilities. This is because each of these utilities has unique factors and differences that need to be considered in arriving at a reasonable return. These unique factors and differences encompass three distinct areas: capital structure, long-term debt and preferred stock costs, and return on common equity. The debt equivalence issue will be addressed prior to determining a fair ROE for SCE and PG&E.

III. Debt Equivalence

Debt equivalence is a term used by credit analysts for treating long-term non-debt obligations, such as purchase power agreements (PPAs), leases, or other contracts, as if they were debt, in assessing an entity's credit rating.

Debt equivalence became an issue in a rulemaking proceeding (R.01-10-024) on establishing policies and cost recovery mechanisms for generation procurement and renewable resource development.
Section 454.5(b)(1)) requires "an assessment of the price risk associated with the electrical corporation's portfolio, including any utility-retained generation,

[5] D.04-01-050, mimeo., p. 188, Finding of Fact 46.

existing power purchase and exchange contracts, and proposed contracts or purchases.

Although debt equivalence was addressed in the discussion portion of an interim decision (D.04-01-050) of the rulemaking proceeding, that issue was deferred to upcoming cost of capital filings where the energy utilities were to present detailed evidence about the treatment of debt equivalence by the rating agencies. In compliance with that decision, SCE and PG&E included the debt equivalence issue in their respective test year 2005 ROE applications. San Diego Gas & Electric Company (SDG&E), the Office of Ratepayer Advocates (ORA), jointly Aglet Consumer Alliance and The Utility Reform Network (Aglet-TURN), Calpine Corporation (Calpine), and the Cogeneration Association of California (CAC) actively participated in this issue. The rating agencies, Fitch, Moody's and Standard & Poors (S&P) did not participate in this proceeding.

According to the utilities, the rating agencies take the view that a utility would either be constructing generation facilities and therefore taking debt onto its balance sheet, or contracting for a purchased-power obligation that is essentially fixed by the nature of the need to provide service, if not by contract terms. Payments on the PPAs are treated as fixed payments. Therefore, those payments are analyzed as if they are interest on a debt obligation by the rating agencies and included in the rating agencies' analysis of interest coverage, cash flow to debt, and balance sheet, debt to capital. However, payments on those PPA contracts having less than three years remaining are excluded from the rating agencies' analyses. The end result of that analysis is a credit rating. The higher the credit rating the more benefit to ratepayers through lower fixed payments and overall costs.

PG&E explained that Moody's and S&P share a philosophy about purchased power but apply different methodologies in assessing debt equivalence to the individual utilities. Moody's determines how to treat PPAs according to the degree that a real transfer of economic risk has occurred from the utility to the power provider. It assesses the risk subjectively, using a sliding scale on what it calls the "risk containment." The more certain it perceives a payment for PPAs to be, the more likely it is that Moody's will include the net present value in its calculations of financial metrics.

The utilities testified that S&P applies a quantitative approach in assessing debt equivalence. Since 1990 S&P capitalized PPAs on a sliding scale it called a risk spectrum, similar to Moody's method. Up to 100% of the net present value of PPAs were included in its calculations of credit metrics. In May 2003, S&P revised its method of debt equivalency risks to a quantitative approach from the subjective approach. S&P now reflects the opinion that there is little difference between a "take-and-pay" PPA and a "take-or-pay" PPA. As a result, S&P's revised method reflects more risk from PPAs than prior to May 2003. S&P now uses a formula to calculate the net present value of the capacity payments of a PPA using a 10% discount rate and a 30% to 50% risk factor. S&P currently assesses a 30% risk factor on the California energy utilities.

The utilities, while acknowledging that debt equivalence has been reflected in the utilities' credit ratings, since at least 1990, are now concerned that the imputation of debt equivalence on their PPAs adversely impacts their PPA evaluations and credit ratings, thereby resulting in a higher level of operating risks and increased costs.

A. Utilities Proposed Solution

SCE, PG&E, and SDG&E recommended that the Commission establish a debt equivalence policy in this proceeding to alleviate their concern that debt equivalence is an added cost that needs to be considered both in determining an appropriate capital structure and in making resource procurement decisions. Policy recommendations proposed, jointly or individually, by the utilities included recognition that debt equivalence adversely impacts credit ratings; use of annual ROE proceedings to update and mitigate debt equivalence impacts on credit ratings; and, adoption of S&P's quantitative debt equivalence formula for use in assessing debt equivalence costs in power procurement decision-making proceedings.

Calpine concurred with the utilities' need to adopt a debt equivalence policy in this proceeding. However, it recommended that any relationship between debt equivalence and power purchase procurement evaluations should be addressed in the long-term procurement rulemaking proceeding, R.04-04-003.

Aglet-TURN, CAC and ORA recommended that debt equivalence adjustments should be considered on only a case-by-case basis and specific to a utility's current credit profile based on quantitative and qualitative evidence. However, Aglet-TURN did propose general guidelines for inclusion of debt equivalence findings of fact and conclusion of law.[6]

1. Debt Equivalence Impact

What impact does debt equivalence have on SCE and PG&E's test year 2005? We know that SCE's long-term debt currently has investment grade

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[6] Exhibit 28, p. 29.

credit ratings of BBB from S&P and A-3 from Moody's, and that its preferred stock has a marginal non-investment grade credit rating of BB+ from S&P and a marginal investment grade credit rating of Baa3 from Moody's. To improve its credit ratings, SCE proposed to increase its preferred stock ratio to 9% from 5% and correspondingly, to reduce its long-term debt ratio to 43% from 47% as a least-cost approach to increase its credit quality. If approved, SCE would maintain its test year 2005 target capital structure on average over time beginning in 2005 as a foundation for its ultimate return to a Single-A credit rating or better.

ORA evaluated SCE's credit profile, rating and capital needs. Based on that evaluation, ORA concluded that SCE's proposal to increase its preferred stock component was a relatively low cost means to enhance SCE's credit profile. Aglet-TURN, acknowledging that the increase in preferred stock and associated reduction in the proportion of long-term debt would improve SCE's credit ratios, but opposed SCE's preferred stock proposal for several reasons. Some of those reasons were that SCE had not shown that improved credit ratios are necessary to maintain adequate service, had not performed any cost-effectiveness study, and that the additional after-tax cash flow generated from the additional preferred stock would not be material.

In D.89-11-068, the Commission reasoned that the utilities should be given some discretion to manage their capitalization with a view towards a balance between shareholders' interest, regulatory requirements, and ratepayers' interest.[7] Here, we find that SCE has designed its preferred stock proposal to

[7] 33 CPUC2d 495 at 541 to 545 (1989).

rebalance its capital structure with the goal of obtaining improved credit ratings, thereby benefiting both shareholders and ratepayers. This approach avoids the need to micro-manage the utility's capital structure and also supports the utility's desire to maintain investment grade ratings; therefore, we concur with SCE's preferred stock proposal.

PG&E, with an investment grade credit rating of BBB- from S&P, did not request any adjustment to its authorized capital structure or ROE applicable to debt equivalence in this proceeding.

Using ratio analysis, SCE and PG&E used the major guideline components of debt to capital, interest coverage, and cash flow to debt used by S&P for assigning credit ratings to compare SCE's and PG&E's test year 2005 ratios on a PPA debt equivalence and non-debt equivalence basis. The result of that comparison is set forth in Appendix A. Of those guideline components, SCE considered cash flow interest coverage the most important benchmark for credit ratings.[8] PG&E also considered cash flow interest coverage the most important, placing next in very close importance cash flow to total debt, and least importance debt to capital.[9]

While Appendix A showed that the inclusion of PPAs would lower SCE and PG&E's cash flow interest coverage and cash flow to debt coverage, the utilities' cash flow interest coverage would remain within S&P's A credit ratio range and their cash flow to debt ratio would remain within S&P's BBB credit ratio range. Those results would not change under either SCE's requested

[8] Reporter's Transcript Vol. 1, p. 28.

[9] Reporter's Transcript Vol. 2, pp. 155 and 156.

11.60% ROE or Aglet-TURN's recommended 10.20% ROE or under PG&E's authorized 11.22% ROE. From that comparison of utility information we can only conclude that debt equivalence would not have a material impact on either SCE's or PG&E's credit ratios or capital structure at this time. Although SDG&E provided information on the impact of debt equivalence on its Otay Mesa PPA, it did not provide any information on what impact, if any, that contract had on its total company credit ratings, total company financial ratios considered by rating agencies, total company capital structure, or total company ROE.

2. Annual ROE Proceeding

Given the changing energy market and utilities' increased dependency on long-term procurement contracts, the utilities' proposal to update debt equivalence impacts on credit ratings and capital structure has merit and should be adopted. The utilities, as part of their annual ROE applications, should include testimony on credit rating and capital structure impacts, including mitigation recommendations, of debt equivalence on their PPAs. Information to be provided in that regard should include current credit ratings from Moody's and S&P; expected impact of its ratings due to debt equivalence; capital structure and ROE with and without debt equivalence; debt to capital, cash flow interest coverage, and cash flow to debt financial ratios with and without debt equivalence; and, pre and post-tax financial ratios. The utilities should also make recommendations for improving and maintaining their credit ratings.

Should a utility find a need for expedited resolution of debt equivalence outside of the annual ROE proceeding due to the lowering of its credit ratings to a non-investment grade level, it should consider filing an application to demonstrate financial need.

SDG&E is in a different situation than SCE and PG&E because it is not required to file an annual ROE application. That is because an all-party settlement agreement to modify SDG&E's Market Indexed Capital Adjustment Mechanism (MICAM) approved by D.03-09-008 included a provision that unless certain off-ramps require otherwise, SDG&E would only file a full ROE application every fifth year. Therefore, absent any unusual circumstances triggering the filing of a ROE application, and absent the Commission's specific order requiring SDG&E to participate in a ROE proceeding, SDG&E's next regularly scheduled ROE application is not due to be filed until May of 2007.

SDG&E intervened in this consolidated ROE proceeding as an interested party on the basis that the general procurement and renewable resource development rulemaking proceeding (R.01-10-024) found in Finding of Fact 46 of D.04-01-050 that the appropriate forum to address debt equivalence is in the ROE proceeding for each utility and that Footnote 26 of D.04-06-011 "required" SDG&E to participate in debt equivalence issues likely to be addressed in this consolidated proceeding to the extent that SDG&E seeks resolution of such issues deferred in the generation procurement and renewable resource development rulemaking (R.01-10-024) proceeding. That footnote actually encouraged, but did not require, SDG&E to participate in this proceeding.

SDG&E, recognizing that the implementation of debt equivalence mitigation can be addressed in annual ROE proceedings,[10] asserted that debt equivalence policy developed in this consolidated ROE proceeding must pertain

[10] Exhibit 18, p. 9.

to SDG&E as well as to SCE and PG&E on the basis that requiring SDG&E to wait until its next ROE proceeding to develop such policy for SDG&E could have a deleterious affect on its creditworthiness evaluation by the credit agencies.

To mitigate negative credit impacts of its long-term PPAs, SDG&E recommended that SDG&E should be authorized to increase its equity with a simultaneous reduction of debt equal to 65% of the debt equivalence for each individual PPA contract approved by the Commission with the cost associated with that capital structure adjustment rolled into the costs of each PPA. The impact of SDG&E's debt equivalence mitigation recommendation on its recently approved Otay Mesa PPA would be $40 million at a net present value impact for the nine-year period January 1, 2006 through December 31, 2014 and based on equity equal to 65% of the debt equivalence added to SDG&E's ratemaking capital structure.[11]

Again, SDG&E provided no information on its current credit ratings and insufficient information to enable us to assess the debt equivalence impact on its overall credit ratings and capital structure. Therefore, we decline to adopt SDG&E's proposal. SDG&E should file a test year 2006 ROE application by May 9, 2005, along with SCE and PG&E, so that we may properly assess what impact, if any, that debt equivalence has on its credit ratings and capital structure, including mitigation recommendations. To the extent that SDG&E believes that debt equivalence may have a material impact and recurring drain on its credit ratios or ratings, SDG&E should consider modifying its MICAM

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[11] Exhibit 33.

settlement agreement so that it may resolve that concern through yearly ROE applications.

3. S&P's Debt Equivalence Formula

Although the utilities recommended adoption of the S&P debt equivalence formula, ORA and Aglet-TURN opposed the use of S&P's debt equivalence formula and any other specific quantitative financial metric method. ORA contended that sole reliance on such a financial method would ignore other measurable mitigating factors such as future utility outlook, changing regulatory environment, and legislative actions.[12] Aglet-TURN argued that debt equivalence risks are not new; substantive increases in debt equivalence risks will come only if new long-term contracts replace electricity production from utility-owned generation stations or existing contracts with lower levels of debt equivalence; adoption of a specific formula method foregoes flexibility in long-term contract provisions; rating agency methods and risk factors are subject to change; and lack of testimony from the rating agencies, academic and industry evaluation of S&P's calculation method did not allow for a thorough analysis of this method.

We concur with ORA and Aglet-TURN. The evidence presented in this proceeding did not substantiate a need to consider the debt equivalence issue outside of our traditional ROE assessment of risks. We will continue to assess debt equivalence risks along with other financial, regulatory, and operational risks in setting a ROE and balanced capital structure reasonably sufficient to assure confidence in the financial soundness of the utility, to

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12 A legislative action example cited by ORA was the passage of Senate Bill 57, which mitigated SCE's power procurement risk in 2004 and 2005. (Exhibit 23, p. 6).

maintain and support investment-grade credit ratings and to enable it to raise money necessary for the proper discharge of its public duties. Based on the record in this proceeding, the S&P's debt equivalence formula should not be adopted at this time. However, that formula or variation thereof may be considered in assessing the viability of future power procurement contracts.

4. Debt Equivalence Policy

We decline to adopt a formal debt equivalence policy. However, we do recognize that debt equivalence associated with PPAs can affect utility credit ratios, credit ratings, and capital structure. Credit rating agencies have long recognized debt equivalence as a risk factor and we have and will continue to reflect the impact of such risk in establishing a fair and reasonable ROE and in approving a balanced ratemaking capital structure. In that regard, we have identified information that the utilities should provide in their annual cost of capital applications to enable us to better assess debt equivalence risks. Our goal is to provide the utilities with a fair and reasonable ROE and ratemaking capital structure that, among other matters, support investment-grade credit ratings.

IV. Capital Structure

Capital structure consists of long-term debt, preferred stock, and common equity.[13] Because the level of financial risk that the utilities face is determined in part by the proportion of their debt to permanent capital, or leverage, we must ensure that the utilities' adopted equity ratios that are sufficient to maintain reasonable credit ratings and to attract capital.

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[13] Excludes short-term debt, debt due within one year.

A. SCE

SCE requested a 2005 capital structure consisting of 43.00% long-term debt, 9.00% preferred stock, and 48.00% common equity. This capital structure reflects a 4.00% reduction in its last authorized debt ratio of 47.00% and a 4.00% increase in its preferred stock ratio. SCE proposed no change to its common equity ratio. The 4% shift of debt to preferred stock was proposed by SCE to mitigate its debt equivalence, improve its financial metrics, encourage the rating agencies to upgrade SCE's credit status, and to lower overall long-term costs.

The only opposition to SCE's proposed capital structure was from Aglet-TURN. Aglet-Turn opposed SCE's request to mitigate debt equivalence by issuing additional preferred stock, as addressed in the prior debt equivalence discussion.

B. PG&E

PG&E requested a true up 2004 capital structure of 48.20% long-term debt, 2.80% preferred stock, and 49.00% common equity. It also requested a 2005 capital structure consisting of 45.50% long-term debt, 2.50% preferred stock, and 52.00% common equity. Its 2005 capital structure reflects a 0.70% reduction in its last authorized long-term debt ratio, a 3.30% reduction in preferred stock, and a 4.00% increase in common equity ratio.

The proposed capital structures of PG&E are consistent with the implementation of its Chapter 11 exit financing and capital structure provision set forth in its Modified Settlement Agreement (MSA). (D.04-12-035, Appendix C, p. 11.)

There is no opposition to PG&E's true up 2004 and 2005 capital structures.

C. Discussion

The capital structures proposed by the utilities are balanced, attainable, intended to maintain an investment grade rating, and to attract capital. For these reasons, we find that the utilities' proposed capital structures are fair. PG&E's true up 2004 capital structure of 48.20% long-term debt, 2.80% preferred stock, and 49.00% common equity and the following test year 2005 capital structures for the utilities are consistent with law, in the public interest, and should be adopted.

	SCE	PG&E
Long-Term Debt	43.00%	45.50%
Preferred Stock	9.00%	2.50%
Common Equity	48.00%	52.00%

The next step in determining a fair ROE is to establish reasonable long-term debt and preferred stock costs.

V. Long-Term Debt and Preferred Stock Costs

Long-term debt and preferred stock costs are based on actual, or embedded, costs. Future interest rates must be anticipated to reflect projected changes in a utility's cost caused by the issuance and retirement of long-term debt and preferred stock during the year. This is because the ROE is established on a forecast basis each year.

In D.90-11-057, we recognized that actual interest rates do vary and that our task is to determine "reasonable" debt cost rather than actual cost based on an arbitrary selection of a past figure.[14] In that regard, we concluded that the latest available interest rate forecast should be used to determine embedded debt cost in ROE proceedings. Consistent with this conclusion, the assigned Commissioners' Scoping Memo and Ruling allowed the utilities to update their long-term debt and preferred stock costs to reflect September 2004 Global Insight forecasted interest rates. That update was submitted on September 27, 2004 as Late-Filed Exhibit 34 by SCE and Late-Filed Exhibit 35 by PG&E.

A. SCE

SCE projected its test year 2005 long-term debt cost to be 6.97% based on a simple average of its year end 2004 and year end 2005 long-term debt forecasts. That forecast provided for the issuance of $100 million in new long-term debt in 2004 and no new long-term debt in 2005. Based on its late-filed exhibit that updated the impact of the most recent forecast of interest rates, SCE lowered its forecast of long-term debt cost to 6.96% from 6.97%. This rate is

[14] 38 CPUC2d 233 at 242 and 243 (1990).

123 basis points lower than the 8.19% long-term debt cost authorized in SCE's test year 2003 ROE proceeding.

SCE used that same method to calculate a preferred stock cost of 7.01%. Its forecast of preferred stock cost provided for the issuance of $200 million of traditional preferred stock in 2004 and an additional $450 million in test year 2005, as detailed in its Exhibit 3 at pages 22 to 24.

Subsequent to the filing of its application, Moody's upgraded SCE's corporate credit rating and preferred stock to investment grade. In response to the preferred stock upgrade, SCE obtained quotes from three investment banks on the coupon rate at which SCE could expect to favorably issue new preferred equity in the current market. Those quotes were 81 basis points, 33 basis points, and 44 basis points, respectively, above the Aa utility bond rate.[15] Based on a 53 basis points simple average of the investment banks quotes, SCE lowered its preferred stock cost to 6.83% from 7.01%. Based on the most recent forecast of interest rates, SCE further lowered its preferred stock cost to 6.73% from 6.83%.

B. PG&E

PG&E projected a true up year 2004 long-term debt cost of 5.82%. That cost was based on a weighted average of its actual 2004 debt cost prior to April 12, 2004 and its forecast of long-term debt changes that would occur as a result of new issuances, retirements, change in interest rates of its floating rate debt, and changes in the amortization of loss on reacquired debt during the year. For 2004, PG&E expects to refinance $799 million of bank debt with the proceeds from the issuance of replacement tax exempt Pollution Control (PC) Bonds.

[15] One basis point equals 0.01%.

Those replacement PC Bonds would be issued in two series, one that is expected to be a three-year fixed-rate bond, and the other a 30-year floating-rate bond.

PG&E projected a test year 2005 long-term debt cost of 5.94%, based in part on its forecast of debt changes that would occur during the year and in part on PG&E's expected implementation of a Dedicated Rate Component (DRC) financing, as provided for in D.03-12-035.

The DRC financing provides a framework for PG&E to refinance a portion of its exit financing if legislation satisfactory to the Commission, TURN, and PG&E is enacted and signed into law that would allow for the securitization of the Modified Settlement Agreement (MSA) Regulatory Asset. Ratepayers would receive the full benefit of this financing through a lower revenue requirement of the MSA Regulatory Asset. After such legislation is enacted, and pursuant to a subsequent financing order from the Commission authorizing the securitization of its DRC, PG&E expects to receive proceeds up to $3 billion.[16] Those DRC proceeds would be used to pay off existing debt and to buy back common stock so that PG&E can achieve and maintain a target capital structure containing 52% common equity.

PG&E included approximately $44 million in interest rate hedging cost as a component of its test year 2005 long-term debt pursuant to D.03-09-020.[17] That interest rate cost resulted from PG&E's October 20 and November 3, 2003 execution of $4.2 billion in interest rate hedges used to implement its approved

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[16] The bonds securitized by a DRC would not be issued by PG&E, but by a special purpose entity created solely for this financing.

[17] D.03-09-020, mimeo., p. 23, Ordering Paragraph 4.

bankruptcy plan to exit from Chapter 11. PG&E seeks to recover its hedging cost over the life of the debt that was hedged.

PG&E projected its preferred stock costs of 6.76% for 2004 and 6.42% for 2005, similar to the method it estimated its embedded long-term cost of debt. The embedded cost of preferred stock reflects the same costs of preferred as authorized in PG&E's 2003 cost of capital proceeding, absent Quarterly Income Preferred Securities (QUIPS).[18] That is because QUIPS, comprised half of PG&E's pre-bankruptcy preferred stock, were deemed in default as a result of its bankruptcy and redeemed on April 12, 2004. For the period after April 12, 2004, PG&E projected changes in its preferred stock. The changes included a decrease due to the removal of the amortization of refunding premiums associated with a 1994 preferred stock redemption and a decrease due to the mandatory redemption of a portion of two issues of higher cost preferred stock.

PG&E also updated its long-term debt costs to reflect the most recent forecast of interest rates. That update resulted in its long-term debt cost being increased to 5.90%[19] from 5.82% in its true up year 2004 and to 6.10%[20] from 5.94% in test year 2005. There was no change in PG&E's preferred stock cost.

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[18] QUIPS are debt instruments with some characteristics of preferred stock, and in the past have been included in the embedded cost of preferred stock net of the tax savings.

[19]

	Weighted Factor	Debt Cost	Weighted Debt Cost
Actual Jan.-April 12th	27.87%	7.51%	2.09%
Projected Post April 12th	72.13%	5.28%	3.81%
Weighted Cost			5.90%

C. Discussion

There was no dispute on SCE's test year 2005 cost of long-term debt, or on PG&E's true up year 2004 and test year 2005 costs of long-term debt and preferred stock.

ORA took exception to SCE's test year 2005 cost of preferred stock. ORA forecasted a 6.04% preferred stock cost for SCE based on the historical spread of mandatory redemption preferred stock[21] issued by SCE in the early 1990's, Moody's recent upgrading of SCE's preferred stock to investment grade, and on the assumption that SCE would continue to issue mandatory redemption preferred stock. However, ORA's forecast of SCE's preferred stock was based on the issuance of a type of preferred stock that SCE will not be issuing. SCE will issue traditional preferred stock, not mandatory preferred stock.[22] Hence, we must reject ORA's forecast of preferred stock cost.

SCE's forecast of preferred stock cost based on quotes from investment banks for the issuance of perpetual preferred stock in the current market is more appropriate. However, SCE provided no explanation on why the quote of 81 basis points above Moody's Aa utility rate spread was more than double the other two quotes. Absent the identification of specific benefits in using the highest Moody's Aa utility rate spread quote, we would expect SCE to exercise

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20 Late-Filed Exhibit 35, Attachment 3.

21 Mandatory redemption preferred stock requires sinking fund provisions and redemption of such preferred stock in full after a period of time ranging from 10 to 15 years.

22 Traditional preferred stock is issued in perpetuity and qualifies for the dividend received deduction credit for federal income tax purposes.

prudent management judgment by rejecting that quote. A simple average of the two remaining quotes would result in a more realistic cost estimate. However, with a trend of rising interest rate projections and the continued existence of prior embedded preferred stock, an adjustment based on the simple average of two investment banks would not materially change SCE's overall revenue requirement at this time.[23]

As required by D.03-09-020, a Commission Financing Team reviewed PG&E's hedging analysis and supported the terms of the hedges and PG&E's strategy for executing the hedges. Although PG&E incurred $44 million in hedging cost, ratepayers benefited by almost $51 million in annual interest expense due to a drop in interest rates, for a present value of $455 million. PG&E has substantiated that its cost incurred during hedging was reasonable and should be authorized to recover its hedging cost as part of its long-term debt.

SCE and PG&E's long-term debt and preferred stock forecasted costs are consistent with the most recent forecast of interest rates. PG&E's 5.90% long-term debt and 6.76% preferred stock costs for true up year 2004 and the following long-term debt and preferred stock costs for the utilities' test year 2005 are consistent with the law, in the public interest and should be adopted.

	SCE	**PG&E**
Long-Term Debt	6.96%	6.10%

[23] For example, SCE's change in total embedded preferred stock cost by 18 basis points from 7.01% to 6.83% reduced SCE's revenue requirement by approximately $2 million (Exhibit 4, p. 38). The adoption of a preferred stock cost of 6.59% based on the two comparable quotes would reduce the 0.61% preferred stock weighted average cost by only 0.6%.

Preferred Stock	6.73%	6.42%

Having determined the appropriate costs of long-term debt and preferred stock we address the appropriate ROE.

VI. Return on Common Equity

The legal standard for setting the fair rate of return has been established by the United States Supreme Court in the Bluefield and Hope cases.[24] The Bluefield decision states that a public utility is entitled to earn a return upon the value of its property employed for the convenience of the public and sets forth parameters to assess a reasonable return. Such return should be equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings attended by corresponding risks and uncertainties. That return should also be reasonably sufficient to assure confidence in the financial soundness of the utility, and adequate, under efficient management, to maintain and support its credit and to enable it to raise the money necessary for the proper discharge of its public duties.

The Hope decision reinforces the Bluefield decision and emphasizes that such returns should be sufficient to cover operating expenses and capital costs of the business. The capital cost of business includes debt service and stock dividends. The return should also be commensurate with returns available on alternative investments of comparable risks. However, in applying these

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24 The Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944) and Bluefield Water Works & Improvement Company v. Public Service Commission of the State of Virginia, 262 U.S. 679 (1923).

parameters, we must not lose sight of our duty to utility ratepayers to protect them from unreasonable risks including risks of imprudent management.

We attempt to set the ROE at a level of return commensurate with market returns on investments having corresponding risks, and adequate to enable a utility to attract investors to finance the replacement and expansion of a utility's facilities to fulfill its public utility service obligation. To accomplish this objective we have consistently evaluated analytical financial models as a starting point to arrive at a fair ROE.

The models commonly used in ROE proceedings are the Capital Asset Pricing Model (CAPM), Discounted Cash Flow (DCF) Analysis, and Market Risk Premium (MRP). Detailed descriptions of each financial model are contained in the record and are not repeated here. It is the application of these subjective inputs that result in a wide range of ROEs being recommended by the parties. The results of these financial models are used to establish a range from which the parties apply risk factors and individual judgment to determine a fair ROE.

A. SCE's Return on Equity

There are two distinct positions on a fair test year 2005 ROE for SCE. SCE and ORA jointly recommended that SCE maintain its currently authorized 11.60% ROE and Aglet—TURN recommended that SCE's authorized ROE be lowered to 10.20%.

1. SCE and ORA's Position

SCE and ORA joint ROE recommendation was based on a Memorandum of Understanding (MOU) they entered into prior to SCE filing its

ROE application. That MOU, signed by SCE on April 26, 2004 and by ORA on April 28, 2004, was based on "the current evidence on interest rates ..."[25]

SCE and ORA identified three specific factors that led to the MOU. First interest rates began to increase in March 2004. By May 5, 2004, the Aa utility bond rate and Treasury long-term average rate had increased by 70 basis points and 72 basis points, respectively, from their lowest levels in March of 2004. SCE and ORA attributed that increase in interest rates to the March 2004 news of a 308,000 increase in non-farm payroll employment, a 5.1% consumer price increase for the first three months of 2004 compared to a 1.9% increase for all of 2003, and news that retail sales rose more rapidly than expected.[26]

Second, their comparison of May 5, 2004 Moody's Aa Utility Bond rate of 6.52% and Treasury long-term average rate of 5.41% with a respective 6.98% and 4.90% average rate at the time SCE's last ROE decision was issued led them to believe that interest rates were returning to interest rate levels that prevailed at the end of 2002, and that the differences were not material enough to indicate a change in SCE's test year 2005 ROE.[27] Further, SCE and ORA comparison of Global Insight Aa utility bond interest rate September 2002 forecast of 7.16% for test year 2003 with its May 2004 test year 2005 interest rate forecast of 6.59% did not warrant a change in SCE's authorized ROE.[28]

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[25] Exhibit 22, p. 9.

[26] *Id.* p. 4

[27] *Id.* p. 5.

[28] *Id.*

Third, they expected interest rates to rise in the future due to the economic news identified above, Global Insight's April 22, 2004 message that higher rates are just a matter of time, and Chairman Greenspan's April 21, 2004 comment that, among other matters, indicators of business investment point to increases in spending for many types of capital equipment.

While ORA relied strictly on the changing interest rate environment, SCE believing that changes in interest rates are only one factor to consider in setting a fair ROE prepared the traditional financial models to support its recommendation.[29] Preliminary financial models were prepared by SCE in February and March 2004, while the financial models incorporated into its testimony were prepared subsequently. Its CAPM model, that incorporated Global Insight May 2004 forecasted treasury rates, was prepared a few days prior to the filing of its May 10, 2004 application. Its DCF and MRP financial models were prepared in late April or early May.[30]

SCE used a proxy group of 14 electric companies in its financial models as risk proxies for SCE. SCE placed no reliance on its DCF result on the basis that many of the comparable companies in proxy group do not comply with DCF formula assumptions, such as having a stable dividend payout ratio, stable price/earnings ratio, and stable market-to-book ratio that is close to one. An SCE example of noncompliance with the formula assumptions was that four of the 14 companies in its proxy group had cut their dividends within the past two years, thereby negating the stable dividend payout assumptions.

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[29] Reporter's Transcript Vol. 3, p. 405, lines 10-13.

[30] *Id.* pp. 404 and 405.

SCE derived a broad 7.89% to 13.72% ROE range from its financial models. This broad range was derived from the lowest and highest result of the financial model undertaken by SCE. The range by individual financial model results undertaken by SCE and by Aglet-TURN, are set forth in Appendix B. The exclusion of its DCF model results compacted that broad range to a 10.33% to 13.72% range.

2. Aglet-TURN's Position

Aglet-TURN applied the CAPM, DCF, and MRP financial models to establish a base for its ROE recommendation. It used a proxy group of 82 electric, combination and natural gas distribution utilities as its proxy group in its financial models as risk proxies for SCE. Its application of those models resulted in a 9.50% to 12.67% ROE range for SCE's test year 2005. From those results Aglet-TURN derived an average CAPM of 11.97%, DCF of 9.66%, and MRP of 11.22%. Aglet-TURN then weighted those average results giving equal weight to its DCF and MRP averages, and placing two-thirds weight to the results of simple MRP and one-third weight to its CAPM.[31] Less weight was given to its CAPM on the basis that some of the measured betas[32] used in the CAPM formula were unstable and subject to severe fluctuations. That weighting resulted in a 10.60% ROE recommendation for SCE prior to any adjustment for risk.

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31 Exhibit 28, p. 10.

32 Beta, measures the sensitivity of the company's return to the market return, company-specific risk measurements.

Aglet-TURN then assessed financial, business and regulatory risk it found facing SCE to determine what impact those risks should have on the overall ROE. From that assessment, Aglet-TURN concluded that adjustments were appropriate to recognize changes in regulatory and interest rate risks.

From its regulatory risk analysis, Aglet-TURN found that SCE had experienced an improved regulatory climate. In support of this finding Aglet-TURN cited recent favorable comments from the three major rating agencies, Moody's, Standard and Poor's (S&P), and Fitch. Those observations included a Moody's June 5, 2004 recognition of a continuing improvement in the California regulatory environment, including the Commission's approval of the Mountainview generation project, and recent Commission actions relating to other energy matters.[33] Approximately two months later, Moody's upgraded SCE's credit rating to A3 from Baa2 in recognition of a more constructive regulatory environment in California.[34] S&P recognized in July of 2003 the Commission's willingness to protect creditworthiness.[35] Fitch noted an improved regulatory environment at the Commission at the time it restored SCE's credit ratings to investment grade in September 2002.[36]

Based on judgment, Aglet-TURN concluded that this improved regulatory climate has reduced the risk of California utilities and their cost of

[33] Exhibit 30, p. 86.

[34] *Id.* p. 88.

[35] *Id.* p. 53.

[36] *Id.* p. 69

equity by approximately 100 basis points. That adjustment, applied to its 10.60% weighted financial models, resulted in an adjusted ROE of 9.60%.

Aglet-TURN's assessment of interest rate changes resulted in an assessment that there was a 60 basis points increased interest rate risks. That interest rate risk added to Aglet-TURN's adjusted 9.60% ROE for SCE resulted in a recommended 10.20% ROE for SCE's test year 2005.

3. Discussion

We must set the ROE at the lowest level that meets the test of reasonableness.[37] At the same time, our adopted ROE should be sufficient to provide a margin of safety for payment of interest and preferred dividends, to pay a reasonable common dividend, and to allow for some money to be kept in the business as retained earnings.

Although the parties agree that the models are objective, the results are dependent on subjective inputs.[38] The parties used different proxy groups, risk-free rates, beta, market risk premiums, growth rates, calculations of market returns, and time periods within their respective financial models. Parties even took different positions on the appropriateness of the individual financial models. For example, SCE rejected its DCF result, while PG&E declined to use the CAPM and Aglet-TURN placed less weight on its CAPM result than on its DCF and MRP results. Each party addressed the strengths of their respective financial modeling results while other parties addressed their defects and some even went so far as to recalculate the other party's financial modeling based on selective changes.[39] Even if those selective changes were considered, the individual party's overall ROE range based on the financial models would not materially change. For example, Aglet-TURN's financial models as recalculated by SCE would result in an overall 11.16% average compared to the 10.95% simple average of Aglet-TURN's financial models. Even if that modified result were

[37] 46 CPUC2d at 369 (1992), 78 CPUC at 723 (1975).

[38] Reporter's Transcript Vol. 3, p. 408, lines 14-20.

[39] Exhibit 4, pp. 25-27.

adopted it would still fall near the midpoint of Aglet-TURN's overall 9.50% to 12.67% range, as shown in Appendix B.

From these broad ROE ranges the parties advance arguments in support for their respective analyses and in criticism of the input assumptions used by other parties. These arguments will not be addressed extensively in this opinion, since they do not materially alter model results.

The following tabulation summarized the average point of the individual financial models used by SCE and Aglet-TURN. The tabulation also includes the simple weighted average of those financial model results and individual ROE recommendation for SCE by SCE, Aglet-TURN and ORA

	CAPM	DCF	MRP	OVERALL AVERAGE	RECOMMENDED ROE
SCE	12.04%	9.16%	11.35%	10.85%[40]	11.60%
Aglet-TURN	11.97%	9.66%	11.22%	10.95%[41]	10.20%
ORA	-	-	-	-	11.60%

The financial models are used only to establish a range from which individual judgment can be applied to determine a fair ROE. Each model complements the other to arrive at a balanced ROE range. The CAPM focuses on

40 SCE did not identify an overall average. This average is a simple average of the three financial model average results calculated by SCE (9.16% plus 12.04% plus 11.35% divided by three).

41 The 10.95% resulted from weighing the CAPM, DCF, and MRP model results equally. Aglet-TURN calculated a 10.60% average by applying less weight to its CAPM model result.

the kinds of risks for which investors demand compensation, the DCF on a cash flow stream, and the MRP risk positioning.

In the final analysis, it is the application of informed judgment, not the precision of financial models, which is the key to selecting a specific ROE estimate. We affirmed this view in D.89-10-031, which established ROEs for GTE California, Inc. and Pacific Bell, noting that we continue to view the financial models with considerable skepticism.

We find no reason to exclude or adopt the financial modeling results of any one party. Therefore, we will establish a ROE range based on the model results and informed judgment. After considering the evidence on the market conditions, trends, creditworthiness, interest rate forecasts, quantitative financial models based on subjective inputs, risk factors, and interest coverage presented by the parties and applying our informed judgment, we conclude that a subjective ROE range deemed fair and reasonable for SCE's test year 2005 is 10.40% to 11.40%.[42]

We compared that range to the overall financial model results of SCE and Aglet-TURN and found it to be within the mid range of SCE's 7.89% to 13.72% and Aglet-TURN's 9.50% to 12.67% broad ROE range. We also observed that SCE's 7.89% to 13.72% broad range was lower than its 13.15% to 13.81% test year 2003 results while its common equity ratio of 48.00% remained constant, indicating a lower required ROE for its test year 2005 than approved for its test year 2003.[43]

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[42] Overall average of SCE and Aglet-TURN's financial models plus and minus 50 basis points.

[43] D.02-11-027, mimeo., Appendix A.

Having established a fair and reasonable ROE range based on the financial models we next consider the additional risks identified by the parties to determine what modification, if any, is warranted in setting a specific ROE. Those factors are regulatory and interest rate risks.

Aglet-TURN identified specific instances of improved California regulatory environment, some of which are identified in the above discussion of its recommendation. There is no dispute that the regulatory climate in California has improved from the utilities' prior ROE proceeding. However, the financial models are based on a proxy of comparable companies selected by the individual parties to assess a range or average ROE prior to assessing risks not reflected in those models.

There is no evidence, let alone a comparison between the California improved regulatory environment to the regulatory environment of the proxy companies, that justifies a substantial (100 basis points) downward adjustment from the financial models.[44] However, there is evidence that California's regulatory environment is rated average. For example, the Regulatory Research Associates raised its rating of California regulation to average in recognition of the progress California has made in stabilizing the electric industry and restoring the major utilities to financial health.[45] Therefore, we find no basis to reduce the utilities ROE for an improved California regulatory climate.

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[44] Based on SCE's Late Filed Exhibit 34, a 100 basis points downward adjustment to SCE's ROE would equate to approximately $77 million (100 basis points time $769,000 per basis point change).

[45] Exhibit 30, p. 40.

As to interest rate risks, we consistently consider the current estimate and anomalous behavior of interest rates when making a final decision on authorizing a fair ROE. In PG&E's 1997 cost of capital proceeding we stated "Our consistent practice has been to moderate changes in ROE relative to changes in interest rates in order to increase the stability of ROE over time."[46] That consistent practice has also resulted in the practice of only adjusting rate of return by one half to two thirds of the change in the benchmark interest rate.[47]

Consistent with our practice to moderate changes in ROE relative to changes in interest rates we compare the most recent trend of interest rate forecasts from the date that testimony was prepared in the April/May time period to the September 2004 submittal date. There was a 10 basis points increase in interest rate forecast from the May 2004 forecast of 6.59% to the September 2004 forecast of 6.69%. In contrast, the test year 2003 ROE proceeding experienced a 46 basis points decrease in interest rate forecast from the May 2002 Aa utility bond interest rate forecast of 7.62% to the September 2002 interest rate forecast of 7.16%. The current interest rate trend is moving in a moderate upward direction indicating increased interest rate risks.

Based on the recent interest rate changes, the utilities are facing increased interest rate risks warranting the approval of an ROE at the upper end of the ROE range found to be fair and reasonable in this proceeding. We apply informed judgment in setting SCE's test year 2005 ROE at 11.40%, the top of the ROE range found fair and reasonable for SCE. A comparison of that authorized

[46] 77 CPUC2d 556 at 563 (1996).

[47] 57 CPUC2d 533 at 549 (1994).

ROE to SCE's 11.60% requested and Aglet-TURN's 10.20% recommended ROE for SCE set forth in Appendix A demonstrates that the adopted ROE would not change SCE's position within the S&P benchmarks. Irrespective of which ROE is used, SCE's cash flow interest coverage, the most important ratio to SCG would remain in the A range of S&P's benchmarks and its debt to capital and cash flow to debt ratios would remain within the BBB range of S&P's benchmarks.

B. PG&E's Return on Equity

There are three distinct positions on PG&E's test year 2005 ROE. PG&E recommended an 11.60% ROE, Aglet-TURN 10.20%, and ORA 10.22%. There is no dispute on approving an 11.20% ROE for PG&E's true up 2004 year. That is because PG&E's Modified Settlement Agreement (MSA) approved in its bankruptcy proceeding requires a minimum of 11.22% ROE for PG&E until one of the rating agencies raises PG&E's company credit rating into an A category, which equates to at least a A-minus rating by S&P or a A3 rating by Moody's.

1. PG&E's Position

PG&E used a proxy group of 29 electric and 13 local natural gas distribution companies in its financial models as risk proxies. PG&E used only the DCF and MRP models. It did not use the CAPM financial model on the basis that significant adjustments to the model would be necessary to compensate for unusual conditions in the U.S. Treasury securities market, interest rate sensitivity of utility stocks, understated cost of equity for companies with betas of less than 1.0, and the CAPM failure to account for risks not accounted for by covariation with the market index.[48]

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[48] Exhibit 9, p. 2-7.

PG&E derived a broad 9.20% to 11.40% ROE range from its financial models. This broad range was derived from the lowest and highest results of the financial models undertaken by PG&E. The range of individual financial model results undertaken by PG&E, along with the results of Aglet-TURN and ORA's financial model results are set forth in Appendix C. The average point of PG&E's DCF was 9.60% and MRP 11.10%. PG&E then derived a 10.60%[49] simple average of its financial models prior to making an adjustment for financial risk. PG&E then adjusted the result of its financial models upward by 100 basis points to mitigate financial risk related to the difference between its equity level to the average equity level of its proxy companies.[50] That 100 basis points upward adjustment added to its 10.60% average result of its financial models equates to a test year 2005 ROE of 11.60%.

PG&E identified other risks in support of its position that its modeling result, even after adjustment for financial leverage, still understates its actual cost of equity. First, a hybrid generation industry, composed of unregulated generators and regulated utility generation, may lead to greater instability before a stable market design can be designed and implemented. Second, PG&E's high bundled electric prices provide a stimulus for the creation and growth of municipally owned and operated distribution systems within PG&E's territory, thereby increasing the potential for increasing competition for

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[49] DCF result of 9.60% plus an ex ante MRP of 11.10% plus an ex post MRP of 11.10% divided by three to equal 10.60%.

[50] PG&E's common equity ratio is 52% in comparison to its electric companies' proxy group common equity average of 56.09% and gas distribution companies' proxy group common equity average of 62.94%.

electric distribution service. Third, a firm just exiting bankruptcy will leave investors with some perception of an elevated level of risk due to the recent financial distress. PG&E equated those additional risks, not measurable by PG&E, to a level of risks that is somewhat greater than the average utility.[51]

2. Aglet-TURN's Position

Aglet-TURN applied its same model results and adjustments for regulatory and interest rate risks to PG&E that were addressed in the above SCE discussion. Although Aglet-TURN recommended a 10.20% ROE for PG&E, consistent with the other parties, it concluded that PG&E should be authorized the 11.22% minimum ROE required by the MSA approved in PG&E's bankruptcy proceeding. It also recommended that as soon as PG&E attains a rating agency upgrade to the A level that PG&E's authorized ROE should be lowered to Aglet-TURN's 10.20% recommended ROE from the 11.22% minimum ROE require by the MSA.

3. ORA's Position

ORA, not relying strictly on the changing interest rate environment as it did for SCE, applied the CAPM, DCF, and MRP financial models to determine its recommended ROE for PG&E. It used a proxy group of 29 electric and 12 local natural gas distribution companies in its financial models as risk proxies for PG&E. From those models, ORA derived a broad 8.99% to 11.15% ROE range. The average point of its CAPM was 10.89%, DCF 9.43%, and MRP 10.34%. Based on a simple average of the average point of its financial models,

[51] Exhibit 9, p. 1-16.

ORA recommended a 10.22% ROE for PG&E's test year 2005. ORA made no adjustment for risks outside of the financial models.

ORA then considered the MSA executed by the Commission and PG&E, which was incorporated into PG&E's confirmed Plan of Reorganization. Based on its model results and the MSA guidelines, ORA recommended a ROE of 11.22% for PG&E's true up year 2004 and test year 2005.

4. Discussion

The process for setting a fair and reasonable ROE and use of financial models to assist us in establishing that ROE is set forth in our discussion of SCE's ROE and will not be repeated herein. Consistent with that discussion we use the same method for establishing a fair and reasonable ROE for PG&E.

The following tabulation summarized the average point of the individual financial models used by PG&E, Aglet-TURN and ORA, including the simple weighted average of the financial model results and recommended test year 2005 ROE for PG&E by those parties.

	CAPM	DCF	MRP	OVERALL AVERAGE	RECOMMENDED ROE
PG&E	9.60%	-	11.10%	10.35%[52]	11.60%
Aglet-TURN	9.66%	11.97%	11.22%	10.95%[53]	10.20%

[52] The 10.35% resulted from weighing the CAPM and MRP model results equally on the basis that PG&E's 11.10% Ex Ante RPM and 11.10% Ex Post RMP result affirmed PG&E's conclusion that its RMP average was 11.10%. PG&E derived a 10.60% overall average based on the inclusion of its CAPM, Ex Ante RPM and Ex Post RMP.

[53] The 10.95% resulted from weighing the CAPM, DCF, and MRP model results equally. Aglet-TURN calculated a 10.60% average by applying less weight to its CAPM model result.

ORA	9.43%	10.89%	10.34%	10.22%	11.22%

Consistent with our SCE financial model discussion, we find no reason to exclude or adopt the financial modeling results of any one party. Therefore, we will establish a ROE range based on the model results and informed judgment.

After considering the evidence on the market conditions, trends, creditworthiness, interest rate forecasts, quantitative financial models based on subjective inputs, risk factors, and interest coverage presented by the parties and applying our informed judgment, we conclude that a subjective range of ROE deemed fair and reasonable for PG&E's test year 2005 is 10.01% to 11.01% prior to consideration of PG&E's financial leverage proposal.[54] A comparison of that range to the overall financial model results of PG&E, Aglet-TURN, and ORA finds it to be in the upper range of PG&E's 9.20% to 11.40% broad range, Aglet-TURN's 9.50% to 12.67%, and ORA's 8.99% to 11.15%.

PG&E's proposal to mitigate financial leverage by a 100 basis points upward adjustment to its authorized ROE was based on an after-tax weighted average cost of capital (ATWACC) difference between its test year 2005 capital structure and the average capital structures of its electric and gas proxy groups.

PG&E introduced the concept of using ATWACC in its test year 1999 ROE proceeding (A.98-05-021). At that time, PG&E sought a 100 basis points upward adjustment to its authorized ROE on the basis that cost of capital is independent of a company's actual debt/equity capital structure as long as its

[54] Overall average of PG&E, Aglet-TURN, and ORA's financial models plus and minus 50 basis points.

structure is within the broad range where cost of capital remains constant.[55] With no evidence on how ATWACC would perform under a range of economic conditions and no comparative information to gauge how it compared to the broader market, we did not find that ATWACC was more accurate or useful than other methods with which we use. We continued to rely on the CAPM, DCF, and MRP as a basis for determining a fair and reasonable ROE.

In this proceeding, PG&E provided evidence on how its ATWACC would compare to its electric and gas proxy groups. PG&E demonstrated that its test year 2005 common equity ratio of 52% is 4% lower than the 56% average of its electric proxy group and 11% lower than the 63% average of its gas proxy group. Based on PG&E's assumption that it was comparable in risks to its electric and gas proxy groups, PG&E applied a 7.82% ATWACC, simple average of its electric companies proxy group ATWACC average of 7.666% and gas proxy group average of 8.079%, to PG&E's Test Year 2005 capital structure. The result of that calculation was 11.65%. The difference between PG&E's financial models simple average result of 10.60% and its ATWAAC result of 11.65% was 105 basis points, of which PG&E rounded to 100 basis points to arrive at a 11.60% ROE for its test year 2005. Based on the 10.51% simple average of all the parties' financial model results, a 100 basis points upward adjustment would equate to a test year 2005 ROE of 11.51%.

If the ATWAAC method proposed by PG&E were adopted, the use of informed judgment in determining a fair and reasonable ROE would appear to be restricted to the selection of only comparable electric and gas proxies,

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[55] D.99-06-057, mimeo., p. 47.

preclude the establishment of a range of reasonableness, and eliminate the need for the CAPM, DCF, and MRP financial models. We are also concerned with PG&E's use of a simple average of electric and gas proxy groups having substantially different common equity ratios (56.09% for electric and 62.94% for gas) while PG&E has a ratemaking common equity ratio of 52.00% and its electric operations represent 75% of its total operations.[56] Absent more evidence on the merits of using an ATWAAC method, we are not prepared to relinquish our informed judgment in establishing either a range of reasonableness or a specific ROE. We do invite PG&E to provide additional evidence on the use of ATWCC in its next ROE proceeding.

With the factoring in of increased interest rate risks and rejection of PG&E's financial leverage proposal, PG&E's test year 2005 ROE should be set at 11.01%, the top of its 10.01% to 11.01% ROE range found reasonable. However, that ROE is lower than the 11.22% ROE approved in PG&E's bankruptcy proceeding as part of the MSA. Therefore, consistent with the terms of the MSA, PG&E's true up year 2004 and test year 2005 ROE should remain at 11.22%. That adopted ROE would not change PG&E's position within the S&P benchmarks, as shown in Appendix A. While PG&E's debt to capital ratio would decline from S&P's A range to BBB range with the inclusion of debt equivalence, PG&E's cash flow interest coverage, the most important ratio to PG&E would remain within S&P's A range benchmark and cash flow to debt remain within S&P's BBB range.

[56] Reporter's Transcript Vol. 2, p. 233, lines 22 to 28.

VII. Implementation

SCE should include the revenue requirement impact of this decision in its test year 2005 advice letter filing.

Consistent with PG&E's implementation proposal, PG&E shall include electric revenue requirement changes authorized in this proceeding in an advice letter filing. Changes in electric distribution, electric generation, regulatory asset revenue requirements for the adopted ROE would accrue in the appropriate balancing or memorandum accounts until they can be incorporated into rates charged customers. Changes applicable to direct access rates would be made at the same time as changes in distribution and regulatory asset rates.

For gas distribution changes, revenue requirement changes would be recorded in its Core Fixed Cost Account and Non-core Customer Class Charge Account for recovery in the next Annual True Up of Balancing Accounts or Biennial Cost Allocation Proceeding. Gas transmission and storage rates would be adjusted to reflect revenue requirement changes affecting those rates. PG&E would allocate the revenue requirement changes to core and non-core customers based on the pro rata share of revenue requirements, consistent with the method approved in Advice Letter 2521-G. The core portion would be transferred to the core fixed cost account and the non-core portion to the non-core customer class charge account for incorporation into rates in its next gas transportation rate change or true up.

VIII. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(d) and Rule 77.1 of the Rules of Practice and Procedure. Comments were filed on December 6 and 7, 2004, and reply comments were filed on December 13, 2004. The comments did not result in any material change. To the extent such comments required discussion or changes to the proposed decision, the discussion or changes have been incorporated into the body of this order.

IX. Assignment of Proceeding and Procedural Matters

Geoffrey F. Brown is the Assigned Commissioner and Michael J. Galvin is the assigned Administrative Law Judge (ALJ) in this proceeding.

The utilities requested that their respective ROE application be classified as a ratesetting proceeding within the meaning of Rule 5(c). By Resolution ALJ 176-3134, dated May 27, 2004, the Commission preliminarily determined that the applications of SCE and PG&E were ratesetting proceedings and that hearings were expected. This ratesetting classification was subsequently affirmed in the Assigned Commissioner Brown's July 15, 2004 Scoping Memo and Ruling.

That Scoping Memo and Ruling, among other matters, designated ALJ Galvin as the principal hearing officer, established an evidentiary hearing schedule and determined the issues of this proceeding. Those issues encompassed all estimates, including debt equivalence, upon which the utilities proposed capital structure and rate of return for the test year 2005 were based on and PG&E's true-up of its 2004 cost of capital, including hedging.

An evidentiary hearing was held on September 13, 2004 and continued through September 16, 2004. Each of the utilities, Aglet-TURN, and ORA submitted testimony and evidence. The proceeding was submitted upon the receipt of October 5, 2004 reply briefs.

Findings of Fact

1. Applicants are public utilities subject to the jurisdiction of this Commission.

2. SCE seeks to maintain its test year 2005 ROE at 11.60%.

3. PG&E seeks to true up its year 2004 capital structure with an 11.22% ROE and to increase its test year 2004 ROE to 11.60%.

4. SCE and PG&E's applications were consolidated pursuant to Rule 55.

5. The issue of debt equivalence was included in this proceeding pursuant to D.04-01-050. SDG&E presented testimony on the impact of debt equivalence policy.

6. Debt equivalence is a term used by credit analysts for treating long-term non-debt obligations, such as PPAs and leases, as if they were debt in assessing an entity's credit rating.

7. Credit rating agencies have long recognized debt equivalence risks.

8. Credit rating agencies impute debt from long-term energy procurement contracts in their credit analyses of California utilities.

9. Debt equivalence associated with long-term PPAs can affect utility credit ratios and credit ratings.

10. The rating agencies, Fitch, Moody's, and S&P did not participate in this proceeding.

11. SCE has investment grade credit ratings of A-3 from Moody's and BBB from S&P.

12. PG&E has an investment grade rating of BBB- from S&P.

13. The inclusion or exclusion of PPA debt equivalence impacts did not materially impact the SCE or PG&E's interest coverage or cash flow to debt results presented in this proceeding.

14. SDG&E provided no information on its current credit ratings and insufficient information to enable us to assess the debt equivalence impact on its overall credit ratings and capital structure.

15. SCE requested a 2005 capital structure consisting of 43.00% long-term debt, 9.00% preferred stock, and 48.00% common equity.

16. PG&E requested a true up 2004 capital structure of 48.20% long-term debt, 2.80% preferred stock, and 49.00% common equity.

17. PG&E's proposed capital structures are consistent with the implementation of its Chapter 11 exit financing and capital structure provision set forth in its MSA.

18. We recognized in D.90-11-057 that actual interest rates do vary and that our task is to determine reasonable debt costs rather than actual cost based on an arbitrary selection of a past figure.

19. SCE submitted late-filed Exhibit 34 and PG&E late-filed Exhibit 35 to reflect the most recent forecast of interest rates, September 2004 Global Insight forecasted interest rates.

20. PG&E's 2005 long-term debt cost is based in part on its forecast in cost of debt changes that would occur and in part on its expected implementation of DRC financing.

21. The DRC proceeds that PG&E expects to receive would be used to pay off existing debt and to buy back common stock so that PG&E can achieve and maintain a target capital structure containing 52% common equity.

22. PG&E included approximately $44 million in interest rate hedging cost as a component of its test year 2005 long-term debt.

23. There was no dispute on SCE's cost of long-term debt or on PG&E's costs of long-term debt and preferred stock.

24. ORA's forecast of SCE's preferred stock cost was based on the issuance of a type of preferred stock that SCE would not be issuing.

25. A Commission Financing Team reviewed PG&E's hedging analysis and supported the terms of the hedges and PG&E's strategy for executing hedges.

26. The legal standard for setting the fair ROE has been established by the United States Supreme Court in the Bluefield and Hope cases.

27. An ROE is set at a level of return commensurate with market returns on investments having corresponding risks, and adequate to enable a utility to attract investors to finance the replacement and expansion of a utility's facilities to fulfill its public utility obligation.

28. Quantitative financial models are commonly used as a starting point to estimate a fair ROE.

29. Although the quantitative financial models are objective, the results are dependent on subjective inputs.

30. It is the application of informed judgment, not the precision of quantitative financial models, which is the key to selecting a specific ROE.

31. The individual parties' use of quantitative financial models resulted in a broad test year 2005 ROE range from 7.89% to 13.72% for SCE and 9.20% to 12.67% for PG&E.

32. Two important components of the Hope and Bluefield decisions are that the utilities have the ability to attract capital to raise money for the proper discharge of their public utility duties and to maintain creditworthiness.

33. Our consistent practice has been to moderate changes in ROE relative to changes in interest rates in order to increase the stability of ROE over time.

34. The September 2004 Aa utility bond interest rate forecast for test year 2005 is 6.69%, a 10 basis points increase in interest rate from the April 2004 forecast of 6.59%.

Conclusions of Law

1. The capital structures proposed by SCE and PG&E should be adopted because they are balanced, attainable, and intended to maintain an investment grade rating and attract capital.

2. The long-term debt and preferred stock costs being proposed by the utilities are consistent with the law, in the public interest, and should be adopted.

3. Debt equivalence does not have a material impact on either SCE or PG&E's credit ratios or capital structure presented and considered in this proceeding.

4. SDG&E should be required to file a test year 2006 cost of capital application.

5. SDG&E should file a test year 2006 ROE application by May 9, 2005, along with SCE and PG&E, so that we may properly assess what impact, if any, that debt equivalence has on its credit ratings and capital structure, including mitigation recommendations.

6. To the extent that SDG&E believes that debt equivalence may have a material impact and recurring drain on its credit ratios or ratings, SDG&E should consider modifying its MICAM settlement agreement so that it may resolve that concern through yearly ROE applications.

7. The utilities should include debt equivalence impacts as part of their ROE applications.

8. Debt equivalence should be considered with other financial, regulatory, and operational risks in setting a fair ROE and balanced capital structure reasonably sufficient to assure confidence in the financial soundness of the utility to maintain and support investment grade credit ratings.

9. The major utilities should include in their annual cost of capital applications recommendations for improving and maintaining their credit ratings.

10. Risks being experienced by the utilities warrant the ROEs being adopted in this proceeding at the upward end of an ROE range found just and reasonable.

11. The latest available interest rate forecast should be used to determine embedded long-term debt and preferred stock costs in ROE proceedings.

12. PG&E should be authorized to recover its hedging costs as part of its long-term debt.

13. PG&E's costs of long-term debt and preferred stock for true up year 2004 and test year 2005 should be adopted.

14. SCE's costs of long-term debt and preferred stock for test year 2005 should be adopted.

15. An upward trend in interest rates warrants an upward adjustment in ROE.

16. A test year ROE range from 10.40% to 11.40% is just and reasonable for SCE based on financial model results.

17. A test year 2005 ROE of 11.40%, which results in an overall 9.07% return on rate base should be adopted as just and reasonable for SCE based upon all of the evidence considered in this proceeding.

18. A test year 2005 ROE range from 10.01% to 11.01% is just and reasonable for PG&E based on financial model results; however, that ROE is lower than the 11.22% ROE approved in PG&E's bankruptcy proceeding, as part of the MSA, which prevents adoption of the lower figure.

19. A true up year 2004 and test year 2005 ROE of 11.22% ROE resulting in an overall 8.53% and 8.77% return on rate base, respectively, is consistent with the MSA should be adopted as just and reasonable for PG&E.

20. The utilities ROE applications should be granted to the extent provided for in the following order.

ORDER

IT IS ORDERED that:

1. Southern California Edison Company's (SCE) cost of capital for its test year 2005 is as follows:

	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	43.00%	6.96%	2.99%
Preferred Stock	9.00	6.73	0.61
Common Stock	48.00	11.40	5.47
Total	100.00%		9.07%

2. Pacific Gas and Electric Company's (PG&E) cost of capital for true up year 2004 electric and gas operations is as follows:

	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	48.20%	5.90%	2.84%
Preferred Stock	2.80	6.76	0.19
Common Stock	49.00	11.22	5.50
Total	100.00%		8.53%

3. PG&E's cost of capital for its test year 2005 electric and gas operations is as follows:

	Capital Ratio	Cost Factor	Weighted Cost
Long-Term Debt	45.50%	6.10%	2.78%
Preferred Stock	2.50	6.42	0.16
Common Stock	52.00	11.22	5.83
Total	100.00%		8.77%

4. PG&E's hedging cost incurred as part of its Commission approved financing plan to exit Chapter 11 was reasonable and is recoverable over the life of the debt that was hedged.

5. SCE and PG&E shall implement the revenue requirement changes authorized by this decision as set forth in the body of this order. If the Energy Division Director suspends any tariffs, such tariffs shall become effective upon the date the Energy Division Director confirms that the tariffs are in compliance.

6. The utilities, as part of their annual cost of capital applications shall include testimony on credit ratios, credit ratings, and capital structure impacts, including mitigation recommendations, of debt equivalence on their PPAs.

Information to be provided shall include current credit ratings from Moody's and S&P; expected impact of its credit ratings due to debt equivalence; capital structure and return on equity with and without debt equivalence; debt to capital, cash flow interest coverage, and cash flow to debt financial ratios with and without debt equivalence; and, pre and post-tax financial ratios. The utilities may also make recommendations for improving and maintaining their credit ratings for Commission consideration.

7. San Diego Gas & Electric Company shall file a test year 2006 cost of capital application by May 9, 2005. That application shall include testimony on the impact that debt equivalence has on its current and projected credit ratings, capital structure, and return on equity.

8. Application (A.) 04-05-021 and A.04-05-023 are closed.

This order is effective today.

Dated December 16, 2004, at San Francisco, California.

MICHAEL R. PEEVEY
President
GEOFFREY F. BROWN
SUSAN P. KENNEDY
Commissioners

I reserve the right to file a dissent.

/s/ CARL W. WOOD
Commissioner

I reserve the right to file a dissent.

/s/ LORETTA M. LYNCH
Commissioner

APPENDIX A

SCE AND PG&E
TEST YEAR 2005 CREDIT RATIOS
DEBT EQUIVALENCE IMPACT ON S&P's BENCHMARKS

Utility	PPAs	Equity Return	Debt to Capital	Interest Coverage	Cash Flow/Debt
SCE 1/	Excluded	10.20%	*51.9%*	**5.18x**	*23.4%*
	Included	10.20%	*55.6%*	**4.23x**	*20.1%*
SCE 2/	Excluded	11.60%		**5.40x**	*24.0%*
	Included	11.60%		**4.40x**	*21.0%*
SCE 3/	Included	11.60%		**4.60x**	*22.0%*
	Included	11.60%		**4.40x**	*21.0%*

S&P BENCHMARKS

A Range **(BOLD NUMBERS)**			**40% - 48%**	**5.2x – 4.2x**	**35% - 28%**
BBB Range *(ITALIC NUMBERS)*			*48%-58%*	*4.2x – 3.0x*	*28% - 18%*
PG&E 4/	Excluded	11.22%	**47.4%**	**6.3x**	*25.7%*
	Included	11.22%	*50.5%*	**5.1x**	*22.5%*

1/ (Exhibit 7, p. 2).

2/ (Exhibit 3, p. 21).

3/ Based on a Preferred Stock ratios of 9% and 5%, respectively. (Exhibit 3, p. 25).

4/ Exhibit 12, p. 6-29.

(END OF APPENDIX A)

APPENDIX B

SOUTHERN CALIFORNIA EDISON COMPANY
RESULTS OF FINANCIAL MODELS

	CAPM	**DCF**	**MRP**
SCE	10.33% - 13.72%	7.89% - 12.06%	11.35%
Aglet	11.27% - 12.67%	9.50% - 10.16%	11.20% - 11.24%
ORA	(Did not apply the Financial Models)		

(END OF APPENDIX B)

APPENDIX C

PACIFIC GAS & ELECTRIC COMPANY
RESULTS OF FINANCIAL MODELS

	CAPM	DCF	MRP
PG&E	-	9.20% - 10.10%	10.80% - 11.40%
Aglet	11.27% - 12.67%	9.50% - 10.16%	11.20% - 11.24%
ORA	10.67% - 11.10%	8.99% - 9.86%	9.53% - 11.15%

(END OF APPENDIX C)

Tab B

Re PSI Energy, Inc.

Cause No. 42359

Indiana Utility Regulatory Commission
May 18, 2004

ORDER authorizing an electric utility to increase its rates and charges for retail service and approving revised rules and regulations applicable to such service.

Commission approves an increase in annual revenue requirement of $107.34 million (8.36%), reflecting an authorized rate of return on common equity (ROE) of 10.5% and an overall cost of capital of 7.3%. A fair rate of return of 4.3% to 6.63% is calculated by removing inflation from the cost of equity as a first determinant, and then from the weighted cost of capital. The authorized increase is allocated in a manner that reduces the current levels of subsidy/excess revenues between rate groups by 33%.

Commission approves three new cost and revenue adjustment mechanisms — a summer reliability tracker, a NO_x emission allowance rate adjustment mechanism, and a Midwest Independent System Operator rate adjustment mechanism. It also approves minor changes to the utility's existing fuel adjustment and SO_2 emission adjustment tracking mechanisms.

The authorized ROE reflects a finding that the utility faces reduced financial risk due to the numerous rate adjustment trackers that allow for periodic, cost-based adjustments between rate cases. In making its findings concerning cost of equity capital, the commission concurs with the observations of its staff witnesses that: (i) the determination of an exact investor required return on equity is impossible; (ii) the results of the capital asset pricing model (CAPM), discounted cash flow (DCF), and risk premium (RP) methods are driven by the inputs of each, of which there are countless possibilities and legitimate arguments to include this and exclude that; and (iii) a petitioning utility will tend to support methodologies and inputs that support a higher result and those in opposition will tend to support methodologies and inputs that produce a lower result. Moreover, the commission finds that the goals for setting a fair rate of return of a public utility go well beyond the use of formulas and mathematical calculations.

Commission finds that the real time pricing program of the utility, as it is currently designed, is not cost effective and does not fulfill its purpose of encouraging customers to shift load in reaction to hourly wholesale market prices. It finds that the program should be terminated on January 31, 2005; however, it directs the parties to engage in a collaborative process to consider ways in which the real time pricing program could be redesigned or modified to make it effective. Commission states that it expects that prior to the scheduled termination, the program will be replaced by one or more innovative pricing options developed during the collaborative.

The utility is authorized to recover costs associated with its incentive compensation plans. Commission finds that rate recovery of incentive compensation costs is appropriate where: (1) the incentive compensation plans are not pure profit-sharing plans, but rather incorporate operational as well as financial performance goals; (2) the incentive compensation plans do not result in excessive pay levels beyond what is reasonably necessary to attract a talented workforce; and (3) shareholders are allocated part of the cost of the incentive compensation programs.

Commission finds that the utility has properly implemented the seven-factor test of the Federal Energy Regulatory Commission in classifying its electric delivery system facilities as transmission or distribution.

Commission rejects a proposal to credit the operating revenues of the utility to reflect the sale of its accounts receivable to an affiliated entity.

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Before Hadley, Ripley and Ziegner, commissioners, and Storms, chief administrative law judge.

BY THE COMMISSION:

On December 30, 2002, PSI Energy, Inc. ("PSI," "Petitioner," or "Company") filed its Petition for authority to increase rates and charges for retail electric utility service and approval of revised rules and regulations applicable to such service. PSI's Petition also sought approval of other items related to rates identified in the caption above, and indicated PSI's intent to comply with and utilize the provisions of the Commission's Minimum Standard Filing Requirements ("MSFRs"). Participants in this Cause included the Indiana Office of Utility Consumer Counselor ("OUCC"), and several parties that intervened in this proceeding including: the Citizens Action Coalition of Indiana, Inc. ("CAC"); Indiana and Purdue Universities; an *ad hoc* group of PSI industrial customers known as the PSI-Industrial Group ("PSI-IG"); the International Brotherhood of Electrical Workers, Local Union No. 1393 ("IBEW Local 1393"); The Kroger Co. ("Kroger"); Steel Dynamics, Inc. — Pittsboro Division ("SDI"); and Nucor Corporation ("Nucor") (collectively, the "Intervenors"). On January 21, 2003, this Commission designated from its staff Bradley K. Borum, Laura Cvengros and Matthew Inman, as testimonial staff in this Cause ("Testimonial Staff" or "Staff"). On April 1, 2003, this Commission designated Kristina Kern-Wheeler and Andrea Brandes as Counsel to the Testimonial Staff.

[1-3] On February 11, 2003, this Commission conducted a Prehearing Conference and thereafter issued its Prehearing Conference Order, which established the 12 months ended September 30, 2002, as the test year in this Cause, with adjustments allowed for changes thereafter that are fixed, known and measurable and occur within 12 months following the end of the test year. May 31, 2003 was established as the cut-off date for rate base determination and for updating Petitioner's actual number of employees, salaries and wages, benefits, payroll taxes and property taxes. Petitioner was ordered to file schedules to support such updates by July 15, 2003. August 31, 2003 was established as the cut-off date for updating Petitioner's major projects as defined in this Commission's MSFRs, Petitioner's construction-work-in-progress ("CWIP") balances, any amounts deferred by Petitioner pursuant to Commission orders, the actual number of customers and the average customer usage. Petitioner identified in its Petition the following projects as major projects eligible for a special later cutoff date: its Noblesville Repowering Project, Madison Generating Station, Henry County Generating Station and Gibson Generating Station Unit 4 selective catalytic reduction equipment ("SCR"). Petitioner was required to support these August 31, 2003 updates by its rebuttal testimony filing date of October 6, 2003. PSI reserved the right to update its major project amounts up to 10 days before the final set of hearings in this Cause.

On March 28 and April 11, 2003, PSI prefiled its case-in-chief testimony and exhibits in this Cause. A hearing on PSI's evidence commenced June 9, 2003. On July 15, 2003 PSI filed its May 31, 2003 Cut-Off Date Update Filing as required by the Prehearing Conference Order. On August 19, 2003, the Intervenors and the OUCC prefiled testimony and exhibits constituting their respective cases-in-chief. The Intervenors filing evidence included the CAC, PSI-IG, Purdue University, and Kroger. The Testimonial Staff filed its report, testimony and exhibits, on September 3, 2003. Petitioner prefiled its August 31, 2003, Cut-Off Date Update Filing, and its rebuttal and update testimony and exhibits, on October 6, 2003. PSI filed a final update to its major projects on October 20, 2003, as provided in the Prehearing Conference Order. The OUCC filed updated and corrected Public's Exhibit ("Pub. Ex.") No. 8U and Revised Pub. Ex. No. 3 on October 31, 2003. PSI filed Petitioner's Exhibit ("Pet. Ex.") X-32 and OO-3, both as corrected, on October 31, 2003. A hearing on the prefiled testimony and exhibits of the Intervenors and Testimonial Staff commenced on November 3, 2003, followed by a hearing on Petitioner's update and rebuttal evidence. On October 22, 2003, a Field Hearing in this Cause was held in Kokomo, Indiana, and on October 27, 2003, a Field Hearing was held in Bloomington, Indiana as required by Ind. Code § 8-1-2-61(b).

At the close of the record, the parties were authorized to file proposed orders and briefs in support, as well as exceptions to proposed orders and reply briefs, in accordance with an agreed upon procedural schedule. The Presiding Commissioner and Chief Administrative Law

Judge attended all of the Evidentiary Hearings in this proceeding, and have thus observed the demeanor and credibility of the witnesses. All proposed findings of the parties not specifically determined in this Order are hereby rejected. This Commission, having examined the evidence and being duly advised in the premises, now finds that:

[4, 5] *1. Notice and Jurisdiction.* Due, legal and timely notice of the filing of the Petition was given and published by PSI, as required by law. Proper and timely notice was given by PSI, as required by law, to its customers summarizing the manner and extent of the proposed changes in its retail rates and charges. Due, legal and timely notice of the public hearings herein was given and published by this Commission. PSI is a public utility as defined in Ind. Code § 8-1-2-1 and is subject to regulation by this Commission in the manner and to the extent provided for in the Public Service Commission Act, Ind. Code § 8-1-2. This Commission has jurisdiction over PSI and the subject matter of this Cause.

2. Petitioner's Characteristics. PSI is an Indiana corporation with its principal office in the Town of Plainfield, Hendricks County, Indiana. PSI is engaged in the business of generating and supplying electric utility service to over 740,000 customers located in 69 counties in the central, north central and southern parts of the State of Indiana. PSI is a wholly-owned subsidiary of Cinergy Corp. ("Cinergy"), a publicly-held corporation, and an affiliate of The Cincinnati Gas & Electric Company ("CG&E"), also wholly owned by Cinergy.

PSI provides electric utility service to the public by means of electric utility plant, properties, equipment and facilities owned, operated, managed and controlled by it, which are used and useful for the convenience of the public in the production, transmission, distribution and furnishing of electric utility service to retail customers in the State of Indiana. PSI also engages in sales for resale of electric energy to municipal utilities, rural electric membership corporations, Wabash Valley Power Association, Inc. ("WVPA"), Indiana Municipal Power Agency ("IMPA"), and other utilities, which in turn supply electric utility service to customers in areas not served directly by PSI.

3. Current Rates and Relief Requested. Petitioner's current base retail electric rates and charges were approved by Order entered by this Commission, on September 27, 1996, in Cause No. 40003 ("1996 Order" or "Cause No. 40003"). By its Petition here, PSI requests this Commission's approval to increase those rates and charges. Petitioner originally requested that this Commission approve an increase in the amount of $200,420,000. However, after the updates made in accordance with the Prehearing Conference Order, and with certain compromise positions set forth in Petitioner's rebuttal testimony, Petitioner reduced the requested increase in its basic retail electric rates to $178,303,000, which would represent an approximately 11.2% increase over Petitioner's current average retail rates. Pet. Ex. OO-3; Pet. Ex. DD, p. 3.

4. Petitioner's Rate Base.

[6, 7] A. *Used and Useful Determinations.* In determining Petitioner's rate base, we have been charged with making basic determinations in connection with our ultimate conclusion as to the fair value of Petitioner's utility plant actually used and useful in rendering retail electric utility service to the public. The following findings underlie these determinations.

(1) *Petitioner's Generating Facilities.* The evidence in this Cause shows that PSI owns and operates 11 generating stations, which are capable of producing approximately 6,800 megawatts ("MW") of electric generating capacity (summer-rated). Approximately 76% of PSI's generating capacity is coal-fired, 20% is natural-gas or synthetic gas-fired, 3.5% is oil-fired and approximately 0.7% is hydro-powered. Pet. Ex. O-1. PSI's Gibson Unit 5 is jointly owned, with PSI owning 50.05% of the unit and WVPA and IMPA owning 25% and 24.95%, respectively. Pursuant to a 2002 Joint Generation Dispatch Agreement ("JGDA"), PSI jointly dispatches its generating plants with CG&E's generating plants. Pet. Ex. B, pp. 7-8.

PSI's electric generating properties consist of five primarily coal-fired hydroelectric generating station (three units), and 27 rapid-start peaking units, including peaking units at PSI's Madison Generating Station and at PSI's Henry County Generating Station. The Madison and Henry County Stations were acquired by PSI, February 5, 2003, after this Commission approved their purchase by PSI in Cause No. 42145. PSI also owns and operates two generating units at its Noblesville Repowering Project, near Noblesville, Indiana, approved by this Commission in Cause No. 41924 and completed in June 2003. Pet. Ex. O, pp. 2-3.

PSI's coal-fired stations use primarily Illinois Basin coal from mines located in Indiana. PSI owns and operates various pollution control equipment located at its generating stations, including flue gas desulfurization equipment ("scrubbers") at its Gibson Units 4 and 5, SCRs at Gibson Units 2, 3 and 4, and modular cooling towers at PSI's Cayuga Station. Pet. Ex. B, p. 9. PSI's witness John J. Roebel, Vice President of the Generating Resources Group, described the status and costs of the Company's evolving plan to comply with federal NO_x reduction requirements ("Compliance Plan"). At the time of PSI's case-in-chief filing, the active NO_x Compliance Plan included SCRs, Boiler Optimization Programs, low-NO_x burners, and new precipitators, at various units at PSI's Gibson, Cayuga, Gallagher, and Wabash River Stations. Several additional projects have been deferred due to the receipt of early reduction credits. Mr. Roebel explained that the following NO_x Compliance Plan projects are in-service or were expected to be in-service by the summer of 2003: Boiler Optimization Programs at Cayuga Units 1 and 2, Gallagher Units 1 and 2, Wabash River Unit 2, and Gibson Unit 3; Low NO_x Burners at Gallagher Unit 4 and Wabash River Unit 6; and SCRs at Gibson Units 2, 3 and 4. Mr. Roebel testified that all of PSI's electric generating and related facilities are used and useful by PSI in the provision of utility service to its retail electric customers. Pet. Ex. O, p. 5.

No party took issue with the used and useful nature of PSI's generating facilities. We find that, as of the applicable cut-off date, updated as permitted by the Prehearing Conference Order, the above-described properties were used and useful and reasonably necessary for the convenience of the public and should be included in PSI's rate base.

[8] (2) *Petitioner's Transmission and Distribution Facilities.* The evidence presented in this Cause demonstrates that PSI owns and/or operates over 5,800 circuit miles of transmission lines, over 130 transmission substations, approximately 20,500 miles of distribution lines, approximately 440 distribution substations and various other distribution equipment, such as capacitors, line transformers, street lights and meters. PSI's transmission system is jointly owned with WVPA and IMPA. PSI is interconnected with nine other utility control areas, and the Cinergy transmission system is interconnected with twelve other utility control areas. Pet. Ex. B, p. 10.

Approximately one year ago, PSI and CG&E transferred functional control of the operation of the Cinergy transmission system to the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO" or "MISO"). PSI and CG&E are also parties to the East Central Area Reliability Council Agreement ("ECAR Agreement"), which coordinates the planning and operation of generation and transmission facilities and provides for maximum reliability of the regional bulk power supply. In the opinion of PSI's witness Ronald R. Jackups, Vice President, Electric System Operations, PSI's transmission facilities are used and useful in providing service to PSI's retail electric customers. Pet. Ex. M, p. 8. No party took issue with the used and useful nature of PSI's transmission and distribution ("T&D") facilities. We find that, as of the applicable cut-off date, such facilities were used and useful and reasonably necessary for the convenience of the public and should be included in PSI's rate base.

[9] (3) *Petitioner's Office and General Facilities.* The evidence shows that PSI's office facilities generally consist of the Company's corporate offices in Plainfield and numerous field offices located throughout PSI's service territory. These office facilities are used to provide customer service, sales, economic development, billing, payment, engineering, financial,

accounting, service dispatch, construction, maintenance, service restoration, and other services necessary in the conduct of the electric utility business. In addition, PSI's 24-hour Call Center, garage and storeroom are located at its corporate offices. Pet. Ex. M, pp. 8-9. No party took issue with the used and useful nature of PSI's office and general facilities. We find that Petitioner's office and general facilities were, as of the applicable cut-off date, used and useful and reasonably necessary for the convenience of the public and should be included in PSI's rate base.

[10, 11] *Original Cost of PSI's Electric Property.* PSI's proposed jurisdictional net original cost of its electric utility plant in service, including plant in service net of accumulated depreciation, fuel stock, emission allowances, and materials and supplies ("M&S"), was $3,662,350,000, as of the appropriate cut-off date in this case. Pet. Ex. OO-3. No party took issue with Petitioner's jurisdictional net original cost rate base, and we find that the jurisdictional net original cost of PSI's electric utility property used and useful for the benefit of the public is $3,662,350,000, comprised of the following elements:

Net Electric Utility Plant in Service	$3,463,726,000
Fuel Stock	$67,925,000
Emission Allowances	$14,651,000
AFUDC Continuation/Deferred Depreciation	$75,202,000
Materials and Supplies	$40,846,000
Net Utility Rate Base	$3,662,350.000

Pet. Ex. X-1, as updated as of October 6, 2003, and as adjusted per Pet. Ex.. OO-3.

C. *Fair Value of PSI's Electric Property.*

[12, 13] (1) *Legal Requirements.* Ind. Code § 8-1-2-6 requires this Commission to value a public utility's property at its "fair value." In *Indianapolis Water Co. v. Public Service Comm'n*, 484 N.E.2d 635 (Ind. Ct. App., 1985), the Indiana Court of Appeals confirmed that a utility should be entitled to earn a fair rate of return on the fair value of its utility property used and useful in serving the public. The Court gave this Commission the following four basic directives regarding the application of the concept of "fair value":

> (a) It is upon the statutory "fair value" of its used and useful property that a utility should be allowed to earn a return.
>
> (b) "Fair value" is not an either/or situation as to original cost or reproduction cost new. It is a conclusion or final figure, drawn from all the various values or factors to be weighed in accordance with the statute by this Commission.
>
> (c) In its determination of "fair value", this Commission may not ignore the commonly known and recognized fact of inflation.
>
> (d) While original cost is one of the factors that this Commission should consider in arriving at a "fair value" figure, it is not necessarily, in and of itself, an accurate reflection of the "fair value" of the utility's property.

In the *Indianapolis Water Co.* case, the Court of Appeals referred to the Supreme Court's holding in *Public Service Comm'n v. City of Indianapolis*, 235 Ind. 70, 131 N.E.2d 308, 325 (1956), that "reproduction cost new less depreciation cannot be disregarded in fixing a valuation for rate making purposes." The Court of Appeals went on to indicate that these observations "are as pertinent today as they were in 1956." *Indianapolis Water*, 484 N.E. 2d at 640. The Court of Appeals reiterated that this Commission must authorize rates that provide the utility with the opportunity to earn a fair rate of return on the fair value of its property in *Gary-Hobart Water Corp. v. Indiana Utility Regulatory Comm'n*, 591 N.E.2d 649, 653-54 (Ind. Ct. App., 1992), *reh'g denied.*

(2) *Reproduction Cost New Less Depreciation.* A valuation of PSI's electric utility plant as of September 30, 2002, was made by PSI witness John J. Spanos. This study was based

on the reproduction cost new of such property, less depreciation. The total appraised value at that date was determined to be not less than $5,269,844,632. The valuation was determined by applying cost trend factors to the original cost of the various types of PSI's utility property. Reductions for depreciation were based on physical inspection, analysis of PSI's mortality experience with respect to its property history and past retirements of property and judgment based upon Mr. Spanos' experience. Pet. Ex. T, p 15. No party took issue with Mr. Spanos' valuation. After adjustments for major projects, fuel stock, emission allowances, M&S and jurisdictional separation, PSI's evidence showed, and we find, that the reproduction cost new less depreciation value of PSI's utility property is not less than $5,799,973,000. Pet. Ex. Z-8.

(3) *Fair Value Determination*. The fair value of Petitioner's used and useful property at August 31, 1995, found in Petitioner's last rate case was $2,838,569,000 (excluding M&S, fuel stockpile and *pro forma* fuel). Adjusting this value for inflation since the cut-off date in the 1996 Order produces a Consumer Price Index ("CPI") adjusted value of $3,438,471,000. To this value must be added PSI's property additions, net of retirements, since the 1996 Order, of $1,215,055,000, and M&S, fuel stock and emission allowances of $203,006,000. Such a calculation results in a valuation of Petitioner's total jurisdictional plant in service and used and useful in the provision of retail electric service to the public of $4,856,532,000. Pet. Ex. C-6. We find that the fair value of Petitioner's total jurisdictional plant in service and used and useful in the provision of retail electric service to the public is $4,856,532,000.

[14-19] 5. *Fair Rate of Return*. Having determined the fair value of Petitioner's used and useful property for the provision of retail electric utility service in Indiana, we turn now to a determination of a level of net operating income that represents a reasonable return on that property. This determination requires balancing the interests of the investors and consumers through the exercise of a fair and enlightened judgment, having regard to all relevant facts. *See, Bethlehem Steel Corp. v. Northern Ind. Public Serv. Co.*, 397 N.E.2d 623, 630 (Ind. Ct. App., 1979).

In the case of *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679, 692-693 (1923), the Court set the standard against which a determination of a fair rate of return is measured:

> What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

262 U.S. at 692-693.

In the case of *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944), the Court expanded on the guidelines to be used to assess the reasonableness of the allowed return, and recognized that revenues must cover capital costs:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock . . . by that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

320 U.S. at 603.

One widely accepted method for evaluating the reasonableness of a public utility's return involves a consideration of capital structure and development of an overall weighted cost of capital. However, this Commission utilizes cost of capital estimation evidence as only one factor in determining the fair rate of return for a public utility. Cost of capital testimony, while relevant evidence in the determination of a fair rate of return, is clearly not the only consideration. We have repeatedly found:

> Cost of capital is an important element of the ratemaking process. However, we have pointed out many times that cost of capital is not synonymous with the fair rate of return. Ultimately, the determination of a fair rate of return is the prerogative of the Commission, taking into consideration all the relevant evidence. The objective is to determine the return which is reasonably sufficient to assure confidence in and financial soundness of the utility and adequate, under efficient and economical management, to maintain and support its credit and to enable it to raise the money necessary for the proper discharge of its public duties. *Columbus Gas Light Co. v. Public Serv. Comm'n of Ind.*, 193 Ind. 399, 404-406, 140 N.E. 538, 540 (1923); *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679, 692-693 (1923). These goals go well beyond the use of formulas and mathematical calculations which may imply a level of precision which does not really exist . . . . Rather, we are to exercise the flexibility afforded us by statute and the Indiana Supreme Court.
>
> *See, PSI Energy, Inc.* Cause No. 40003, (Ind. Util. Reg. Comm'n, September 27, 1996), at 34-35.

The Indiana courts have supported this view and have held that, in determining an appropriate rate of return, it is not necessary for this Commission to determine the cost of capital, and that the Commission may consider evidence regarding the cost of capital in conjunction with other evidence presented in the proceeding. *Bethlehem Steel Corp. v. Northern Ind. Public Serv. Co.*, 397 N.E.2d 623, 630 (Ind. Ct. App., 1979); *Office of Utility Consumer Counselor v. Public Serv. Co.*, 449 N.E.2d 604, 607 (Ind. Ct. App., 1983). Determining a fair rate of return is the prerogative of this Commission after giving weight to all material evidence. The Indiana Court of Appeals has recognized that it is appropriate for this Commission to utilize the rate of return as a "balance wheel" to provide a limited margin of error for the resolution of other issues. The Commission's primary objective is to reach an overall result that is equitable and that will permit continuity of utility services on a sound financial basis. *L. S. Ayres & Co. v. Indianapolis Power & Light Co.*, 351 N.E.2d 814, 821 (Ind. Ct. App., 1976). The determination of a utility's revenue requirement is primarily an exercise of informed regulatory judgment. If the judgment is to be exercised properly, the Commission must examine every aspect of the utility's operation, and the economic environment in which the utility functions, to ensure that the data it has received is representative of operating conditions that will, or should, prevail in future years. *City of Evansville v. Southern Ind. Gas & Electric Co.*, 339 N.E.2d 562, 568 (Ind. Ct. App., 1975).

With this background in mind, we now turn our attention to the evidence submitted in this proceeding concerning Petitioner's capital structure, cost of capital, and other matters relevant to the determination of a fair return for Petitioner, including: the relative risks facing the energy industry and PSI; PSI's financial condition, financing requirements and financial objectives; PSI's credit quality; and PSI's performance in rendering retail electric utility service in Indiana.

[20, 21] A. *Capital Structure.* The Prehearing Conference Order provided that the economic and financial data used in determining Petitioner's cost of capital and capital structure shall not be restricted as to the time or method of adjustment used for financial and accounting exhibits, but should be as current as possible and updated as of the prefiling dates set forth in that order. Pursuant to this provision, Petitioner's October 6, 2003 filing updated its actual capital structure as of August 31, 2003, with certain updates for events that occurred in September 2003. Pet. Ex. X-32, Corrected; Pet. Ex. VV-1.

Intervenor Kroger took issue with PSI's regulatory capital structure and argued that short-term debt should be included in PSI's capital structure for ratemaking purposes. Kroger Ex. No. 1, p. 16. Additionally, PSI-IG witness Michael Gorman expressed concern about the $200 million equity infusion to PSI from its parent company, Cinergy Corp. PSI-IG Ex. No. 3, p. 8. PSI witnesses Stephen M. Farmer and Ronald R. Reising addressed these arguments and concerns relative to the capital structure to be utilized in this case for ratemaking purposes.

(1) *Short-Term Debt in the Regulatory Capital Structure.* Mr. Stephen Farmer, PSI's Revenue Requirements Manager, opposed the inclusion of short-term debt in PSI's capital structure for regulatory purposes, explaining that short-term debt is used to finance items that are not in rate base, such as certain regulatory assets and cash working capital needs and CWIP. Pet. Ex. QQ, p. 2. Mr. Farmer pointed out that this Commission, in excluding short-term debt from PSI's regulatory capital structure in Cause No. 40003, rejected the OUCC's argument in that case — and not repeated by the OUCC here — that the portion of PSI's short-term debt that exceeded PSI's CWIP balance should be included in PSI's capital structure for ratemaking purposes. *Id.*

Mr. Farmer further noted that in Cause No. 40003, the OUCC witness Matthew Kahal testified that it would be appropriate to exclude short-term debt from the capital structure only if short-term debt balances are comparable to (or less than) CWIP balances. Mr. Farmer pointed out that the balance of PSI's short-term debt outstanding at August 31, 2003, was $112,333,000, while its CWIP balance was $154,456,000. While acknowledging that a portion of PSI's CWIP is eligible for CWIP ratemaking treatment (*i.e.*, qualified pollution control expenditures), Mr. Farmer pointed out that short-term debt is also used to finance working capital needs and costs of assets that are not recovered in rates. Pet. Ex. QQ, p. 3. As for a suggestion that short-term debt may have become a permanent component of PSI's capital structure, Mr. Farmer observed that PSI's investment in plant in service has increased significantly since the end of the test period in this case — yet during this same period PSI's short-term debt balance has not increased appreciably.

In support of Kroger's position, Mr. Kevin Higgins quoted from Standard and Poor's 2001 publication, "Corporate Ratings Criteria" that states:

> Traditional measures focusing on long-term debt have lost much of their significance, since companies rely increasingly on short-term borrowings. It is now commonplace to find permanent layers of short-term debt, which finance not only seasonal working capital but also an ongoing portion of the asset base.

Mr. Farmer responded that financial analysts do not make a regulatory distinction between used and useful plant included in rate base and other assets. Pet. Ex. QQ, p. 5. Financial analysts, he said, include short-term debt as part of company capitalization because the "asset base" of a company would include investments in plant not receiving rate treatment (*e.g.*, non-qualified pollution control property CWIP investments and regulatory assets). During cross-examination, Mr. Farmer also pointed out that the same Standard and Poor's publication quoted by Mr. Higgins also states that "Flexibility can be jeopardized when a firm is overly reliant on bank borrowings or commercial paper." Tr. at Y88.

As additional support for its position that short-term debt should be included in PSI's capital structure, Kroger emphasized the difference between PSI's capitalization and PSI's original cost depreciated rate base, arguing that a utility's rate base should approximate its capitalization. Kroger Ex. No. 1, pp. 10-11.

In response, Mr. Farmer indicated that that balance between capitalization and rate base is simply a theory that presumes "perfect ratemaking" — that is, perfect and perfectly timed recovery of the utility's costs, and consistently fair returns earned by the utility, year in and year out. In reality, ratemaking and recovery of costs are not perfect. The utility may or may not earn consistently fair returns year in and year out. Tr. at Y56-61 and Y89-90. Mr. Farmer presented a number of explanations for the difference between PSI's rate base and its capitalization. These explanations include: changes in accounts receivables balances; changes in accounts payable balances; different rate case cut-off dates for rate base on the one hand, and capital structure on the other; PSI's use of its sale of accounts receivables proceeds to redeem outstanding first mortgage bonds and preferred stock; impacts on capital structure and retained earnings produced by various accounting requirements; and less than reasonable returns earned by PSI at various times, effectively shrinking investors' capital investments. Tr. at Y56-61. With regard to this latter reason — investors' capital investments effectively diminishing over time to the extent that the utility earns less than a reasonable return — Mr. Farmer emphasized that utility investors expect and demand a reasonable return over time of their principal actually invested, not a return on a diminished capital investment. Tr. at Y60.

The evidence indicates that Petitioner's short-term debt balances have been used to finance construction-work-in-progress and other capital items, such as regulatory assets, not in PSI's rate base. If short-term debt had been financing plant additions in Petitioner's rate base, the short-term debt would have been increasing appreciably as substantial plant was added. Moreover, as Mr. Farmer pointed out, the cost of short-term debt is reflected in the application of Allowance for Funds Used During Construction ("AFUDC") to CWIP expenditures. Consequently, customers regularly receive the benefit of Petitioner's lower-cost short-term debt through lower capitalized AFUDC rates. Accordingly, based on our review of the evidence presented in this Cause, we conclude — as we did in Cause No. 40003 — that PSI's short-term debt should not be included in its capital structure for ratemaking purposes.

(2) *Cinergy's $200 Million Equity Infusion to PSI.* PSI-IG witness Michael Gorman expressed concern over PSI's receipt of a $200 million equity infusion from its parent company, Cinergy Corp., and recommended that certain assurances be made by PSI in order to support its claim that the equity infusion will positively enhance its credit rating. PSI-IG Ex. No. 3, p. 8. The assurance Mr. Gorman wanted was that such equity infusion will occur without increasing Cinergy's overall debt level. *Id.* Mr. Gorman argued that if Cinergy is making an equity infusion in PSI by issuing additional debt, the higher debt level of Cinergy could have as much negative credit rating impact on PSI as the positive impact credited from the increase in PSI's common equity and the decrease in its debt leverage. *Id.* Mr. Gorman noted that PSI's bond rating is heavily tied to Cinergy's bond rating and he said that analysts were concerned with Cinergy's highly leveraged capital structure. *Id.* at 9.

In response to Mr. Gorman's concern, PSI witness Ronald R. Reising, Cinergy's Vice President of Finance, noted that Cinergy has raised over $900 million in additional equity since December 2001, and that the funds raised by Cinergy's equity issuances supported the funding of the $200 million infusion to PSI. Pet. Ex. EE, p. 15. Similarly, in earlier testimony, PSI witness Mr. James E. Rogers, Chairman and CEO of both Cinergy and PSI, explained that Cinergy made the $200 million equity infusion in order to strengthen PSI's balance sheet and maintain PSI's credit ratings. Pet. Ex. A, p. 29.

Regarding the $200 million equity infusion from PSI's parent, we conclude that PSI adequately explained both the source of the funds (from the $900 million in equity issuance funds raised by Cinergy since December 2001) and, more importantly, the use of the funds to strengthen PSI's balance sheet and preserve PSI's credit quality.

(3) *Commission's Ultimate Finding Regarding PSI's Regulatory Capital Structure.* Based on the foregoing, we find that the PSI capital structure to be used in this case is:

Description	*Capitalization*
Common Equity	$1,603,374,000
Preferred Stock	42,333,000
Long Term Debt	1,402,254,000
Deferred Income Taxes	519,273,000
Unamortized ITC — 1970 & Earlier	193,000
Unamortized ITC — 1971 & Later	30,571,000
Customer Deposits	9,741,000
Total Capitalization	$3,607,739,000

B. *Cost of Capital.* It was undisputed that PSI's evidence demonstrated that its embedded cost of long-term debt was 6.37%, preferred stock 6.11%, and customer deposits 6%, or that post-1970 unamortized investment tax credits should have the weighted cost of long-term debt, preferred stock and common equity capital. Pet. Ex. X-32 Corrected; Pet. Ex. VV-1. There was disagreement only concerning Petitioner's current cost of common equity capital. Petitioner, OUCC, and PSI-IG submitted testimony sponsoring the results of their respective cost of common equity capital studies. Staff submitted testimony concerning the results of these three studies. CAC submitted testimony addressing certain aspects of Petitioner's risk profile.

[22] (1) *Petitioner's Cost of Common Equity Evidence.* In his testimony filed on March 28, 2003, Petitioner's witness Dr. Roger A. Morin recommended that PSI be allowed to earn an 11.5% return on its common equity capital, based on studies he performed using the Capital Asset Pricing Model ("CAPM"), the Risk Premium ("RP"), and Discounted Cash Flow ("DCF") methods of determining the cost of such capital. Pet. Ex. G, p. 4. During his oral testimony on June 12, 2003, Dr. Morin indicated that there had been a slight decrease in long-term interest rates and some slight changes in dividend yields from the time of his March 2003 prefiled testimony, resulting in a slight decrease in his recommended return on common equity from 11.5% to in the vicinity of 11.2% to 11.3%. Dr. Morin noted in his oral update that he would be submitting a full-fledged update before the final phase of hearings. Tr. at G109-G110. In his testimony filed as a part of PSI's August 31, 2003 Update, Dr. Morin reduced his recommended cost of common equity to 11.2%, based on more recent data. Pet. Ex. TT, pp. 2-3. Use of Dr. Morin's cost of common equity in PSI's proposed regulatory capital structure produced an overall, weighted cost of capital of 7.63%. Pet. Ex. X-32, Corrected; Pet. Ex. VV-1.

Dr. Morin performed two CAPM analyses, one using what he characterized as the "plain vanilla" CAPM and another using an empirical approximation of the CAPM ("ECAPM"). He also performed six RP analyses: (i) a historical RP analysis of the electric utility industry using Treasury bond yields; (ii) a historical RP analysis of the electric industry using A-rated utility bond yields; (iii) a historical RP analysis of the natural gas utility industry using Treasury bond yields; (iv) a historical RP analysis of the natural gas industry using A-rated utility bond yields; (v) a study of the risk premiums allowed in the electric utility industry relative to Treasury bond yields; and (vi) a study of the risk premiums allowed in the electric utility industry relative to A-rated utility bond yields. He performed DCF analyses, using both Zacks Investment Research, Inc. ("Zacks") and Value Line Investors' Service ("Value Line") dividend growth estimates, on three surrogates for the Company: (i) a group of electric utilities that make up Moody's Electric Utility Index; (ii) a group of investment-grade, vertically integrated electric utilities; and (iii) a group of natural gas distribution utilities. Pet. Ex. G, pp. 4 and 46; and Pet. Ex. TT, p. 3. His revised cost of common equity capital results ranged from 10.3% to 12.5%, averaging 11.2%. Pet. Ex. TT, p. 3.

In his testimony, Dr. Morin indicated that he believes that all of the traditional cost of equity estimation methodologies are difficult to implement when you are dealing with the fast-changing circumstances of the current electric utility industry. Dr. Morin indicated that he believes that past earnings and dividends of electric utilities are simply not indicative of the future, as historical growth rates of earnings and dividends have been depressed by eroding margins due to a variety of factors, including structural transformation to a more competitive environment. As a result, Dr. Morin testified that he believes that these historical data are not representative of the future long-term earning power of these companies. Moreover, Dr. Morin indicated that he believes that historical growth rates are not representative of future trends for several electric utilities involved in mergers and acquisitions, as these companies going forward are not the same companies for which historical data are available. Pet. Ex. G, pp. 13-14. Dr. Morin indicated that a similar conclusion applies to historical risk premiums. He testified that historical measures of risk, such as beta, are necessarily downward-biased in assessing the present fluid circumstances of the electric utility industry. Current changes in the fundamentals of electric utilities are not yet fully reflected in historical data. Pet. Ex. G, p. 14.

Dr. Morin stated that the return allowed for a public utility must necessarily reflect the investors' return requirements and be commensurate with returns on investments in other firms having corresponding risks. The allowed return, he said, should be sufficient to assure confidence in the financial integrity or strength of the firm, in order to maintain its creditworthiness and the ability to attract capital on reasonable terms. The attraction of capital standard focuses, he testified, on investors' return requirements that are generally determined using market value methods, such as the RP, CAPM or DCF methods. These market value tests define fair return as the return investors anticipate when they purchase equity shares of comparable risk in the financial marketplace. The economic basis for market value tests is that new capital will be attracted to a firm only if the return expected by the suppliers of funds is commensurate with that available from alternatives of comparable risk. Pet. Ex. G, pp. 6-8.

Dr. Morin testified that the heart of utility regulation is the setting of just and reasonable rates by way of a fair and reasonable return, and concluded that the end result of this Commission's decision in this proceeding should be to allow PSI the opportunity to earn a return on common equity capital that is: (i) commensurate with returns on investments in other firms having corresponding risks; (ii) sufficient to assure confidence in PSI's financial integrity; and (iii) sufficient to maintain PSI's creditworthiness and ability to attract capital on reasonable terms. Pet. Ex. G, p. 10.

(a) *Dr. Morin's CAPM and Risk Premium Results.* Dr. Morin testified that the fundamental concept underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. Denoting the risk-free rate by "R_F" and the return on the market as a whole by "R_M", he stated the formula for the "plain vanilla" CAPM is as follows:

$$K = R_F + \beta\ (R_M - R_F)$$

Dr. Morin testified that under this formula the return required by investors (K) is made up of a risk-free component (R_F), plus a risk premium given by β (R_M - R_F). To derive the CAPM risk premium estimate, three inputs are required: the risk-free rate (R_F), the beta (β) and the market risk premium (R_M − R_F). For the risk-free rate, Dr. Morin used 5.0%. For the beta, he used 0.72, and for the market risk premium, he used 6.8%. Pet. Ex. G, p. 15.

Dr. Morin explained that the basis for his 5% risk-free rate was the actual yield on long-term Treasury bonds, in February 2003, shortly before he filed his initial testimony in March of 2003. Pet. Ex. G, p. 16. Dr. Morin's market risk premium of 6.8%, was based on the results of both forward-looking and historical studies of long-term risk premiums, as shown in the Ibbotson Associates study, *Stocks, Bonds, Bills, and Inflation, 2002 Yearbook*. Pet. Ex. G, p. 20. This study, he said, compiles security returns from 1926 to 2001 and shows that a broad market sample of common stocks outperformed the income component of long-term U.S. government bonds by approximately 7.5%. Pet. Ex. G, p. 20.

To determine an appropriate beta for PSI, whose common stock is not publicly traded, Dr. Morin used two proxies — the average beta for the electric utility industry, as reported by Value Line, and the average beta of a group of natural gas distribution utilities that he selected. Pet. Ex. G, p. 17. The average beta for the electric utility industry, he said, was 0.71 as of January 2003, and the average beta for the group of natural gas distribution utilities was 0.72 as of January 2003. Pet. Ex. G, pp. 17-18; Pet. Ex. G-2; and Pet. Ex. G-3. He observed that ongoing changes in risk fundamentals are not yet fully reflected in historical beta estimates for electric utilities and, as a result, the historic beta estimates are downward biased. Pet. Ex. G, p. 19. Given the dramatic changes occurring in the electric utility operating environment, Dr. Morin stressed the need to be forward-looking because investors consider prospective long-term risks when making investment decisions. Pet. Ex. G, p. 18. In his "plain vanilla" CAPM study, Dr. Morin used a beta of 0.72, for what he characterized as a conservative estimate, of the beta applicable to PSI's electric utility operations. Pet. Ex. G, p. 20. Use of that beta, together with a risk-free rate of 5.0% and a market risk premium of 6.8%, produced in Dr. Morin's initial testimony a CAPM-based estimate of PSI's cost of common equity of 9.9% ($5.0\% + 0.72 \times 6.8\%$), and 10.2% with flotation costs. Pet. Ex. G, p. 23.

Dr. Morin testified that because the CAPM produces a downward-biased estimate of equity cost for companies with a beta of less than 1.00, expanded CAPMs have been developed, which relax some of the more restrictive assumptions underlying the traditional CAPM responsible for this bias and thereby enrich its conceptual validity. Pet. Ex. G, p. 23. Using this "empirical" version of the CAPM, he said that the formula becomes:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\,\beta\,(R_M - R_F)$$

Utilization of this formula produced a return on common equity of 10.4% without flotation cost, and 10.7% with flotation costs, using 5.0% for R_F, a market risk premium of 6.8% and a beta of 0.72. Pet. Ex. G, p. 23.

For his RP approach to cost of common equity, Dr. Morin examined historical risk premiums for the electric utility industry from 1931 to 2001 using Moody's Electric Utility Index as an industry proxy. Pet. Ex. G, p. 24; and Pet Ex. G-4. A risk premium was estimated by computing the actual return on equity capital for Moody's Index for each year from 1931 to 2001, using the actual stock prices and dividends of the index, and then subtracting the long-term government bond return for that year. The resulting average risk premium over the period was 5.6% over long-term Treasury bonds. Given that long-term Treasury bonds were yielding 5.0% shortly before Dr. Morin's March 2003 filing, he determined the implied cost of equity for the average electric utility using this method to be 5.0% + 5.6% = 10.6% without flotation cost, and 10.9% with flotation costs. Pet. Ex. G, p. 24.

Dr. Morin testified that he did not adjust his risk premium results to account for PSI's risk relative to the industry because PSI's total investment risks are currently comparable to those of the electric utility industry. He noted that PSI's bonds are currently rated "A3", which is close to the industry average. Because the historical risk premium estimate from the Moody's electric utility industry group reflects the risk of the average electric utility and because PSI's total investment risks are currently comparable to those of the industry, Dr. Morin concluded that the expected equity return

from the Moody's group is applicable to PSI. Pet. Ex. G, p. 24.

Using the same historical analysis described above, but substituting the yield on A-rated electric utility bonds for the yield on U.S. Treasury bonds, produced an average risk premium of 4.5% in Dr. Morin's initial testimony. Pet. Ex. G, pp. 25-26; and Pet. Ex. G-5. Adding this premium to the current yield on A-rated bonds of 7.0% produced an implied cost of equity for the average electric utility of 11.5% without flotation cost, and 11.8% with flotation costs, he said. Pet. Ex. G, p. 26.

Applying the same risk premium analysis to the natural gas utility industry produced an implied cost of equity for the average electric utility of 10.7% without flotation cost, and 11.0% with flotation costs, using long-term Treasury bonds for the risk free rate, in Dr. Morin's initial testimony. Pet. Ex. G, p. 26; and Pet Ex. G-6, Substituting the long-term bond yield for A-rated utilities for the yield on Treasury bonds produced an average risk premium of 5.0%, which, when added to the yield on A-rated bonds of 7.0% at the time of his initial testimony, produced an implied cost of equity of 12% (7.0% + 5.0%) without flotation cost, and 12.3% with flotation costs.[1] Pet. Ex. G, pp. 26-27; and Pet Ex. G-7.

Dr. Morin also examined the historical risk premiums implied in the returns on common equity ("ROE") allowed by regulatory commissions over the last decade relative to the contemporaneous level of the long-term Treasury bond yield. Pet. Ex. G, p. 27. This allowed risk premium approach produced an average ROE spread over long-term Treasury yields of 5.1% for the 1993-2002 period. Dr. Morin's data showed that there has been a rising trend of the risk premium in response to lower interest rates and rising competition and restructuring. Pet. Ex. G, pp. 27-28. These studies produced costs of common equity of 11.3% and 11.4% at the time of Dr. Morin's initial testimony, depending on whether long term Treasury bonds or A-rated utility bonds were used. Pet. Ex. G, pp. 27-30. Dr. Morin updated the CAPM and RP results of his study in October 2003, using data as of the end of August. He indicated that, as of the end of August 2003, the yield on long-term Treasury bonds was 5.3%, compared to 5.0% in February when he prepared his initial study. The following table summarizes Dr. Morin's ROE estimates obtained from his CAPM and RP studies, updated as of August 31, 2003:

Risk Premium Methods	*%ROE*
CAPM	10.9%
ECAPM	11.4%
Risk Premium Electric Utility Treasury Bonds	11.2%
Risk Premium Electric Utility "A"-Rated Bonds	12.1%
Risk Premium Natural Gas Treasury Bonds	11.3%
Risk Premium Natural Gas "A"-Rated Bonds	12.5%
Allowed Risk Premium Treasury Bonds	11.3%
Allowed Risk Premium "A"-Rated Bonds	11.4%

Pet. Ex. TT, p. 3.

(b) *Dr. Morin's DCF Results*. Dr. Morin observed that according to DCF theory, the value of any security to an investor is the expected discounted value of the future stream of dividends or other benefits. Pet. Ex. G, p. 30. One widely used method to measure these anticipated benefits in the case of a non-static company, he said, is to examine the current dividend plus the increases in future dividend payments expected by investors. This valuation process, he said, can be represented by the following formula, for the traditional DCF model:

$$K_e = D_1/P_o + g$$

K_e = investors' expected return on equity

D_1 = expected dividend during the coming year

P_o = current stock price

g = expected growth rate of future dividends, earnings, book value

Pet. Ex. G, pp. 30-31. The idea of this market value approach, is to infer K_e from the observed share price, dividend, and from an estimate of investors' expected future growth. Pet. Ex. G, p. 31.

Dr. Morin applied the DCF model to three proxy groups for PSI: (i) Moody's electric utilities; (ii) a group of vertically integrated electric utilities that he selected; and (iii) a group consisting of widely-traded dividend-paying natural gas distribution companies, drawn from the Value Line edition of the Value Line Gas Distribution Group. Dr. Morin used the spot dividend yields reported in the January 2003 edition of Value Line. Pet. Ex. G, pp. 31-32. Because dividends are paid quarterly in practice, Dr. Morin observed, the investors' required return must be determined with a DCF model that reflects the quarterly nature of dividends payments. Pet. Ex. G, p. 33; see also, Pet. Ex. G, pp. 33-36; and Pet. Ex. G-8.

Dr. Morin explained that, as a proxy for expected growth, he examined growth estimates developed by professional analysts employed by large investment brokerage institutions. These forecasts, he said, are made by large reputable organizations, and the data are readily available to investors and representative of the consensus view of investors. Because of the dominance of institutional investors in investment management and security selection, and their influence on individual investment decisions, analysts' growth forecasts influence investor growth expectations and provide a sound basis for estimating the cost of equity with the DCF model. Dr. Morin used analysts' long-term growth forecasts contained in Zacks as proxies for investors' growth expectations in applying the DCF model. He also used Value Line's growth forecast as an additional proxy. Pet. Ex. G, p. 37.

Dr. Morin did not use historical growth rates in his DCF approach because he believes that they have little relevance as proxies for future long-term growth. Pet. Ex. G, p. 38. They are downward-biased by the sluggish earnings performance in the last five years, due to the structural transformation of the electric utility industry from a regulated monopoly to a more competitive environment. Pet. Ex. G, p. 38. He illustrated this point by adding the historical growth rates over the past five years of 2.1%, -1.3%, and 3.5% for the electric utility companies that make up Value Line's Electric Utility composite group to the average 5.0% dividend yield prevailing in February of 2003 for the companies he examined; this produced cost of equity estimates of 7.1%, 3.7%, and 8.5%, using earnings, dividends, and book value growth rates, respectively. He observed that such estimates of common equity costs are less than, or close to, the cost of debt for these companies. Pet. Ex. G, p. 38.

Dr. Morin, in his initial testimony, stated that for the electric utilities that make up Moody's Electric Utility Index (Column 2 of page 1 of Pet. Ex. G-10), the average long-term growth forecast obtained from Zacks was 5.2% and, adding this growth rate to the average expected dividend yield of 5.8% (Column 3), produced an estimate of equity costs of 11.0% for the group, unadjusted for flotation costs or quarterly timing. Providing for the quarterly timing of dividends and adding an allowance for flotation costs to these results brings the cost of equity estimate to 11.5%, shown in Column 5 of Pet. Ex. G-10. Pet. Ex. G, p. 39. Using Value Line's long-term earnings growth forecast of 5.4%, instead of the Zacks consensus forecast, the cost of equity for the Moody's group is 11.1%, and, after provision for quarterly timing and allowance for flotation costs, the cost of equity estimate is 11.6%, as shown on page 2 of Pet. Ex. G-10. Pet. Ex. G, p. 39.

Using a group of 13 vertically integrated electric utilities (*i.e.*, publicly listed parent companies whose electric utility operating subsidiaries include both transmission and distribution ("T&D") and generation activities), and the average long-term growth forecast obtained from Zacks of 6.6% for this group, and adding this growth rate to the average expected dividend yield of 5.6%, produced an estimate of equity costs of 12.2% for the group. Pet. Ex. G, pp. 39-40; and Pet. Ex. G-11 Providing for quarterly timing of dividends and adding an allowance for flotation costs to the results of Column 4 of Pet. Ex. G-11 brings the cost of equity estimate to 12.7%. Pet. Ex. G, p. 40. Removing the impact of significant outliers from the result, to produce a truncated average, resulted in a 12.0% cost of common equity. Pet. Ex. G, p. 40.

Using Value Line's long-term earnings growth forecast of 6.5%, instead of the Zacks consensus forecast, Dr. Morin produced a cost of equity for the vertically integrated electrics of 12.0%. Pet. Ex. G, p. 40. Allowance for quarterly timing and flotation costs brought that cost of equity to 12.5%. The truncated average was 12.0%. Pet. Ex. G, p. 40.

Dr. Morin testified that using the average long-term growth forecast obtained from the Zacks corporate earnings database for the gas distribution group of 5.5%, and adding that growth rate to the average expected dividend yield of 4.7%, produced an estimate of equity costs of 10.2% for the gas distribution group. Pet. Ex. G, p. 41, and Pet. Ex. G-12. Dr. Morin added that providing for quarterly timing of dividends and flotation costs to this result brings the cost of equity estimate to 10.7%. Pet. Ex. G, p. 41. Repeating the same procedure, but using Value Line's long-term earnings growth forecast of 8.7%, instead of the Zacks consensus growth forecast, produced a cost of common equity for the gas distribution group of 13.6%, unadjusted for flotation costs. Pet. Ex. G, p. 41. Adding an allowance for flotation costs and allowing for quarterly dividend payments brought this cost of equity estimate to 13.8%, while the truncated average result was 13.6%. Pet. Ex. G, p. 41; and Pet. Ex. G-12.

Dr. Morin updated the DCF results of his study in October 2003, using data as of the end of August. He indicated that the DCF results for the vertically integrated electric and natural gas distribution utilities had decreased significantly from February when he prepared his initial study, in part due to the substantial revision in dividend taxation which lowered dividend yields (increased stock prices) and in part due to the lowering of utility growth forecast by analysts. The table below summarizes Dr. Morin's DCF estimates of the costs of common equity to PSI, updated as of August 31, 2003:

DCF Study	*%ROE*
Moody's Electrics Zacks Growth	10.3%
Moody's Electrics Value Line Growth	10.3%
Vertically Integrated Electrics Zacks Growth	10.6%
Vertically Integrated Electrics Value Line Growth	10.8%
Natural Gas Distribution Zacks Growth	10.4%
Natural Gas Distribution Value Line Growth	12.1%

Pet. Ex. TT, p. 3.

(2) *OUCC's Cost of Common Equity Evidence*. Edward R. Kaufman, OUCC's Lead Financial Analyst testified regarding PSI's financial condition, overall capital market conditions, and conducted analyses resulting in an initial recommended cost of equity of 9.15%. Mr. Kaufman subsequently updated his recommended cost of equity in October 2003 ("October Update") to 9.25%. Pub. Ex. No. 8U, p. 2. To estimate PSI's cost of equity, Mr. Kaufman employed DCF analyses as well as CAPM methodologies, using two proxy groups of electric companies as well as PSI's parent company, Cinergy. Pub. Ex. No. 8, p. 4. Mr. Kaufman's cost of equity estimates from these analyses ranged from 7.94% to 10.12% in his initial prefiled testimony, and 8.02% to 9.67% in his October Update. Pub. Ex. No. 8, p. 4; and Pub. Ex. No. 8U, Schedule 1, p. 2.

Mr. Steven C. Carver, a principal in the firm Utilitech, Inc., also testified on behalf of the OUCC, and sponsored a weighted overall cost of capital of 6.86%, based upon Mr. Kaufman's initial 9.15% recommendation. Both were later updated to 6.74% and 9.25%, respectively. Pub. Ex. No. 8, p. 4. and Pub. Ex. 3 Revised at Schedule D. OUCC witnesses Mr. Timothy Geswein and Dr. Peter M. Boerger also testified regarding PSI risk levels and required ROE in light of such risks.

Mr. Kaufman characterized Petitioner's financial condition as strong, with a common equity ratio of 47.9% (using a "traditional" securities rating capital structure) that is higher than the 24 electric utilities covered in the C.A. Turner Utility Reports ("Turner Reports"). Pub. Ex. No. 8, p. 5. His testimony quoted from Cinergy's presentations to analysts and the testimony of its CEO, Mr. Rogers, to illustrate how the Company believes it has solid liquidity, recently affirmed investment grade credit ratings, increasing cash flow based on reduced environmental capital requirements and rate increases, and substantially reduced risk due to regulatory and legislative relief as well as improvements in system reliability. Pub. Ex. No. 8, p.6.

Mr. Kaufman observed that the interest rates for US Treasury Bonds are currently at their lowest point in 30-40 years, and indicated that the year-end 2002 yield on long-term government bonds was 4.55% — the lowest year-end yield since 1966. He also identified the fact that the yield on "A" rated utility bonds as of August 5, 2003 was 6.64% and that their annual average yield had not been below 7% since 1968. Pub. Ex. No. 8, p. 7. Mr. Kaufman added that the current 4% prime rate is the lowest since April of 1959. These low costs of debt, he explained, should translate into lower costs of equity as well. Pub. Ex. No. 8, p. 7. Mr. Kaufman noted that the Petitioner recognized a 130 basis point decline in the long term risk free rate of return since Petitioner's last rate case (as demonstrated comparing of Dr. Morin's CAPM risk free rate of return in the last case (6.3%) and the CAPM risk free rate of return he used in the current proceeding (5.0%)).

Mr. Kaufman stated that because PSI's common stock was not publicly traded, one could not apply the DCF or CAPM model directly to PSI. Rather, PSI's cost of equity could be estimated only through the use of a proxy group. Pub. Ex. No. 8, p. 8. He first applied the DCF and CAPM analysis to Dr. Morin's selection of vertically integrated electric utilities as a proxy group. Pub. Ex. No. 8, p. 11. He also examined his own proxy group of electric utilities, using a set of screening criteria that yielded a similar but not identical selection to that used by Dr. Morin. Mr. Kaufman also used Cinergy as a proxy for PSI. Pub. Ex. No. 8, p. 11. The main difference between the criteria Mr. Kaufman used to form his proxy group and that which Dr. Morin used was that Mr. Kaufman included a combination of electric and gas companies in his proxy group and required companies he used in his proxy group to derive at least 75% of revenues from electric operations (instead of 50%, as used by Dr. Morin). Pub. Ex. No. 8, p. 11. Mr. Kaufman explained that he believes that all three of the selected proxy groups in his analysis are notably riskier than PSI because of the group members exposure to power market trading and foreign operations. Pub. Ex. No. 8, p. 13.

In doing his DCF analyses, Mr. Kaufman used the Turner Reports for current dividend yields of large publicly held utilities, converting the current yield to a forward yield by multiplying the current yield by 1 + 1/2 of the Company's expected growth rate. He noted that this conversion methodology has been regularly accepted by the Commission in prior rate proceedings. Pub. Ex. No. 8, pp. 16-17. To estimate the growth rate, Mr. Kaufman employed both historical and forecasted growth rates of earnings, dividends and book value per share, using Value Line as the primary source of growth data. The estimated growth rates that he used were 4.35% for his primary proxy group, 4.18% for Dr. Morin's vertically integrated electric utility proxy, and 2.90% for Cinergy. Pub. Ex. No. 8, p. 18. In an effort to ensure that his analysis was conservative Mr. Kaufman did not include any negative or very low positive growth figures in his analysis. Pub. Ex. No. 8, p. 18. Mr. Kaufman reviewed his estimate of long run growth rates by reference to Reuters Multex.com and CA Turner's Quarterly Dividend Monitor reported data. Pub. Ex. No. 8, p. 19.

Mr. Kaufman prepared multiple DCF analyses intended to allow him to cross check results and examine the impacts of alternative data sources. He summarized these alternative analyses in a chart within his testimony that reflects 3 and 6 month average dividend yields:

	3-month	6-month
Value Line (Primary Proxy)	9.09%	9.31%
Multex (Primary Proxy)	9.80%	10.02%
Value Line (Dr. Morin's Proxy)	9.12%	9.43%
Multex (Dr. Morin's Proxy)	9.81%	10.12%
Cinergy (Value Line)	7.94%	8.24%
Cinergy (Multex)	9.71%	10.02%

Mr. Kaufman's initial prefiled range of common equity costs for his DCF methodology ranged from 7.94% to 10.12%. Pub. Ex. No. 8, p. 21. His October Update reflected a narrower range of DCF results from 8.02% to 9.62%. Pub. Ex. No. 8U, Schedule 1, p. 1.

	3-month	6-month
Value Line (Primary Proxy)	9.15%	9.11%
Multex (Primary Proxy)	9.53%	9.49%
Value Line (Dr. Morin's Proxy)	9.17%	9.19%
Multex (Dr. Morin's Proxy)	9.59%	9.62%
Cinergy (Value Line)	8.02%	8.21%
Cinergy (Multex)	9.48%	9.67%

Mr. Kaufman employed the same proxy groups that he used in his DCF analysis and explained that he believes that the CAPM is typically less reliable than the DCF model because of challenges associated with estimating the market risk premium; issues concerning the application of arithmetic versus geometric means; and, controversies surrounding the basis selected for the risk-free return rate. Pub. Ex. No. 8, pp. 23-25.

For his CAPM risk-free rate, Mr. Kaufman reviewed short term, intermediate term and long term interest rates, ultimately using 30-year Treasury securities as an estimate of long-term yields, and giving virtually no weight to short term and intermediate term interest rates. Pub. Ex. No. 8, p. 26. In an effort to produce a result that is more consistent with the long term perspective needed for cost of equity, Mr. Kaufman used both 3-month and 6-month average yields, rather than a spot yield that might subject his results to unreasonable variability. Pub. Ex. No. 8, p. 26.

Mr. Kaufman's CAPM calculations relied primarily upon Value Line's published betas, but he also reviewed and presented two other sources of beta, derived from Security Risk Evaluation by Merrill Lynch and SmartMoney.com. Pub. Ex. No.8, p. 27. A review of the other betas presented by Mr. Kaufman demonstrates that the betas he relied upon were the largest betas from the three sources that he reviewed. Mr. Kaufman calculated both a geometric mean risk premium and an arithmetic mean risk premium, then averaged the risk premiums, multiplied the average by beta, and combined the product with the risk-free interest rates of long term Treasury securities, producing three CAPM results. Mr. Kaufman supported his use of both the geometric and arithmetic mean risk premium by quoting from a 1982 edition of *Stocks Bonds Bills and Inflation*, by Dr. Roger Ibbotson and from two final orders of this Commission, *People's Gas and Power*, Cause No. 39315, (*Ind. Util. Reg. Comm'n*, October 21, 1992) and *Indiana American Water*, Cause No. 40103, (*Ind. Util. Reg. Comm'n*, May 30, 1996). OUCC Exhibit 8, Kaufman Direct, page 24 line 17 through page 25 line 18. Mr. Kaufman's primary CAPM proxy group relied upon a beta of 0.610, as compared with the average beta for Dr. Morin's proxy group of 0.642 and Cinergy's beta of 0.70. Pub. Ex. No. 8, p. 27.

Mr. Kaufman's CAPM study results are summarized in the following table:

	3 month	6 month
Primary proxy group	7.98%	8.09%
Dr. Morin's proxy	8.15%	8.26%
Cinergy	8.48%	8.59%

Mr. Kaufman's October Update to his CAPM analysis showed the following increases from the results of his direct testimony:

	3 month	6 month
Primary proxy group	8.81%	8.50%
Dr. Morin's proxy	8.79%	8.48%
Cinergy	9.09%	8.78%

Mr. Kaufman's cost of equity ("COE") results in his initial prefiled testimony ranged from 7.94% to 10.12%, with the midpoint of his range at 9.03%. Pub. Ex. No. 8, p. 29. Giving more weight to his DCF results, Mr. Kaufman concluded in his initial prefiled testimony that

Petitioner's cost of equity was 9.15%. In his October Update he concluded that cost of equity had increased 10 basis points to 9.25%. Pub. Ex. No. 8U, p. 6, and Pub. Ex. No. 8, p. 29.

Mr. Kaufman indicated on cross-examination that, while his updated recommended cost of equity for PSI increased, the bottom-end of his updated range increased (from 7.94% to 8.02%) and the top-end of his updated range came down significantly (from 10.12% to 9.67%). Tr. at Q86-Q88. Mr. Kaufman also acknowledged that there was no specific numerical weighting assigned by him to arrive at his estimate of cost of equity for PSI. Tr. at Q88. Mr. Kaufman further acknowledged that he basically combined them and reached his ultimate conclusion concerning his recommended cost of equity for PSI. Tr. at Q88.

Mr. Kaufman testified on cross-examination that he believes that his 9.25% cost of equity for PSI should be reduced if this Commission approves PSI's proposed trackers in this proceeding, as trackers serve to reduce risk. Mr. Kaufman explained that he was not independently testifying to that conclusion; but instead was merely summarizing the testimony of other OUCC witnesses who address the risk mitigation effects of such trackers. Tr. at Q92-Q93 and Q98. Mr. Kaufman clarified on cross-examination that his reference to PSI's proposed trackers that reduce risk, and therefore require a reduction in PSI's cost of equity, do not include PSI's existing: (i) Fuel Cost Charge tracker; (ii) Demand-Side Management tracker; (iii) Construction Work In Progress tracker; or (iv) Sulfur Dioxide Emission Allowance tracker. Tr. at Q93-Q97. Instead, Mr. Kaufman testified that he was only referring to PSI's newly proposed: (i) Nitrogen Oxide Emission Allowance tracker; (ii) Midwest ISO Management Cost and Revenue Adjustment tracker; and (iii) Purchased Power tracker. Tr. at. Q97-Q98.[2]

Mr. Kaufman noted that Dr. Morin's proxy groups contain some electric utilities that were not comparable to PSI. Pub. Ex. No. 8, pp. 36-37. Mr. Kaufman also explained how Dr. Morin's exclusive reliance on forecasted earnings per share in arriving at a growth rate for the DCF method, while ignoring actual growth in dividends per share and book value per share tended to overstate the cost of equity. Pub. Ex. No. 8, pp. 37-38. Mr. Kaufman was also critical of Dr. Morin's method for increasing the actual current dividend yield to a future yield by multiplying the current yield by one plus the Company's expected growth rate, rather than one plus one-half the expected growth rate. Mr. Kaufman supported his one plus one-half growth position by quoting from prior Commission orders and argued that Dr. Morin's full year growth adjustment inappropriately assumes a full year's worth of growth, while a half-year growth adjustment for converting a current yield into a forward annual yield for the DCF model is more appropriate. Pub. Ex. No. 8, pp. 37-39. He was further critical of the fact Dr. Morin's growth rate forecasts were applicable to the next 5-7 years, rather than in perpetuity. Pub. Ex. No.8, p. 39.

Mr. Kaufman also responded to Dr. Morin's argument that many electric utilities have experienced low or negative growth over the last several years, and criticized Dr. Morin's use of Green Mountain Power's forecasted earnings rate of 19.5% per year. Mr. Kaufman explained that historical data can be used in determining a growth rate for a DCF analysis only if such dramatic "outliers" are removed from the analysis. Pub. Ex. No. 8, pp. 40-42. Mr. Kaufman defended the use of historical data and criticized Dr. Morin's analysis in exhibit RAM-9 which purportedly demonstrates that it is inappropriate to use historical growth rates. Mr. Kaufman noted that many of the companies used by Dr. Morin in RAM-9 are not used by Dr. Morin in his DCF analysis, and contends that if one removes outliers and uses reasonable judgment any concerns about using historical growth rates can be alleviated. Mr. Kaufman added that at the current retention ratios employed by most utilities, the dividend growth rates predicted by Dr. Morin's DCF models are not supportable. Pub. Ex. No. 8, pp. 46-47.

Mr. Kaufman further criticized Dr. Morin for: (a) relying exclusively on intermediate-term

forecasts in earnings per share to estimate the growth rate in dividends for his DCF model; (b) his failure to use historical growth data; and (c) adjusting his DCF models by 20 basis points to account for the quarterly timing of dividends.[3] Mr. Kaufman also disagreed with the market risk premium used by Dr. Morin in his CAPM analysis, as well as Dr. Morin's exclusive reliance on the arithmetic mean return to estimate his historic risk premium. Pub. Ex. No. 8, pp. 51 and 53. Mr. Kaufman noted that Dr. Morin's reliance on income returns, rather than total returns, overstates the market risk premium in his CAPM analysis. Mr. Kaufman explained that, while Dr. Morin relies on Ibbotson Associates ("Ibbotson") to support his use of income returns versus total returns, Mr. Kaufman believes that Ibbotson's conclusion is illogical on this point and actually supports a lower, rather than higher, risk premium. Pub. Ex. No. 8, pp. 53-55.

Mr. Kaufman further testified in response to Dr. Morin's estimate of a prospective market risk premium, and explained that Dr. Morin's analysis was based on a DCF model, adjusted to capture a full year's future growth, which overstates the forward yield. Mr. Kaufman indicated that Dr. Morin's model compounds that error by inappropriately adjusting for quarterly timing of dividends. He added that Dr. Morin's aggregate market data produces an unusually high dividend yield of 2.5%, particularly in relation to Value Line's calculated averages of 2.1%. Pub. Ex. No. 8, pp. 55-57. He was further skeptical of Dr. Morin's 2.5% figure because his calculation included non-dividend paying companies, whereas Mr. Kaufman's Value Line data excluded those companies, logically meaning Dr. Morin's results should be lower, not higher, than Mr. Kaufman's. Mr. Kaufman questioned Dr. Morin's exclusive reliance on long-term government yields, as a proxy for his risk-free rate of return, claiming that it is also appropriate to consider other maturities as a proxy for the risk free rate of return. Pub. Ex. No. 8, p. 57.

Mr. Kaufman also responded to Dr. Morin's testimony regarding an upward adjustment to beta for delayed recognition within beta of changes in risk fundamentals. Mr. Kaufman noted that Dr. Morin made a similar argument in PSI's last rate case and indicated that Cinergy's beta has declined since PSI's last rate case. Mr. Kaufman also indicated that he believes that Dr. Morin's ECAPM analysis is redundant, and notes that this type of analysis was rejected by the Commission in PSI's last rate case as the use of adjusted beta already increases beta for companies with a beta that is below 1.0. Pub. Ex. No. 8, p. 64.

With respect to Dr. Morin's RP models, Mr. Kaufman indicated that Dr. Morin's failure to include 2002 data in his risk premium analysis very likely serves to artificially overstate the historical risk premium. Pub. Ex. No. 8, pp. 65-66. He also noted that most of Dr. Morin's RP models were biased as they are based on an arithmetic mean risk premium. Pub. Ex. No. 8, p. 67. Mr. Kaufman further indicated that Dr. Morin's risk premium models do not react to changes in capital markets and should be given little if any weight.

Mr. Kaufman challenged Dr. Morin's proposed 30 basis point upward adjustment to the cost of equity to account for, what he believes to be, overstated flotation costs. Mr. Kaufman explained that actual flotation costs associated with Cinergy's most recent stock issuance amounted to $1.55 million, or less than 1% of the stock issue. Mr. Kaufman stated that while he believes that some adjustment for flotation costs is merited, he recommends the adjustment be only 5-10 basis points. Mr. Kaufman stated that the flotation cost adjustment proposed by the OUCC would increase PSI's net operating income ("NOI") by approximately $1.1 million per year whereas the Petitioner's proposed adjustment would increase PSI's NOI by approximately $5.5 million per year. Pub. Ex. No. 8, pp. 75-76. Mr. Kaufman noted that the Commission rejected Dr. Morin's overstated estimate of flotation costs in the last PSI rate case, Cause No. 40003. Pub. Ex. No. 8, pp. 75-77.

OUCC witness Timothy Geswein testified regarding the general business risk levels faced by PSI and in response to observations made by PSI witness Rogers regarding industry risks.

Mr. Geswein explained that, as a regulated monopoly energy provider, PSI Energy is insulated from many risks and feels few direct impacts from national economic events of the type referenced by Mr. Rogers. He characterized PSI Energy as a "low-risk regulated, franchise monopoly" for which even the Company's regulatory risks have been mitigated.

OUCC witness Dr. Peter Boerger testified in response to Mr. Reising regarding his analysis and discussion regarding PSI's risk profile, and noted that every business faces risks, but that the state's grant of a monopoly service territory to PSI causes electric utilities to be viewed as low risk enterprises despite the factors raised by Mr. Reising. Pub. Ex. No. 5, pp. 3-4. Dr. Boerger also indicated that legislation enacted since PSI's last rate case has favorably affected the Company's risk profile. Changing the Fuel Adjustment Charge ("FAC") earnings test under IC 8-1-2-42.3 has reduced the probability that PSI would return excess earnings to ratepayers, compared to the situation that existed during the last rate case. In 2002, new financial incentive and cost recovery mechanisms for coal-fired investment and related environmental expenditures were enacted within IC 8-1-8.8 that may allow PSI to track increased depreciation and operation and maintenance ("O&M") for its new NO_x investments. These legislative changes should be considered as reducing the company's cost of equity below that which would be required in the absence of such legislation. Pub. Ex. No. 5, pp. 12-13.

Dr. Boerger also explained the need to segregate the risks imposed on PSI Energy by its parent in determining the utility's cost of capital. He notes Cinergy's involvement in recent years with relatively risky merchant activities and the role of PSI to sponsor a large power trading operation, explains how Standard & Poors attributed such higher-risk nonregulated activities to both Cinergy and PSI in its publications. Pub. Ex. No. 5, p. 14. Dr. Boerger noted that a substantial share of the risk facing the company has been mitigated, and the cost of that mitigation is being paid already by Indiana consumers. Pub. Ex. No. 5, p. 15.

(3) *PSI-IG's Cost of Common Equity Evidence*. Michael Gorman testified for the PSI-IG and recommended that PSI's cost of common equity capital should be in the range of 9.7% to 10.3% and that PSI's authorized return on equity in this case not exceed 10%. PSI-IG Ex. No. 3, p. 2. He based his recommendation on a DCF analysis (10.1%), an RP analysis (9.9% -10.3%), and a CAPM model (9.7%). PSI-IG Ex. No. 3, p. 2. He stated that Cinergy's use of leveraging and entry into more risky power/gas trading and a merchant generation operation had created credit rating pressure on PSI. Mr. Gorman maintained that rates should not be set in a way that will allow PSI to contribute dividends in excess of reasonable levels to its parent company to help accelerate the pay-down of parent company debt related to failed unregulated business investments. PSI-IG Ex. No. 3, p. 3. On cross-examination Mr. Gorman acknowledged that he was not aware of any year since the formation of the Cinergy Corp. holding company structure in which the Cinergy operating companies had funneled up to Cinergy Corp. cash in excess of the Cinergy Corp. annual dividend. Tr. at T35-T36. Mr. Gorman agreed with PSI's proposed capital structure, consisting of common equity, preferred stock and long-term debt, but not short-term debt. PSI-IG Ex. No. 3, p. 7.

Mr. Gorman testified that the *Bluefield* and *Hope* cases have established that the return for a public utility should: (i) be sufficient to maintain financial integrity; (ii) attract capital under reasonable terms; and (iii) be commensurate with returns investors could earn by investing in other enterprises of comparable risk. PSI-IG Ex. No. 3, p. 11. Mr. Gorman also testified that the utility's cost of common equity is the return that investors expect, or require, in order to make an equity investment in the utility. PSI-IG Ex. No. 3, p. 11. Mr. Gorman also testified that it is extremely difficult, if highly impractical, to eliminate all higher equity return component premiums to compensate for deregulated market risks. PSI-IG Ex. No. 3, p. 13.

In doing his DCF analysis and RP estimates for PSI, Mr. Gorman used the group of electric utility companies that Dr. Morin selected for his analysis, agreeing that this

group is reasonably comparable to PSI. PSI-IG Ex. No. 3, p. 12, and PSI-IG Ex. No. 3, Schedule 1. In his constant growth DCF analysis, Mr. Gorman relied upon the average of the weekly high and low stock prices over a 13-week period ending July 14, 2003. PSI-IG Ex. No. 3, p. 14. He also used the most recently paid quarterly dividend, as reported in Value Line, which he annualized and adjusted for the next year's growth to produce the adjusted dividend rate that he used. PSI-IG Ex. No. 3, p. 14.

With respect to dividend growth rates, Mr. Gorman relied on a consensus of professional security analysts as a proxy for investor consensus of future dividend growth rate expectations. Mr. Gorman testified that security analyst growth estimates have been shown to be more accurate predictors of future returns than growth rates derived from historical data. He used the average of three sources of growth rate estimates, including Zack's Detailed Analyst Estimates, First Call and Multex.com Investors. The consensus estimate was a simple arithmetic average or mean of surveyed analysts' earnings growth forecasts.

The result of his DCF analyses was a cost of common equity of 10.1%. PSI-IG Ex. No. 3, p. 16. He said that his comparable group average five-year growth rate of 4.65% is sustainable over an indefinite period of time, because it does not exceed the growth rate of the overall U.S. economy, which, is estimated to grow at a rate of 5.6%. According to Mr. Gorman, this represents a ceiling for a sustainable growth rate for a utility over an indefinite period of time. PSI-IG Ex. No. 3, p. 16.

With respect to Mr. Gorman's RP analysis, his first such model estimated the difference between the required return on utility common equity investments and U.S. Treasury bonds over the period 1986 through 2002, using regulatory commission authorized common equity returns for electric utility companies. PSI-IG Ex. No. 3, p. 17. His second equity RP method was based on the difference between regulatory commission authorized returns on common equity and contemporary A-rated utility bond yields, over the period 1986 through July, 2003. PSI-IG Ex. No. 3, p. 17. This analysis, he said, showed an average indicated equity RP of authorized electric utility common equity returns over U.S. Treasury bonds of 4.86%. PSI-IG Ex. No. 3, p. 17 and Schedule 5. Mr. Gorman testified that his average indicated equity RP authorized electric utility common equity returns over contemporary Moody's utility bond yields was 3.43%, and, removing the two highest and lowest premium estimates, produced an equity RP in the range of 3% to 4% over that period. PSI-IG Ex. No. 3, p. 18 and Schedule 6. Using the long-term Treasury bond yield of 5.3% (projected by Blue Chip Financial Forecasts) and an equity risk premium of 4.4% to 5.6%, produced an estimated common equity return in the range of 9.7% - 10.9%, with a midpoint estimate at 10.3%. PSI-IG Ex. No. 3, p. 18. Adding his equity risk premium of 3% to 4% over utility bond yields to the average yield on a utility bond with an A-rating for a 13-week period ending July 11, 2003 of 6.37%, produced a cost rate for common equity in the range of 9.4% to 10.4%. PSI-IG Ex. No. 3, p. 18.

With respect to his CAPM approach, Mr. Gorman started with the Blue Chip Financial Forecasts for projected long-term Treasury bond yields of 5.3% for his risk-free cost rate. PSI-IG Ex. No. 3, p. 20. He used a beta of 0.64 obtained by averaging the group betas for his comparable group of electric utilities. PSI-IG Ex. No. 3, p. 21 and Schedule 8. He derived two market based premium estimates, one forward looking and one based on long-term historical average. He estimated the expected return on the Standard & Poor's ("S&P") 500 by adding an expected inflation rate of 2.2%, to the long-term historical arithmetic average real return on the market. He produced an estimated return of 9.4%. PSI-IG Ex. No. 3, p. 21. The market premium is the difference, he said, between the 11.8% expected market return and his 5.3% risk-free estimate, or 6.5%. PSI-IG Ex. No. 3, p. 21. Using Ibbotson's arithmetic average of achieved total returns on the S&P 500 of 12.7% and the total return on long-term Treasury bonds of 5.7%, produced an indicated equity risk premium of 7.0%. His CAPM estimated return on common equity ranged from 9.5% to 9.8%. PSI-IG Ex. No. 3, p. 22. He concluded that PSI's cost of common equity was in a range from 9.7% to 10.3%. PSI-IG Ex. No. 3, p. 22.

Mr. Gorman was critical of Dr. Morin's original recommendation of an 11.5% cost of common equity. PSI-IG Ex. No. 3, pp. 24-25. Mr. Gorman said that in his CAPM analysis Dr. Morin used a beta of 0.72 which was considerably higher than the actual Value Line beta of 0.65 for his investment grade vertically integrated electric utility companies. His use of a beta higher than his electric utility sample increased his result. PSI-IG Ex. 3 pp. 25-26. Mr. Gorman also took issue with Dr. Morin's 30 basis point adjustment for flotation costs. *Id.* Mr. Gorman also did not accept Dr. Morin's ECAPM analysis. Mr. Gorman testified that that the Value Line beta Dr. Morin relied on to estimate a utility beta is already adjusted for the tendencies of betas lower than one to increase toward a market beta of one over time. Thus Dr. Morin's adjustment is redundant. PSI-IG Ex. No. 3, p. 26.

With respect to Dr. Morin's historical RP analysis, Mr. Gorman was critical of Dr. Morin's achieved return on utility stocks, compared with Treasury securities and utility bond yields. PSI-IG Ex. No. 3, p. 27. He said that the yields on Treasury securities and utility bonds have been depressed by the dramatic decrease in interest rates over the last 20 years. PSI-IG Ex. No. 3, pp. 27-28. He stated further that the achieved returns on the utility stocks and yields on utility bonds over the last several years have been driven by high expectations of large profits produced by competitive operations related to the wholesale market trading and merchant plant development. PSI-IG Ex. No. 3, p. 28. This, he said, gave the indicated equity risk premium a bias upward. PSI-IG Ex. No. 3, p. 28.

Mr. Gorman also took issue with Dr. Morin's computation of an allowed risk premium on electric utilities. He said that Dr. Morin arbitrarily selected the time period 1993 through 2002 to estimate the spread between regulatory-authorized returns on equity and contemporary utility bond yields and Treasury bond yields. Mr. Gorman also questioned the implication in Dr. Morin's approach, that a utility's equity risk increases with decreases in interest rates. Mr. Gorman further testified that he thought that Dr. Morin's additions of an equity risk premium to contemporary utility bond yields may overstate a fair return for regulated utility operations. PSI-IG Ex. No. 3, p. 30. He said that current bond yields are affected by the much higher risk of non-regulated energy markets, and said that the average authorized return on equity above contemporary energy industry bond yields produces a return on equity that may exceed that appropriate for lower risk regulated operations. PSI-IG Ex. No. 3, pp.30-31.

In discussing Dr. Morin's DCF analyses, Mr. Gorman claimed that the information supporting Dr. Morin's analyses was stale and needed to be updated. PSI-IG Ex. No. 3, p. 33. Mr. Gorman criticized Dr. Morin's proposal for a 30-basis point flotation cost adjustment. Mr. Gorman said that PSI should not be accorded flotation costs, because it is a wholly-owned subsidiary of Cinergy and does not sell its stock to the public. PSI-IG Ex. No. 3, pp. 34-35. He added, however, that if it is reasonable to allocate a portion of Cinergy's flotation expenses to PSI, PSI should be required to account for those expenses. PSI-IG Ex. No. 3, p. 35. Mr. Gorman also questioned Dr. Morin's proposal for a 20-basis point adjustment to reflect quarterly dividend compounding, claiming that it provides investors an opportunity to earn the dividend reinvestment return twice, once through the authorized return on equity and a second time when dividends are received by investors and actually reinvested by investors. PSI-IG Ex. No. 3, p. 33.

Mr. Gorman testified that he believes a commission should exercise its judgment, based on the arguments and positions taken by the expert witnesses, in determining the fair rate of return for the utility. Tr. at T27. In this regard, Mr. Gorman indicated that relevant considerations for a commission in determining a utility's fair rate of return include the utility's financial condition, the prospects for a credit rating downgrade for the utility, and the utility's performance in rendering utility service. Tr. at T28-T30. Mr. Gorman further testified that, in determining the fair rate of return for a utility, a

commission should be forward-looking and consider business, financial, regulatory, and other issues likely to be experienced by the utility while the rates approved are expected to be in effect. Tr. at T29. Mr. Gorman acknowledged that the fair rate of return authorized for a utility could be different than the estimated cost of capital for the utility. Tr. at T30-T31.

(4) *CAC Evidence on Cost of Equity*. Dr. Michael F. Sheehan testified on behalf of CAC and addressed certain factors which are relevant to PSI's risk and ROE. He noted that in regulatory proceedings, risk has a significant impact on the determination of the return on equity and provided an assessment of how the industry and PSI's risks have changed, with specific reference to the many supportive and risk-reducing regulatory structures that have been adopted by this Commission. While Dr. Sheehan did not sponsor specific calculations of risk premiums or adjustments to PSI's return on equity, his testimony provides an overview of PSI's level of risk that is relevant to our overall consideration of the fair return for PSI.

Dr. Sheehan noted that he believes that since PSI's last rate case in Cause No. 40003, Cinergy has adopted a policy of gradually shifting risk from the holding company to PSI ratepayers. This was done through requests for preapprovals of investment expenditures; preapprovals of cost deferrals to subsequent rate cases; and, the adoption of a growing number of trackers, such that much of the revenue requirement is now governed by trackers. CAC Ex. C, p. 31. He explained that the regulatory mechanisms have shifted risks to ratepayers as, without the use of trackers, cost increases occurring between rate cases would have to be absorbed by the utility. With the use of trackers cost increases are automatically passed on to ratepayers in higher rates as they occur. These shifts in risk, according to Dr. Sheehan, argue for elimination of some of the risk premium received by the utility in the ROE determination. CAC Ex. C, p. 33.

Mr. Bruce Biewald also testified on behalf of CAC on the subject of PSI risk exposure and return on equity. Mr. Biewald indicated that the Commission should consider, in determining whether the Company's requested ROE is excessive, the risk reduction effect that has occurred due to the Company's existing and proposed trackers and pre-approved costs; and, whether the approval of the Company's merchant plant acquisition acted to shift risks from Cinergy to PSI customers regarding the investment in those plants. CAC Ex. B, p. 7.

Mr. Biewald explained that he believes the Company's various special rate riders and its CWIP tracker have allowed the recovery of 8.4% of its operating income during the test year. CAC Ex. B, pp. 8-9. He noted that in addition to the existing Riders 60, 62, 63, 66 and 67, PSI is seeking approval for new proposed trackers in the form of Rider 68 (MISO), Rider 69 (NO_x) and Rider 70 (Purchased Power). CAC Ex. B, p. 9. According to Mr. Biewald, the Company's rate tracking mechanisms effectively reduce its shareholders' exposure to risk in that they: (1) reduce regulatory lag; (2) allow certain significant categories of costs (*e.g.* environmental costs) that increase to be put into rates without consideration of other, related categories of costs (*e.g.* cost of capital) that decrease; (3) tend to defer general rate cases with their attendant risks and costs; and, (4) tend to decrease the scope and detail of regulatory review of tracked costs compared to a general rate case. In addition, Mr. Biewald noted, "such riders can, in many situations, greatly reduce volatility of net earnings on a monthly, quarterly and annual basis." CAC Ex. B, p. 10.

With respect to Dr. Morin's peer group of utility companies used to calculate his ROE, Mr. Biewald noted that PSI has the highest number of trackers among the 26 utility companies, and is one of only two companies that have trackers for perhaps the four most significant cost categories that are commonly tracked: 1) fuel adjustment; 2) purchased power; 3) environmental cost recovery; and, 4) emission allowances. According to Mr. Biewald's analysis, the large number of PSI's rate adjustment trackers relative to its industry peers suggest that the Company is relatively well protected against many risks to which other utilities are often exposed. CAC Ex. B, p. 11.

(5) *Testimonial Staff's Testimony*. In his

testimony Mr. Inman indicated that he did not prepare an independent cost of equity study for PSI, choosing instead to analyze the cost of equity estimates of PSI and other parties in the case. IURC Staff Ex. No. 1, p. 3. Mr. Inman agreed with Dr. Morin's 20-basis point quarterly dividend adjustment to reflect the fact that current stock prices, which reflect expected quarterly dividend payments, are lower than the standard DCF result suggests. IURC Staff Ex. No. 1, p. 5. Logic dictates, he said, that an upward adjustment to the standard DCF model would correct the understatement. IURC Staff Ex. No. 1, p. 5. Mr. Inman also testified that, in the DCF model, the current dividend yield must be adjusted to reflect the expected dividend yield. Mr. Inman indicated that there are two common methods which calculate the expected, or forward, dividend yield — full-year and half-year. Citing recent Commission proceedings, Testimonial Staff recommended use of the half-year method of calculating forward dividend yield. IURC Staff Ex. No. 1, p. 5. Mr. Inman further noted that Dr. Morin's DCF results were higher in his March 2003 prefiled testimony than those produced by other methods of determining the cost of common equity capital.[4] Mr. Inman stated that Staff's final DCF recommendations begin with Dr. Morin's current yield data and growth forecasts for each of his DCF calculations and adjust for the half-year dividend yield method, a quarterly dividend adjustment and direct flotation costs. IURC Staff Ex. No. 1, p. 7.

With respect to the CAPM model, Testimonial Staff used the February to July 2003 six-month average of 30-year Treasury bond yields to obtain a rate of 4.86%. This average was used to smooth out the recent swings in long-term bond yields. IURC Staff Ex. No. 1, p. 8. By comparison, Dr. Morin used 5.0% in his initial testimony, and 5.3% in his updated testimony. Pet. Ex. G, p. 16; and Pet. Ex. TT, p. 3. Mr. Inman anticipated the higher interest rate in Dr. Morin's update and stated in his September 2003 prefiled testimony that considering the bottoming out of interest rates and the recent upswing in long-term bond yields, it would not be surprising if Dr. Morin chooses to leave his estimate as it is or even revises it upward. IURC Staff Ex. No. 1, p. 8.

Mr. Inman indicated that Testimonial Staff did not dispute Dr. Morin's use of the 0.72 Value Line suggested beta in his CAPM calculations. IURC Staff Ex. No. 1, p. 9. For the market rate of return, Staff agreed with Dr. Morin's use of the period beginning 1926 and extending through the most recent available year as this takes into account nearly all economic scenarios and is most representative of all possible returns. IURC Staff Ex. No. 1, p. 9. However, while supporting this approach, Mr. Inman observed that Dr. Morin failed to include 2002 data in his calculation of the market risk premium. To adjust for this deficiency, Mr. Inman included 2002 data in his market risk premium calculation to ensure that his calculation accurately reflects data extending through this period. Mr. Inman stated that Testimonial Staff supported giving weight to both the arithmetic and geometric means of computing annual growth rates. IURC Staff Ex. No. 1, pp. 12-13.

Mr. Inman said that Testimonial Staff believes that the proper market risk premium to be used in this case should include total return on long-term Treasury bonds, and not just income thereon. Adjusting Dr. Morin's results for use of total return on long-term bonds, and giving equal weight to the arithmetic mean and the geometric mean market risk premiums, Testimonial Staff arrived at a market risk premium of 5.55%. IURC Staff Ex. No. 1, p. 14. Testimonial Staff used Dr. Morin's 6.1% prospective risk premium, resulting in a CAPM market risk premium input of 5.83%, which produced a CAPM estimate of PSI's cost of common equity of 9.05%. Mr. Inman said that the primary reasons for the 85 basis point difference between Staff's and Dr. Morin's original unadjusted CAPM estimates are: (i) Staff's use of then more current, lower risk-free rates; (ii) Staff's use of lower market risk premium due to inclusion of 2002 data; (iii) Staff's equal weighting of the geometric and arithmetic mean risk premiums; and (iv) Staff's use of 30-year Treasury bond total return. IURC Staff Ex. No. 1, p. 15.

With respect to flotation costs, Staff recommended allowing one-half of Dr. Morin's proposed flotation cost adjustment, which would amount to a 15 basis point adjustment to the CAPM and RP methods, and a 2.5% gross up of the dividend yield produced by the DCF method. IURC Staff Ex. No. 1, p. 17. Testimonial Staff recommended rejection of Dr. Morin's ECAPM calculation on the grounds that the Value Line beta already contains an adjustment of beta, therefore it was unnecessary for Dr. Morin to make a further adjustment of beta. IURC Staff Ex. No. 1, p. 17.

With respect to the RP method Mr. Inman, in conformity with previous Commission orders, adjusted Dr. Morin's RP calculations by equally weighting the arithmetic and geometric mean risk premium, using Dr. Morin's source data. IURC Staff Ex. No. 1, p. 18. Testimonial Staff then adjusted Dr. Morin's flotation costs to allow for direct costs only and updated his 30-year Treasury bond data and A-rated utility bond yields. IURC Staff Ex. No. 1, p. 18. Testimonial Staff accepted Dr. Morin's statistical analyses of hundreds of risk premiums allowed by state regulatory commissions over a 10-year period compared with long-term Treasury bond yields, but observed that Dr. Morin's results do not account for the differences in risk factors that may have been considered by the various state commissions in the hundreds of data points. IURC Staff Ex. No. 1, pp. 18-19. For that reason, Testimonial Staff said, the results of Dr. Morin's allowed RP calculations are questionable. IURC Staff Ex. No. 1, p. 19.

Giving somewhat less weight to the DCF results than Dr. Morin, Testimonial Staff produced lower results, concluding that a reasonable cost of common equity would be in the range of 10.25% to 10.50%, which, as Mr. Inman observed, falls in the lower end of Dr. Morin's suggested range of 10.2% to 13.6%. IURC Staff Ex. No. 1, p. 19. In his oral direct testimony, Mr. Inman updated his reasonable range of cost of equity for PSI to 10.35% to 10.55%. Tr. at T51-T52. Mr. Inman noted that Staff offered several different weighting mechanisms for consideration to provide this Commission with options based upon previous Commission orders which have given less weight to the DCF method. IURC Staff Ex. No. 1, p. 19. Staff's different weighting mechanisms included a 8%/46%/46% CAPM/RP/DCF (excluding ECAPM) weighting which produced a top-end 10.96% cost of equity, and a 40%/40%/20% CAPM/RP/DCF (excluding ECAPM) weighting which produced a low-end 10.24% cost of equity. IURC Staff Ex. No. 1, p. 20.

Mr. Inman observed that Regulatory Research Associates, Inc. ("RRA") tracks major rate case decisions by state commissions. Mr. Inman testified that RRA reported that the average cost of equity authorized by state commissions for the electric industry for the first six months of 2003 was 11.38%, and 11.16% for all of 2002. IURC Staff Ex. No. 1, p. 22. Mr. Inman stated on cross-examination that RRA reported that the average cost of equity authorized by state commissions for the electric industry for the first nine months of 2003 was 10.91%, which could be 11% if you excluded the 9.5% awarded to New Jersey Central Power & Light.[5] Tr. at T106-T107. Mr. Inman observed that Dr. Morin's original 11.5% recommendation falls just above the midpoint, and Staff's recommended range falls in the lower end, of the range RRA reported thus far for 2003. IURC Staff Ex. No. 1, p. 22.

Observing that the determination of an exact investor required return on equity is impossible, Mr. Inman said that finding a range of reasonableness for ROE is more realistic. IURC Staff Ex. No. 1, p. 22. He observed that experts and non-experts alike will agree that the results of the CAPM, RP and DCF methods are driven by the inputs, of which there are countless possibilities and legitimate arguments regarding the appropriate inclusion or exclusion of various inputs. IURC Staff Ex. No. 1, pp. 22-23. Mr. Inman testified that Mr. Gorman also used DCF, RP and CAPM calculations in formulating his cost of equity recommendation of 9.7% to 10.3%, and noted that experts that use different inputs into the same formulas can arrive at different final cost of equity ("COE") estimates. IURC Staff Ex. No. 1, pp. 23-24. Mr. Inman concluded with the observation that, as the Commission has noted in other cases, the

Petitioner has recommended a high COE and all opposing experts have recommended much lower COE's. The true COE most probably lies somewhere in between. IURC Staff Ex. No. 1, p. 24.

Mr. Inman stated in his prefiled testimony that PSI's credit rating downgrade risk could increase as a result of this rate case. IURC Staff Ex. No. 1, p. 24. In this regard, Mr. Inman stated that a downgrade of PSI's credit rating would lead to increased debt costs, a reduction in financing options, and ultimately higher costs to consumers. IURC Staff Ex. No. 1, p. 25. Therefore, Mr. Inman testified that it is important to PSI and to its customers that this Commission's final order in this Cause, regardless of the findings on cost of capital and rate of return, recognizes PSI's strengths and position relative to its industry peers. IURC Staff Ex. No. 1, p. 25. Mr. Inman noted that conspicuously absent from Petitioner's case-in-chief testimony was an analysis of the impact of PSI receiving something less than its requested increase, such as 50% or 75%.[6] Mr. Inman concluded that he believes that approval of a rate increase for PSI which is less than the full amount requested, but is an amount that could still be considered "substantially all" will not endanger PSI's credit rating. IURC Staff Ex. No. 1, p. 26.

(6) *Petitioner's Rebuttal Evidence on Cost of Equity.*

(a) *Rebuttal Concerning OUCC's Cost of Common Equity Evidence.* Dr. Morin testified for PSI in rebuttal to the cost of common equity capital testimony submitted by other parties. Dr. Morin observed that Mr. Kaufman's recommended ROE of 9.15% (prior to being updated to 9.25%) was substantially under the average returns on common equity allowed in the electric and natural gas utility rate cases in the first six months in 2003 of 11.40% and 11.38%, respectively, as reported by RRA in its survey of regulatory decisions dated June, 2003. Pet. Ex. No. FF, p. 15. Dr. Morin also observed that it was well under the average returns of 11.6% and 11.7% allowed on common equity for the utilities in Mr. Kaufman's sample groups as reported in the Turner Reports survey for September, 2003. Pet. Ex. FF, p. 15. Dr. Morin concluded that Mr. Kaufman's recommendation was: (a) well outside the zone of currently allowed rates of return for Mr. Kaufman's comparable companies; (b) well outside the mainstream of recently authorized returns for electric and natural gas utilities allowed by state regulatory agencies throughout the country; and (c) would be among the lowest, if not the lowest, in the country if adopted. Pet. Ex. FF, p. 16.

Dr. Morin testified that he believes that Mr. Kaufman's dividend yield calculation in his DCF analysis understate flotation costs by 20-25 basis points. Pet. Ex. FF, pp. 16-17. Mr. Kaufman's flotation cost approach, Dr. Morin observed, assumes that all past flotation costs associated with past securities issues have been recovered, which he said is not the case here. Pet. Ex. FF, p. 17. Because such costs were not expensed in the past, Dr. Morin said, investors should be compensated for flotation costs for the entire time that these initial funds are retained by the firm, on an on-going basis. Pet. Ex. FF, pp. 17-18. In theory, Dr. Morin said, flotation costs could be expensed and recovered through rates as they are incurred. However, this procedure is not considered appropriate here because the common equity capital raised in a given stock issue remains in the utility's common equity account and continues to provide benefits to ratepayers indefinitely. Pet. Ex. FF, p. 18. He reiterated that unlike the case of bonds, common stock has no finite life, so that flotation costs cannot be amortized and must, therefore, be recovered via an upward adjustment to the allowed return on equity. Pet. Ex. FF, p. 18.

Dr. Morin also disagreed with Mr. Kaufman's dividend yield calculation in his DCF analysis, because Mr. Kaufman multiplied the current dividend yield by one plus one half the expected growth rate (1 + 0.5g), rather than by one plus the expected growth rate (1 + g), thereby understating the return expected by the investor. Pet. Ex. FF, p. 19. Dr. Morin explained that the fundamental assumption of the annual DCF model used by Mr. Kaufman is that dividends are received by investors annually, at the end of each year, and that the first dividend is to

be received by the investor one year from now. Pet. Ex. FF, p. 19. Instead, he said, dividends are received quarterly. Because the appropriate amount of dividends to use in the annual DCF model is the prospective dividend one year from now, rather than the dividend one-half year from now, Mr. Kaufman's approach, Dr. Morin testified, understates the proper dividend yield, thereby understating PSI's cost of equity by approximately 15 basis points. Pet. Ex. FF, p. 19. Dr. Morin emphasized that because the price of a stock reflects the quarterly payment of dividends, it is essential that the DCF model used to estimate equity costs also reflect the compounding or quarterly dividends in the same way that bond yield calculations are routinely adjusted to reflect semiannual interest payments. Pet. Ex. FF, p. 20. By failing to recognize the quarterly nature of dividend payments in his DCF computation, Dr. Morin said that Mr. Kaufman understated PSI's cost ofequity capital by about 20 basis points. Pet. Ex. FF, p. 21.

Dr. Morin also disagreed with Mr. Kaufman's use of the average stock price over the past three and six months to derive the dividend yield to use in his DCF. Pet. Ex. FF, p. 23. Dr. Morin indicated that he believes because the analyst is attempting to determine a utility's cost of equity in the future, current stock prices provide a better indication of expected future prices than any other price. Pet. Ex. FF, p. 23. Dr. Morin also took issue with Mr. Kaufman's proxies used to derive his DCF growth rate component, which was an average of all of the rates calculated, using Mr. Kaufman's proxy group. Pet. Ex. FF, p. 24. Dr. Morin reproduced those rates in the following table, based on Mr. Kaufman's Schedule 4:

TABLE 3

Mr. Kaufman's Growth Rates
Primary Group of Electric Utilities

	ALL (1)	*Excl DPS* (2)	*Forecast* (3)	*Only DPS* (4)
Historical 10 yr. EPS	3.8%	3.8%		
Historical 5 yr. EPS	4.5%	4.5%		
Historical 10 yr. DPS	2.2%			2.2%
Historical 5 yr. DPS	3.1%			3.1%
Historical 10 yr. BPS	3.1%	3.1%		
Historical 5 yr. BPS	4.2%	4.2%		
Forecast EPS	6.2%	6.2%	6.2%	
Forecast DPS	4.7%		4.7%	4.7%
Forecast BPS	4.7%	4.7%	4.7%	
Multex Forecast EPS	4.9%	4.9%	4.9%	
Turner Forecast DPS	3.1%		3.1%	3.1%
Average	*4.0%*	*4.5%*	*4.7%*	*3.3%*

Pet. Ex. FF, p. 25.

Dr. Morin said that based on this table the overall average growth rate from all the proxies, as shown in Column 1, is 4.0%, and that the dividend growth proxies average of 3.3% shown at the bottom of Column 4 is an outlier, compared to the average of 4.5% computed by excluding the dividend proxies (Column 2) and compared to the average of 4.7% obtained from the growth forecast proxies (Column 3). Pet. Ex. FF, p. 25. Dr. Morin testified that historical growth rates are inappropriate proxies for expected growth at this time, as are dividend growth rates, both historical and prospective. Excluding the historical proxies and the outlying dividend growth forecast from Mr. Kaufman's numbers, he said, produced average growth estimates of between 5% and 6%. Pet. Ex. FF, p. 25. Use of a 5% growth rate, he said, would have raised Mr. Kaufman's DCF estimates by at least 100 basis points. A similar bias applies to Mr. Kaufman's estimates derived from his second group of vertically integrated electric utilities. Pet. Ex. FF, pp. 25-26.

With respect to Mr. Kaufman's use, as proxies for the DCF growth component, of historical ten-year and five-year growth rates, Dr. Morin stated that, under circumstances of stability, it would be reasonable to assume that historical growth rates in dividends/earnings influence investors' assessment of the long-run growth rate of future dividends/earnings; however, Dr. Morin concluded that these are anything but stable times in the electric utility industry. Pet. Ex. FF, p. 26. Dr. Morin went on to indicate that historical growth rates are downward-biased by the sluggish earnings performance in the last five years. In addition, Dr, Morin testified that he believes historical growth rates are largely redundant, because such historical growth patterns are already incorporated in analysts' growth forecasts, which, he said, should be used in the DCF model. Pet. Ex. FF, p. 26. Dr. Morin added that published studies in academic literature demonstrate that growth forecasts made by security analysts are reasonable indicators of investor expectations and that investors rely on such forecasts. Pet. Ex. FF, p. 28. These studies, he said, present detailed empirical evidence that the average analysts' expectation is more similar to expectations being reflected in the market place than are historical growth rates. Pet. Ex. FF, p. 28. Based on the foregoing analysis, Dr. Morin recommended that this Commission reject the use of historical growth rates as proxies for expected growth in the DCF calculation in this proceeding.

While Dr. Morin agreed with Mr. Kaufman's proxy used for the risk-free rate in his CAPM analysis, he said that he believes that Mr. Kaufman utilized an understated beta. Pet. Ex. FF, p. 29. He also criticized Mr. Kaufman's use of the geometric average of realized returns in measuring market return, as well as Mr. Kaufman's use of the "plain vanilla" CAPM without adjustment. Pet. Ex. FF, pp. 29-30. Dr. Morin maintained that the problem he saw with Mr. Kaufman's beta estimates of 0.61 and 0.64 for his two samples of electric utilities, is that historical betas are downward-biased estimates of the true risk of electric utilities. Pet. Ex. FF, p. 30. The true underlying beta of electric utilities, he said, has been gradually increasing in past years because of increasing risk for electric utilities. Yet, the historical beta measured over a five-year estimation period lies midway between the true beginning-of-period beta and the current end-of-period beta, seriously underestimating the current beta. Pet. Ex. FF, p. 31. Dr. Morin said that use of a beta of 0.70, rather than Mr. Kaufman's beta of 0.61-0.64, would increase his ROE estimate by approximately 40-50 basis points, assuming a market risk premium in the range of 6.0%-7.0%. Pet. Ex. FF, p. 32.

Dr. Morin maintained that only arithmetic averages are appropriate when measuring investor expected returns and criticized Mr. Kaufman for using geometric, as well as arithmetic, mean returns in his CAPM analysis. Pet. Ex. FF, pp. 32-33. He pointed out that the effect of using both the geometric and arithmetic mean market risk premiums of 4.7% and 6.4%, rather than the arithmetic mean of 6.4% alone (see Pub. Ex. 8, Schedule 5), was to decrease Mr. Kaufman's estimate of the required market return by 0.90%. Pet. Ex. FF, p. 33. This, in turn, biased his CAPM result downward by some 55-65 basis points, using Mr. Kaufman's beta estimates 0.61-0.64. Pet. Ex. FF, p, 33. Dr. Morin noted that the widely-cited Ibbotson Associates publication from which Mr. Kaufman's market return estimate is derived, and from which Mr. Kaufman quotes in his testimony, contains a detailed and rigorous discussion of why geometric averages should not be used in estimating the cost of capital. Pet. Ex. FF, p. 33. Dr. Morin maintained that performance appraisal is one thing and cost of

capital estimation is another matter entirely. In estimating the cost of capital, he said, the goal is to obtain the rate of return that investors expect, that is, a target rate of return. On average, investors expect to achieve their target return. This target expected return is, in effect, an arithmetic average. The achieved or retrospective return is the geometric average. In statistical parlance, the arithmetic average is the unbiased measure of the expected value of repeated observations of a random variable, not the geometric mean. Pet. Ex. FF, p. 34.

Dr. Morin also disagreed with Mr. Kaufman's sole use of the raw form of the CAPM to estimate the cost of capital. He said that there have been countless empirical tests of the "plain vanilla" CAPM to determine to what extent security returns and betas are related in the manner predicted by the CAPM. The results of the tests, he said, support the conclusion that beta is related to security returns, that the risk-return tradeoff is positive, and that the relationship is linear. The contradictory finding is that the risk-return tradeoff is not as steeply sloped as the predicted CAPM. That is, low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. Pet. Ex. FF, p. 37. The result of these observations, he said, is that a CAPM-based estimate of the cost of capital underestimates the return required from low-beta securities and overstates the return from high-beta securities. He said that Mr. Kaufman's CAPM based estimate understated PSI's equity cost by about 50-60 basis points from this bias alone, as shown by a comparison of Dr. Morin's CAPM and ECAPM studies. Pet. Ex. FF, p. 37.

Dr. Morin also noted that Mr. Kaufman's original ROE recommendation for PSI of 9.15% implies a risk premium of only 3.75% over long-term U.S. Treasury bonds, given that long-term Treasury bonds were yielding about 5.4% in the month of August, 2003. Pet. Ex. FF, p. 39. He said that the implied risk premium over "A"-rated electric utility bonds would be about 2.35%, given that A-rated electric utility bonds are currently yielding about 6.8%. Pet. Ex. FF, p. 39. Dr. Morin cited empirical risk premium literature and evidence that indicates that current risk premiums are much higher, and concluded that the risk premium implied in Mr. Kaufman's recommendation is much lower than generally found in empirical finance literature. Pet. Ex. FF, p. 40.

Dr. Morin did not agree with Mr. Kaufman's view that the market risk premium between stocks and bonds has narrowed over time. Pet. Ex. FF, p. 40. In fact, he stated that he believes the opposite to be true, particularly for the electric utility industry, citing studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992), Carleton, Chambers and Lakonishok (1983), and Maddox, Pippert and Sullivan (1995), who, he said, have demonstrated that, beginning in 1980, utility risk premiums varied inversely with the level of interest rates, rising when interest rates fell and declining when interest rates rose. Pet. Ex. FF, pp. 40-41. Concurrent with the steady decrease in interest rates in the last decade, he said, utility risk premiums have thus escalated — not narrowed. Pet. Ex. FF, p. 41. The reason for the inverse relationship, he said, is that when interest rates rise, bondholders, whose interest rates are fixed, often suffer a decrease in the market value of their bonds, experiencing a capital loss. This is referred to as interest rate risk. Stockholders, on the other hand, are more concerned with the firm's earning power. In order to avoid interest rate risk in an environment of rising interest rates, investors tend to become more willing to undertake equity investment which, although subject to some fear of loss of earning power, is less sensitive to the fear of interest rate risk. Pet. Ex. FF, p. 41. The resulting increase in the supply of funds available for such equity investments causes a downward pressure on the market price for equity. So, generally it is observed that if bondholders' fear of interest rate risk exceeds shareholders' fear of loss of earning power, the risk differential will narrow and hence the risk premium will shrink. Pet. Ex. FF, p. 41. This is particularly true, he said, in high inflation environments. Interest rates rise as a result of accelerating inflation, and the interest rate risk of bonds intensifies more than the earnings risk of common stocks, which are partially hedged from the ravages of inflation. This phenomenon, he said, has been termed as a "lock-in" premium. Conversely, in low interest rate environments, he said, as in the case currently, when bondholders' interest rate fears subside and shareholders' fear of loss of earning power dominate, the risk differential will widen and hence the risk premium will increase. Pet. Ex. FF, pp. 41-42. To corroborate this phenomenon further, Dr. Morin said that regulators have, in fact, systematically and correctly increased the authorized risk premium when interest rates declined, and conversely decreased the authorized risk premium when interest rates increased. Pet. Ex. FF, p. 42.

Dr. Morin pointed out that Mr. Kaufman's contention that the market risk premium has declined over time is undermined by his own references, citing the Ibbotson Associates study often quoted in Mr. Kaufman's testimony, which finds no evidence that the market price of risk or the amount of risk in common stocks has changed over time. Pet. Ex. FF, p. 42. Rather, Ibbotson said that there is no significant statistical correlation in successive annual market risk premiums, that is, there is no trend. Pet. Ex. FF, p. 42.

In rebuttal to Mr. Kaufman's criticism of Dr. Morin's ECAPM analysis, Dr. Morin said that he believes that unadjusted raw betas are inappropriate to use in a CAPM analysis because current stock prices reflect expected risk, that is, expected beta, rather than historical risk or historical beta. Pet. Ex. FF, p. 43. Historical betas, he said, whether raw or adjusted, are only surrogates for expected beta, which is why Value Line and other investment information services report adjusted betas. Pet. Ex. FF, pp. 43-44. He said that one of the most well known results in finance is that a CAPM-based estimate of cost of capital underestimates the return required from low-beta securities and overstates the return from high-beta securities based on the empirical evidence. Pet. Ex. FF, p. 44. The empirical form of the CAPM that he used in his initial testimony, he said, refines the standard form of the CAPM to account for this phenomenon. Pet. Ex. FF, p. 44.

Dr. Morin also rejected Mr. Kaufman's criticism of his use in his DCF analysis of an analyst's earning growth forecast as a proxy for the growth component, pointing out that near-term dividend growth rates cannot be relied upon, as it is widely expected that energy utilities will continue to lower their dividend payout ratio over the next several years, in response to the gradual penetration of competition in the revenue stream. Pet. Ex. FF, p. 45. Dr. Morin also rejected Mr. Kaufman's claim that additional risks and higher expected returns associated with unregulated activities of electric utility holding companies overstate investors' required returns for their regulated operations. Pet. Ex. FF, p. 47. He pointed out that the energy utilities in his sample groups are largely dominated by their regulated operations and that Mr. Kaufman, himself, included in his proxy groups only those companies with at least 75% of revenues derived from electric utility operations. Pet. Ex. FF, p. 48.

Dr. Morin testified that he believes that Mr. Kaufman's DCF analysis result is understated by 155 basis points: (i) 20 basis points from the omission of an appropriate flotation cost allowance; (ii) 15 basis points from the understatement of growth in the dividend yield component due to the use of the wrong DCF functional form; (iii) 20 basis points due to the use of the annual DCF model rather than the quarterly version; and (iv) 100 basis points from the understated growth rates, mainly the inappropriate use of the dividend growth rates. Pet. Ex. FF, p. 53. Adjusting these numbers in this manner would raise Mr. Kaufman's original DCF range of ROEs from 7.94% - 10.12% to 9.5%-11.7%, Dr. Morin said. Pet. Ex. FF, pp. 53-54.

Dr. Morin concluded that he believes that Mr. Kaufman's CAPM analysis results are understated by 165-195 basis points: (i) 40-50 basis points from the use of an understated beta; (ii) 55-65 basis points from using geometric means instead of arithmetic means in estimating the market risk premium from historical data; (iii) 50-60 basis points from the understatement of expected return inherent in the "plain vanilla" version of the CAPM; and (iv) 20 basis points from the understatement of flotation costs. Pet.

Ex. FF, p. 54. Allowance for the understatements would raise Mr. Kaufman's recommended original ROE from a range of 7.98%-8.59% for his CAPM studies to a range of 9.7% - 10.6%. Pet. Ex. FF, pp. 54-55.

(b) *Rebuttal Concerning PSI-IG's Cost of Common Equity Evidence.* Dr. Morin indicated that he believes that Mr. Gorman's procedures and methodologies are generally sound and in keeping with the practices of finance professionals. Pet. Ex. No. FF, p. 56. He agreed with: (i) Mr. Gorman's sample of electric utilities used in his DCF and CAPM analyses; (ii) his use of analysts' growth forecasts as proxies for expected growth in the DCF model; (iii) his use of long-term Treasury bond yields as proxies for the risk-free rate in the CAPM analysis; (iv) part of his market risk premium component of the CAPM analysis; and (v) the broad outline of his risk premium analysis. Pet. Ex. No. FF, pp. 56-57. He disagreed with Mr. Gorman regarding: (i) the absence of a flotation cost adjustment; (ii) the failure of his DCF model to recognize the quarterly payment of dividends; (iii) the beta estimates used in his CAPM analysis; (iv) part of his market risk premium component in the CAPM analysis; (v) the failure to employ the empirical version of the CAPM in keeping with the vast literature on the subject; and (vi) the failure to account for the inverse behavior between the allowed risk premium and the level of interest rates. Pet. Ex. No. FF, p. 57.

Dr. Morin said that in his opinion Mr. Gorman's dividend yield component in his DCF analysis is understated by 30 basis points as it does not allow for flotation costs, and, as a result, a legitimate expense is left unrecovered. Pet. Ex. FF, pp. 57 and 59. Dr. Morin testified that Mr. Gorman's allegation that a flotation cost allowance is inappropriate if the utility is a subsidiary whose equity capital is obtained from its parent, such as is the case of PSI, ignores the fact that the parent-subsidiary relationship does not eliminate the costs of a new issue — it merely transfers them to the parent. Pet. Ex. FF, p. 59. Fair treatment, he said, must consider that, if the utility-subsidiary had gone to the capital markets directly, flotation costs would have been incurred by that utility. Pet. Ex. FF, p. 59.

Dr. Morin said that Mr. Gorman's failure to recognize the quarterly nature of dividend payments in his DCF computation understates his cost of equity capital by about 20 basis points. Pet. Ex. FF, p. 61. He said that Mr. Gorman's use of a 0.64 historic beta for his electric sample understates his results because historical beta measures for an industry in a state of heightened risk are understated. Pet. Ex. FF, pp. 61-62. He observed that use of a more appropriate beta for PSI of 0.70 would raise Mr. Gorman's CAPM estimates by approximately 50 basis points, using Mr. Gorman's market risk premium estimate of 7.0%. Pet. Ex. FF, p. 62.

Dr. Morin believed that, in his risk premium analysis, Mr. Gorman appropriately examined the historical risk premiums implied in the ROEs allowed by state regulatory commissions in hundreds of electric utility ROE decisions over a 16-year period, 1986-2002, relative to the contemporaneous level of long-term Treasury bond yields and A-rated utility bond yields. However, although the average ROE spread over long-term Treasury yields was 4.9% for the 1986-2002 period, Mr. Gorman used a range of 4.4% to 5.6% rather than 4.9%. Pet. Ex. FF, pp. 63-64. Dr. Morin disagreed with the use of this range because of the rising trend of the risk premium in response to lower interest rates, rising competition and restructuring. Pet. Ex. FF, p. 64.

Dr. Morin testified that in his DCF approach, Mr. Gorman did not allow for flotation costs (30 basis points) and employed underestimated dividend yield data (20 basis points), thereby understating PSI's cost of equity by 50 basis points. Pet. Ex. FF, p. 68. He added that Mr. Gorman's CAPM result was further understated by 50 basis points because of his use of the raw form of the CAPM. Finally, he said, a recognition of the rising allowed risk premium over time in response to lower interest rates and rising competition and restructuring, ignored by Mr. Gorman, would have raised his risk premium estimate to above 11%. Pet. Ex. FF, p. 68.

(c) *Rebuttal Concerning Staff's Cost of Common Equity Evidence.* In his response to

Testimonial Staff's original recommendation of ROE allowance in the range of 10.25% to 10.50%, Dr. Morin said he disagreed with Staff's two adjustments to his DCF analysis. Staff used the one-half year (1 + 0.5g) adjustment factor to the dividend yield, rather than the full year (1 + g) factor. Second, Staff reduced his flotation cost adjustment by one half, from 30 to 15 basis points, based on the actual costs reported for Cinergy's most recent stock offering. Restoration of the full flotation cost adjustment and application of the functional form of the DCF model he proposed would raise Staff's original range by 30 basis points from 10.25% – 10.50% to 10.55% – 10.80%. Pet. Ex. FF, p. 70.

Dr. Morin also disagreed with two of Staff's adjustments to his CAPM analysis. First, he said that he believes that Staff's risk-free rate needed to be updated to reflect current capital market conditions. Staff used a 4.9% risk-free rate based on a six-month average of 30-year Treasury bond yields. The yield was in excess of 5% for the months of August and September 2003, Dr. Morin said, and was 5.3% at the time Dr. Morin's rebuttal testimony was prepared at the end of September. Pet. Ex. FF, p. 70. He was also critical of Staff's use of geometric means to measure expected returns. Failure to rely exclusively on the arithmetic mean biased Staff's CAPM result downward by some 55-65 basis points, he said. Pet. Ex. FF, p. 70. He also was critical of Staff's ignoring what Dr. Morin considered the overwhelming empirical evidence that the "plain vanilla" CAPM understates the return on low-beta stocks. Pet. Ex. FF, p. 71.

[23] (7) *Discussion and Findings Concerning Cost of Equity Capital Evidence.* Based on the entirety of the testimony presented on this issue, it is apparent that we have been presented with a highly detailed discussion of the cost of equity capital by various parties to this proceeding. In evaluating the evidence presented on this issue we concur with Mr. Inman's observations that: (i) the determination of an exact investor required return on equity is impossible; (ii) the results of the CAPM, DCF and RP methods are driven by the inputs for each, of which there are countless possibilities and legitimate arguments to include this and exclude that; and (iii) a petitioning utility will tend to support methodologies and inputs that support a higher result and those in opposition will tend to support methodologies and inputs which produce a lower result. IURC Staff Ex. No. 1, pp. 22-23. Our discussion and analysis of this issue also serves to illustrate that the goals for setting the fair rate of return for a public utility go well beyond the use of formulas and mathematical calculations which may imply a level of precision which does not really exist. With this in mind, we turn our analysis to the cost of capital evidence submitted in this proceeding.

The witnesses testifying concerning Petitioner's cost of capital all used similar approaches. Dr. Morin, Mr. Kaufman and Mr. Gorman, all utilized standard methodologies for determining a cost of common equity capital: DCF studies, the CAPM model, and/or the RP approach. As is typically the case, however, they came to different conclusions. Dr. Morin's updated DCF studies produced a range in the cost of equity from 10.3% to 12.1%. His updated CAPM and RP methods produced costs of equity in the range of 10.9% to 12.5%. Mr. Kaufman, on the other hand, produced lower estimated costs of equity in his updated study, ranging from 8.02% to 9.67% utilizing the DCF methodology, and from 8.48% to 9.09% utilizing the CAPM model. Mr. Kaufman's initial study produced DCF results ranging from 7.94% to 10.12%, and CAPM results ranging from 7.98% to 8.59%. Mr. Gorman calculated a cost of equity in the range of 9.7% to 10.3%, utilizing a DCF analysis, a RP analysis, and the CAPM model. Testimonial Staff witness Inman, analyzing the cost of equity estimates of the other parties, recommended a cost of equity range of 10.25% to 10.50% in his prefiled testimony. Mr. Inman noted on cross-examination that he did not perform a complete update of his analysis; however, as part of his testimony, Mr. Inman provided an updated range of PSI's cost of equity capital from 10.35%-10.55%.

We note that unlike the last PSI rate case in which there was extensive testimony from the

experts regarding the strengths and weaknesses of the DCF, RP, CAPM, and ECAPM *models*, the issues in the present cause focus more on the *inputs* utilized in the models, rather than the models themselves. While the parties offer little insight as to why their approach has changed, it is apparent based on our review of the evidence in this Cause that unlike the last rate case in which the DCF model presented lower results compared to the other models, the models utilized in the present proceeding offer a certain level of uniformity in their results. Perhaps this fact alone helped to eliminate any incentive an expert might otherwise have to criticize the results of a particular model as part of this proceeding.[7] While it is not necessary for us to resolve extensive debate regarding the value and utilization of each of the models, there are disagreements regarding some of the major inputs used by the experts within the various models. While we do not believe that it is necessary for us to address every issue upon which the experts disagreed, we think that it is important for us to review the major areas of disagreement prior to reaching a conclusion on these issues.

The evidence presented in this Cause, on cost of equity issues and the major areas of disagreement among the various experts, is summarized in the following table:

Summary of ROE Estimates and Areas of Disagreement

	Witness / Party	*Morin / PSI*	*Inman / IURC*	*Kaufman / OUCC*	*Gorman / PSI-IG*
Original	CAPM	10.20 – 10.70%	9.21%	7.98 - 8.59%	9.50 - 9.80%
	DCF	10.70 – 13.60%	10.42 - 13.52%	7.94 – 10..12%	10.10%
	RP	10.90 – 12.30%	9.69 - 11.02%	NA	NA
	ARP	11.30 – 11.40%	11.30 - 11.40%	NA	9.40 - 10.90%
	Recommendation	**11.50%**	**10.25 - 10.50%**	**9.15%**	**10.00%**
Updated	CAPM	10.90 – 11.40%	NA	8.48 - 9.09%	NA
	DCF	10.30 – 12.10%	NA	8.02 - 9.67%	NA
	RP	10.90 – 12.50%	NA	NA	NA
	ARP	11.30 – 11.40%	NA	NA	NA
	Recommendation	**11.20%**	**10.35 - 10.55%**	**9.25%**	**NA**
	Major Areas of Disagreement - All Models				
All	Floatation costs Adjustment	0.30%	0.15%	0.05 - 0.10%	0.00%
CAPM	Beta	0.72	0.72	0.65 – 0.70	0.64
	Market Risk Premium Mean "Arithmetic vs. Geometric"	Arithmetic	Both	Both	Arithmetic
	ECAPM	Accept	Reject	Reject	Reject
DCF	Half - vs. Full -Year Div. Growth	Full-Year	Half-Year	Half-Year	Full-Year
	Quarterly Compounding Adj.	0.20%	0.20%	0.00%	0.00%
RP	Risk Premium Mean "Arithmetic vs. Geometric"	Arithmetic	Both	NA	NA

The recommended ROE estimates (as adjusted) presented in this Cause range from 9.25-11.20%, a spread of 195 basis points. Several factors contributed to the variation in estimates including: varying weights applied by the experts to several ROE models; the use of Arithmetic vs. Geometric mean returns; Spot vs. Average T-Bond and dividend yields; and, the wide array of proxy groups used in an effort to replicate PSI's risk profile. While we do not find it necessary to resolve each of the sometimes overlapping disagreements between Dr.

Morin, Mr. Kaufman, Mr. Gorman and Mr. Inman, in arriving at either an appropriate cost of capital, or a fair rate of return determination, we note that specific aspects of Dr. Morin's analyses raised concerns on the part of the various other parties and are therefore worthy of additional review and discussion by the Commission.

The Commission recognizes that there were disagreements between the Petitioner and the other witnesses with respect to the following issues: 1) The level, or inclusion, of flotation costs by Dr. Morin (Kaufman, Inman and Gorman); 2) Dr. Morin's failure to utilize the one-half year (1 + 0.5g) adjustment factor for the dividend yield in the DCF model (Kaufman and Inman); 3) the beta estimate utilized by Dr. Morin in his CAPM Model (Kaufman and Gorman); 4) Dr. Morin's use of only the Arithmetic Mean rather than Arithmetic & Geometric mean in his CAPM and/or RP Model (Kaufman and Inman); and, 5) the appropriate inclusion of the ECAPM analysis performed by Dr. Morin (Kaufman, Inman and Gorman). We discuss each of these issues as follows:

(a) Flotation Costs (Applicable to all Models)

[24] In his testimony Dr. Morin cited empirical finance literature to support his conclusion that flotation costs are roughly equal to 5% of electric utility stock offering proceeds. Therefore, with an average expected dividend yield of 5% for electric utility stocks, Dr. Morin concluded that the proper adjustment to the return on equity should be [5/(1.00-.05)]-5 = 0.3% (thirty (30) basis points). Pet. Ex. G, p. 44.

Mr. Kaufman questioned Dr. Morin's proposed thirty (30) basis point upward adjustment to the cost of equity. Mr. Kaufman took issue with Dr. Morin's use of empirical studies of average electric utility stock issue costs and indicated that the actual flotation costs incurred by Cinergy should be considered when determining a fair flotation cost adjustment. Mr. Kaufman explained that actual flotation costs associated with Cinergy's most recent stock issuance amounted to $1.55 million, or less than 1% of the stock issue, which Mr. Kaufman contends supports a reduction from the 30 basis points proposed by Dr. Morin. While Mr. Kaufman indicated that he believes that some adjustment for flotation costs is merited, he recommends the adjustment be only 5-10 basis points. Pub. Ex. No. 8 p. 77.

Mr. Gorman indicated that he does not believe flotation costs are applicable to PSI, as the company does not have publicly traded common stock. If Cinergy's flotation costs are applicable to PSI, then PSI should account for them explicitly and not simply add a blanket flotation adjustment as suggested by Dr. Morin.

Testimonial Staff recommended allowing a 15 basis point adjustment to the CAPM and RP methods and a 2.5% gross up of the dividend yield produced by the DCF method. Mr. Inman's flotation cost adjustment is based on Dr. Morin's flotation cost estimate and Cinergy's actual flotation costs related to their most recent stock offering.

Analysis and Findings of the Commission on this Issue

Based on the testimony presented, we are faced with a range of recommendations regarding flotation costs. Mr. Kaufman and Mr. Inman both agree that flotation costs may appropriately be included, albeit at a reduced level from that proposed by Dr. Morin. Mr. Gorman contends that if flotation costs are allowed at all, they should be subject to specific accounting treatment to ensure that only costs incurred by PSI are charged to PSI. The witnesses that favor a reduction or elimination of flotation costs are fairly uniform in their assessment that an analysis of the actual flotation costs incurred by Cinergy should result in a determination by the Commission that a reduction of the upward adjustment proposed by Dr. Morin to account for flotation costs is appropriate.

In undertaking a textbook analysis of the flotation costs issue, Dr. Morin provides a formula that estimates flotation costs that typically might be encountered as part of an electric utility stock offering. While Dr. Morin provides testimony as to why he believes the other witnesses are wrong in proposing to reduce flotation costs, and the impact that such a reduction would have on his proposal, he does not explore the possibility that a reduction of flotation costs could appropriately occur based on the modification of his flotation cost estimate, which does not consider the actual costs encountered by Cinergy. The fact that Dr. Morin's mathematical equation does not overlay fact specific issues applicable to PSI, demonstrates the shortcomings of a formula as it does not include a mechanism to allow the Commission to consider the actual flotation costs encountered by Cinergy as part of recent stock offerings. We believe that our review of this issue would be incomplete without consideration of this very important fact specific issue.

Accordingly, having reviewed the entirety of the record on this issue, the Commission agrees that an adjustment to the return on equity to account for flotation costs is appropriate. We find the recommendations of Mr. Kaufman and Mr. Inman to be particularly instructive on this issue as they both favor a reduction of the flotation costs proposed by Dr. Morin, based on consideration of actual flotation costs incurred by Cinergy. We find this approach to be reasonable and hereby find that a fifteen (15) basis point upward adjustment to the cost of equity to account for flotation costs is appropriate and should be approved in this Cause.

(b) Quarterly Compounding Adjustment and Expected Dividend Yield (DCF Model)

[25, 26] In his testimony, Dr. Morin explained that the common practice of companies is to pay dividends quarterly. Therefore, Dr. Morin indicated that investors' required return must be determined with a DCF model that reflects the quarterly nature of dividend payments. Dr. Morin asserted that an upward adjustment to the return on equity should be made to account for quarterly payment and compounding of dividends, based on the assumption that dividends received may be reinvested at the return on equity rate. Dr. Morin explicitly adjusted his DCF estimates upward by 20 basis points to account for the quarterly timing of dividend payments.

Mr. Kaufman agreed with Dr. Morin's reasoning, but did not agree that an explicit adjustment should be made to the DCF model. Mr. Kaufman reasoned that utilities receive payments from customers on a monthly basis instead of a yearly basis. This allows the utility to invest their monthly profits in projects that earn a fair return for the utility. However, no downward adjustment is made to the utility's return on equity to account for the monthly timing of these payments. Therefore, Mr. Kaufman concluded that an adjustment should not be made for quarterly payment of dividends. Mr. Gorman testified that he believes that adding the adjustment suggested by Dr. Morin would allow shareholders to earn the dividend compounding return twice, once on the authorized return on equity and the second time when dividends are received. PSI-IG Ex. No. 3, p. 33.

Dr. Morin and Mr. Gorman both used the full-year method to estimate the expected dividend yield. Dr. Morin indicated that he believes that the use of a one-half year adjustment to the dividend yield in the DCF model results in the understatement of the appropriate dividend yield, which in turn results in an understatement of PSI's cost of equity. In contrast to the position set forth by Dr. Morin and Mr. Gorman, Mr. Kaufman and Mr. Inman utilized a one-half year (1+0.5g) adjustment factor to the dividend yield in the DCF model. Mr. Kaufman recognized that Dr. Morin's analysis was based on a DCF model adjusted to capture a full year's future growth, and indicated that he believes this approach overstates the forward yield. Mr. Inman agreed with Mr. Kaufman's criticism of applying the full year's growth to the current dividend yield. Citing recent Commission rate case proceedings, including *In re Indiana American Water Company*, Cause No. 42029 (*Ind. Util. Reg. Comm'n*, November 6, 2002), Testimonial Staff recommended use of the half-year method of calculating forward dividend yields.

Commission Analysis and Findings on these Issues

With respect Dr. Morin's testimony in which he indicates that an adjustment to the DCF model must be made to reflect the quarterly nature of dividends, we note that this issue is not new. This very issue was presented to the Commission in Cause No. 40003, (*Ind. Util. Reg. Comm.*, September 27, 1996). In Cause No. 40003, the Commission found, in resolving a dispute on this issue between the OUCC witness and Dr. Morin, that:

> We find the logic of the quarterly DCF a useful alternative, and no sufficiently sound reason has been presented for rejecting it. We find it difficult to believe that the timing of dividend payments is not reflected in the price of a stock. We agree with Dr. Morin that it is inconsistent to use a stock price which reflects quarterly dividends in a model which assumes annual dividend payments unless the model is adjusted to reflect the quarterly dividends which lend to the investor expectations which give rise to the stock price.

Cause No. 40003 at 28-29

While we may appropriately be guided by precedent on this issue, we also find that we could revisit this issue if faced with a persuasive argument. However, the only persuasive argument put forth on this issue was presented by Dr. Morin. Therefore, we again find, based on the evidence presented in this Cause that it would be inconsistent to use a stock price which reflects quarterly compounding of dividends in a model that assumes annual dividend payments unless the model is adjusted to reflect the quarterly compounding of dividends. Therefore, we agree with Dr. Morin on this issue and find that his upward adjustment to the return on equity was appropriately included to account for quarterly payment and compounding of dividends.

With respect to our consideration of forward dividend yield, the Commission is persuaded by the arguments presented by Mr. Kaufman and Mr. Inman in support of their use of the half year method of calculating the forward dividend yield. In reaching this determination we also recognize that we have recently accepted this approach in other proceedings, including Cause No. 42029 (*Ind. Util. Reg. Comm'n*, November 6, 2002), which was referenced by Mr. Inman. In Cause No. 42029 we stated that:

> The Commission has considerable experience with the DCF model for estimating the cost of equity. We are well aware of the advantages and limitations of the various approaches used by each of the witnesses. For example, the half-year method used by the OUCC for calculating the forward yield is the most frequently used approach in this jurisdiction and is rarely a point of contention in DCF analysis. We believe it fairly represents the dividend payments expected and received by investors, while the full-year method employed by Petitioner overstates dividend yield.

Cause No. 42029 at 31.

Therefore, based on our review of the specific evidence presented in this case, we find that the proposal set forth by Mr. Inman and Mr. Kaufman to use of the half year method of calculating the forward dividend yield, is appropriate as it fairly represents the dividend payments expected and received by investors. We find that the full-year method employed by Dr. Morin overstates the dividend yield, and is therefore rejected by the Commission in this Cause.

(c) Arithmetic and Geometric Means (CAPM and RP Models)

[27-29] The application of geometric and/or arithmetic mean risk premiums was an important point of dispute in both the CAPM and RP models in this Cause. Dr. Morin testified that he believes that only arithmetic averages are appropriate when measuring expected risk premiums. Dr. Morin pointed out that the effect of using both the geometric and arithmetic mean risk premiums, rather than the arithmetic mean alone, is to decrease estimates of expected risk premiums. This in turn, according to Dr. Morin, biases the CAPM and RP results downward. Consistent with Dr. Morin, Mr.

Gorman utilized arithmetic averages in the calculation of his risk premiums.

In performing his CAPM analysis Mr. Kaufman averaged his calculated geometric and arithmetic market risk premium means for use as the market risk premium. Mr. Kaufman stated that this approach is consistent with the Commission's past approval of arithmetic and geometric means. Mr. Kaufman directed us to two final orders of this Commission, *People's Gas and Power*, Cause No. 39315, (Ind. Util. Reg. Comm'n, October 21, 1992); and, *Indiana American Water*, Cause No. 40103, (Ind. Util. Reg. Comm'n, May 30, 1996), which he indicated support his conclusion that the use of geometric and arithmetic mean risk premiums are appropriate. Mr. Inman stated that Testimonial Staff agrees with Mr. Kaufman's approach in which he gives weight to both the arithmetic and geometric means when computing the appropriate risk premium means to apply to the CAPM and RP models.

ECAPM and Beta.

Dr. Morin used "plain vanilla" and "empirical" versions of the CAPM. He was the only expert that performed an ECAPM analysis. In his testimony, Dr. Morin asserted that empirical studies have shown that betas tend to converge to unity over time (i.e., historical betas below one are expected to rise to 1.00, and betas above 1.00 are expected to fall to one). Therefore, the use of historical betas necessarily biases a security's market risk downward for a security with a beta less than 1.00. Dr. Morin testified that the ECAPM adjusts beta for its tendency to move to 1.00.

Mr. Kaufman, Mr. Gorman, and Mr. Inman made exclusive use of the "plain vanilla" version of the CAPM and expressly rejected Dr. Morin's use of the ECAPM. Each stated that Value Line (the source of Dr. Morin's beta estimates) adjusts betas for their tendency to move to 1.00 over time. Therefore, the ECAPM analysis performed by Dr. Morin is redundant. These witnesses also noted that the ECAPM model was rejected by the Commission in Cause No. 40003.

While all parties used Value Line as their source for beta estimates in their CAPM models, there was no overall consensus among the experts with respect to the use of an appropriate *estimate* of the beta to be utilized. As with the foregoing issues, the variation in the approaches taken by the experts only serves to further demonstrate that expert opinions will differ with respect to the inputs they utilize — as well as the conclusions they ultimately reach — in undertaking an individual analysis of the issues.

In his testimony, Dr. Morin examined the average betas of two proxy groups: the average of Value Line's reported betas for the electric utility industry, which is 0.71; and, the average beta of Value Line's natural gas distribution universe with a market value in excess of $500MM, which is 0.72. Based on his evaluation of these two proxy groups, and his assertion that backward looking betas do not fully reflect a company's risk profile, Dr. Motion utilized the higher of the two betas, or 0.72.

While Mr. Inman accepted Dr. Morin's beta of 0.72, Mr. Kaufman and Mr. Gorman both expressed concern regarding the beta utilized by PSI's witness. Mr. Kaufman and Mr. Gorman both rejected Dr. Morin's use of a proxy group of Natural Gas Distribution companies that are not involved in electric operations, as they do not believe that this group can serve as a reasonable proxy for PSI. Based on his analysis of this issue, Mr. Kaufman established a beta of 0.610, for the proxy group that he developed; an average beta of 0.642 based on his review of Dr. Morin's proxy group; and, a beta of 0.70 for Cinergy. Based on this overall review, Mr. Kaufman initially recommended a beta in the range of 0.610 to 0.70. In updating his testimony in this Cause, Mr. Kaufman revised his beta range to 0.65-0.70. Mr. Gorman testified that he used a beta of 0.64, obtained by averaging the group betas for his comparable group of electric utilities.

Commission Analysis on these Issues

The application of geometric and/or arithmetic mean risk premiums has been previously presented to the Commission for consideration.

This issue was raised in *Indiana American Water*, Cause No. 40103, (*Ind. Util. Reg. Comm'n*, May 30, 1996), in which the Commission stated:

> The debate over the proper use of the arithmetic and geometric means is an issue we consider resolved. As we stated in Indianapolis Water Company, Cause No. 39713-39843, each method has its strengths and weaknesses, and neither is so clearly appropriate as to exclude consideration of the other.

Cause No. 40103 at 41.

Mr. Kaufman and Mr. Inman utilized arithmetic and geometric means, while Dr. Morin and Mr. Gorman utilized only arithmetic means. Based on the disparate results from the experts, and consistent with our findings in Cause No. 40103, we find that we must analyze this issue based on our understanding that each method has its strengths and weaknesses, and neither is so clearly appropriate as to exclude consideration of the other.

With respect to the appropriate beta to be utilized, we have been presented with a number of options by the experts regarding this input, ranging from 0.64-0.72. In reviewing this issue the Commission recognizes that the modification of this single input in the CAPM model results in dramatically different proposals regarding the recommended cost of equity. A comparison between Dr. Morin and Mr. Gorman's CAPM analysis, and the beta they utilized, is instructive regarding the impact of this single input. While these two witnesses agreed on many issues, they did not agree on beta. Dr. Morin concluded that 0.72 was an appropriate beta and Mr. Gorman indicated that he believed a beta of 0.64 should be utilized. The difference in this single input, between these two experts, accounted for a swing of 54 basis points and resulted in vastly different outputs from their respective CAPM models. While we do not believe that it is necessary for us to choose a single beta from among those utilized by the experts, we recognize that this issue is one important factor for us to consider in reaching a determination on an appropriate cost of equity.

With respect to the ECAPM analysis preformed by Dr. Morin we note that the Commission rejected this model in Cause No. 40003, and found that: "the Empirical CAPM is not sufficiently reliable for ratemaking purposes." Cause No. 40003 at 32. We went on to conclude that the ECAPM " . . . would adjust, in essence, future expectations with regard to investor perceptions of relative risks for further change which may occur years hence." The Commission concluded that ". . . we do not believe exercises in approximating future cost of capital are conducive to such precise estimation as the Empirical CAPM would suggest." *Id.* We find that nothing presented in this Cause has changed our prior determination that ECAPM is not sufficiently reliable for ratemaking purposes and hereby reject the model in this proceeding.

(d) Other Evidence Relevant to the Determination of a Fair Return

[30-41] (1) *Petitioner's Current Financial Condition and Financial Objectives.* PSI witnesses Reising and Esamann testified concerning PSI's current financial condition and financial objectives. Pet. Ex. B, pp. 3-5, and 32-41; Pet. Ex. E, pp. 10-19; and Pet Ex. DD, pp 3-10 and 27-35. PSI's capital structure on a financial basis as of September 30, 2003 reflects 52.60% common equity, including a $200 million capital infusion from Cinergy. According to Mr. Reising, PSI's general financial objective is to achieve the fundamentals necessary to provide assured and reasonable access to capital markets in order to continue to provide cost effective, safe, adequate, environmentally compliant and reliable service to its customers. Specific financial objectives necessary to enhance or maintain the desired financial strength include: (1) achieving and maintaining at least a 50% common equity ratio for PSI on a financial capitalization basis; and (2) maintaining PSI's credit ratings at current levels (*e.g.*, an "A-" rating for PSI's senior secured debt), with an ultimate goal of improving PSI's credit ratings one notch (to "A" for PSI's senior secured debt). Pet. Ex. E, pp. 10-11.

With respect to PSI's stated objective of improving its credit rating, Dr. Morin offered an analysis of what he believes the optimal bond rating for an electric utility's senior secured securities should be. Dr. Morin explained that when a company substitutes lower cost debt for equity, the average weighted cost of capital decreases up to a point, while the bond rating progressively deteriorates. Dr. Morin testified that over the long run, a strong "A" bond rating will minimize the cost of capital to customers. According to Dr. Morin, the implication for PSI is clear that long-term achievement and maintenance of a strong "A" bond rating is in both investors' and customers' best interests; and this Commission should establish rates so as to create the financial conditions conducive to PSI achieving an "A" credit rating. Pet. Ex. G, pp. 47-51; and Pet. Ex. FF, pp. 76-78.

Mr. Fetter testified that recent events have negatively impacted the views of credit rating agencies and investors with regard to the utility sector. According to Mr. Fetter, utilities operating within today's financial environment should seek to minimize the uncertainties that could affect a utility's financial health and its credit ratings. Pet. Ex. H, pp. 15-17; Pet. Ex. E, pp. 6-8; and Pet. Ex. EE, pp. 7-8.

Mr. Fetter testified that PSI's securities are currently rated by the three major credit rating agencies as follows:

	Fitch	*Moody's*	*Standard & Poor's*
Senior Secured Debt	A-	A3	A-
Senior Unsecured Debt	BBB+	Baa1	BBB
Junior Unsecured Debt	BBB	Baa2	BBB-
Preferred Stock	BBB	Baa3	BBB-

Pet. Ex. E, p. 12.

In recent assessments of PSI's credit ratings, the three major credit rating agencies have all emphasized PSI's large capital expenditure requirements and the importance of constructive regulatory support. For example, Fitch's August 2001 report stated that "PSI's rising capital requirements related to compliance with environmental regulations and planned new capacity additions is a credit concern and will require regulatory support to prevent a decline in credit quality." Pet. Ex. E, p. 13. Similarly, Fitch's June 2002 report on PSI summarized PSI's key credit concerns as "the relatively high level of capital expenditures needed to comply with environmental regulations and the need for rate increases in Indiana to support the asset transfers." Pet. Ex. E, p. 13. Moody's September 2002 report commented on its rating of PSI as follows: "The rating, however, considers PSI's somewhat high debt load, future capital expenditures for environmental compliance, and financial measures which on a stand alone basis are relatively low when compared to most other companies in their peer rating category." Pet. Ex. E, p. 14. S&P's July 2002 report on PSI addressed certain regulatory challenges facing PSI, including: "uncertainty involving environmental issues related to new source review, as well as the potential for stricter emission standards." Pet. Ex. E, p. 14. Finally, Moody's third quarter 2002 report on PSI noted the following concerns: "PSI's liquidity will continue to be negatively affected by large environmental expenditures for its coal plants and its somewhat high debt load" and "PSI's cash flow has been variable in recent years and generally insufficient to cover dividend requirements and capital expenditure needs." Pet. Ex. E, pp. 14-15.

Mr. Fetter explained that regulation is a key factor in assessing the credit profile of a utility, because a state public utility commission determines rate levels and terms and conditions of service. Investors want to be confident that the utility operates within a stable regulatory environment that will allow the utility the opportunity to earn a reasonable return on its investment while meeting the demand, reliability, service, and environmental requirements of its service area. Important considerations include the allowed rate of return, the cash quality of earnings, the timely recovery of capital investments, the stability of earnings, the strength of its capital structure and moderation of the utility's need to finance externally. Positive consideration is also given to mechanisms that enable rates to be adjusted expeditiously to accommodate major swings in costs which cannot be reasonably forecasted to fit into a standard base rate case proceeding. Pet. Ex. H, pp. 7-10.

Mr. Fetter, along with PSI witnesses Reising and Paul G. Smith, General Manager, Budgets and Forecasts for Cinergy Services, examined several rate increase scenarios and their expected impact on PSI's credit quality. Mr. Fetter initially examined both a "status quo" (*i.e.*, no rate relief) scenario and a full rate relief scenario. He concluded that if the Commission did not approve substantially all of the rate relief requested by PSI, certain key credit ratios for PSI — specifically, cash flow, interest protection, and leverage measures — would significantly decline within a very short period of time. PSI would be reviewed for a possible credit rating downgrade. Pet. Ex. H, pp. 16-22; Pet. Ex. E, p.19; Pet. Ex. F, pp. 3-9; Pet. Ex. GG, pp. 2-10; Pet. HH, pp. 2-5; and Pet. Ex. EE, pp. 3-6.

In rebuttal testimony, PSI and Mr. Fetter analyzed the potential impact of the OUCC's $18 million rate increase recommendation on PSI's credit quality. Additionally, in response to Mr. Inman's observation that PSI failed to examine alternative rate increase scenarios and their impact on PSI's credit quality, PSI and Mr. Fetter analyzed the potential impact of a $150 million rate increase on PSI's credit quality.

Mr. Fetter emphasized that a small increase, such as that proposed by the OUCC, would be inconsistent with PSI maintaining its current "BBB+" corporate credit rating status and would preclude PSI from having any opportunity to improve its credit rating. In Mr. Fetter's judgment, given PSI's ongoing need for capital expenditures, under this $18 million rate increase scenario, credit rating agencies would not only review PSI for a likely downgrade, but might even downgrade PSI two notches. Pet. Ex. GG, pp. 2-6. Additionally, if this Commission authorized a $150 million annual increase, Mr. Fetter indicated that from a credit quality perspective, PSI would likely be on the dividing line between its current "BBB+" rating and a downgraded "BBB" credit rating. At a minimum, Mr. Fetter felt that serious consideration would be given to a negative watch or outlook if current rating levels were maintained.

(2) *Relative Risk Faced by PSI.* The various parties in this case held divergent views concerning the risks currently facing the energy industry in general and PSI in particular. PSI's witnesses were of the view that the energy industry is in a highly uncertain state, stemming from a number of extreme and unexpected industry events. Mr. Rogers explained that PSI faces both expected and unexpected challenges. Chief among these challenges is the substantial uncertainty associated with environmental regulation; the ownership, operation, pricing, and reliability of the transmission grid; continuing uncertainty about wholesale market design and operation; and risks associated with achieving fair returns demanded by investors. Pet. Ex. A, pp. 3-4 and 16-29; Pet. Ex. DD, pp. 7-10; and Pet. Ex. EE, pp. 7-8.

Other parties to this proceeding took the view that Indiana's constructive regulatory statutes and policies, combined with the numerous trackers utilized by PSI, effectively mitigate virtually all environmental, transmission, and resource adequacy risks that might otherwise be faced by PSI. As pointed out by Dr. Sheehan, the use of trackers allows for periodic cost adjustments between rate cases and thus eliminates financial risk for a utility. These reduced risks, according to Dr. Sheehan, argue for elimination of some of the risk premium received by the utility in the ROE determination. CAC Ex. C, p. 33. Mr. Biewald shared Dr. Sheehan's conclusion and observed that, of Dr. Morin's peer group of utility companies used to calculate his ROE, PSI has the highest number of trackers. Mr. Biewald indicated that the large number of PSI's rate adjustment trackers, relative to its industry peers, suggest that the Company is well protected against many risks to which other utilities are often exposed. CAC Ex. B, p. 11.

Testimonial Staff also recognized that PSI is protected from certain risks by its use of trackers. Dr. Borum indicated that Indiana law and the rate adjustment tracking mechanisms proposed by the Company give PSI the flexibility to address future challenges and mitigate future uncertainties in a constructive manner. However, he observed, this flexibility and mitigation is achieved by shifting much of the uncertainty and the associated risks to ratepayers. Such shifting of risk must be recognized and reflected in the Commission's decision regarding the cost of equity capital. IURC Staff Ex. No. 3, p. 5. Therefore, Dr. Borum concluded that we should feel comfortable approving a ROE on the lower end of the range recommend by Mr. Inman.

Mr. Kaufman shared the concerns expressed by other witnesses and recommended that his proposed cost of equity should be reduced if the trackers requested by PSI in this Cause are approved. While we do not accept Mr. Kaufman's invitation to reduce his proposed cost of equity, clearly the trackers PSI has requested are an important consideration vis-`a-vis our overall consideration of risks faced by PSI and our determination of an appropriate cost of equity.

(3) *PSI's Operational Performance.* PSI presented evidence concerning its operational and financial performance, and encouraged this Commission to consider its performance in this rate setting process. Specifically, PSI urged this Commission to determine a fair return for PSI based on the higher end of the cost of equity range to reward the company for its performance in terms of reliability, efficiency, cost competitiveness, and customer service. Both Mr. Rogers and Mr. Esamann argued that rewarding strong performance represented good public policy. Dr. Borum of the Testimonial Staff opined on cross-examination that rewarding strong performing utilities through the rate setting process, and in particular in the determination of a fair return for the utility, was consistent with good public policy. Dr. Borum also testified that he believed that PSI was a strong performer in terms of the various attributes that make up customer service — reliability, efficiency, cost-competitiveness, etc. Pet. Ex. B, pp. 11-31; Pet. Ex. DD, pp. 10-21 and 31-34; Pet. Ex. FF, pp. 78-80; Pet. Ex. GG, pp. 19-20; Tr. at E39-E43, E106-E109, E118-E119 and R98-R99.

PSI presented evidence demonstrating that its electric delivery system performed reliably in terms of the frequency and duration of customer interruptions, and outage restoration, and had relatively low O&M costs as compared to peers. While cautioning that individual service territory characteristics make comparisons in this area difficult, Mr. Esamann testified that, in 2002, the average number of sustained interruptions for the year per customer, known as the Electric System Average Interruption Frequency Index ("SAIFI") (including severe storm impacts) was 1.57, and the average time to restore power after an interruption, known as the Electric Customer Average Interruption Duration Index ("CAIDI") (again including severe storm impacts) was 1.81 hours. In 2003, PSI's overall average SAIFI and CAIDI results remained good, even including the effect of an extended period of severe weather in July. Pet. Ex. B. pp. 20-23; Pet. Ex. M, pp. 59-63; and Pet. Ex. DD. p. 32.

The evidence also shows that PSI provides quality customer service, at competitive costs, as measured by both external and internal customer satisfaction measurements. According to the most recent J.D. Power and Associates customer satisfaction studies, Cinergy and PSI finished in the top quartile for overall residential and midsize business customer satisfaction. In both surveys — residential and midsize business — Cinergy ranked #2 overall in the Midwest region. PSI's own surveys of its residential customers indicate that 89% of responding customers are "satisfied" or "very satisfied" with PSI's customer service. At the same time, PSI's customer service cost per customer is slightly below the ECAR investor-owned utility average. Pet. Ex. B, pp. 27-31; and Pet. Ex. DD, pp. 31-32.

C. *Ultimate Findings Regarding Fair Rate of Return for Petitioner.* As we have discussed, the courts have emphasized that the determination of a fair rate of return is the prerogative of this Commission, taking into consideration all of the evidence. Our primary objectives in determining a fair rate of return for PSI are to determine a return which is reasonably sufficient to: instill confidence in the financial soundness of the utility; allow PSI to maintain and support its credit ratings; and, to enable PSI to raise the money necessary for the proper discharge of its public utility responsibilities. We have also examined a number of qualitative factors relevant to the determination of a fair return for PSI, specifically: PSI's financial condition and financial requirements; PSI's credit quality; risks facing PSI and the mitigation of those risks through the use of trackers; and PSI's performance as a utility. We find as follows with regard to these important qualitative factors.

First, we find that PSI has continuing, significant financing requirements — a minimum of $600 million of capital expenditure needs during 2004 and 2005. Next, we find that PSI's current credit quality is investment grade (a BBB+ corporate credit rating), but that the lack of substantial rate relief in light of PSI's current and continuing capital investments could potentially result in a downgrade. The prospect of a downgrade or a negative credit outlook — and the accompanying impact on PSI's ability to access financing on reasonable terms — could be significant given PSI's ongoing financing needs. Further, we find that today's energy industry presents numerous risks, perhaps especially to Midwestern utilities that are heavily reliant on coal.

The expert testimony in this Cause presents us with a range of options with respect to our determination of an appropriate cost of equity. As noted previously, the recommended estimates presented in this matter range from 9.25 - 11.20%, a spread of 195 basis points. Mr. Kaufman's proposal fell at the low end of the range, as he recommended a cost of equity of 9.25% and prefaced this recommendation with a recommendation that this percentage should be reduced if this Commission approves PSI's proposed trackers in this proceeding. Dr. Morin came in with the highest recommended cost of equity of 11.2%. The cost of equity proposed by Mr. Gorman and Mr. Inman fell within the range established by Mr. Kaufman and Dr. Morin. Consistent with our analysis of the specific inputs and issues in dispute, we recognize that it is not necessary for us to agree or disagree with the specific inputs or overall cost of equity proposed by any single expert. Rather, our determination regarding the appropriate cost of equity in this matter should be a product of our evaluation of the entirety of the evidence presented on this issue by the various parties.

In the present case, PSI presented their proposed cost of equity of 11.2%, as consistent with the cost of equity approved for most other electric utilities throughout the country. Implicit in this approach is the view that proposals that are lower than that proposed by PSI should be rejected by the Commission as outside of the norm. Dr. Morin testified that Mr. Kaufman's recommended ROE of 9.15% (prior to being updated to 9.25%) was substantially under the average returns on common equity allowed in electric and natural gas utility rate cases in the first six months in 2003 of 11.40% and 11.38%, respectively. Pet. Ex. FF, p. 15. While Dr. Morin was quick to criticize Mr. Kaufman's proposal, conspicuously absent from his own analysis is any consideration of the impact that PSI's requested trackers have (or should have) on his proposed cost of equity.

The use of trackers is a significant issue that distinguishes PSI from other electric utilities, and was subject to much discussion in this Cause. While we recognize PSI's strong performance as compared to many of its industry peers, and believe that the ROE approved in this case reflects our positive assessment of PSI on this issue, the inescapable fact is that *trackers reduce risk* to a utility and PSI has many more trackers than its peers. Therefore, we must — in reaching our determination regarding an appropriate cost of equity — properly consider the effect these trackers have in reducing risk, to ensure that these reduced risks are properly reflected in the cost of equity approved by the Commission.

Under these circumstances, we recognize that our determination may not readily allow for the side-by-side comparison of PSI's cost of equity to that of its peers, as advocated by Dr. Morin. However, we also recognize that PSI's decision to utilize trackers, coupled with the divergent options of the experts regarding the various inputs used in the models presented in this matter, has made our decision on the cost of equity issue very fact specific. Because of this, any attempt to make a generalized comparison between the cost of equity approved in this case, and the cost of equity approved for other electric utilities, will undoubtedly fail, unless the comparison fully and carefully reflects the fact specific issues that underlie the basis of our decision on this issue.

Therefore, based on the entirety of the evidence on this issue, including consideration of the Company's performance, in terms of customer service quality, reliability, efficiency, cost-competitiveness, the results contained in well respected customer satisfaction studies, and the risks faced by PSI, we find that it is appropriate to consider the efficiency and quality with which the utility is managed and the utility's overall performance in our determination of a fair rate of return for the utility. Accordingly, based on our review of the testimony presented by all of the parties, and consistent with our analysis of the specific issues disputed by the parties referenced in the our foregoing discussion of these issues, the Commission is persuaded, that the evidence in this proceeding supports an authorized cost of equity capital for PSI of 10.5%. Therefore, we find for purposes of this Cause, that PSI's cost of common equity capital should be 10.5% and its overall cost of capital is 7.30%, computed as follows:

Description	*Capitalization (in thousands)*	*Ratio*	*Cost*	*Weighted Cost*
Common Equity	$1,603,374	44.44%	10.50%	4.67%
Preferred Stock	42,333	1.17%	6.11%	0.07%
Long Term Debt	1,402,254	38.87%	6.37%	2.48%
Deferred Income Taxes	519,273	14.39%	0.00%	0.00%
Unamortized ITC — 1970 & Earlier	193	0.01%	0.00%	0.00%
Unamortized ITC — 1971 & Later	30,571	0.85%	8.53%	0.07%
Customer Deposits	9,741	0.27%	6.00%	0.01%
Total	*$3,607,739*	*100.00%*		*7.30%*

Having determined the cost of capital we must now determine a reasonable fair rate of return for Petitioner. Given that the Commission's determination of Petitioner's fair value rate base of $4,856,532,000 includes inflation, a comparable amount of inflation must be removed from the rate of return to reach a determination regarding the fair rate of return. The removal of inflation from the cost of equity and/or from the weighted cost of capital provides a reasonable fair rate of return. The inflation factors as provided by OUCC's, witness Mr. Kaufman in Attachment 1, of his testimony, reference inflation from the Consumer Price Index ranging from 1.5% to 3.0%. To determine a range for the fair rate of return, inflation was removed from the cost of equity as a first determinant, and then from the weighted cost of capital. Therefore we find that a reasonable fair rate of return is in the range of 4.30% to 6.63%

6. Operating Income at Present Rates.

A. *General.* For the 12 months ending September 30, 2002, PSI's jurisdictional operating income from its electric utility operations on a going level basis; adjusted for changes which were fixed known and measurable at the time of the hearing; and, which occurred during the test year, or on or before September 30, 2003, was shown by PSI to be as follows:

Operating Revenues (including CWIP)	$1,284,140,000
Operating Expenses and Taxes	
Fuel Expense	378,286,000
Purchased & Exchanged Power Expense	9,519,000
Other Operation and Maintenance Expense	391,580,000
Operating Revenue Deduction	(28,917,000)
Depreciation and Amortization Expense	218,316,000
Taxes Other than Income Taxes	58,415,000
Federal and State Income Taxes	69,215,000
Total Operating Expenses and Taxes	$1,096,414,000
Net Operating Income	$187,726,000

Pet. Ex. OO-3, updated October 31, 2003.

This represents a rate of return on original cost depreciated rate base under present rates of 5.13%.

B. *Undisputed Pro Forma Adjustments.* PSI proposed a number of *pro forma* adjustments to its operating income, per books, which were undisputed. It proposed other adjustments that, though disputed at some point in the process of this rate case, were compromised or were no longer in dispute at the conclusion of the Evidentiary Hearing in this Cause. All such *pro forma* adjustments proposed by PSI, either as originally proposed and undisputed, or as compromised with the compromised positions having been fully identified by the parties, are hereby accepted even though they may not be specifically discussed herein. The disputed adjustments are hereinafter discussed.

[42] C. *Disputed Pro Forma Revenue Adjustments.* In making our determinations regarding an appropriate level of operating expenses to be used in setting Petitioner's rates, we are guided by our overall objective of achieving a level of expenses which are representative of probable future experience. The Indiana courts have emphasized the importance of viewing test year results and out of period adjustments in the context of estimating a representative ongoing level of utility expenses. *See, e.g.*, City of Evansville v. Southern Indiana Gas & Electric Co., 167 Ind. App. 472, 339 N.E.2d 562, 575, in which the Court stated that: "The theory underlying the use of any test year and of any adjustment method in the rate-making process demands that the data used provide an accurate picture of the utility's operations during the period in which the proposed rates will be in effect." In the matter of *L.S. Ayres & Co. v. IPALCO et al.*, 169 Ind. Ct. App. 652; 351 N.E.2d 814, p. 820, the Court stated that: "test-year results are relevant for a determination of utility rates only to the extent that past operations are representative of probable future experience. . . . [I]f future operations will be required to bear higher tax rates or higher levels of wages and salaries than were incurred during the test year, test-year data must be adjusted to reflect increased costs." With these guidelines in mind, we turn to an examination of the disputed pro forma revenue and expense adjustments at issue in this case.

In this Cause, PSI proposed a Summer Reliability Tracker to allow the Company to adjust its rates to reflect the fluctuating cost of purchased power necessary to meet reserve requirements, and PowerShare® costs during the months of June through September. PSI's proposal included an offset to these summer expenses in the form of crediting the adjustment with a portion of annual off-system sales profits. Because this proposed mechanism tracked

the off-system sales profits from a zero base, PSI made adjustments to remove retail and wholesale non-firm revenue and expenses from its test period income statement.

The Summer Reliability Tracker and its components; Trading Expenses, Purchased Power and PowerShare® costs, are discussed in detail later in this order. We will begin with a discussion of the off-system sales adjustment.

[43, 44] (1) *Off-System Sales Profits.* As part of its Summer Reliability Tracker PSI proposed to adjust its rates for purchase power costs during the months of June through September. PSI's porposal included an offset to these expenses in the form of crediting the adjustment with a portion of annual off-system sales profits. Because this proposed mechanism tracked the off-system sales profits from a zero base, PSI made adjustments to remove retail and wholesale non-firm revenue and expenses from its test period income statement. Through its Summer Reliability Tracker, PSI initially proposed to flow back to its customers 100% of its June through September off-system sales profits, plus 25% of its off-system sales profits earned in the non-summer months (October through May). Mr. Esamann testified that he believes off-system sales profits, like purchased power costs, are variable, can be substantial, and are ultimately unpredictable. He proposed to use a tracking mechanism for such credits to customers, rather than trying to build an ongoing level into base rates. Pet. Ex. B, p. 58. Modifying its initial proposal that its customers be credited with 100% of off-system sales profits achieved during the summer months and 25% of such profits achieved during the eight non-summer months, PSI ultimately proposed a 50-50 sharing of profits throughout the year. Pet. Ex. DD, pp. 25-26.

The OUCC opposed PSI's Summer Reliability Tracker and proposed instead that test period off-system sales profits of $18.7 million or some other reasonable *pro forma* projection be reflected as a credit to PSI's revenue requirements. Pub. Ex. No. 6, p. 16; Pub. Ex. No. 2, p. 28. PSI-IG witness Phillips concurred with the OUCC and indicated that he believed that customers should be credited with the profits from off-system sales in PSI's base rates. Testimonial Staff witness Cvengros testified that while the test year shows approximately $18 million in off-system sales, the Commission could instead choose to utilize a tracking mechanism, comparable to PSI's current purchased power tracker in the amount of $13 million, with or without a sharing mechanism for profits exceeding the amount in base rates.

As discussed in greater detail below, the Commission is persuaded that PSI's off-system sales profits are highly variable and therefore are appropriate for tracking treatment. In addition, the Commission hereby finds that PSI's approximate test period off-system sales profits in the amount of $18.7 million should be recognized in base rates, as discussed below.

(2) *Rate Migration.*

[45, 46] (a) *PSI Proposal.* PSI porposed an adjustment to reflect lost revenues from customer migrations in its power rate schedules. Testifying in support of the adjustment, PSI witness Bailey observed that any time rates are redesigned or modified to produce a different revenue requirement, there is a potential that specific customers may be better off under a different rate schedule than the one under which they are currently billed. Pet. Ex. BB, p. 7. The Company's analysis in this case showed that 1,537 accounts would migrate from Rate LLF to Rate HLF, resulting in a $3,233,000 net revenue loss. *Id.* Its analysis further showed that the migrations from Rate HLF to LLF will involve 410 customers, with net lost revenue of $3,419,000, for a total of $6,652,000 in lost revenues from customer migration. *Id.* The Company's experience, he said, indicates that, even with notification, only about 50% of customers will actually migrate. Accordingly, PSI reduced the total amount of potential revenue loss by 50% to $3,326,000. This amount was proportionally allocated to the two power rate schedules and used to develop the Company's revenue requirements. *Id.* In addition, as PSI's proposed phasing-in of rate design allows an opportunity to determine the actual number of migrations, the Company proposed to limit the amount to be recovered in Phase II rates to the actual effects of the migrations. *Id.* PSI further proposed to reconcile actual lost revenue due to migrations during Phase I to the amount included in rates. Any difference would be returned or charged to customers through one of the Company's standard contract riders. *Id.* at 7-8.[8]

(b) *Kroger Position.* Kroger opposed Petitioner's migration revenue adjustment, and indicated that PSI's potential for revenue losses from customers switching rate schedules is an ordinary risk of business under current rates. Kroger Ex. No. 1, p. 24. Kroger's witness Mr. Higgins argued that revenue impacts from customers who switched rate schedules prior to the test year cutoff are already included in the Company's proposed revenue requirements, and there is nothing in this case that changes the fundamental relationship between HLF and LLF. So, he contended, there is no reason to reward PSI with additional revenues on the speculation that customers, who have not previously seen fit to change their rate schedules, will suddenly do so now. *Id.*

(c) *PSI Response.* In response to Mr. Higgins' testimony, Mr. Bailey testified that PSI has strived to provide customers with rate options, among them being rates that reflect more than just differences associated with voltage level, but also rate options relative to their load factor. It would make little sense, Mr. Bailey observed, for PSI actively to identify and notify customers of potential savings if the only end result for PSI was a reduction in revenue. Pet. Ex. SS, pp. 14-15. PSI contends the proper course is to notify customers of potential savings and allow a known, quantifiable revenue shortfall to be reflected in rates. Mr. Bailey rejected Mr. Higgins' contention that nothing changes the relationship of HLF and LLF in this case, pointing out how much additional revenue could be potentially lost solely as a result of incorporating the effects of the rate increase into the rate design. *Id.*

(d) *Discussion and Findings.* We find that PSI's proposed rate treatment associated with expected migrations is reasonable as the procedure provides rate options to affected customers, which allows them to select rates most favorable to their respective operations. In addition, the Company indicated that it makes an extensive effort to notify customers of potential bill savings, and that the phased-in rates provide an opportunity to "true-up" the estimated migrations to actual. In conjunction with the phased adjustment, actual migrations will be known prior to the second phase, so the revenue impact can be readily determined. This revenue figure can then be used to develop Phase II rates, and any over-or under-recovery of funds from Phase I rates can be reconciled. As PSI is seeking a dollar for dollar recovery of funds lost through rate migrations — no more and no less — we find that PSI will not be financially rewarded by this adjustment. Therefore, we find that, in this instance, this adjustment is reasonable and is hereby approved.

D. *Disputed Pro Forma Expense Adjustments.*

[47-51] (1) *Depreciation Expense.*

(a) Rates.

(i) *Evidence.* PSI proposes to increase its annual depreciation accrual by $79,088,000, for a total *pro forma* annual depreciation expense of $233,022,000, Pet. Ex. X-21, Sch. C-3.36 (as updated by Pet. Ex. OO-3), based on a traditional depreciation study prepared by Mr. John J. Spanos, of Gannett Fleming, Inc. Mr. Spanos testified for PSI, and began his testimony by defining depreciation as the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of the utility plant in the course of service from causes that can be reasonably anticipated or contemplated against which the Company is not protected by insurance. As examples of such causes, Mr. Spanos cited wear and tear, decay, exposure to the elements, inadequacy, obsolescence, change in demand and the requirements of public authorities. Mr. Spanos' depreciation study was presented in Pet. Ex. T-1.

Mr. Spanos stated that he utilized the straight line remaining life method of depreciation with equal life group procedures. He testified that annual depreciation is based on a method of depreciation accounting that seeks to distribute the unrecovered costs of fixed capital assets over the estimated remaining useful life of each unit or group of assets in a systematic and rational manner. Pet. Ex. T, p. 7. Mr. Spanos determined his recommended annual depreciation rates in two phases. First, he estimated the service life and net salvage characteristics for each depreciable group. Then he calculated the composite remaining life and annual depreciation rates based on the service life and net salvage estimates determined in the first phase.

With regard to the first phase, Mr. Spanos stated that his service life and net salvage study consisted of compiling historical data from records related to PSI's plant, analyzing this data to obtain historic trends of survival and net salvage characteristics, obtaining supplementary information from management and operating personnel, interpreting that data and forming judgments of average service life and net salvage characteristics. He analyzed the Company's accounting entries that recorded plant transactions during the period 1956 through 2001. These transactions included additions, retirements, transfers, sales and the related balances. Mr. Spanos utilized the retirement rate method to analyze this service life data. He stated this method is most appropriate because it determines the average rate of retirement actually experienced by the Company during the period of time covered by his study.

Mr. Spanos applied the retirement rate method to each different group of property, using the retirement rate method to form a life table, which, when plotted, shows an original survivor curve for that property group. *Id.* at 9. Each original survivor curve, according to Mr. Spanos, represents the average survivor pattern experienced by these several vintage groups during the experience band study. He said that the survivor patterns did not necessarily describe the life characteristics of the property group. Therefore, he must interpret the original survivor curves in order to use them as valid considerations in estimating service life. He utilized the Iowa type survivor curves to perform these interpretations.

Mr. Spanos made field reviews of PSI's properties in September, 1999 and April, 2002. The purpose of his field review was to allow him to become familiar with Company operations and obtain an understanding of the function of the plant; the reasons for past retirement; and, the expected future causes of retirement. *Id.* at 10. Mr. Spanos estimated the net salvage percentages by incorporating the historical data for the period 1989 through 2001 and considering estimates for other electric companies. He also utilized the demolition cost estimates prepared by Sargent & Lundy and sponsored by PSI witness Mr. Alan Wendorf.

As to the second phase of his study, in which he calculated the composite remaining life and annual depreciation rates, Mr. Spanos testified that he calculated annual depreciation rates for each group based on the straight line remaining life method, using remaining lives weighted consistent with the equal life group procedure. His calculations of annual depreciation accrual rates were developed as of September 30, 2002. *Id.* at 11. Mr. Spanos stated that the straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage value, in equal amounts to each year of remaining service life. As to the equal life group procedure, he stated the property group is subdivided according to service life. The relative size of each equal life group is determined from the property's survivor curve. This procedure eliminates the need to base depreciation on average lives. The full cost of short lived units are accrued during their lives leaving no deferral of accruals required to be added to the annual cost associated with long lived units. He further stated that the equal life group procedure allocates the capital costs of a property group to annual expense in accordance with the consumption of the service value of the group.

PSI witness Alan Wendorf, Executive Vice President of Sargent & Lundy, LLC, ("S&L") testified regarding the results of a study that estimated the cost of dismantling certain PSI generating stations. Pet. Ex. U, p. 2. Mr. Wendorf testified that in its study S&L made several assumptions with respect to the decommissioning of PSI's plants. For example, they assumed that the only thing necessary to decommission an ash pond was to pump it dry and cover the ash pond with approximately two feet of soft soil. They also assumed that there was sufficient room on site to dispose of all the non-hazardous debris and that there was sufficient fill material on site to cover all this debris. *Id.* at 3. They also assumed that tens of thousands of feet of underground pipe and electrical conduit could be left in place and it would not be necessary to fill in the cooling lake at the Gibson Generating Station. In Mr. Wendorf's opinion, many of these assumptions were conservative and minimized dismantling cost numbers — *i.e.*, the estimated costs represent the lower end of potential dismantling costs.

Mr. Wendorf estimates of the net cost of dismantling each of PSI's generation stations in 2002 dollars are: Gallagher Generating Station - $23,691,800; Wabash River Generating Station including the PSI portion of the Wabash River Repowering project - $33,698,900; Cayuga Generating Station - $37,544,000; Gibson Generating Station - $118,434,500; Edwardsport Generating Station - $12,376,200; and Noblesville Generating Station - $7,554,000. *Id.* at 6. The details of these estimates are contained in Mr. Wendorf's exhibits, Pet. Ex. U-1 through U-6.

Mr. Michael Majoros testified for the OUCC and indicated that before the Commission allows the current recovery of a future dismantlement cost, it should ensure that such cost will in fact be incurred. He said it is doubtful PSI will dismantle plants unless the Company plans to install new plants at the same site and location as the retired plant. In these circumstances Mr. Majoros said that if there were dismantling costs, such costs should be part of the cost of a new plant. In his opinion, based on the probability of actual plant dismantlement for PSI, Mr. Wendorf's dismantlement estimates should be excluded in their entirety in determining depreciation rates in this proceeding. Pub. Ex. No. 9, p. 20.

Mr. Majoros said that he believes that the underlying premise for including dismantling costs is false. In his opinion it is doubtful that PSI will ever dismantle any of its generation plants to "Greenfield" conditions. Based on his observations during his own plant tour, he concluded that the Company has no plans to even retire these plants, let alone dismantle them. He noted that the retired boilers that he observed had been retired in place, yet this was the largest component of Mr. Spanos' dismantlement costs, *Id.* at 18 Mr. Majoros also relied on a nationwide survey conducted by his firm of steam generating units exceeding 50 MW that have been retired since 1982. According to Mr. Majoros, as of the date of his testimony, 64% of the retired generating units contained in the nationwide survey were retired in place, not dismantled. *Id.* at 19. Finally, Mr. Majoros indicated that PSI has not recorded any final retirements for any electric generating units or plant sites in the last 15 years, and other than Henry County, has no legal obligation to dismantle any of its plants. Mr. Majoros observed that it is unreasonable to assume that PSI, or any other utility, would spend $700 million to dismantle its production plants, absent a legal obligation to do so. *Id.* at 18-19.

Mr. Majoros went on to state that Mr. Spanos' approach projects substantial past inflation into the future. Thus, he said, Mr. Spanos' future net salvage rates for all other accounts are inflated future net salvage ratios. In Mr. Majoros' opinion, this results in excessive costs of removal charges because the inflated ratios charge current ratepayers for future inflation that has not occurred. Mr. Majoros calculated that over the most recent five years, PSI has only experienced $7.1 million in negative net salvage on average. This number, he said, should be contrasted with Mr. Spanos' recommendation of $54.2 million annual recovery of negative net salvage. *Id.* at 24.

Mr. Majoros disagreed with Mr. Spanos regarding the incorporation of future net salvage and terminal net salvage values in depreciation rates. Mr. Majoros indicated that he believes the incorporation of future net salvage and terminal net salvage values increase depreciation rates and inflate estimates of costs that will probably not be incurred. Mr. Majoros also stated that six (6) of the Company's proposed lives in the transmission, distribution and general plant function are too short, thereby overstating the associated depreciation expense. Pub. Ex. No. 9, p. 4. Mr. Majoros proposed a substantially lower annual depreciation expense primarily based on his conclusion that net salvage value should be ignored. *Id.* at 5.

Mr. Majoros also disagreed with Mr. Spanos' use of net salvage ratios in his depreciation rate calculation. He said that this issue is significant, because Mr. Spanos essentially capitalized costs the Company has no real obligation to incur and then inflated those costs. Mr. Majoros complained that Mr. Spanos was less than forthcoming about how he utilized Mr. Wendorf's cost study. *Id.* at 17. He said that Mr. Wendorf's cost studies were estimates made in terms of 2002 dollars. He said that even though Mr. Spanos stated he relied on Mr. Wendorf's studies, the figures from Mr. Wendorf are not traceable to Mr. Spanos study. Instead, he said, Mr. Spanos applied net salvage ratios to plant balances which resulted in substantially greater amounts of dismantlement costs than estimated by Mr. Wendorf. Mr. Spanos' equivalent numbers exceed $700,000,000, which means, Mr. Majoros contended, that Mr. Spanos inflated Mr. Wendorf's estimates. *Id.* at 18.

Mr. Majoros went on to discuss the Statement of Financial Accounting Standards ("SFAS") No. 143. He said that pursuant to this accounting standard, all companies, including PSI, must determine whether or not they have an actual legal obligation to dismantle and/or remove retired assets. Pub. Ex. No. 9, p. 25. These legal obligations are called "Asset Retirement Obligations" ("AROs"). If the Company does have an ARO, the net present value of the cost of removal is capitalized and included in the cost of the asset and depreciated over the life of the asset. It is not included as a negative net salvage ratio in depreciation rate calculation, as proposed by Mr. Spanos, but rather, it is added directly to the cost of the assets. He stated that if a Company does not have an ARO, future costs of removal are not considered as a cost of the asset and, therefore, should not be included in the company's depreciation expense on its general financial statements. Mr. Majoros stated that under Generally Accepted Accounting Principles ("GAAP"), electric utilities are required to conduct a review to determine if they have any AROs. PSI, he said, conducted such a review and had quantifiable AROs of $6,890,212. *Id.* at 27.

Mr. Majoros then went into a discussion of the life study methods. He stated that Mr. Spanos used two basic methods. The life span method and the retirement rate actuarial method. In addition to these methods Mr. Majoros also used the geometric mean turnover ("GMT") method. *Id.* at 50. Mr. Majoros testified that he did not disagree with Mr. Spanos' use of the life span method, but did disagree with his application of the method because Mr. Spanos included negative future net salvage in his calculations.

Mr. Majoros also discussed the production life depreciation calculations performed by Mr. Spanos. He said these calculations were predicated on the life method. Based upon his own calculations and independent studies, Mr. Majoros accepted Mr. Spanos' terminal retirement years for steam and other production functions and found them to be reasonable. *Id.* at pp. 52-57. With regard to transmission, distribution and general functions, Mr. Majoros concluded that some of the accounts analyzed by Mr. Spanos utilized service lives that were too short. In particular, Mr. Majoros objected to the service lives used by Mr. Spanos for account 354, 356, 365, 366, 367 and 397. Pub. Ex. No. 9, p. 60. As to vintage amortization accounting Mr. Majoros only disagreed with the five years Mr. Spanos proposed for Account 391.1, office furniture and equipment -IT systems. Mr. Majoros recommended a 10 year amortization for this account. *Id.* at 64.

Mr. Majoros then described an analysis to identify the amount of past collections of non-legal AROs included in PSI's accumulated depreciation account and two alternative versions for a specific going forward allowance. As to the former, he stated that Mr. Spanos estimated the amounts to be $281 million as of December 31, 2002. Mr. Majoros said that this amount represents money charged to ratepayers in the past for which PSI has no legal cost or obligation. *Id.* at 36-37. With regard to his proposed going forward allowance, he stated that non-legal AROs included in depreciation expense should be included in a specifically identifiable allowance and should be accounted for separately in depreciation expense and accumulated depreciation accounts. He described his first alternative as an allowance calculated in much the same manner as the Company allowances for legal AROs. For this calculation, Mr. Majoros used Mr. Wendorf's 2002 net present value amount for production plants. For transmission, distribution and general plant, he used Mr. Spanos' future net salvage proposal and estimated remaining life to determine the net present value of these amounts. He stated that the annual allowance using this method is $3.3 million.

Mr. Majoros' preference is to use his second alternative, a five year rolling net salvage allowance approach which has been used by other administrative agencies such as the New Jersey Board of Public Utilities; the Pennsylvania Public Utility Commission; the Missouri Public Service Commission; and, on a trial basis by the Kentucky Public Service Commission. *Id.* at 45-50. Mr. Majoros characterized this as the Pennsylvania Public Utility Commission's normalized net salvage allowance approach. This approach is based on the average of the most recent five years worth of actual net salvage activity shown in PSI's depreciation study. *Id.* at 38. He said that the net salvage is treated just as any other normalized expense, except that it is charged to accumulated depreciation. He said that the normalized net salvage allowance amount under this proposal is $7.1 million. Mr. Majoros concluded this portion of his testimony by stating that the Commission should reject PSI's net salvage amount of $54.2 million and substitute his preferred normalized allowance of $7.1 million.

The PSI-IG presented the testimony of James T. Selecky with regard to depreciation. Mr. Selecky stated that he supports excluding net salvage from the development of the calculation of book transmission, distribution and general depreciation rates. In his opinion, the net salvage expense should be included in the revenue requirement as a cost to serve as an operating expense, and not a component of depreciation rates. PSI-IG Ex. No. 2, p. 4. Mr. Selecky stated that the annual net salvage component of depreciation expense that PSI is requesting is significantly greater than PSI's actual net salvage expense. In fact, he states, the level of expense as proposed by PSI is approximately six times greater than the historical level typically incurred by PSI on an annual basis. He said that the consequences of PSI's proposed treatment of net salvage are that it unnecessarily raises rates for today's ratepayers and produces intergenerational inequities by shifting cost burdens to today's ratepayers from future ratepayers.

Mr. Selecky stated that PSI's proposed depreciation expense for transmission, distribution and general plant contains an annual net salvage component of $23,460,000. However, PSI's average actual annual net salvage expense over the last 10 years was a negative $3,879,000 and over the last 5 years PSI's net salvage expenses averaged a negative $3,737,000.

Mr. Selecky stated that the large difference between net salvage expense proposed to be included in depreciation rates and PSI's actual net salvage expense in recent years is due in part to the fact that proposed net salvage percentages included in the development of depreciation rates include estimates of future inflation and may not capture the economies of scale that would occur if large retirement activity occurred during a single year. Also, net salvage ratios included in depreciation rates, he contended, may be developed from limited retirement experience that is not typical. *Id.* at 7. Mr. Selecky stated that under PSI's methodology, if an asset with a service life of 50 years is retired in 2000, PSI compares the cost to remove the asset in 2000 dollars with the installed cost of the asset which, in this case, was measured in 1950 dollars. As a result, the net salvage ratio is developed in costs stated in dollars from different time periods. While the cost of the asset and the cost to remove the asset are stated in nominal dollars, the net salvage ratio provides an estimate of future inflation. As the result, according to Mr. Selecky, PSI's net salvage percentages require today's ratepayers to pay estimated costs of future inflation based on historic trends.

Mr. Selecky proposes that this Commission eliminate the net salvage ratio from the development of depreciation rates and include a net salvage provision as an operating expense. He recommends that a 10 year average actual net salvage expense be included as an operating expense in PSI's total cost of service. *Id.* at 10. He states that two other commissions have adopted this approach — the Pennsylvania Utility Commission and the Missouri Public Service Commission. He proposed a reduction of $23,460,000 in depreciation expense and an increase of $3,879,000 in operating expense.

Mr. Selecky also claimed that the use of an inflation factor applied to Mr. Wendorf's dismantling studies was inappropriate in that this would require today's customers to pay for inflation that may not occur. Mr. Selecky developed his own net salvage ratios for production plant. *Id.* at 18. In developing his proposed ratios, he excluded switchyard costs and contingency costs from the ratios. In his opinion, switchyard costs represent the costs associated with non-steam production investment and it would be inappropriate to recover these costs in depreciation rates developed for steam plant. He removed Mr. Wendorf's contingency because he believes it does not represent a true cost, and, he maintained that as more plants are dismantled, one would expect technological improvements over 2002 technology. This resulted in a proposed reduction to the steam production depreciation expense of approximately $28,038,000.

Mr. Selecky also opposed PSI's use of the equal life group ("ELG") procedure and recommended that the Commission order PSI to revert to the use of the Average Life Group ("ALG") procedure to develop depreciation rates. Mr. Selecky claimed that use of the ELG procedure results in increasing the depreciation rates in the early life of an asset and implies a precision for allocating consumption of assets that does not exist. PSI-IG Ex. No. 2, p. 28.

Laura L. Cvengros, Assistant Director of the Electricity Division, for the Commission, also presented testimony with respect to depreciation. Ms. Cvengros performed a "reality check" on how PSI's $84 million depreciation adjustment was derived. IURC Staff Ex. No. 2, p. 3. She reviewed the depreciation study sponsored by Mr. Spanos and compared that depreciation study to PSI's current depreciation rates. PSI current depreciation rates are based on the testimony and exhibits presented by the OUCC, which resulted of a settlement in a prior PSI rate case, Cause No. 39584 that carried the rates forward into PSI's last rate case, Cause No. 40003.

Ms. Cvengros testified that she compared various components of PSI's depreciation study with similar components of the OUCC's depreciation study in Cause No. 39584. Staff compared the net salvage ratios proposed by Mr. Spanos in this proceeding with those used by the OUCC and found them to be consistent except for five accounts. IURC Staff Ex. No. 2, p. 12. She also found that, generally, the average service lives used by Mr. Spanos in his study were longer than those used by the OUCC to develop PSI's current depreciation rates. Ms. Cvengros explained that the general lengthening of average service lives for most accounts would have the effect of reducing the depreciation expense for those accounts. Ms. Cvengros concluded that Staff does not believe that the increased depreciation expense in this Cause was caused by significant changes in methods/procedures from the depreciation study used to set PSI's current depreciation rates, and recommended that the Commission approve PSI's proposed depreciation rates. *Id.* at 9 and 13.

Mr. Spanos testified in rebuttal to the testimony of Messrs. Majoros and Selecky. He first discussed why the ELG procedure should be preferred to the ALG procedure. He opined that the ELG procedure, contrary to Mr. Selecky's opinion, can be viewed as an accurate form of book depreciation. Pet. Ex. II, p. 2.

In Mr. Spanos' opinion, the ELG procedure correctly matches depreciation expense of the straight line allocation of service value over the period the assets are in service and avoids the back-end loading of the ALG procedure. Under the ALG procedure, he observed, the depreciation for each property group is based on the average service life of the account or vintage. As a result of using an average, the cost of short term lives is not fully accrued by the time of their retirement and the service value of long lived items is more than fully accrued in order to make up for the under accruals of the short lived items. Mr. Spanos testified that the ELG method has been known to experts for many years but its widespread use was constrained by the large amount of computation required. Because the ALG procedure can be readily performed, it became the choice of experts by default prior to the use of computers due to ease of understanding. *Id.* at 3. With the advent of modern computer equipment, however, this constraint has been removed and this procedure, which is more accurate, is available to all companies.

Mr. Spanos stated that his service life estimates were based on a number of factors, including judgment. *Id.* at 8. According to Mr. Spanos, Mr. Majoros should have incorporated other considerations and made better use of industry data. Mr. Spanos stated the retirement rate method is the most commonly used life analysis when age retirement data are available. It develops historical indications of the rate of retirements by age intervals. The Geometric Mean Method, included in Mr. Majoros analysis, was used many years ago according to Mr. Spanos, to analyze un-aged data before the development of the simulated plant record method. It is no longer used to analyze un-aged data and was never used when age retirement data was available.

Mr. Spanos then discussed Mr. Majoros' use of industry data. *Id.* at 9. Although Mr. Majoros presented several statistics, Mr. Spanos stated he used only the maximum life or the upper limit as a measure of the reasonableness of his estimate. This use of the maximum recorded lives, in Mr. Spanos' opinion, is not appropriate. According to Mr. Spanos, the purpose of comparing the results of statistical analysis with other electric utilities' data is to ascertain whether the results fall within a range of reasonableness. Typically, when defining the range of reasonable service life estimates for an account, Mr. Spanos excludes several estimates of both the low and upper end of the range. In contrast, Mr. Majoros relied on the very longest service lives used in the industry to justify his estimates, Mr. Spanos observed. Mr. Spanos described in detail a number of examples where he believes Mr. Majoros inappropriately used industry data. *Id.* at 9-11. Due to these problems, Mr. Spanos concluded that all the bases used by Mr. Majoros are flawed and his recommendations as to survivor curve estimates must be rejected. *Id.* at 12.

In response to the recommendations of Mr. Majoros and Mr. Selecky with regard to net salvage for accounts other than production, Mr. Spanos indicated that these witnesses have proposed a radical change in the basis for determining PSI's allowance for net salvage for transmission, distribution and general plant. He noted that Mr. Majoros also proposed this treatment for the production plant accounts. *Id.* at 13. Their proposal is that the net salvage be removed from the calculation of depreciation and be included as an operating expense. Mr. Spanos characterized this proposal as one of net salvage costs incurred in the past, related to retired plant that served customers in the past, to be collected from current customers in the same manner as current operation and maintenance expense is collected. *Id.* at p. 13.

Mr. Spanos was not aware of any authoritative text on the subject of depreciation that supports their proposal to expense net salvage costs. He stated that the two depreciation texts most often cited by depreciation experts as authoritative support the traditional approach that he used here. Addressing Mr. Majoros' statement that state commissions have adopted his approach, Mr. Spanos said that the Pennsylvania Commission does use the five-year net salvage amortization, because it was required to under a 1962 court order interpreting a Pennsylvania statute. Mr. Spanos agreed that the Missouri Commission adopted the Majoros ap-

proach in a case. He noted, however, that Mr. Majoros failed to mention that this approach was not used in a later case by the Missouri Commission but, rather, the traditional approach used by Mr. Spanos in this matter was used. As to the two Kentucky cases cited by Mr. Majoros, Mr. Spanos stated that the two utilities were small cooperatives that did not maintain detailed records of costs of removal and gross salvage by account. In other Kentucky cases where the utility maintains detailed records of net salvage, as PSI does, Mr. Spanos noted the traditional methodology had been used. He concluded, by stating that 47 state utility commissions use the traditional method of incorporating net salvage in determination of annual depreciation rates. *Id.* at 15.

Mr. Spanos stated why it is more appropriate and equitable to recognize net salvage costs during the life of the plant. He said the net salvage value cost of an item of plant is part of its service value and, therefore, is part of the item's cost of providing service. That cost, he said, should be collected from the customers that receive the service. Thus, an allocable portion of the net salvage costs should be recovered each year from the customers receiving the value of the service rendered by the item of plant. *Id.* at 15-16. In his opinion, this approach is equitable in that the customers are responsible for the costs of plant that provides them with service. In contrast, Mr. Spanos said, expensing net salvage after the item has been removed from service recovers an entire element of an item's cost of service from customers who do not receive service from that item, or if a customer has received service from the Company for a number of years, that customer has received only a portion of the item's service value. These results are not equitable, he contended, and violate the principle that customers should pay the cost of plant that serves them.

Mr. Spanos also disagreed with the position of Mr. Selecky and Mr. Majoros that net salvage costs for accounts other than for production plant that may occur in the future should not be collected from customers until they occur. Mr. Spanos testified that the amount of net salvage that should be included in the annual cost of service, and collected from current customers, is a portion of the net salvage related to the current plant in service as a result of allocating these costs to each year of service rendered by the plant. The amount should not be limited only to the current net salvage costs. Current net salvage costs are related to plant that previously rendered service. *Id.* at 18. Mr. Spanos stated that allocating net salvage costs during the life of the related plant is more appropriate and equitable and is in accord with sound ratemaking principles. In his opinion, delaying collection until such costs are incurred results in a charge to customers for plant from which they did not receive service, and as a result of the delay of recovery, also results in higher revenue requirements.

Mr. Spanos said that the current net salvage accruals are larger than current salvage costs because current cost experience is related to plant retirements that largely come from an older plant base that was constructed to serve fewer customers, while current net salvage accruals relate to plant presently in service that serves a much larger customer base. *Id.* at 23. In his opinion, it is appropriate for PSI to recover amounts for future net salvage costs that are greater than the amounts currently expended for such costs because the amount that PSI spends for plant additions is far greater than the amount it proposes for recovery of original costs. For example, according to Mr. Spanos, in the year 2001 PSI total plant additions were over $236,000,000. Adding the net salvage costs of $6.5 million for that year to this amount results in a total expenditure of over $240 million in 2001. This total expenditure is approximately $60 million greater than the proposed level of depreciation expense that includes recovery of past original costs and future net salvage costs. *Id.* at 23. In Mr. Spanos' opinion, basic equity requires that customers pay for the service value, original cost less net salvage of the plant, from which they receive the service. The fact that this results in accruals for net salvage that are greater than the current experience is neither unfair nor unusual. It is reality, according to Mr. Spanos.

In response to Mr. Majoros' discussion of SFAS 143 and FERC Order 631, Mr. Spanos stated these accounting pronouncements do not control ratemaking. *Id.* at 24. He said that, in general, GAAP in recent years has moved away from the matching principle in favor of an asset and liability based approach for purposes of improving potential investors' ability to ascertain a company's financial condition. Mr. Spanos said blind compliance would set standards for ratemaking purposes that would violate principles of customer equity by expensing the cost of retiring plant, resulting in charges to today's customers for plant that served past customers. Mr. Spanos added that although utilities may not have a legal obligation to remove plant, they nevertheless do so on a regular basis and will continue to do so in the future.

Mr. Spanos also testified that it is not appropriate to develop net salvage percents for production plant based on the estimated costs of dismantling in current dollars as Mr. Selecky did. Pet. Ex. II, p. 28. He stated that the net salvage costs to be recovered from current customers are those costs that will be incurred when the plant currently providing service is retired. Mr. Spanos escalated the dismantling cost developed by Mr. Wendorf to the year of probable retirement as a factor to be considered in the estimation of net salvage for production plant account. Mr. Spanos stated that the use of current dollar amount to cover future dismantling costs will result in under recovery and customer inequity. Mr. Spanos also considered the indication of net salvage developed from historical retirements, most if not all of which represent interim retirements, and compared these results to the escalated costs from Mr. Wendorf's dismantlement studies. The historical data, he said, also supports the net salvage percent that he has estimated for the accounts. He said that the net salvage percents that he developed result in an estimate of future net salvage costs that are less than the sum of the probable future net salvage costs related to both interim and final retirement. *Id.* at 29.

Mr. Spanos also stated, contrary to Mr. Selecky's position, that it is appropriate to expect that costs of dismantling will escalate at a rate of 3% per year. He noted the long term inflation rate as measured by the Consumer Price Index has averaged approximately 3%. He noted that the Handy Whitman Index for all steam production plant has increased at an average rate of 5.1% during the past 30 years. Therefore, in his opinion, it is more likely the dismantling costs will escalate at a rate greater than 3%.

Mr. Wendorf also presented rebuttal testimony on behalf of PSI. He first discussed Mr. Selecky's exclusion of the contingency factor that Mr. Wendorf included in his demolition estimate. Mr. Wendorf stated that this contingency factor was intended to cover unknowns and that experience teaches that almost every complex project, such as demolition of a generation station, ends up with unknowns. Many unknowns do not become apparent until detailed engineering proceeds immediately prior to actual demolition activities and still others will not be identified until actual demolition activities commence. *Id.* at 2.

Mr. Wendorf noted that his estimates assumed that all underground piping, electric duct and foundations would remain in place, an unlikely event if the sites are reused. Mr. Wendorf looked at the resulting increased costs for one station, Cayuga, if these assumptions were changed. If below ground items have to be demolished and moved, PSI would have to backfill the voids and the debris would have to be disposed off-site. This simple change, according to Mr. Wendorf, results in a significant increase (over $15 million) in the estimated cost to demolish the Cayuga station. This change alone is approximately double the 25% contingency ($8,139,000) included in the demolition estimates which Mr. Sleekly removed. *Id.* at 4.

In response to the position of Mr. Majoros, that his estimates assume returning the sites to a "Greenfield" condition, Mr. Wendorf stated that a key assumption in his demolition estimates was that PSI would not have to remove the contents at the ash ponds at the stations. He assumed that the ash ponds at all these stations could be pumped dry and covered with two feet of soil and seeded. He stated that, contrary to

the position set forth by Mr. Majoros, the use of two feet of soil to cover several years of bottom and fly ash does not constitute a return to a Greenfield condition. Pet. Ex. JJ, p. 5. Mr. Wendorf investigated what it would cost if PSI were required to remove and dispose of all stored ash from the existing ash pond at Cayuga to an off site landfill designed to contain the material in an environmentally acceptable manner. He assumed that such a landfill could be required and constructed within 10 miles of the Cayuga site. Changing this assumption about ash removal according to Mr. Wendorf, would add more than $100 million to the estimated cost of demolishing the Cayuga site. *Id.* at 5. Mr. Wendorf sponsored an exhibit detailing his analysis and that exhibit demonstrates that the incremental costs of demolishing the Cayuga station would be at least $155 million as compared with the original demolition cost estimate of $37,544,000. *Id.* at 6. He believes that the demolition estimates that he has developed in this proceeding are conservatively low with the 25% contingency factor included.

In response to Mr. Majoros' conclusion that, as certain boilers have been retired in place, PSI will never dismantle these plants to Greenfield conditions, Mr. Wendorf indicated that the only retired in place boilers on the PSI system are the recently retired boilers at Noblesville and the Wabash River Unit 1. *Id.* at 7. The turbines associated with all three of these boilers are still in service as part of the Noblesville Repowering Project or the Wabash River Coal Gasification Repowering Project. This situation is entirely different from a completely retired plant, he observed. Removal of these boilers while the remainder of the plant continues in operation would be a very complicated and expensive matter, with no real benefit, since there are interconnecting pipelines and electrical cables located in the area of this boiler which are still in use. Before demolition could begin on a single boiler it would be necessary to determine which of these pipelines and cables would have to be protected, terminated, capped or rerouted to allow continued operation of the remaining units. This process would require extensive engineering and field investigatory work. *Id.* at 8.

Mr. John Roebel was the Company's final rebuttal witness on the subject of depreciation. He responded to Mr. Majoros' assertion that PSI will not dismantle certain generating stations at the end of their useful lives. Pet. Ex. KK, p. 2. Mr. Roebel stated that, in his opinion, demolition will take place, because it is the reasonable thing to do. He stated that he believes that PSI will dismantle these stations in order to reuse the sites as future generating stations. According to Mr. Roebel, the Commission is well aware of the public concern that has accompanied some attempts to construct new generation in Indiana and elsewhere. In contrast, Mr. Roebel noted that there was virtually no local opposition to the recent Noblesville Repowering Project. These sites were selected originally because they were good sites for generation stations with access to water and to fuel supplies. He noted that there are not many good generating sites that are not already being used today and that he is not aware of any open sites that could be used for a major generation station without significant expenditures for new transmission facilities alone.

Mr. Roebel then discussed PSI's experience with regard to dismantling generating units and re-using sites. He stated the Company had completely retired one major generation station, its Dresser Generating Station, located near Terre Haute. PSI, he said, had dismantled that station and is now using the site for a machine shop. *Id.* at 3. He also noted that PSI has constructed additional generation at existing sites. PSI's Cayuga CT Peaking Unit was built at the Company's Cayuga Station site, the Wabash River Coal Gasification Repowering Project was constructed at the Wabash River Station reusing the existing Unit 1 turbine and other facilities and most recently PSI has reused the Noblesville site and many existing facilities and infrastructures as part of the Noblesville Repowering Project.

(ii) *Discussion and Findings*. In evaluating the merits of this issue we are faced with various proposals from expert witnesses in response to depreciation expenses proposed by PSI. In undertaking our review of this issue, the Commission recognizes our evaluation of depreciation expenses involves the examination of many variables. The U.S. Supreme Court identified the uncertainties associated with the use of depreciation expenses in *Lindheimer v. Illinois Bell Telephone Company*, 292 U.S. 151, 168-170, 54 S.Ct. 658, 665-666 (1934), in which it stated:

> If the predictions of service life were entirely accurate and retirements were made when and as these predictions were precisely fulfilled, the depreciation reserve would represent the consumption of capital, on a cost basis, according to the method which spreads that loss over the respective service periods. But if the amounts charged to operating expenses and credited to the account for depreciation reserve are excessive, to that extent subscribers for the telephone service are required to provide, in effect, capital contributions, not to make good losses incurred by the utility in the service rendered and thus to keep its investment unimpaired, but to secure additional plant and equipment upon which the utility expects a return.
>
> Confiscation being the issue, the company has the burden of making a convincing showing that the amounts it has charged to operating expenses for depreciation have not been excessive. That burden is not sustained by proof that its general accounting system has been correct. The calculations are mathematical, but the predictions underlying them are essentially matters of opinion. They proceed from studies of the behavior of large groups of items. These studies are beset with a host of perplexing problems. Their determination involves the examination of many variable elements and opportunities for excessive allowances, even under a correct system of accounting, [are] always present. The necessity of checking the results is not questioned. The predictions must meet the controlling test of experience.

Id.

Our determination of appropriate depreciation rates is important, as excessive depreciation rates produce excessive depreciation expense. Since depreciation expense flows dollar-for-dollar into the revenue requirement, excessive depreciation expense results in an excessive revenue requirement that is ultimately passed on to ratepayers.

As alluded to by various witnesses in this proceeding, PSI's current depreciation rates are a result of a Settlement Agreement in Cause Nos. 39584 and 39584-S-2 (*Ind. Util. Reg. Comm'n*, February 17, 1995), the terms of which were subsequently incorporated into Cause No. 40003. While we have been presented with a wealth of testimony on this issue, we recognize that the determination of appropriate depreciation levels is far from an exact science, and decisions on this issue must be made on a case-by-case basis.

To assist us in our evaluation of the issues, we were presented with a traditional Depreciation Study ("Depreciation Study") prepared by Mr. Spanos. A second study, in response to the Depreciation Study, was prepared by Mr. Majoros. In response to PSI's testimony, Mr. Selecky and Mr. Majoros both proposed to remove some amount of net salvage from depreciation rates and proposed to treat such costs as expenses. The most contentious issue with regard to the determination of depreciation rates and expense in this proceeding was the proper treatment of dismantling costs. Mr. Spanos testified that dismantling costs should be included in current depreciation rates. Mr. Majoros disagreed and indicated that he does not believe that PSI will dismantle its generation stations and return them to Greenfield conditions, as it has no legal obligation to do so.

In our consideration of this issue we note that PSI's estimates are not based on the cost of returning these generating station sites to Greenfield conditions. In addition, we do not find testimony, that indicated that three boilers located at operating generating stations were retired in place, controlling in our consideration as to whether these stations will be demolished at the end of their useful lives. The rebuttal testimony of Mr. Wendorf and Mr. Roebel make it clear that it is much more expensive and difficult to remove a single boiler and associated

equipment while other units at a generating station are still in operation than to do so when the entire plant is demolished. This Commission is aware of the controversy that can be generated when a public utility proposes to construct a generation facility on a new site. It appears reasonable for PSI to maintain its current generation sites for future use as generating stations. Therefore, this Commission concludes dismantling costs should be included in fixing PSI's depreciation rates.

The next issue is the timing of the collection of such costs. The parties did not disagree that dismantling costs are a part of the cost of current facilities providing current service. They disagreed as to the timing of the collection of such costs and their amount. This Commission can either find that current customers should pay a share of dismantling costs, which will not be incurred for a number of years, or, in the alternative, conclude that these costs should be passed on to a future generation of customers. This Commission does not believe that the latter alternative constitutes sound regulatory policy, or is based on sound ratemaking principles. Current customers are receiving service from PSI's generation facilities. A part of the costs of those facilities is dismantlement upon retirement. Therefore, we do not believe it would be appropriate for the Company to backload the dismantlement costs for future ratepayers to pay when the facilities associated with these costs are providing service to current customers. Rather, we find it is appropriate that these costs be shared by all customers that received service from PSI's generation facilities. Accordingly, this Commission finds that dismantlement costs are properly included in determining the depreciation rates approved in this cause.

The only challenge to the estimated costs of dismantling PSI's generating stations, presented by Mr. Wendorf, was Mr. Selecky's proposal to eliminate the 25% contingency. We believe that Mr. Wendorf's testimony on this issue provides an adequate explanation as to why such a contingency is needed. Mr. Wendorf also demonstrated that minor changes in conservative assumptions could more than use up the contingency. Therefore, based on the facts presented in this Cause, we find that Mr. Wendorf's approach is acceptable to the Commission.

The final issue regarding dismantlement costs is whether inflation should be factored into the dismantlement cost estimates to be utilized in determining PSI's depreciation rates. Mr. Selecky and Mr. Majoros objected to the use of inflation. Mr. Spanos utilized Mr. Wendorf's dismantlement costs which are stated in 2002 dollars, and factored inflation up to the year of the projected dismantlement as a factor in his consideration, along with his analyses of historical, or interim retirements. We find Mr. Spanos' approach to be realistic and consistent with past experience. Inflation has been a fact of life in the American economy for many years. Not factoring inflation into dismantlement costs to be incurred in the future would understate those costs, with the result being that future customers would have to pay costs arising from facilities that are not serving them. This result flies in the face of matching rates with costs incurred for service, a sound ratemaking principle followed by this Commission. Moreover, current customers receive a benefit by factoring in inflation, as it may appropriately allow for a reduction in rate base because of the increased accumulated reserve for depreciation. Accordingly this Commission finds that accounting for inflation in determining the dismantlement estimates to be used as part of PSI's depreciation rates is reasonable.

Turning to the net salvage values for transmission, distribution and general plant, Mr. Selecky and Mr. Majoros urged this Commission to utilize historical average of actual net salvage expense incurred by PSI for determining the net salvage to be utilized for these accounts and then expense these averages as a separate cost of service item. In effect, they are proposing that net salvage values be eliminated from the depreciation rates determination in this proceeding.[9] In contrast, Mr. Spanos took the traditional approach and utilized estimated net salvage values for these accounts based on historical net salvage costs as a percent of the original cost of the retired assets that produced the gross salvage or required costs to remove. Pet.

Ex. II, p. 20. Mr. Majoros recognized that Mr. Spanos' approach was not abnormal, but he and Mr. Selecky cited a number of state commissions where an historical average approach had been adopted.

Based on our review of the decisions cited by Mr. Majoros and Mr. Selecky, we note that only one state commission, the Pennsylvania Public Service Commission, following the directive in a decision by the Pennsylvania Supreme Court, has implemented the historical average approach. While the Missouri and Kentucky Public Service Commissions have utilized the historical approach to net salvage values in some cases or on a trial basis, subsequent decisions have adopted the approach advocated by Mr. Spanos.

We believe that there is a sound basis for the traditional approach on this issue that is utilized by a majority of states. Utilizing historical averages as an item to be expensed to current customers means that these customers will be paying for salvage costs at levels that may not be sufficient. That means that the next generation of customers will be paying for salvage costs related to facilities from which they may never have received service. The use of best estimates of future salvage costs addresses this inequity. Moreover, use of historical averages for dismantling costs does not take into account the current configuration of PSI's system with regard to its production, transmission, distribution and general facilities. Facilities in service 40-50 years ago did not take into account the significantly enhanced customer base that PSI now serves, nor the current configuration of PSI's facilities that serve these customers. It seems appropriate to utilize best cost estimates for net salvage values taking into account specific facilities now serving PSI's customers in developing depreciation rates that today's customers should pay. Accordingly, we find that the use of historical averages for net salvage values with regard to transmission, distribution and general plant for the purpose of expensing them outside the context of the depreciation determination should be, and hereby is, rejected.[10]

With respect to the use of the ELG or ALG methodologies to determine average service lives, we note that Mr. Selecky advocates the use of ALG to determine average service lives as opposed to Mr. Spanos' ELG methodology. This Commission on numerous occasions has accepted the use of the ELG methodology. *See, Indiana-American Water Co.*, Cause No. 40703, 1997 Ind. PUC LEXIS 429 (*Ind. Util. Reg. Comm'n*, December 11, 1997). Therefore, based on our review of the testimony we find that Mr. Spanos' use of the ELG methodology is acceptable.

Based on our review of the record on this issue, we find that the depreciation rates developed in Mr. Spanos' Depreciation Study and proposed by PSI for approval by this Commission are reasonable and appropriate and should be approved and used to determine PSI's *pro forma* operating expenses in this case. In approving PSI's proposal in this Cause, we recognize the complexity of this issue, and the fact that it will be necessary for us to carefully review this issue on a case-by-case basis in future proceedings before the Commission.

[52, 53] (b) *Accelerated Depreciation on NO_x Equipment.*

(i) *Evidence.* In its case-in-chief testimony, PSI requested authority to apply a 15-year depreciation rate to its NO_x compliance projects for the purpose of providing assurance of equipment cost recovery. Pet. Ex. C, p. 24. In particular, the Company would apply this accelerated depreciation rate to the same equipment approved by this Commission for use by PSI in Cause Nos. 41744, 41744-S1, 42061 and 42061-S1. Subsequently, PSI altered its request to seek authority to apply an 18-year depreciation rate to its NO_x compliance equipment. Pet. Ex. OO, p. 4.

The only party to oppose this request was Kroger. Mr. Higgins testified that PSI's request would result in a depreciation rate of 6.67% instead of the 3.52% rate derived from the depreciation study sponsored by PSI witness Spanos, and the revenue requirement related to this difference was $10.5 million. Mr. Higgins testified that he believed that this request should

be denied as it would compound the cost burden to customers at a time when the Company was seeking a 15% rate increase. Kroger Ex. No. 1, p. 21.

(ii) *Discussion and Findings.* We find PSI's request to be in accordance with the law and reasonable. IC 8-1-2-6.7(b) permits PSI to seek Commission approval of a 10-year depreciation rate for equipment deemed to be clean coal technology. We believe PSI's proposal is reasonable, will ensure cost recovery of Commission approved projects to which PSI is statutorily entitled, and should be approved. Therefore, we find that PSI should be authorized to utilize an 18-year life over which to depreciate its Commission-approved NO_x equipment. We note that our decision here is entirely consistent with our November 25, 2003 Order in Cause No. 42411.

[54] (2) *Purchased Power.* In opposing PSI's proposed Summer Reliability Tracker, the OUCC contended that PSI's 2003 level of purchased power expense should be included in base rates. In response, Mr. Esamann indicated that the inclusion of the OUCC's proposed level of purchased power expense in PSI's base rates would require the Commission to use an abnormally low level for the expense, given that the Company's 2003 purchased power costs were by far the lowest level of forward reliability purchased power costs experienced by PSI since prior to 1999 (less than $2 million). Pet. Ex. DD, pp. 18-19. He said, this low level of purchased power expense is likely to be temporary, given the expected gradual increase in wholesale power prices and the approximately 100 MW of annual demand growth PSI is experiencing on its retail system. *Id at* 19. Accordingly, Mr. Esamann said, if the Commission were to include a base amount in PSI's rates, he would recommend the use of an average of the last two years' forward reliability purchased power costs, which amounts to $10.5 million. *Id.* That level, he said, is still lower than PSI's estimated annual purchased power costs over the next few years. *Id.*

Consistent with our discussion of the issue below, we find that PSI's purchased power costs are variable and therefore appropriate for tracking treatment. Accordingly, we decline to include an amount of purchased power costs in base rates. The details of our finding on this issue are set forth below.

[55] (3) *PowerShare®* PowerShare® is a peak load managing program that provides PSI's commercial and industrial customers with two options, CallOption and QuoteOption. Under CallOption, the customer contractually commits to reduce its load under certain prescribed circumstances in exchange for a premium. In addition, at times of system peak when the customer is called on to reduce its load, and the customer complies, the customer receives an energy credit. The QuoteOption program is similar, except that the customer is not required to reduce its load when called upon. Pet. Ex. AA, pp. 11-12. Therefore, QuoteOption customers receive only the energy credits if they are called to reduce load and they comply. *Id.*

PSI proposed that the test period level of PowerShare® expense should be included in base rates, in an amount of approximately $1 million. No party objected to the base level amount of PowerShare® expense. PSI also proposed that PowerShare® costs be tracked as part of the Summer Reliability Tracker, so that only actual PowerShare® costs are collected from ratepayers. While we discuss the entirety of the Summer Reliability Tracker below, we find that that PSI's base rate amount of $1,023,000 million of test year expense is reasonable and should be approved as an appropriate level of PowerShare® expense.

[56-59] (4) *Service Company Allocations.*

(a) *Evidence.* PSI witness Barry F. Blackwell, Director of Cost Accounting and External Reporting for Cinergy Services, Inc., (the "Service Company") provided testimony regarding the processes used to assign costs between PSI and its affiliate companies, pursuant to various service agreements which PSI has entered into with those affiliates. Pet. Ex. L, p. 2. Mr. Blackwell testified that the Service Company updates the cost allocation ratios it uses in allocating costs to its client companies by performing a cost study at least annually, taking into consideration specific changes that are fixed, known and measurable. *Id.* at 10-12. Mr. Blackwell cited as an example of such a change the Financial Accounting Standards Board's ("FASB") Emerging Issues Task Force ("EITF") Issue 02-3, Accounting for Contracts Involved in Energy Trading and Risk Management Activities ("EITF 02-3"), which requires that all revenues and expenses on energy trading derivatives be presented on a net basis beginning January 1, 2003. *Id.* at 12-13.

Mr. Blackwell stated that this change will result in substantial reductions in reported operating revenues, purchased and exchanged power expenses and gas purchased expenses. *Id.* Mr. Blackwell explained that prior to this accounting change, these revenues and expenses were recorded on a gross basis, with no offset of energy trading revenues against energy trading costs. *Id.* In Mr. Blackwell's opinion the accounting changes mandated by EITF 02-3 comport with cost causation principles, because costs will be allocated to Cinergy's trading operations in a manner more closely aligned with the services that they receive from the Service Company. *Id.* at 13-14.

OUCC witness Carver testified in opposition to PSI's adjustment related to changes in the allocation ratios, citing three issues with the allocation methods used by the Service Company: 1) use of net versus gross revenues in determining allocation factors; 2) the Service Company's derivation of the peak demand allocator; and 3) consideration of newly acquired and sold properties. Mr. Carver recommended that PSI back out $3.045 million in *pro forma* adjustment to test year operating expenses related to costs allocated to PSI by the Service Company. Pub. Rev. Ex. No. 3, Sch. C-17.

With respect to Mr. Carver's first issue, the net versus gross revenue issue, Mr. Carver believes that PSI's reliance on EITF 02-3 in developing its proposed allocation factors inconsistently applies net versus gross revenue recognition in developing revenue-related allocation factors. Mr. Carver asserts that when net revenue is used to derive allocation factors for trading operations, the same approach should be used in deriving allocation factors for non-trading operations. Mr. Carver argued that the approach of using net revenues for trading operations but gross revenues for regulated operations means that a disproportionate share of costs are allocated to regulated operations. Pub. Ex. No. 1, p. 96.

With respect to Mr. Carver's second issue, the derivation of the peak demand allocation factor, Mr. Carver testified that PSI erred when it adjusted this allocation factor to add the capacity of the Madison and Henry County generating units to PSI's actual system peak demands. *Id.* at 97. Mr. Carver stated that this adjustment is contrary to the Utility Service Agreement, which states that the electric peak load ratio should reflect the domestic firm electric maximum system demands for the immediately preceding 12 calendar months. According to Mr. Carver, the Utility Service Agreement requires the allocation to be based on demand, not capacity or supply levels. *Id.* at 98.

Turning to Mr. Carver's third issue, the full year effect of properties newly acquired or sold during 2002 and 2003, Mr. Carver cited, as one example, a discontinued operation that had been removed from the development of allocation factors as its operations were winding down in 2002 and was expected to have little or no activity in 2003. *Id.* at 99-100. In contrast, he cited a newly acquired property that began operations in 2002, but the allocation study only included three months of revenue for this property. *Id.* The effect of this inconsistency, according to Mr. Carver, is that more costs are allocated to regulated operations than appropriate. *Id.* Mr. Carver argued that these types of transactions should be fully and consistently recognized on a forward-looking basis. *Id.* Mr. Carver concluded that PSI should perform a new allocation study, with updated numbers consistent with the fixed, known and measurable provisions of the Prehearing Conference Order so that, in his view, more appropriate allocation factors could be developed. *Id.*

Testifying in rebuttal, Mr. Blackwell addressed the three issues raised by Mr. Carver. Pet. Ex. NN, p. 1. Mr. Blackwell criticized Mr. Carver's proposal to use revenues from non-

trading operations net of fuel and purchased power costs to derive revenue-based allocators. *Id* at 2-5. He noted that many of Cinergy's companies do not have fuel purchases and purchased power costs. Thus, Mr. Blackwell pointed out, utilizing Mr. Carver's methodology of using revenues, net of fuel and purchased power costs, would result in just the sort of mixing of net and gross revenues that Mr. Carver claimed to be seeking to avoid. *Id.* That is, Mr. Carver is recommending that the Service Company use *gross* revenues for affiliated companies that do not have fuel and purchased power costs and *net* revenues for those that do. *Id.*

Mr. Blackwell observed that fuel and purchased power costs should be treated differently in non-trading operations than they are in trading operations, because fuel and purchased power are real costs of power furnished to end-use customers. *Id.* Mr. Blackwell explained that fuel and purchased power costs represent real costs of goods sold in a traditional sense when incurred in serving end-use customers, while on the other hand, financial trading transactions are simply financial transactions, with no physical goods flowing from one party to another. *Id.* at 3. Mr. Blackwell testified that EITF 02-3 recognized this distinction by requiring all physical trading activity be presented on a gross revenue basis and financial trading activity to be presented on a net revenue basis. *Id.* at 2-5. Moreover, as explained by Mr. Blackwell, the same issue arises in the cost allocation process, where gross revenues from trading operations do not accurately convey the extent of services being provided to these trading operations. *Id.* Mr. Blackwell produced a chart (Pet. Ex. NN-1) illustrating a trend in which a decreasing level of costs are allocated to the Service Company's utility company affiliates, including PSI, during a time in which PSI's business, and presumably the amount of services it utilizes from the Service Company, has not changed to a significant degree. Pet. Ex. NN, p. 7.

Regarding Mr. Carver's issue with the derivation of the peak demand allocator, Mr. Blackwell conceded that the Service Company had deviated from the allocation methodology set forth in the Utility Service Agreement. Accordingly, Mr. Blackwell stated, the Service Company revised its system peak demand allocation ratios to conform to the requirements of the Utility Service Agreement. PSI adjusted its earlier *pro forma* to reflect this change. Pet. Ex. NN, p. 7; Pet. Ex. PP, p. 3.

With respect to Mr. Carver's third issue with the Service Company's cost assignment practices, that of the consideration given to newly acquired and/or sold properties, Mr. Blackwell disagreed with Mr. Carver. *Id.* at 7. Mr. Blackwell explained that, in accordance with the Utility Service Agreement, the Service Company performs an annual cost allocation study, based on historical data gathered during the third quarter. *Id.* at 7 - 8. He said that when the Service Company knows of companies that are winding down their operations and will no longer be taking services from the Service Company, it excludes from its calculations of the allocation factors the data associated with these companies. *Id.* Mr. Blackwell testified that when an acquisition of a company occurs outside the annual study timeline, the Service Company determines the effect of the acquisition and updates the appropriate allocation factors where such effect is expected to be material. *Id.* He testified that the Service Company reviewed all revenue/sales based allocation factors, picking up twelve months of data for various entities sold/purchased/discontinued in 2002 and 2003, as requested by Mr. Carver, and determined that the amount of costs allocated to PSI based on these allocation factors would have been merely $90,000 less, which in Mr. Blackwell's opinion is not material in PSI's case. *Id.* at 9 -10.

(b) *Discussion and Findings*. Other than the three issues identified by the OUCC, there were no issues raised with respect to the assignment of costs between PSI and its affiliates. Regarding the first issue raised by OUCC, the derivation of revenue-based cost allocation factors on net revenue versus gross revenue basis, this Commission finds that the methodology proposed by PSI is reasonable. The evidence supports PSI's proposition that there is a sound basis for distinguishing between revenues generated from trading operations and revenues generated from other types of operations. The FASB has required that financial trading transactions should be accounted for on a net revenue basis, whereas physical trading transactions should continue to be accounted for on a gross revenue basis. Although Mr. Carver argues that consistency requires that net costs be used for both, PSI's testimony demonstrated that Mr. Carver's approach, while resolving one set of inconsistencies, introduces another set of inconsistencies. This Commission is aware of the possible concern of the financial community regarding measuring financial trading operations based on gross revenues, and agrees that deriving allocation factors based on these gross revenues can distort the apparent extent of trading operations and the amount of services they may take from the Service Company. Ultimately, whether or not an allocation methodology allocates more costs to utility affiliates, as opposed to non-utility affiliates, is not the issue. The determination that must be made is whether the costs incurred by the Service Company are allocated properly to those affiliates that cause the costs to be incurred.

With respect to Mr. Carver's second issue, the derivation of the peak demand allocation factor, Mr. Blackwell conceded that Mr. Carver correctly determined that PSI erred when it adjusted this allocation factor to add the capacity of PSI's new generating units (Madison and Henry County) to PSI's actual system peak demands, in a manner contrary to the Utility Service Agreement. Mr. Blackwell indicated that he revised the system peak demand allocation ratios to conform to the requirements of the Utility Service Agreement. Therefore, as Mr. Blackwell corrected this error there is no pending dispute between the parties on this issue.

With respect to Mr. Carver's conclusion that a complete updated cost allocation study, based on the acquisition or dissolution of properties is needed, we find that while Mr. Carver raises legitimate concerns on certain aspects of this issue, based on the totality of the evidence presented in this Cause we question the overall cost/benefit of doing such a study. Based on our review of the evidence presented, it is apparent that PSI reviewed all revenue/sales based allocation factors, picking up twelve months of data for various entities sold/purchased/discontinued in 2002 and 2003, and determined that the amount of costs allocated to PSI would have been merely $90,000 less. There is no indication in the record that a complete updated study would yield a materially different result than that used by PSI here. Furthermore, at the Evidentiary Hearing in this Cause, Mr. Howe observed that in order to include all changes in test year operating expenses related to changes in allocation factors which were fixed, known, and measurable by September 30, 2003 (12 months after the test period), as allowed by the Prehearing Conference Order, PSI could not begin the required cost allocation study until October 1, 2003, when the latest data through September 30, 2003 would have become available. Since such a study takes several months to complete, it clearly could not have been completed by the date of PSI's rebuttal prefiling, or even the date of the evidentiary hearing. Tr. at Y30 - Y31.

In any event, the issue before this Commission is whether the cost allocation methodology utilized by the Service Company is representative of future costs to be properly allocated to PSI, when the rates determined in this proceeding will be effective. Other than the three issues raised by OUCC, there were no issues raised with regard to the assignment of costs between PSI and its affiliate companies. We find that the costs assigned to PSI represented in this proceeding are just and reasonable and should be fully recoverable by PSI.

[60, 61] (5) *Sale of Accounts Receivable/Forfeited Discounts/Uncollectible Expense.*

(a) *Evidence.* In February 2002, Cinergy replaced an existing accounts receivable sales agreement with a newly structured receivables sales facility that has a maximum funding capacity of $400 million. Under this Agreement, PSI, along with Cinergy's other utility operating companies, sells its accounts receivable to an affiliate, Cinergy Receivables Com-

pany, LLC ("Cinergy Receivables"). The receivables purchased by Cinergy Receivable are then used as collateral for Cinergy Receivables to secure non-recourse loans from third party lenders. The purpose of these loans is to enable Cinergy Receivables to purchase the accounts receivable. PSI sells its accounts receivables in order to receive upfront cash, rather than waiting until the accounts receivables are collected. This cash helps the Company preserve its various bank lines of credit to meet other short-term financing needs. Pet. Ex. QQ, p. 8.

Summarizing the Company's own adjustment in computing *pro forma* operating income under current rates, Mr. Farmer said that the Company eliminated all test period expenses related to the sale of accounts receivable other than uncollectible accounts expense totaling $5.7 million. *Id.* at 13. Uncollectible accounts expense was not eliminated, he said, because the Company recognized that a portion of *pro forma* revenues included in this case would not be realized, because they would be uncollectible. PSI developed a factor, based on a four-year average relationship of uncollectible accounts expense to revenues that was applied to *pro forma* test period revenues. The effect of PSI's adjustment was to adjust test period uncollectible accounts expense for changes in revenue levels in addition to the elimination of all costs not directly related to non-payment by customers.

OUCC witness Carver sponsored OUCC Adjustment C-5, which increased PSI's test period revenues by $5,419,000, the test year's level of forfeited discount revenues, which PSI had proposed to exclude. Pub. Ex. No. 1, p. 17. Forfeited discounts and late payment fees are merely different names for the same revenue (*i.e.*, customer charges due to late bill payment). Mr. Carver stated that it was his view that the ratepayers should be no worse off as a result of PSI selling its accounts receivable than would be the case if the account receivable sale had never occurred. *Id.* at 21. Mr. Carver testified that if the effect of the sale is a good deal for the regulatory participants, it would be reasonable to expect the arrangements to positively improve the utility's operating income and cash flow, and ratepayers should reasonably expect to participate in these benefits. However, in Mr. Carver's view, the net impact of the Company's arrangement to finance its receivables with an affiliate was detrimental to the ratepayers.

Mr. Carver conceded that it is certainly possible that the receivable sales agreement could accelerate PSI's cash realization to the point that this annual cost could be reasonable. However, the only way, he said, to determine the benefit of cash flow acceleration is through a lead-lag study, which PSI has not done. *Id.* at 24-25. Instead, he said, PSI's rate base calculation assumes that "zero" is a reasonable approximation of PSI's cash working capital requirement that would result from a detailed lead/lag study. In Mr. Carver's opinion, such an assumption is inappropriate because a properly conducted lead/lag study could result in a negative cash working capital requirement. Mr. Carver indicated that a zero cash working capital assumption is inappropriate where ratepayers are asked to bear the additional costs of the "zero" cash working capital requirement assumption, but receive no benefit from the receivable sales agreement.

Mr. Carver calculated that Cinergy Receivables realized net income of about $4.4 million in 2002, before income taxes. He stated that OUCC Schedule A-1 recognizes both forfeited discount and uncollectibles in the development of the revenue conversion factor, while the Company recognized only the uncollectibles. He added that if the Commission concludes that the forfeited discount should be removed from test year revenues and excluded from the revenue conversion factor calculation, then the Commission should also revise PSI's tariff to remove all provisions for charging late payment fees to its customers.

Mr. Farmer testified in rebuttal to Mr. Carver's adjustment. He stated it would not be proper to credit the cost of service with forfeited discount revenues, because under the Cinergy Accounts Receivable Purchase and Sales Agreement, PSI does not retain the right to keep revenues received from customers due to late payments. Rather, he observed, PSI has transferred that right to the purchaser of the receivables. However, he pointed out, PSI's customers *have* received significant benefits from the sale of accounts receivable in the form of cost savings. Pet. Ex. QQ, p. 7. Mr. Farmer explained that by selling accounts receivable the Company is able to accelerate the recovery/realization of billed revenues by converting receivables (a non-earning asset) immediately into cash. He stated that if PSI did not sell these receivables, it would incur costs to finance the lag between the time when revenues are billed and payment is received from customers. Accordingly, without the accounts receivable sales agreement, PSI would incur a permanent financing requirement that would likely be met by issuing commercial paper, borrowing against credit lines, or reflecting increased equity and/or debt borrowing in PSI's capital structure. By selling the accounts receivable, PSI is able to eliminate this payment lag. PSI and its customers will benefit to the extent that the fee charged by the purchaser of the receivables is less than the cost that would have been incurred if the Company were to finance the receivable itself. *Id.* at p. 8-10.

Mr. Farmer gave examples of ways in which PSI customers have benefited from such accounts receivable sales. *Id.* One example was the Company's use of the proceeds from its initial sales of account receivables to retire/redeem preferred stock and first mortgage bonds, as part of the financial restructuring that took place in the late 1980's. In addition, the Company used some of the cash to finance capital investments. However, Mr. Farmer pointed out that the primary benefit of selling accounts receivable is to utilize the cash received from such sales to meet ongoing working capital needs. If a utility has working capital needs due to the lag in the cash realization of billed revenues relative to the payment of operating costs incurred by the Company, that capital need is generally recognized in the setting of rates by including a cash working capital allowance in the rate base. However, because of its accounts receivable sales, Mr. Farmer stated, the Company has not requested, and is not requesting, that a cash working capital allowance be reflected in the rates approved in this case. *Id.* at 8-10.

Mr. Farmer noted that in order for Mr. Carver's contention that customers have not benefited from the sale of accounts receivable to be accurate, the Company's cash working capital needs must be negative. This statement, according to Mr. Farmer, is incorrect because PSI's accounts receivable balance (an indicator of potential cash working capital needs) is approximately $175 million. At the hearing on PSI's rebuttal testimony, Mr. Farmer was questioned about the level of profit earned by Cinergy Receivables as a result of its sale of accounts receivable agreement with PSI. Mr. Farmer indicated that approximately 40% of the $4.4 million (*i.e.*, $1.76 million) of profits in 2002 was attributable to the purchase of PSI's accounts receivable Tr. at Y123-Y124. The remainder of the $4.4 million is attributable to the purchase of accounts receivable from CG&E.

Mr. Farmer pointed out that Mr. Carver agrees that PSI, under its arrangement with Cinergy Receivables, has transferred, and, therefore, does not own the rights to forfeited revenues. At the same time, Mr. Carver observed, PSI also no longer incurs costs associated with late payment by its customers. Mr. Farmer stated that if one were to accept Mr. Carver's adjustment, the cost of service used to set rates in this proceeding would be credited with revenues that PSI does not retain. Mr. Farmer disagreed with Mr. Carver's position that if the Commission accepts PSI's adjustment, it should revise PSI's tariff to remove all provisions for charging late payments to its customers. Pet. Ex. QQ, p. 15. Mr. Farmer stated that there is a cost when a customer makes a payment late that is not changed, regardless of which party is bearing that cost. In this case, PSI has passed the risk of late payment to the purchaser of its accounts receivable, and it is appropriate that the purchaser receive the late payment revenues.

(b) *Discussion and Findings*. The effect of Mr. Carver's adjustment is to credit PSI's revenues with $5.4 million that is not in fact retained by the Company. Based on our review of the record it appears that PSI will not realize its account receivable revenues, because they have been sold to an affiliated entity. Mr. Carver

does not dispute the terms and conditions under which the account receivables are being sold to Cinergy Receivables. Nor does Mr. Carver disagree that if the deal is a good one for PSI, then customers will share in the benefits. Mr. Farmer testified that historically PSI customers *have* benefited from the Company's sale of account receivables, as PSI has used the revenues from previous sales to refinance preferred stock and long-term debt and finance construction investments.

In the current proceeding, Mr. Farmer made it clear that selling the account receivables has enabled the Company not to request working capital as a component of its rate request, even though PSI's account receivables total $175 million. This level of receivables is a strong indication that PSI would not have a negative working capital allowance as suggested by Mr. Carver, even if we recognized a negative cash working capital requirement, which we do not. We find that there is a cash working capital benefit to PSI and customers that results from PSI's sale of accounts receivable, albeit one that is not quantified. Accordingly, we do not accept Mr. Carver's recommendation that PSI be credited with $5.4 million in revenues. At most, the record reflects that a $1.76 million credit to revenues might be justified to reflect the level of annual profit earned by Cinergy Receivables by virtue of its agreement with PSI. However, even that amount of credit fails to recognize that PSI does not retain those revenues, and for this reason we will decline to make any adjustment to PSI's proposed *pro forma* revenues. We also decline to revise PSI's tariff to remove all late payment charges, as there is a cost associated with the late payment of bills, and this cost should be recovered from the late payees to address these costs.

[62] (6) *Production O&M Expenses.*

(a) *Evidence*. OUCC witness Brosch proposed two adjustments with regard to PSI's production O&M expenses. OUCC Adjustment C-7 reduced production, non-fuel O&M expenses related to PSI's Madison, Henry County, Edwardsport and Noblesville production facilities. Mr. Brosch claimed that the costs included by PSI for the Madison and Henry County stations are based upon budget values that are not fixed, known and measurable and in his opinion, overstate the expenses related to actual cost levels experienced at those stations. He stated that his Adjustment C-7 reflects the adjustments that are needed to restate the Madison and Henry County related O&M increases, based upon actual 2002 expense levels, in lieu of the Company's budgeted values.

OUCC Adjustment C-8 was made, according to Mr. Brosch, to correct and restate amounts within PSI's adjustment for NO_x expenses sponsored by Mr. Farmer. Pub. Ex. No. 2, p. 90. According to Mr. Brosch, the Company's proposed adjustment is predicated entirely upon budgeted costs for ammonia and contractors' services anticipated to be incurred due to the addition of the SCR equipment at Gibson Units 2, 3 and 4. The OUCC's Adjustment C-8, he said, substitutes actual SCR O&M cost information for the estimates utilized by the Company. Mr. Brosch stated that the largest differences between the Company's adjustments and OUCC's Adjustment C-8 relates to the difference in ammonia costs. Mr. Brosch concluded that an allowance for ammonia of $141,000 for each of the Gibson SCR units is appropriate.

Mr. Farmer presented rebuttal testimony in response to the OUCC's Adjustments C-7 and C-8. Mr. Farmer noted that, as a practical matter, a utility must estimate annual costs of new projects which have not been in-service during all 12 months of the test year. Pet. Ex. QQ, pp. 16-18. With regard to Adjustment C-7, Mr. Farmer stated that Mr. Brosch had made a mathematical error and had double counted a $380,000 reduction. After correcting for this error, Mr. Farmer determined that the difference between the O&M expenses related to this issue as presented by PSI were only 17% greater than the actual 2002 expenses, recommended by Mr. Brosch. Pet. Ex. QQ, pp. 16-18. In order to test the reasonableness of PSI's estimates for purposes of reflecting an ongoing level of production O&M, Mr. Farmer compared PSI's estimates to the actual, non-labor

O&M incurred for the 12 months ended August 31, 2003 at the Madison and Henry County facilities. This comparison showed a difference of only 9%. Given this small difference, Mr. Farmer concluded that the Company's *pro forma* cost level was reasonably representative of an ongoing cost level. In Revised Schedule C-7, Mr. Brosch corrected the double counting error, but still proposed lower O&M costs for the Madison and Henry County Stations.

With respect to the OUCC's Adjustment C-8, Mr. Farmer confirmed that the NO_x O&M costs included in the case are primarily driven by costs incurred to operate the Gibson SCRs. The SCRs were operated in 2002 and are being operated in 2003 in order to generate early reduction NO_x credits. *Id.* at 18-20. He noted that Gibson Units 2 and 3 SCRs were declared commercial in July, 2002 and that the Gibson Unit 4 SCR was declared commercial in July, 2003. He stated the in-service dates are significant to the issue of determining annual O&M costs, because in both 2002 and 2003 the SCRs were declared commercial two months into the NO*x* compliance season of May-September. Accordingly, because the SCRs were in service during only a portion of the NO*x* compliance season and not the normal five months, the 2002 data used by Mr. Brosch to make his adjustment is not representative of normal ongoing cost levels.

Mr. Farmer testified that SCR operating expenses are primarily driven by the costs of ammonia and that Mr. Brosch's ammonia costs are predicated on information provided by PSI in response to OUCC Discovery Request 23-565. At the time the responses were provided, the latest available month was May, 2003, and the Company's response set forth an *average* price paid in 2002 up to that time of $170.09 per ton. However, that same data response stated that the price paid in May was $322.70 per ton, an increase of 90% when compared to the average 2002 price. Mr. Brosch did not take into account, Mr. Farmer pointed out, the higher prices for ammonia in 2003, compared with 2002, which were set forth in the data response.

To test the reasonableness of Mr. Brosch's ammonia costs and PSI's projected ammonia costs utilized in its adjustment, Mr. Farmer looked at current information based on actual deliveries and costs of the ammonia used at the Gibson Station. The Company's invoiced cost of ammonia purchased for 2003 was $1,107,659, excluding the cost of one tanker load, which remained outstanding at that time. Pet. Ex. QQ, p. 20. Given the fact that the Gibson Unit 4 SCR ran for only a part of the season, Mr. Farmer concluded that the Company's $1,141,000 initial estimate of annual ammonia expense for a normal five-month compliance period at today's prices is reasonable and more representative of ongoing cost levels. In contrast, Mr. Farmer noted that Mr. Brosch's allowance for annual ammonia expense of $423,000 would grossly understate the costs being incurred by PSI in operating its Gibson Units. In Revised Schedule C-8, Mr. Brosch revised his *pro forma* adjustment to accept PSI's proposed ammonia costs. However, Mr. Brosch maintained his lower O&M Material, and Contractor Labor amounts.

(b) *Discussion and Findings*. We find that PSI's estimates of the subject costs are reasonable. In making OUCC Adjustment C-7, regarding PSI's production non-fuel O&M expenses, Mr. Brosch utilized actual 2002 data in an effort to demonstrate that PSI's adjustment was overstated. Mr. Farmer utilized more recent data in an effort to show that Mr. Brosch's adjustment was understated. The difference between the actual twelve months ended August 31, 2003, and PSI's original *pro forma* adjustment amount was only 9%. Given the apparent variability in non-labor O&M costs, as evidenced by the fact that the twelve months ended August 31, 2003 for the Henry County Plant was $158,000 less than the actual 2002 costs, this Commission finds that PSI's estimate represents a reasonable approximation of an ongoing level of production, non-fuel O&M expenses and it should be approved.

The lack of a full test year of operating data also was present in determining the ongoing level of production O&M expenses related to the operation of the Gibson SCR units. Mr. Farmer explained that the SCRs were not declared commercial until July 2002 and July 2003, and the normal NO_x compliance five-month season is May 1 through October 1. Thus, actual O&M expense for 2002 data used by Mr. Brosch was understated. Mr. Farmer, again utilizing more recent data than Mr. Brosch, testified that it could cost PSI $1,316,700 for the cost of ammonia, alone, to operate these SCR units using actual 2003 ammonia prices. PSI had proposed a total annual production O&M expense for NO_x equipment of $1,333,000. With Mr. Brosch's acceptance of PSI's proposed ammonia expense, the difference between PSI's proposed adjustment and the OUCC's proposed adjustment is only $170,000. Because PSI used more recent data, we find that Mr. Farmer's estimate of production O&M costs for operating the Company's SCR facilities is not unreasonable.

[63, 64] (7) *Software Amortization Costs.*

(a) *Evidence*. OUCC witness Carver sponsored OUCC Adjustment C-12, which reduced PSI's amortization expense by $1,257,489. Mr. Carver explained that this adjustment recognized the August, 2003 termination of certain software investment amortizations. Pub. Ex. No. 1, p. 33. He stated that in general the Company records its software investment as Intangible Plant and then amortizes the investment over its anticipated useful life, normally five or ten years. Mr. Carver noted that PSI's July 31, 2003 update filing removed amortizations that expired by May 31, 2003. Mr. Carver opined that his adjustment to remove all amortizations that will expire by September 30, 2003, was in accord with the Prehearing Conference Order, which allowed for fixed, known and measurable adjustments through the twelve months following the end of the test year.

On rebuttal Mr. Farmer pointed out that he believed that Mr. Carver was applying inconsistent standards in making his adjustments to Intangible Plant and Tangible Plant. For purposes of depreciation expense, Mr. Farmer noted, Mr. Carver had utilized plant balances as of May 31, 2003, which Mr. Farmer observed was consistent with his reading of the Prehearing Conference Order. Pet. Ex. QQ, pp. 29-31. Mr. Farmer testified that, at a minimum, intangible and tangible plant should be treated alike. If PSI's depreciable plant were updated to August 31, 2003, PSI's investment in depreciable plant, excluding plant subject to amortization, would increase by $25,675,000 and amortizable plant would decrease by $6,598,000. He also stated that if the depreciable plant were so updated to September 30, 2003, as Mr. Carver updated plant subject to amortization, the increase in PSI's depreciation expense may be even higher, due to additional depreciable plant investment. *Id.* at 31-32. Mr. Farmer stated that the cut-off date should be the same for items as interrelated as depreciation and amortization expense associated with PSI's rate base.

(b) *Discussion and Findings*. Based on our review of the testimony it appears that Mr. Carver applied inconsistent standards to plant subject to depreciation and plant subject to amortization. For the former, he used plant balances as of May 31, 2003. For the latter, he used plant balances at September 30, 2003. This resulted in the update of an expense that was decreasing, without a corresponding update to an almost identical expense that was increasing. We find that adjustments to test year results of the same basic cost items should be done in a consistent manner. Therefore, in this case we agree with Mr. Farmer that it makes sense to use the general rate base cut-off date of May 31, 2003 which was agreed to by all parties, and to also update depreciation and amortization expense which constitute a *return of* that same rate base amount.

[65] (8) *Public Safety Advertising*.

(a) *Evidence*. PSI proposed an adjustment to test year expenses in the amount of $619,000 related to the Company's public safety advertising program. Pet. Ex. Y-18. In support of that adjustment, PSI witness Leigh J. Pefley testified that, beginning in 2003, PSI significantly stepped up its public safety advertising. Pet. Ex. J, p. 10. She stated that through periodic radio advertising, PSI intends to build public awareness of where power lines are located and the need to stay clear of them. She said that the initial phase of the campaign consisted of a nine-week schedule, beginning in March, of radio advertisements in the major markets of Indianapolis, Terre Haute and Lafayette as well as over 27 non-major markets. The second phase of the project will consist of ten weeks of radio advertising during the months of June through November. She stated that PSI plans to continue its public safety awareness advertising on an annual basis. Ms. Pefley was of the opinion that it was important to convey to PSI's customers how to be safe around electricity and that the Company's program accomplished that goal.

OUCC witness Carver stated that while the OUCC encourages public utilities to conduct public safety awareness campaigns, in his opinion, there were too many uncertainties surrounding the annually recurring magnitude of PSI's campaign, implemented in 2003, to fully justify the adjustment. Pub. Ex. No. 1 p. 64. He testified that PSI did not provide any studies or quantitative analyses to support the decision to implement the new safety advertising program. *Id.* at p. 64. Instead, the Company appears to have decided to increase its public safety advertising based on recent incidents involving public contact with electrical facilities, where the victims may not have been aware of the existence of electrical facilities or the dangers posed by electricity — however, specific information regarding incidents of this nature had not been provided by PSI. *Id.*, at 64-67. Mr. Carver added that PSI also had expended less than $10,000 in public safety advertising during the six-year period ending with calendar year 2002. He stated that PSI's affiliates similarly expended little on public safety advertising, even though significant levels of advertising expense appear to have been included in PSI's last Indiana retail rate case. *Id.* at 68-71. Given this history, Mr. Carver was concerned that, absent assurance otherwise, PSI's safety advertising expenditures could again be reduced following this rate case. *Id.*, at 72-73. Mr. Carver proposed that if PSI is allowed to recover some level of safety advertising expense in retail rates, the Company's adjustment should either be reduced by 50%, or PSI should be required to make an annual filing with the Commission, with copies to the OUCC, explaining any reduction in public safety advertising expense greater than 10% of the allowed amount.

Mr. Esamann submitted rebuttal testimony in response to Mr. Carver's testimony. He described the Company's 2003 campaign and said that by the end of August, 2003, PSI had incurred actual expenditures of $408,000. Pet. Ex. DD, pp. 40-41. Mr. Esamann also gave assurance that PSI is committed to a multi-year public safety campaign. He said that PSI has already undertaken steps to develop a media schedule for 2004, with the creation of at least two additional media spots for 2004. Mr. Esamann stated that these costs were prudently incurred and should be fully reflected in the ratemaking process. He also said that PSI would have no objection to filing an annual report as suggested by Mr. Carver. *Id.* at 42.

(b) *Discussion and Findings.* Based on the evidence presented on this issue, we find that PSI should be allowed to recover some level of public safety advertising expense and that it should not be necessary for PSI to report to the Commission regarding the ongoing level of these expenditures. Through its testimony, PSI demonstrated the importance of undertaking an ongoing public safety advertising campaign and we believe that PSI should, and will, utilize the full amount allocated by the Commission for this purpose.

Mr. Carver does not contest the level of the $619,000 expense or the actual expenditures made by PSI in 2003, but believes that the Company did not fully demonstrate the need for the recurring level of such costs. While Mr. Esamann's rebuttal testimony provides some assurance that PSI plans to continue its public safety advertising program in the future, our review of the historic level of these expenditures indicates that even if the amount requested by PSI is reduced as Mr. Carver proposed, it would still represent a dramatic increase in expenditures for this purpose. Therefore, we agree with the OUCC that a 50% reduction in the amount proposed by PSI is warranted and find that PSI should be allowed to recover $310,000 of program costs. We also find that

the Company should not be required to submit annual reports regarding its expenditures on public safety advertising campaigns.

[66, 67] (9) *Salaries, Wages, Benefits, and Incentive Compensation.*

(a) *Evidence.* PSI proposed a *pro forma* adjustment which reflected an annualized level of salaries, wages, and benefits at the May 31, 2003 cut-off date. In the end, there was no challenge to PSI's proposed adjustments. Tr. at P50. We find that PSI's proposed salaries, wages and benefits should be approved. In addition, PSI also seeks recovery of $12,883,000 in incentive pay expense. Pet. Ex. PP-8, Sch. C-3.17, p. 2. Mr. Verhagen testified in support of PSI's level of incentive. He stated that PSI began using incentive pay in 1987 and described the Company's major incentive pay programs: (1) the Cinergy Corp. Annual Incentive Plan ("AIP"); (2) the Energy Merchant Business Unit Annual Incentive Plan ("EMBU AIP"); (3) the Cinergy Corp. Non-Union Employee Incentive Plan ("NEIP"); (4) the Cinergy Corp. Union Employee Incentive Plan ("UEIP"); and (5) the Cinergy Corp. 1996 Long-Term Incentive Compensation Plan ("LTIP"). Pet. Ex. R, p. 10.

According to Mr. Verhagen, the AIP is a short-term incentive plan that allows employees to receive cash payments as certain performance goals are attained during the preceding calendar year. The AIP is available to selected exempt employees of PSI and Cinergy Services. The purpose of the AIP is to attract, retain and motivate employees, enhance teamwork and high levels of achievement and to facilitate the accomplishment of specific corporate business units and individual goals. Employees are selected to participate in the AIP. Mr. Verhagen stated that the compensation committee of the Cinergy Corp. Board of Directors monitors on an ongoing basis the AIP performance goals and the level of compensation paid through the AIP. Performance goals are the objective that the relevant business unit and individual employees must attain in order for the employees to receive payment under the AIP. Mr. Verhagen stated that for the Regulated Business Unit ("RBU") employees participating in the AIP, the individual goals and the employee's business unit goals were weighted equally. *Id* at 11-12. In 2002, the business unit goals of the RBU were based on the following factors: (1) electric SAIDI; (2) electric CAIDI; (3) gas CAIDI; (4) lost time accident rate; (5) number of traffic accidents; (6) customer satisfaction score results; (7) O&M expense levels; and (8) capital expenditure level. *Id.*

The EMBU AIP, according to Mr. Verhagen, is another short-term incentive plan that provides cash payments to employees if certain performance goals are met. Like the AIP, the EMBU AIP is available to selected employees, but these employees do not participate in the AIP. The performance goals for the EMBU AIP consist of a corporate earnings component and EMBU earnings component. Performance goals are related to the business segment of the EMBU to which the employees are assigned individual performance goals. Mr. Verhagen noted that PSI's rates reflect labor expense from Cinergy Services and Cinergy Power Generation Services employees who allocate time to PSI and who participate in the EMBU AIP because they work at PSI's generating stations, provide generation support and provide back office support. The EMBU AIP goals for the generation business segment are based on the actual performance of Cinergy's generation fleet and the individual generating station where the respective employees work. *Id.* at 12-14.

The NEIP is available to exempt and non-exempt employees of PSI and Cinergy Services who do not participate in another incentive plan. The NEIP is a short-term incentive plan, according to Mr. Vethagen, that allows employees to receive cash payments if Cinergy Corp. attains certain corporate performance goals during the calendar year. Mr. Verhagen testified the purpose of the NEIP is to attract, retain and motivate employees, enhance teamwork and achieve high levels of corporate goals. This plan, like the others, is monitored by the compensation committee. The NEIP uses the same performance measures as the AIP's corporate performance measure. *Id.* at 14-15.

Mr. Verhagen testified that the UEIP is available to union employees of PSI, Cinergy Services and CPGS who do not participate in another incentive plan. Like the other plans described, the UEIP permits union employees to receive cash payments if Cinergy Corp. attains certain performance goals or if their business unit attains certain performance goals during the preceding calendar year. *Id.* at 15-16.

The purpose of the LTIP is to assist in attracting, retaining and motivating executives by keeping Cinergy's compensation package competitive and to align a portion of the executive compensation with corporate interests by encouraging and enabling executives to acquire Cinergy stock. Mr. Verhagen stated that under the LTIP certain employees may be granted an incentive and non-qualified stock options, stock appreciation rights, restrictive stock, dividends equivalent to opportunity to earn performance based shares and certain other stock-based awards. *Id.* at 17-18.

Mr. Verhagen testified that this Commission has previously considered PSI's incentive compensation plans. He said that PSI's current AIP and LTIP are similar to the AIP and performance share plans previously reviewed in Cause No. 40003. In addition, PSI's AIP and performance share plans were considered in Cause Nos. 37414-S2 and 38809 (1989) and Cause Nos. 39584 and 39584-S2 (1994). He stated that in each case the proceedings resulted in PSI's rates reflecting incentive compensation costs. *Id.* at 19. Mr. Verhagen stated that incentive compensation is a necessary component of any company's compensation and benefit package in order to keep total compensation competitive. He pointed out that many utility companies and non-utility companies offer these types of incentive compensation plans. PSI must offer such plans in order to remain competitive and be able to attract and retain a high caliber workforce. In addition, PSI's incentive compensation plans pay out reasonable levels of incentive compensation. For these reasons, Mr. Verhagen believed that it is appropriate for PSI to reflect these costs in its rates. *Id.* at 20.

Mr. Verhagen also discussed the allocation of the costs of the various compensation plans to PSI. He said that PSI recognizes that this Commission has required shareholders to bear a portion of the incentive compensation costs. He also recognizes that Cinergy's shareholders, as well as its customers, benefit from the achievement of the goals used in these incentive compensation plans. Mr. Verhagen stated that the costs of the corporate goals under the AIP and EMBU AIP, were allocated 50% to the shareholders, 50% to the customers. The individual goals and the RBU goals under the AIP were allocated 100% to the customers. The EMBU AIP earnings goals were allocated 50% to the shareholders and 50% to the customers. Like the AIP, the EMBU business segment goals and the individual goals were allocated 100% to the customers. For the LTIP, Mr. Verhagen stated that the total shareholder return was allocated on a 50%/50% basis. Mr. Verhagen allocated 100% of NEIP and UEIP costs to PSI's customers. *Id.* at 21-22.

The OUCC did not propose any adjustment to PSI's proposed level of incentive compensation expense to be included in PSI's rates. Mr. Carver presented detailed testimony discussing our past treatment of incentive compensation in Indiana rate cases. Pub. Ex. 1, pp. 77-80. His testimony also highlighted the significant escalation in PSI's incentive compensation costs in relation to the amount PSI has proposed to include in cost of service. *Id.* at 80-82. Mr. Carver further testified that it was unnecessary for the Commission to create unique shareholder incentive mechanisms in order to focus individual employees on achievements that enhance corporate financial objectives. Any additional shareholder incentives would not directly influence the day-to-day activities of individual employees who, on average, have about 9.8% of their compensation "at risk" through the incentive plans discussed by Mr. Verhagen. *Id.* at 82-83.

CAC presented the direct testimony of Dr. Michael Sheehan, who testified that he had five problems with PSI's executive incentive program. First, he said, the levels appeared to be excessive. Second, the underlying premise that high levels of incentive pay produce high levels of corporate performance has not been substantiated. Third, he said, not only do incentives appear not to work, in fact they have a tendency to produce bad behavior on the part of a significant number of executives. Fourth, he said, even if the incentives proposed by PSI might work in theory, they are usually tied to goals that have flaws or lead to misdirection. Finally, he maintained that building incentives into rates means that ratepayers are charged for incentive payments even when the incentives are subsequently not justified by performance or are not paid to employees of the utility.

Dr. Sheehan noted that under the allocation of the incentive programs proposed by Mr. Verhagen, 75% of the costs of these programs are being allocated to PSI's ratepayers which in his opinion is not appropriate, at least as the programs are applied to executives. CAC Ex. C, p. 64. First, he said the incentive programs are primarily directed to the goals of maximizing the financial performance of the holding company, Cinergy, which, in his opinion, is not an appropriate goal and embodies an intrinsic conflict of interest for PSI employees. He said that this Commission should not allow any cost of recovery at all for the costs associated with Cinergy's financial performance. *Id.* at 64.

In support of his argument that the costs of executive incentive plans should not be allocated to PSI, Dr. Sheehan cited three articles, from researchers at the Wharton School of Business, Indiana University, and Harvard University, respectively. *Id.* at 66-68. Dr. Sheehan claimed that these studies tended to show that substantial incentives have motivated counterproductive behavior. He said that the provision of substantial incentives to Cinergy executives on loan to PSI to maximize the returns to PSI, could, in his opinion, lead to predatory behavior against PSI. *Id.* at 69. He said that if the Commission approves the allocation of the costs to PSI, it should only be done in conjunction with the creation of a tracker or true-up mechanism. Otherwise, in cases where the goals are not met and the anticipated ratepayer benefits are not forthcoming, and thus the costs are not offset, the ratepayers will still have to fund the full cost of the incentive programs and Cinergy will "pocket the money." Dr. Sheehan conceded during cross-examination that he had not read the Wharton study prior to preparing his testimony, and that these studies did not support his opinions in several key respects. For example, he indicated that the Harvard study was based on the "rent extraction" theory, which is a minority theory in the field of incentive compensation. In addition, the Indiana University study did not differentiate whether the stock options it studied were paid as part of a base compensation package or incentive pay to motivate a desired behavior.

In response, Mr. Verhagen pointed out that Dr. Sheehan performed no analysis of the programs involved in this case. On the other hand, Towers Perrin Company ("Towers") had analyzed Cinergy's executive compensation programs and concluded that: (1) Cinergy's total annual executive compensation is competitive with the proxy peer group at the 50th percentile; and (2) the long-term incentives paid by Cinergy in 2002 were only 66% of the level of long-term incentives paid by the proxy peer group at the 50th percentile and 33% of the long-term incentives paid by the proxy peer group at the 75th percentile. In Mr. Verhagen's opinion, these studies show that Cinergy's compensation programs result in reasonable levels of compensation when compared to its proxy peer group. Pet. Ex. MM, p. 2.

Mr. Verhagen pointed out that Dr. Sheehan presented no evidence to support his conclusion that the structure of PSI's incentive compensation program is flawed because it motivates executives to accomplish goals contrary to PSI's best interests. Mr. Verhagen said that PSI's interest and Cinergy's interests are interwoven and inseparable. He noted that the AIP for the RBU has performance goals based on electric service reliability, safety and customer satisfaction and that these goals are obviously in the best interest of PSI customers. *Id.* at 3-4.

Mr. Verhagen stated that Dr. Sheehan erred in contending that performance goals based on the corporate performance and total shareholder return are contrary to the interests of PSI's customers. Over the long term, he said, Cinergy Corp. could not favor shareholders interest over the interest of PSI customers. Doing so would ultimately cause PSI's service level to deteriorate, which would produce widespread customer dissatisfaction. This would ultimately reduce Cinergy Corp. net income and total shareholder return. *Id.* Mr. Verhagen also responded to Dr. Sheehan's statement that the portion of the incentive expense allocated to PSI is not appropriate. Mr. Verhagen stated that PSI's *pro forma* adjustment strikes a reasonable balance as the costs of AIP performance goals related to corporate performance and the total cost of the LTIP are allocated 50% to shareholders and 50% to customers. He said such an allocation is reasonable given that the performance goals provide inexplicably intertwined benefits to shareholders and customers and these incentive programs result in total compensation levels that are reasonable and necessary to attract talented employees.

(b) *Discussion and Findings*. It is commonly accepted that incentive compensation plans may be necessary in order for utilities to attract and retain highly qualified individuals. Dr. Sheehan does not dispute this fact. Instead, he generally objects to PSI's *pro forma* executive compensation adjustment on two grounds: (1) there is no showing that executive compensation plans enhance employee performance; and (2) the percent of the expense allocated to PSI is not appropriate.

Dr. Sheehan cites three business journal articles in support of his conclusion that there is not a link between incentive compensation and corporate performance. The first article surveyed several studies on the relationship between corporate performance and the levels of equity ownership by a firm's management and concluded that the studies were mixed as to whether increased equity ownership produced improved firm performance. The second article was admittedly a minority view and was predicated on the "rent extraction theory" in executive compensation. The final article cited by Dr. Sheehan is also a minority view, which leads us to the conclusion that the majority view is that there is a direct link between executive compensation and improved corporate performance.

As to Dr. Sheehan's objections regarding the level of costs assigned to the PSI shareholders, we have previously approved the recovery of incentive compensation costs through rates where: (1) the incentive compensation plans are not pure profit-sharing plans, but rather incorporate operational as well as financial performance goals; (2) the incentive compensation plans do not result in excessive pay levels beyond what is reasonably necessary to attract a talented workforce; and (3) shareholders are allocated part of the cost of the incentive compensation programs. PSI's incentive compensation plans incorporates operational goals as well as pure profit sharing goals. The Towers study demonstrates that these incentive compensation plans are not excessive and are reasonable to attract and retain the employees required to manage and operate PSI. Accordingly, we find that PSI's *pro forma* adjustment for employee incentive compensation is appropriate and should be approved.

[68] (10) *Voluntary Early Retirement Program Expense.*

(a) *Evidence*. PSI proposed an adjustment to its test year Voluntary Early Retirement Program ("VERP") expense. It proposed to eliminate the actual 2002 VERP expense of $19,100,000 and replace it with a representative level of annual VERP expense of $5,389,000. Pet. Ex. Y-6, Sch. C-3.9. Mr. Howe sponsored this adjustment on the basis that all related employee expense levels in this case reflect the reduced number of employees resulting from PSI's VERP. It is only appropriate, he said, to reflect the corresponding costs of those employee reduction programs over the years for which rates approved in this case will be in effect, especially when such costs are less than the corresponding cost savings (benefits) proposed to be reflected in PSI's rates. Pet. Ex. Y, pp. 6-7.

Mr. Verhagen testified that from 1995 through 2001, PSI offered five different VERPs to reduce employees. Pet. Ex. R, pp. 38-39. In 2002, he said, PSI offered three separate VERPs which essentially offered enhanced retirement benefits to those employees who accepted early retirement. *Id.* at 39. Mr. Verhagen stated that of

the 425 employees eligible to participate in the Company's 2002 VERPs, 302 employees accepted the Company's offer.

OUCC witness Carver proposed to eliminate PSI's VERP adjustment, thereby eliminating from rates any VERP expenses. Pub. Ex. No., 3, Adj. C-13. Mr. Carver did not dispute the wisdom of, or need for, VERPs. Pub. Ex. No. 1, at 40. Nor did he question the recurring nature of these expenses. Tr. at P62-P63. Rather, the basis for his disallowance was his opinion that because the reduced expenses have been experienced since 2002, but will not be reflected in rates until April, 2004, PSI's shareholders have already received some of the benefits of the VERPs. *Id.* at 41. Mr. Carver claimed that the Company was seeking a deferral and amortization of the actual 2002 VERP expenses, and that it was not appropriate to recover from customers the costs of the VERPs on a prospective basis when PSI does not propose to flow through to customers the related savings on a retroactive basis. Mr. Carver estimated these retroactive savings to be $16.9 million. As an alternative to complete disallowance, Mr. Carver proposed that PSI be allowed to amortize over four years the difference between the 2002-03 expense of $21.554 million and the pre-2004 savings estimate of $16.9 million.

In response, Mr. Howe pointed out that PSI's salaries and wage expense in this case eliminated all of the former employees who elected to take the 2002 VERP, even if those people had not yet left the Company. Pet. Ex. PP, pp. 5-6. He clarified that PSI was not seeking a deferral and amortization of the actual 2002 VERP expenses, but rather, PSI was seeking to have a representative level of VERP expenses built into future rates. At the hearing on PSI's rebuttal case, Mr. Howe indicated that he has checked the reasonableness of his proposed annual VERP amount. He indicated that PSI has conducted six VERP offerings in the last five years, with an average annual cost of approximately $5.6 million. He also noted, that since PSI filed its case-in-chief testimony, the Company has instituted another VERP program in 2003 at a cost of about $4 million. Mr. Howe indicated that this evidence supports PSI's proposed annual VERP expense of approximately $5.4 million. Tr. at Y34 - Y35.

(b) *Discussion and Findings*. In order to frame the issue for our consideration, PSI proposed to eliminate the actual 2002 VERP expense of $19,100,000 and replace it with a representative level of annual VERP expense of $5,389,000. Pet. Ex. Y-6, Sch. C-3.9. The OUCC's proposed adjustment, taken in conjunction with PSI's adjustment, would serve to eliminate VERP expenses from rates. Pub. Ex. No., 3, Adj. C-13. In order to undertake our review of this issue, we accept PSI's VERP adjustment as the appropriate starting point for our consideration and resolution of this issue.

Based on our review of the evidence presented on this issue, PSI appears to have premised its *pro forma* adjustment on a methodology that would effectively amortize the cost of its 2002 VERP over a four-year period. While we recognize that costs rise and fall between rate cases, the *pro forma* adjustment developed by PSI, which projects future costs (but not savings) from programs that may or may not occur, fails to fully address many issues, including: the anticipated level of any future workforce reduction programs; the costs associated with the programs; and, the anticipated level of overall savings associated with the implementation of future VERPs.

In evaluating PSI's request for a *pro forma* adjustment for VERP expenses, we recognize that implicit in undertaking VERPs is the expectation that there will be short term costs and possible long term savings associated with the programs. Accordingly, in undertaking our review of this issue we must consider the anticipated future level of such programs in conjunction with any cost savings that may occur as a result of the programs. Based on the evidence presented, we cannot determine, with any degree of certainty the actual level of costs and savings associated with the possible implementation of future VERPs. Therefore, we accept the OUCC's adjustment and find that VERP expenses should not be included in rates.

[69] (11) *Property Taxes.*

(a) *Evidence.* PSI's *pro forma* operating expenses included an adjustment of $151,000 to test period property taxes. Pet. Ex. X-23, as revised by the August 31, 2003 cut-off date update filing. PSI witness Farmer sponsored this adjustment and included the tax law changes noted in the testimony of PSI witness Charles J. Winger.

Mr. Winger explained that the 2002 Indiana General Assembly legislated changes in the manner that required Indiana property taxes to be re-calculated for the actual 2002-pay 2003 tax year. Pet. Ex. Q, p. 7; Pet. Ex. X, p. 29. Mr. Winger testified that property tax is a function of two basic factors: (1) the assessed value of real and personal property; and (2) the property tax rate. Pet. Ex. Q, p. 11. PSI estimated the assessed value of its real and personal property to be $1,301,708,000, which represented actual plant balances as of September 30, 2002, plus *pro forma* adjustments for plant additions, retirements and estimated changes in material, supplies and fuel inventories, as determined by Mr. Farmer. Mr. Winger estimated the tax rate to be 2.49%. He started with the actual 2001-pay 2002 average tax rate for PSI of 2.64% and adjusted it downward by 5.7%. This downward adjustment was determined by comparing the average Indiana statewide net tax rate for the 1994-pay 1995 to the same rate for the 1995-pay 1996, the last time that Indiana experienced a statewide reassessment of real property.

Mr. Farmer took into account the information provided by Mr. Winger and accounted for the *pro forma* plant additions and retirements listed on Schedule B-2, the adjustment to the coal stock inventory from Schedule B-4 and the adjustment to the material and supplies inventory from Schedule B-6. He also estimated a payment in lieu of taxes applicable to the Madison Generating Station, in the amount of $952,000, and he eliminated 50% of the Child Care Center property taxes. These changes resulted in a *pro forma* total property tax expense of $31,421,000 and an adjustment to test year operating expense of $151,000. Pet. Ex. X-23, updated October 6, 2003.

OUCC witness Carver proposed the elimination of Mr. Farmer's adjustment to test year property taxes. Pub. Ex. No. 3, Adj. C-19. Mr. Carver did not necessarily disagree with PSI's calculations. Rather, he said, the basis for his disallowance is the delay that has been experienced statewide in the finalizing of assessed values, tax rates and tax bills. Pub. Ex. No. 1, p. 104. Mr. Carver's adjustment was a "placeholder" until more complete property tax data becomes available in August and September, 2003, he said. Mr. Carver proposed that the property tax annualization be updated as an exception to the Prehearing Conference Order. Pub. Ex. No. 1, pp. 107-108. He proposed that: (1) PSI update its calculations for actual tax bills; (2) update Schedule WPC-3.38c to reflect final and provisional tax bills; (3) if any provisional tax bill exceeds 50% of the previous tax bill, reduce such amount to reflect the lesser of 50% of the prior tax bill or the 2001 total tax bill adjusted to reflect the composite net increment/decrement for all other counties with final tax bills; and (4) identify all counties that have failed to provide final or provisional tax bills and the annualization for these counties should be based on the 2001 tax bill adjusted in the manner called for in item (3).

Mr. Farmer opposed Mr. Carver's proposal and noted that the 2001 tax liability is primarily based upon the assessed value of property at December 31, 2000. Pet. Ex. QQ, pp. 34-37. The problem with Mr. Carver's proposal is that these assessed values will not be matched or synchronized with the value of plant included in this case and therefore will likely not be representative of an ongoing level. Mr. Farmer further observed that changing the property tax valuation method to fair value will not have a significant impact on PSI property assessments, because over 90% of PSI's assessed value is made up of property referred to as "state board distributable" property. The assessed value of such property is predicated on the net tax basis of the property (net book value) as recorded on the Company's books. In Mr. Farmer's view, it would be inappropriate to use the net book values as of December 31, 2000, as proposed by Mr. Carver, given that the test period in this case is based on a 2002 test period pro formed

into 2003. Mr. Farmer opined that the December 31, 2000 property evaluation and assessments are stale and do not provide the proper matching of plant costs included in the rate base in this case. *Id.*. Mr. Farmer also testified that Mr. Carver's proposal to use the lesser of 2001 pay 2002 tax or the 2001 tax adjusted for some net increment/decrement is also flawed because the basic presumption behind Mr. Carver's proposal is that the 2002 pay 2003 tax bills in all counties will change from the prior year by the same percentage relationship.

As an alternative to Mr. Carver's proposal, Mr. Farmer proposed that the Company's proposed retail jurisdictional portion of property tax expense ($30,100,000) should be included in PSI's base rates. *Id.* at 38-39. If the jurisdictional portion of any future annual property tax expense, using allocators approved in this case, is less than $30,100,000, PSI will return to customers the amount by which the base level exceeds the jurisdictional portion of property tax actually billed and charged to expense. PSI will return any excess amount to customers through one of PSI's tracking mechanisms that allocate costs based on demand allocators, since property tax is allocated based on demand. (*i.e.*, CWIP tracker, Clean Coal Operating Cost tracker, or Summer Reliability Tracker). This credit mechanism would continue until the first year that PSI's actual property tax expense exceeds the amount included in base rates, at which time the crediting would end for that and all succeeding years.

(b) *Discussion and Findings.* This Commission is certainly cognizant of the uncertainty facing millions of property owners, including public utilities, created by the statewide reassessment mandated by the Indiana courts and the General Assembly. We appreciate the creativity of the parties in attempting to deal with these uncertainties. After considering all of the evidence, we are persuaded that Mr. Farmer's rebuttal proposal should be adopted. Importantly, this ensures that PSI's customers will pay no more than PSI's actual property tax expense for a given year. Another advantage of this proposal is the administrative ease by which it can be implemented and reviewed by this Commission and any party of interest. Given that PSI's actual 2001-pay 2002 tax is within $151,000 of PSI's proposed property tax level, and that PSI has added significant taxable property since 2001, we find it reasonable for PSI to include its proposed property tax expense in base rates and to implement its proposed reconciliation and crediting mechanism, utilizing the CWIP tracker, Standard Contract Rider No. 62.

[70] (12) *Trading Expense.*

(a) *Evidence.* PSI proposed an adjustment to test period expenses related to certain trading expenses. Mr. Farmer testified as to a representative level of trading expense based on actual test period amounts. Pet. Ex. QQ, pp. 39-40. He stated that PSI's July 31, 2003 update removed $5,124,000 in trading expenses for trading floor rent, building expense and other trading related costs that were charged to test period expense. A portion of this *pro forma* adjustment (approximately $3.9 million) was removed from test period expenses, not because it was not representative or properly allocated to PSI, but because of the existence of an explicit off-system sales profit sharing mechanism included in PSI's proposed Summer Reliability Tracker. PSI's rationale for excluding this portion of the trading expenses was that there were likely incremental O&M expenses embedded in its test period expenses associated with maximizing off-system sales profits. Because incremental O&M expenses associated with maximizing off-system profits are not separately identified or accounted for on PSI's books and records, these trading expenses are intended to serve as a proxy for the potentially embedded incremental O&M costs. PSI reasoned that, if the explicit off-system profits incentive sharing mechanism in its proposed Summer Reliability Tracker is approved and implemented, it would be appropriate to remove these "proxy" incremental O&M expenses. Conversely, PSI stated that if the proposed Summer Reliability Tracker is not approved, it would be appropriate to include these trading expenses in PSI's revenue requirements.

Mr. Farmer explained that these expenses represent personnel and systems costs that are properly allocated to PSI based upon PSI's use of trading personnel for both off-system purchases and sales. These expenses consist of costs related to power trading functions; rent and building expense; salaries, benefits and expenses for confirmation and billing functions; generation and supply scheduling; costs of transmission scheduling and congestion management; Information Technology support; trading expenses in the Midwest; and general management of trading activities. Mr. Farmer testified that these expenses result in a total cost of $3,953,000. Mr. Farmer indicated that the remainder of the expenses eliminated by PSI in its July 31, 2003 update ($1,171,000) did not support PSI's off-system sales activities and therefore should be excluded from PSI's revenue requirements with or without approval of the Summer Reliability Tracker. Pet. Ex. QQ, p. 40.

The OUCC, while opposing the Summer Reliability Tracker and the explicit incentive sharing mechanism for off-system profits, made no corresponding adjustment for PSI's elimination of the related trading expenses. Mr. Brosch surmised that the trading cost exclusion remained appropriate even if PSI off-system sales are not tracked because the implementation of the JGDA results in PSI being more insulated from trading results in that all new off-system sales of PSI energy occur though intercompany transfers to CG&E.

(b) *Discussion and Findings*. Consistent with our determination that test-period off-system sales profits of $18.7 million should be included in base rates, and that an amount for trading expenses should be reflected in a corresponding reduction of the amount included in base rates, we find that PSI's *pro forma* expenses shall include $3,953,000 for trading expenses.

(13) *Deferred Costs*.

[71] (a) *Deferred Dynegy Buyout Costs*.

(i) *Evidence*. In 1999, PSI and the OUCC entered into a Settlement Agreement pertaining to a buyout of PSI's Gasification Services Agreement with Dynegy Power Corp. — an agreement whereby Dynegy provided PSI with synthetic gas for use at PSI's Wabash River Coal Gasification Repowering Project ("WRCGRP"). This Commission, in an order dated September 9, 1999 in Cause No. 41468, approved the PSI/OUCC Settlement Agreement. Pursuant to this settlement agreement, PSI was authorized to recover the costs of the contract buyout fee, "Costs to Achieve" (additional costs to implement the buyout transaction, specifically, the costs involved in converting the WRCGRP to use both natural gas and syngas), and carrying costs on the unamortized balance of the buyout fee and the costs to achieve, over an 18-year period (the "Dynegy Buy-out Amortization"). Pet. Ex. X, pp. 22-23; Settlement Agreement, Cause No. 39312, pp. 3-4 (PSI Motion for Administrative Notice Filed May 30, 2003).

In this case, PSI proposed an upward adjustment of $928,000 to the annual Dynegy Buy-out Amortization. Pet. Ex. X-14, Sch. C-3.25. Mr. Farmer explained that this adjustment reflects the transfer of certain plant installed in the WRCGRP conversion process from the Dynegy Buy-out Amortization amount to PSI's rate base, and the "true-up" of the costs to achieve to the actual costs incurred by PSI in connection with the buyout and conversion. Pet. Ex. X. p. 22.

OUCC witness Brosch, in OUCC Adjustment C-9, proposed a $2,651,000 reduction in PSI's total Dynergy Buy-out Amortization expense, citing a number of perceived problems with PSI's calculations underlying the unamortized amount. First, Mr. Brosch objected to the capitalization of labor costs within the deferred costs to achieve, theorizing that such capitalization could lead to a double recovery of labor costs that were reflected in PSI's rates in Cause No. 40003. Pub. Ex. No. 2, p. 79. Accordingly, Mr. Brosch removed $981,608 in capitalized labor costs that were incurred to convert the facility to a dual fuel plant. Pub. Ex. No. 2, pp. 81-82. Second, Mr. Brosch objected to PSI's calculation of the Buy-out Amortization amount

because he believed the Amortization amount should be calculated to reflect tax savings created by the deductibility of the one-time buy-out cost of $246.7 million. *Id.* Mr. Brosch stated that PSI is calculating carrying costs on the entire buy-out amount of $246.7 million, even though its actual cash outlay was $146.7 million, by his calculations, after taking into consideration his estimate of the associated tax benefits. According to Mr. Brosch, customers have received no benefit from the income tax deferrals, because there has been no rate case to account for changes in capital structure and capital costs since Cause No. 40003. *Id.* at 84. Mr. Brosch thus calculated carrying charges on the buy-out amount *after* deducting his estimated tax benefits. *Id.* at 84-85.

In response, Mr. Farmer indicated that there is no double recovery, real or potential, of labor costs. Pet. Ex. QQ, pp. 22-24. He pointed out that labor costs associated with construction projects are capitalized and are not treated as an ongoing expense for ratemaking purposes — a point that Mr. Brosch generally agreed with on cross-examination. Pet. Ex. QQ, p. 22; Tr. at Q25-Q28. Mr. Farmer explained that Mr. Brosch's labor adjustment assumes that the labor force involved in the conversion came from the labor pool, the costs of which were expensed in the last rate case as non-construction, as opposed to the pool of employees the costs of which were capitalized. Mr. Farmer pointed out that Mr. Brosch has provided no support for this assumption. In fact, as Mr. Farmer explained, in PSI's last rate case, 22% of the Company's labor costs were capitalized. Mr. Farmer also pointed out that capitalized labor costs are ultimately recovered from customers over time in the form of depreciation expense. Hence, he said, there is no double recovery of labor costs because the labor costs incurred during the conversion are likewise recovered over time through the Buy-out Amortization, not as an ongoing level of expense. Pet. Ex. QQ, pp. 22-24.

As to Mr. Brosch's proposal to reflect tax benefits as a reduction in the amount to be recovered through the Buy-out Amortization, Mr. Farmer explained that the entire basis for Mr. Brosch's adjustment (*i.e.*, that customers have not benefited from the income tax deferrals because the transaction occurred between rate cases) is incorrect. Customers have, in fact, received benefits. Pet. Ex. QQ, p. 26. Mr. Farmer cites three changes in PSI's rates related to the recovery of carrying charges on qualified pollution control property that utilized PSI's updated cost of capital — including the tax benefits cited by Mr. Brosch. Mr. Farmer testified that each updated cost of capital included zero cost deferred income taxes as recorded on the Company's books, including the Dynegy deferred income taxes related to the Dynegy buyout. Mr. Farmer calculated this benefit as producing $1,102,000 in annual savings to customers. Pet. Ex. QQ, p. 27. Mr. Farmer pointed out that if Mr. Brosch's adjustment were accepted, customers would receive benefits from Dynegy deferred taxes twice: once through the reduction in the amoritization of the Dynegy regulatory asset, and a second time through calculation of CWIP revenues. *Id.* In addition, Mr. Farmer pointed out that Mr. Brosch only considered the cash flow implications of the Dynegy deferred income taxes up until the assumed order date in this proceeding, without looking beyond the cash flow implications after the order in this proceeding. For example, Mr. Farmer explained that, the cash flow benefit of the Dynegy tax deduction decreases over time as the deferred taxes payback.

With regard to Mr. Brosch's elimination of depreciation expense when calculating interest and the regulatory asset amortization, Mr. Farmer observed that the Settlement Agreement in Cause No. 41468 clearly states that PSI is entitled to recover "costs to achieve" in addition to recovery of carrying charges on the unrecovered amounts. Pet. Ex. QQ, pp. 28-29. Thus, according to Mr. Farmer, PSI is entitled to recover a return on, as well as a return of, PSI's actual costs to achieve.

(ii) *Discussion and Findings*. The outcome of this dispute is determined by our approval of the provisions of the Settlement Agreement and basic utility ratemaking principles. The Settlement Agreement provides that PSI shall be entitled to recover, over an 18-year period, the Indiana retail jurisdictional portion of the Buy-Out Fee, including estimated costs to achieve. The Settlement Agreement further provides that PSI shall also be entitled to recover carrying costs on the unamortized balance of such amount. In short, this provision provides that PSI is entitled to a return of (*e.g.*, labor and depreciation expense), and a return on (*e.g.*, carrying costs), its investment associated with the Dynegy buy-out.

The Settlement Agreement expresses the intent that PSI be allowed to recover all of the costs associated with converting the WRCGRP to natural gas. To the extent that labor costs were incurred as part of the conversion project, Mr. Farmer demonstrated that such costs were capitalized and were properly recorded as costs to achieve. Pursuant to the Settlement Agreement, PSI is entitled to recover these labor costs through amortization. The same conclusion for depreciation (PSI's capital investment) is inescapable under the Settlement Agreement. In fact, Mr. Brosch agreed on cross-examination that both labor and depreciation (capital investment) costs were incurred by PSI in connection with the conversion of the WRCGRP to natural gas use. Significantly, while Mr. Brosch proposed to exclude both labor and depreciation costs from the amortization calculations, he confirmed that depreciation costs were a part of PSI's initial 1999 estimate of costs to achieve.

In sum, we decline the invitation to reopen the Settlement Agreement entered into between PSI and the OUCC, and find that PSI's adjustment for the Dynegy Buy-out Amortization is reasonable and should be accepted.

[72] (b) *Merger Costs.*

(i) *Evidence.* In this case, PSI proposed a *pro forma* adjustment of $7,419,000 for unrecovered merger transaction costs and costs to achieve merger benefits incurred through October 31, 1996. This *pro forma* adjustment was designed to allow PSI to recover its total unrecovered merger-related costs of $46,206,000 over a four-year period. Mr. Howe sponsored the annual amortization amount of $11,559,000. Pet. Ex. Y-12, Sch. C-3.16.

PSI witness Steffen explained that this Commission, in Cause No. 40003, determined that PSI's deferred merger transaction costs were reasonable, and authorized PSI to recover the merger transaction costs deferred through January, 1995 ($23.7 million) over a 10-year period ($2.4 million per year), beginning October 1, 1994. Pet. Ex. C, p. 25. He testified that as of the applicable cut-off date, PSI's unrecovered deferred merger transaction costs will approximate $2.6 million. PSI proposes to amortize the projected unamortized balance of merger transition costs over four years.

Mr. Steffen further testified that this Commission in Cause No. 40003 authorized PSI to recover in rates its costs to achieve merger savings incurred up to August 31, 1995 ($17.7 million), amortized over a 10-year period, and to defer, for subsequent recovery, its costs to achieve merger savings incurred after August 31, 1995 until October 31, 1996. Pet. Ex. C, p. 26. Mr. Steffen stated that the Company's incurred costs to achieve merger savings consisted primarily of the costs of voluntary workforce reductions programs, relocation, information systems consolidation and re-engineering efforts associated with the consolidation of operations. *Id.* He also testified that the recovery of such costs was reasonable and consistent with the Settlement Agreement and Orders in Cause No. 40003, because they were required to complete the merger and realize the related merger benefits reflected in PSI's proposed revenue requirement. *Id.* at 27.

OUCC witness Brosch proposed to significantly reduce PSI's proposed adjustment, so as to lengthen the recovery period from four additional years (PSI's proposal) to ten additional years — without carrying costs. Pub. Ex. No. 3, Adj. C-10. Mr. Brosch rationalized this additional 6-year recovery period on the basis that PSI retained the labor savings realized from 1997 through 2003 for its shareholders and now proposes to charge customers, over a 4-year period, the costs that generated such savings. Pub. Ex. No. 2, p. 97.

In rebuttal testimony, Mr. Howe disputed

Mr. Brosch's proposal that PSI recover its merger savings costs over ten years, without carrying charges. Pet. Ex. PP, pp. 7-8. He noted that the Settlement Agreement and the related Commission Order in Cause No. 40003 approved a total amortization period of ten years, and that PSI's adjustment even increases the recovery period by one year. By comparison, he pointed out, Mr. Brosch's adjustment increases the recovery period to a total of 16 years.

(ii) *Discussion and Findings.* Pursuant to several settlement agreements and orders, we have previously recognized that PSI is entitled to recover merger transaction costs, and costs to achieve merger savings incurred up until October 31, 1996, over a 10-year period. Mr. Brosch does not dispute the reasonableness of these deferred merger savings costs, nor does he dispute the entitlement of PSI to recover these costs. Instead, Mr. Brosch argues that since the related merger savings were not reflected in the Company's rates during the deferral period, the amortization period agreed to by the OUCC in Cause No. 40003 should be extended by six additional years. As we have previously authorized PSI's recovery of these incurred costs over a 10-year period we find that the Company's proposed adjustment reflects a consistent application of the previously-approved settlement agreements and orders. Accordingly, we approve PSI's proposed *pro forma* adjustment on this issue.

[73] (c) *Amortization of Midwest ISO-Related Deferred Costs.*

(i) *Evidence.* PSI proposed recovery, via a four year amortization, of the deferred MISO administrative costs, consistent with this Commission's December 1, 2002, Order in Cause Nos. 42257 and 42266, which authorized the deferral of certain costs incurred as a result of taking transmission service for retail customers under the Midwest ISO open access transmission tariff ("OATT"). In entering that order, we approved a Settlement Agreement among PSI, Vectren Energy Delivery of Indiana, Inc., Indianapolis Power & Light Company and the OUCC that allowed PSI and the other utilities to defer ongoing Midwest ISO Administrative Adder Costs (*i.e.*, costs incurred under Midwest ISO Schedules 10 and 10-B), for subsequent recovery in a base rate case from Indiana retail customers, over a four-year amortization period. Pet. Ex. Z, pp. 29-30.

OUCC witness Mr. Carver originally opposed the recovery for the reason that the "MISO cost deferral and amortization recovery request does not appear to represent either the net cost incurred by the Company or ongoing expense levels." Pub. Ex. No. 1, pp. 51-53. Mr. Carver testified that, the Company experienced a rather notable increase in 2002 transmission revenues in comparison to 2001 and that this increase over 2001 appears to have been maintained during 2003. *Id.*, at 56. Mr. Carver concluded that because PSI had the benefit of these increased revenues, it should be denied recovery of the deferred costs.

On rebuttal, PSI witness Kent K. Freeman pointed out that the assumption upon which Mr. Carver based his position, namely that "PSI has realized a significant increase in transmission revenues," was unfounded. In comparing later periods to 2001, Mr. Carver had failed to include all transmission revenues which are included in two different account numbers, — accounts 447850 and 456850. Pet. Ex. RR, p. 2. Mr. Freeman observed that, if the overlooked revenue from account 447850 had been included for the calendar years 2001 and 2002 and year-to-date August, 2003, Mr. Carver would have seen that there was *not* a significant increase in transmission revenues in 2002 over 2001. *Id.* at 3. Indeed, including revenues from both accounts for all three periods showed that PSI transmission revenues had *decreased* in both 2002 and year-to-date 2003. *Id.*

Additionally, Mr. Freeman observed that Mr. Carver, failed to take into account the substantial benefits that the Midwest ISO has provided to PSI's customers, as discussed in the testimony of PSI witness Ronald R. Jackups, Pet. Ex. M, pp. 23-26, and as observed by this Commission in its final order entered in Cause Nos. 42027 and 42032 (*Ind. Util, Reg. Comm'n*, December 17, 2001), approving the transfer to the Midwest ISO of functional control of operation of PSI's transmission facilities. These benefits, he said, include, among other things, the substantial benefits of increased market competition and elimination of pancaked transmission rates within the Midwest ISO. *Id.*

In reaction to Mr. Freeman's testimony, Mr. Carver presented a Revised Pub. Ex. No. 3, which, in effect, accepted PSI's amortization of deferred MISO costs. Mr. Carver admitted that his adjustment to Schedule C-14 was intended to allow PSI recovery of the full amount of its proposed MISO amortization. Tr. at P70. On direct examination at the hearing, Mr. Freeman indicated that it was his understanding that Mr. Carver had intended to accept PSI's proposal, but that in order to do so, Mr. Carver needed to make one minor adjustment to his schedule. Mr. Carver had made an adjustment to the *pro forma* level to eliminate the portion related to PSI's wholesale customers. However, when the deferred balance was updated through August 31, 2003, PSI had removed the wholesale portion from the account, correcting the error. Thus, Mr. Carver's adjustment was no longer necessary.

(ii) *Discussion and Findings.* It appears based on the foregoing, that there is no current dispute over the appropriateness of including the four-year amortization of deferred MISO expenses. We therefore accept PSI's adjustment in this case to recover over four years its deferred Midwest ISO-related administrative costs.

(d) *Post-In Service (Deferred) Depreciation and AFUDC.*

(i) *Evidence.* Mr. Carver sponsored OUCC Adjustments B-1 and C-18. Adjustment B-1 adjusts PSI's Schedule B-3, which includes in PSI's rate base an estimate, subject to true-up, of the August 31, 2003 book balance related to the post-in-service capitalization of carrying costs and depreciation expense. Adjustment C-18 adjusts the Company's Schedule C-3.37, which reflects the Company's *pro forma* amortization of deferred depreciation and AFUDC/carrying cost continuation on estimated deferral balances as of August 31, 2003.

[74] (ii) *Discussion and Findings.* The sole basis for these adjustments was Mr. Carver's utilization of Mr. Majoros' depreciation rates instead of the depreciation rates sponsored by Mr. Spanos. Public's Ex. No. 1, p. 103. Given our findings above with respect to PSI's depreciation in this order it is not appropriate to make further adjustments.

(14) *Interest Synchronization.* Mr. Carver sponsored OUCC Adjustment C-20, which synchronized the interest deduction for income tax purposes with the OUCC's weighted cost of debt and rate base recommendations. As Mr. Carver made clear, however, the only reason for this adjustment is that the OUCC utilized a different rate base and cost of capital than PSI. Pub. Ex. No. 1, p. 111. He indicated that if the Commission ultimately adopts a rate base and cost of capital different than that proposed by the OUCC or PSI, interest synchronization should be recalculated, using the Commission's findings. Thus, there is really no issue here. The Commission's revenue requirement ultimately approved here will include interest synchronization that is consistent with the rate base and cost of capital approved herein.

E. *Conclusion.* On the basis of the foregoing, we find that PSI's *pro forma* jurisdictional electric net operating income under present rates, adjusted to a level which fairly represents its current operations, is $196,564,000, summarized as follows:

Operating Revenues	$1,284,140,000
Operating Expenses and Taxes:	
Fuel Expense	378,286,000
Purchased & Exchanged Power Expense	(5,228,000)
Other Operation and Maintenance Expense	386,214,000
Operating Revenue Deduction	(28,917,000)
Depreciation and Amortization Expense	218,316,000
Taxes Other than Income Taxes	58,415,000
Federal and State Income Taxes	80,491,000
Total Operating Expenses and Taxes	$1,087,576,000
Net Operating Income	196,564,000

When applied to the fair value rate base determined for Petitioner in Finding No. 4C above, this operating income produces a return of only 4.05%, which is outside the range established in Finding No. 5C. In addition, the return on Petitioner's original cost depreciated rate base would be 5.37%, which is below the Commission's determination of 7.30%. Accordingly, on the basis of the evidence and the foregoing determinations, we find that the electric operating income to Petitioner, under its present rates for the electric utility service rendered and to be rendered by it, is not sufficient to provide Petitioner a fair return upon the fair value of its electric properties used and useful for the convenience of the public. Therefore, Petitioner's current rates are unjust and unreasonable.

7. *Rate Level to be Authorized.* We find that a net operating income of $267,500,000 is hereby found to be a fair return upon the fair value of Petitioner's electric property used and useful and reasonably necessary for the convenience of the public. This provides a fair rate of return of approximately 5.51% which is within the range of reasonableness established in Finding No. 5C. In order to provide such utility operating income, an increase in Petitioner's gross annual retail electric operating revenues to $1,406,596,000 is required. The increase in revenues will give rise to increased tax expense and as a result, total operating expenses will be $1,139,096,000. On that basis, we find that Petitioner's *pro forma* operating results will be:

Operating Revenues	$1,406,596,000
Operating Expenses and Taxes:	
Operation and Maintenance Expenses	731,041,000
Depreciation and Amortization Expenses	218,942,000
Taxes Other than Income Taxes	60,129,000
Federal and State Income Taxes	128,984,000
Total Operating Expenses and Taxes	$1,139,096,000
Net Operating Income	$267,500,000

Our findings as to the appropriate level of *pro forma* operating results are based on the evidence of record and giving appropriate weight to the need for Petitioner to maintain and support its credit, to attract capital necessary to discharge its public duties and to earn a return commensurate with that earned by enterprises of corresponding risk. We find that rates estimated to produce these results are just and fair and should allow Petitioner the opportunity to earn a reasonable return on its property dedicated to providing electric utility service to the public. Accordingly, on the basis of all of the evidence and the foregoing determinations, we find that the retail electric rates authorized herein for the electric utility service rendered, and to be rendered, should provide a fair return on the fair value rate base of its electric properties used and useful for the convenience of the public, and therefore are just and reasonable.

8. Revenue Allocation.

[75-77] A. *Jurisdictional Separation and Retail Cost of Service Studies.*

(1) *Evidence.* PSI submitted the results of its jurisdictional separation and retail cost of service studies, prepared by Kent K. Freeman, PSI's Manager, Rates Services. In performing these studies, Mr. Freeman utilized the average of the 12 monthly coincident peak demands on its system ("12-CP") methodology to allocate production and transmission demand-related plant costs and expenses. Mr. Freeman testified that use of the 12-CP methodology allocates production demand related costs to each customer class on the basis of its contribution to the average of the 12 coincident monthly peaks during the test year. Pet. Ex. Z, pp. 3, 5, 19,22 and 23. This is the same methodology that PSI has utilized, and this Commission has accepted, on numerous occasions since 1971. According to Mr. Freeman, the 12-CP method is also consistent with the FERC's allocation guidelines in PSI's case.

In performing his separation study, Mr. Freeman said that he first segregated PSI's customers into three categories: (1) one customer who purchases high pressure steam from PSI's Cayuga Generating Station; (2) wholesale customers who purchase firm power from PSI and resell it to ultimate consumers or to their members for resale (*e.g.*, WVPA and IMPA); and (3) retail electric customers who purchase firm power from PSI as ultimate consumers. *Id.* at 6. Thereafter he allocated costs among PSI's retail customers, utilizing the 12-CP method to allocate production demand related costs. Pet. Ex. Z-7 summarizes the resulting jurisdictional separation based on Mr. Freeman's studies. Pet. Ex. Z-13 summarizes the results of PSI's retail cost service study, after reflecting a proposed 33% subsidy/excess reduction. *Id.* at 28.

Nicholas Phillips testified for the PSI-IG and proposed an alternative cost of service study methodology. His methodology was based on the average of the coincident peaks in the four summer months ("4-CP"), which he contended, because PSI has been a summer peaking system in recent years, "more accurately reflect PSI's electric system and cost structure." PSI-IG Ex. No.1, p. 10. He contended that the 12-CP method is appropriate only for a system with a flat load pattern in which each of the monthly coincident peaks is relatively equal. PSI-IG Ex. No.1, p. 10.

OUCC witness Michael Brosch, supported Petitioner's use of the 12-CP method to allocate production demand related costs. He discussed the "peak and average" method to allocate such costs, which includes an energy weighting in the development of the production demand allocator, but accepted the use the 12-CP methodology, as a "compromise between usage of fewer peak hours and utilization of an energy weighted methodology such as Peak and Average." Pub. Ex. No. 2, pp. 100-106.

In response to Mr. Phillips' proposition to utilize the 4-CP method to allocate production demand related costs, Mr. Freeman indicated that this Commission has recognized that a utility's ability to utilize valley period months to perform scheduled maintenance is a reason to use the 12-CP approach. Pet. Ex. RR, p. 12. In that regard, this Commission has stated, "the 12-CP method is often utilized to reflect the full range of operating realities throughout the year including system demand, scheduled maintenance, and reserve requirements." *Indiana Michigan Power Company*, Cause No. 39314, (*Ind. Util. Reg, Comm'n*, October 15, 1997, at 171). Mr. Freeman defended his continued use of the 12-CP methodology and was critical of Mr. Phillips for having analyzed only system demand, without taking into account these other considerations. Pet. Ex. RR, p. 12. Mr. Freeman noted that the 4-CP methodology is used by PSI where it is appropriate — in the tracking of purchased power costs incurred for the summer months only. Pet. Ex. RR, p. 13.

Mr. Freeman testified that the utilization of a cost allocation methodology has a major impact on the total cost of service assigned to the retail jurisdiction and then among retail customer classes. Pet. Ex. RR, p. 12. It similarly has a significant impact on rate groups and, thus, even if one were to agree with Mr. Phillips that PSI's loads have changed, he did not believe that such a fact would automatically lead to a reallocation of all past investments in production facilities. He observed that a majority of PSI's production facilities were in service during the last PSI retail rate case test period and the 12-CP methodology was utilized in the retail cost of service study underlying the rates approved in that case. He thought it inappropriate now to in effect "reallocate" those facilities in this case." Pet. Ex. RR, pp. 12-13.

(2) *Discussion and Findings.* We find that PSI's use of the 12-CP methodology to allocate production demand related plant and operating costs is reasonable, based on the testimony of Messrs. Freeman and Brosch. While qualified experts may differ on which methodology is the best fit, based on the evidence presented in this Cause, we cannot conclude that PSI's choice of the 12-CP is unreasonable. We agree with Mr. Freeman that a change in cost allocation methodology can have significant impacts on customer classes and, thus, such a change should not be lightly undertaken, especially where, as here, so much of PSI's plant was in service at the time of its last rate case and costs were assigned using the 12-CP methodology in that case. We find that the results of PSI's jurisdictional separation and retail cost of service studies should be accepted and utilized to allocate operating revenues among customer classes and to design PSI's retail electric rates.

[78] B. *Reduction in Subsidy/Excess Revenues.*

(1) *Evidence.* PSI proposed a 33% reduction in the current levels of subsidy/excess revenues between rate groups as its movement towards fully reflecting its cost of service. Mr. Freeman explained that a review of the Company's four major rate groups shows a narrow band of current levels of subsidy/excess revenues. Further, Mr. Freeman testified that the Company's current retail cost of service study shows that the Company's current rates are substantially within the reasonable bounds of cost-based rates. Pet. Ex. Z, p. 29, and Pet Ex. RR, pp. 8-10.

Mr. Brosch recommended that PSI's rate class RS be "assigned no more than the overall percentage increase in total retail revenues ultimately ordered by the Commission." Pub. Ex. No. 2, pp. 108-109. Mr. Freeman concluded that Mr. Brosch's approach would decrease revenues from Rate RS by approximately $6.5 million if the Company's rate request were approved in this case, which then would have to be allocated to other customer groups. *Id.* Mr. Freeman pointed out that such a shifting of cost responsibilities would negate the Company's proposed 33% reduction in inter-class subsidies, and move RS away from producing a return at virtually the system average rate of return, to a rate below the system average, as shown on Pet. Ex. RR-2, p. 2, and Pet. Ex. RR, p. 10.

(2) *Discussion and Findings.* We do not accept Mr. Brosch's invitation to ignore existing subsidies disclosed by Mr. Freeman's cost of service study in this case. We find that the 33% reduction in those subsidies is appropriate and should be ordered. This will be a significant step in achieving equity among rate classes, and it is consistent with past orders of this Commission on this subject. The rates as approved herein shall produce substantially the revenue shown in the columns under Column L in Pet. Ex. Z-13, filed as part of PSI's October 15, 2003 workpapers.

9. Rate Design.

[79] A. *Cost and Revenue Adjustment Mechanisms.* The Petitioner proposed three mechanisms to track costs and revenues that it contends are substantial, variable and largely outside of its control. They include a Summer Reliability Tracker (proposed new Standard Contract Rider 70); a NO_x Emission Allowance rate adjustment mechanism (initially proposed new Standard Contract Rider 69); and, a Midwest ISO-Related rate adjustment mechanism (proposed new Standard Contract Rider 68). PSI also proposed minor changes to its existing fuel adjustment ("Rider 60") and SO_2 emission allowance (Rider 63) tracking mechanisms, which were unopposed. We approve each of these cost and revenue tracking mechanisms as discussed below.

[80-84] (1) *Petitioner's Proposed Summer Reliability Tracker.*

(a) *Background.* Mr. Esamann explained that, since 1999, PSI has had to make substantial forward reliability power purchases for the summer months to maintain adequate reserves to meet anticipated customer peak load requirements. Pet. Ex. B, p. 41. Because of these substantial purchased power needs, in 1999 PSI petitioned this Commission for approval of a purchased power cost tracking mechanism. This Commission initially approved PSI's purchased power tracking mechanism (PSI Standard Contract Rider 67) on a limited basis in Cause No. 41448. *Id.* at 42. In our April 2001 Order in Cause No. 41448-S1, this Commission approved the extension of that mechanism through 2002. In March 2002, in Cause No. 42200, PSI petitioned this Commission and requested the indefinite extension of its purchased power tracker. Alternatively, PSI requested that this Commission extend PSI's purchased power tracker for a 2-year period in Cause No. 42200, and ultimately resolve the design of PSI's tracker in this rate case. *Id.* at 43-44. In our June 2003 Order in Cause No. 42200, we approved the extension of PSI's purchased power tracker through 2004, and determined that the ultimate resolution of the future use of the tracker would be made in this rate case.

PSI implemented its PowerShare® program in 2000, in the wake of the Midwest capacity shortage and the resulting 1998 and 1999 wholesale power market price spikes. *Id.* at 44. PowerShare® CallOption creates demand reductions through customer commitments to reduce load during times of system peak. Customers are compensated for this commitment to reduce demand in two ways: (1) an option premium payment, which gives PSI the right to call for load reductions within certain parameters, and (2) an energy payment based on actual load reductions. The payments are provided in the form of customer bill credits. *Id.* Mr. Esamann said that although no contractual load reduction commitments are provided under PSI's QuoteOption, the latter is also capable of reducing demand, through appropriate pricing signals to its customers. *Id.* at 45. Under the QuoteOption, customers are compensated by means of energy credits when they choose to reduce load in response to these price signals. *Id.*

With respect to off-system sales, Mr. Esamann testified that in Cause No. 40003, $6 million of off-system sales profits were built into PSI's base rates. Accordingly, in each year since 1996, PSI retail customers have received the benefit of this annual $6 million credit through rates.

(b) *Petitioner's Proposal.* PSI's proposed Summer Reliability Tracker consists of the three components discussed immediately above — purchased power costs, PowerShare® costs, and off-system sales profits. With regard to the purchased power component, PSI proposed that the tracker apply to PSI's actual purchased power costs (demand components only) for forward reliability purchases (*e.g.*, monthly or weekly forward purchases) made for the summer months of June through September in order to maintain an adequate PSI reserve margin (15% to 17%). These forward reliability purchased power costs would be eligible for recovery via the tracker, subject to PSI's demonstration to the Commission that its purchase decisions were reasonable at the time made. The energy components of such purchase costs would be eligible for recovery via PSI's fuel adjustment charge tracker. Pet. Ex. B, at p. 46. Under PSI's proposal, no level of purchased power costs would be reflected in PSI's base rates. Pet. Ex. CC, pp. 1-9.

With regard to the PowerShare® component of the Summer Reliability Tracker, PSI proposed that the tracker allow recovery of

PSI's actual June through September PowerShare® CallOption and QuoteOption costs above (or below) the $1,023,000 test period level to be included in base rates. Mr. Bailey testified that the test year contains $1,023,000 of expenditures in the form of bill credits related to PSI's PowerShare® CallOption program, and that even with PSI's proposed transition of this program to more traditional DSM pricing, PSI believes that program expenditures will be at or above this level. Pet. Ex. AA, p. 14; Pet. Ex. CC, pp. 1-9.

With regard to the off-system sales profits component of the Summer Reliability Tracker, PSI initially proposed to flow back to customers 100% of PSI's actual June through September off-system sales profits, plus 25% of actual PSI off-system sales profits earned in the non-summer months (October through May). In response to other parties' concerns, in rebuttal PSI modified this sharing proposal to a 50%/50% sharing of off-system sales profits achieved on a year-round basis. In the early years of the tracker's existence, PSI believes that this feature could result in the net impact of the tracker being a credit, rather than a charge, to customers. Pet. Ex. B, p. 47. Pet. Ex. CC, pp. 1-9.

Similar to the process that has been utilized for its current purchased power tracking mechanism (PSI Standard Contract Rider 67), PSI proposed on an annual basis, in the spring, to present to the Commission its June through September forward purchased power and PowerShare® arrangements. After the close of that summer period, PSI would present the Commission with its actual June through September purchased power, PowerShare®, CallOption and QuoteOption costs, as well as its annual off-system sales profits. After the Commission has completed its review, the net impact (credit or charge) of these June through September costs, along with 50% of PSI's annual off-system sales profits, would be passed through to retail customers via the Summer Reliability Tracker. *Id.* Pet. Ex. CC. p. 8.

Under PSI's proposal, the Summer Reliability Tracker credit or charge will be allocated to all firm retail customers based on their contribution to the summer peak demand, and the credit or charge would be refunded or collected over a 12-month period. Non-firm or interruptible customer loads would not be allocated any of the costs or credits related to the Tracker. The credit or charge would be reconciled to actual at the end of the 12-month cycle to ensure that only the approved credit or charge was ultimately refunded or collected through the Tracker. Pet. Ex. CC, pp. 3-4; Pet. Ex. CC-1.

In connection with its Summer Reliability Tracker proposal, PSI requested corresponding accounting relief, specifically, authority to defer for subsequent recovery or credit, its June through September purchased power and PowerShare® costs, and its off-system sales profits. Pet. Ex. CC, p. 9.

(c) *Rationale for PSI's Proposal.* Mr. Esamann indicated that he believes that a continuation of a purchased power tracking mechanism, such as that incorporated into PSI's proposed Summer Reliability Tracker, is desirable. The continuing volatility of the wholesale power market; PSI's increasing need for purchased power to maintain an adequate reserve margin; the positive credit quality implications of such a mechanism; and, sound regulatory policy reasons support having such a tracker in place. Pet. Ex. B, at 49. Mr. Esamann testified that the wholesale power market continues to present the potential for high prices, volatility and price spikes. As recently as March 2003, he related, wholesale market prices spiked to $135 per MWH. *Id.* at. 50. He pointed out that almost 130,000 MWs of power plant projects have been cancelled since the beginning of 2000, with the majority of those cancellations occurring in the Eastern Interconnect region. As projects are cancelled and demand grows, demand will catch up or overtake supply, leading to increasing prices, he predicted. *Id.* at 51. Mr. Esamann concluded that he cannot envision a Midwest wholesale power market that, for many years into the future, does not have some price spikes. *Id.* at 52. According to Mr. Esamann, the question is not whether there will be price spikes, but how frequently and how high they will be. For this reason, PSI believes that it is far more appropriate to address its purchased power costs via a tracker mechanism, rather than attempt to build a representative level into base rates.

Mr. Esamann next turned to the issue of PSI's continuing need for purchased power. He emphasized that PSI customers' demand for electricity continues to grow. Mr. Esamann testified that, even during this period of economic downturn, the PSI system experienced a new peak record demand in the Summer of 2002, after experiencing a 3.6% increase in peak in 2001. *Id.* He explained that even with the addition of the Noblesville Repowering Project (representing approximately 200 additional MWs) and the Madison and Henry County Generating Stations (approximately 663 MWs combined), PSI's projected planning reserve margins for 2003 and beyond, without forward reliability purchases, are well below PSI's 15% minimum reserve margin. PSI's projected reserve margins range from just below 11% in 2003, down to 8.3% in 2006, and 11.4% in 2010 — a deficit of several hundred megawatts in almost every year for the next eight years. *Id.* at 53. Thus, he said, PSI will need to continue to purchase several hundred megawatts of forward power to satisfy its reserve margin needs for the next several summers. By 2006, he said, PSI's purchased power needs will rise to almost 450 MWs. *Id.*

Mr. Esamann also addressed the positive credit quality implications associated with the purchased power tracking component of the Summer Reliability Tracker. He observed that Commission approval of PSI's continued use of a purchased power tracking mechanism will give investors and credit rating agencies assurance that PSI will have an opportunity to recover the majority of its purchased power costs incurred to provide reliable service to customers, and this assurance should assist PSI in attracting necessary capital at reasonable costs. *Id.* at 55. Maintenance of credit quality is important both for utilities and their customers, he observed. *Id.* at 56. Reduced credit quality results in higher debt costs that, in turn, will result in higher rates charged to customers in the future. *Id.*

Mr. Fetter underscored the credit quality implications associated with tracking and recovery of purchased power costs. According to Mr. Fetter, the financial community relies on the presence of fuel and purchased power adjustment mechanisms to protect investors from the variability of fuel and purchased power costs that can have a substantial impact on the credit profile of a utility, even when prudently managed. These mechanisms mitigate a portion of the risk and uncertainty related to the day-to-day management of a regulated utility's operations. Conversely, the absence of such protection is factored into a utility's credit profile as a negative element. Pet. Ex. H, pp. 25-26.

Mr. Fetter noted that Standard & Poor's stated in November 2002 its opinion concerning the importance of electric utilities having the opportunity to recover fuel and purchased power expenses:

> When assessing the importance of productive regulation to the credit strength of an electric utility, something to consider is the means by which the utility can expect to recover variable expenses, particularly fuel and purchased-power expenses, which have highly erratic unit costs. Recent, and in some cases, extreme volatility in the U.S. wholesale electricity markets, as well as in the natural gas markets, underscores this importance. It is no coincidence that utilities with stronger fuel and power cost recovery mechanisms typically enjoy loftier credit ratings.

Pet. Ex. H, at pp. 26-27.

Mr. Esamann offered a number of regulatory policy rationales in favor of the use of purchased power tracking mechanisms. For example, a utility should have a reasonable opportunity to recover the prudently incurred costs associated with meeting its obligation to provide adequate and reliable service to its customers. Moreover, a basic principle of ratemaking is that reasonable costs of providing utility service should be reflected in the prices charged for that service. In Mr. Esamann's opinion, consistent with these principles, tracking mechanisms are appropriate regulatory tools for reflecting costs that are volatile, substantial, and largely outside of the utility's control. Mr. Esamann noted that another way to encourage cost-effective supply decisions is to set up regulatory mechanisms that encourage the utility to plan in advance and to hedge against spot market price volatility and availability risk. PSI believes strongly that encouraging advance planning and hedging strategies will align customer and shareholder interests in achieving reliable and cost-effective electric utility service.

As to the PowerShare® component of the Summer Reliability Tracker, Mr. Esamann noted that PSI's PowerShare® program impacts are analogous to purchased power and, as such, should be treated the same as purchased power for ratemaking purposes. In PSI's experience, PowerShare® costs tend to be highly variable from year to year, and thus lend themselves to tracking treatment. Having a tracker, and assurance of cost recovery for prudent PowerShare® costs, will also provide PSI with an incentive to maximize the use of the PowerShare® program. Pet. Ex. B, at p. 57.

With regard to the off-system sales profit component of the Summer Reliability Tracker, Mr. Esamann testified as to why he believes that tracking, rather than base rate treatment of such revenues is appropriate, and why an explicit incentive sharing mechanism should be included. Because off-system sales profit can be variable, unpredictable, and largely outside of the utility's control, Mr. Esamann explained that it makes sense to use a tracking mechanism for such credits to customers, rather than building an ongoing level into rates. Pet. Ex. B, pp. 57-58. He noted that off-system sales profits will vary widely from year to year, depending upon a number of factors such as wholesale market conditions, the performance of PSI's generating system, and PSI native load customer demand and energy requirements.

As for the 50/50 incentive sharing proposal, Mr. Esamann testified that allowing PSI the opportunity to earn and retain a portion of off-system sale profits will encourage PSI to maximize off-system sales opportunities. In Mr. Esamann's view, such a sharing aligns customer and shareholder interests in maximizing off-system profits for the benefit of all stakeholders. Mr. Fetter shared this view, emphasizing that such activities, which are outside the sphere of PSI's traditional regulated operations, deserve to be encouraged with the benefits being shared by both customers and shareholders. Pet. Ex. B, pp. 61-62. Mr. Esamann testified that PSI takes on potential costs and risks whenever it transacts business in the wholesale market and without the opportunity to retain a portion of off-system sales profits, a rational utility would work to ensure that its native load customer demands are met, but would not necessarily take on the potential incremental costs and risks necessary to maximize the use of its generation in the off-system sales market. Pet. Ex. B, pp. 58-61.

Finally, Mr. Esamann testified that off-system sales represent one area where a utility can work to actually earn a return that approximates the net operating income authorized by the Commission in the utility's rate order. Allowing PSI to retain a portion of off-system sales profits achieved will give PSI a more realistic opportunity to earn its authorized return, while still remaining subject to the fuel adjustment charge statute's earnings test. Pet. Ex. B, pp. 60-61. Mr. Esamann concluded that PSI's proposed Summer Reliability Tracker is designed with symmetry and balance, with appropriate consideration to risk and reward. Customers will pay for PSI's costs of forward reliability purchases and PowerShare® costs for the summer months (subject to PSI's demonstrating the reasonableness of its forward purchases), while throughout the year customers will receive the benefits of off-system sales profits generated from PSI generation. Pet. Ex. B, p. 59.

(d) *Positions of OUCC, Intervenors, and Testimonial Staff.* The OUCC opposed the totality of PSI's proposed Summer Reliability Tracker, while other Intervenors opposed certain aspects of the proposal. The OUCC took the position that tracking treatment was neither necessary nor desirable for PSI's purchased power costs, for PSI's PowerShare® costs, or for PSI's off-system profits. Rather, the OUCC proposed that a test period base level of such costs and revenues be built into PSI's base rates in this case, with no tracking mechanisms for fluctuations between those base levels and actual levels experienced by PSI in the future. Additionally, the OUCC opposed the Summer Reliability Tracker's explicit sharing mechanism for off-system sales profits. Pub. Ex. No. 2, p. 28.

OUCC witness Brosch testified that tracking treatment is not necessary for several reasons. First, he argued that tracking is no longer necessary because PSI has recently added capacity to its system, thus reducing its purchased power needs, and because wholesale market prices have moderated since PSI's purchased power tracker was first approved in 2000. He also argued that revenues from load growth should be sufficient to compensate PSI for any increased purchased power expense it experiences going forward. Pub. Ex. No. 2, pp. 32-33. OUCC witness Endris added his view that "a request to track a cost [of purchased power] that represents only 1% of the test year fuel expense is insubstantial and undeserving of tracker treatment." Pub. Ex. No. 6, p. 8. Instead of tracking treatment, the OUCC argued for base rate treatment of PSI's purchased power costs, based on PSI's actual Summer 2003 purchased power costs (approximately $2 million). As for PSI's PowerShare® costs, OUCC witness Endris took the position that "The CallOption program expense is similarly negligible compared to total fuel expenses . . . ." Pub. Ex. 6, p. 8.

OUCC witnesses Brosch and Endris also testified on the off-system sales component of PSI's proposed Summer Reliability Tracker. Mr. Brosch opposed tracking off-system profits and recommended building in a base level instead. He offered his opinion that the test period level of off-system profits achieved by PSI of approximately $18.7 million appeared to be representative of an ongoing level of such profits and even possibly conservative since the test period level did not include the availability of new generation added by PSI (Madison, Henry County, and Noblesville Repowering). Pub. Ex. No. 2, pp. 41-43. In further support of the OUCC's position that PSI's off-system sales should be addressed through base rates rather than through a tracking mechanism, Mr. Endris testified that in his opinion PSI native load customers likely would not receive as much benefit through the Company's proposed off-system sales profit sharing mechanism as they would get through continued traditional ratemaking treatment that includes actual test year results in setting rates. Pub. Ex. No. 6, p. 5.

With respect to PSI's proposed sharing of off-system sales profits, Mr. Brosch testified that PSI needs no special incentive to make off-system sales. In his view, the better answer would be an approach where there is no tracking, whereby the Company would have the opportunity to retain for shareholders 100% of any incremental profits earned on such sales between rate cases. Public's Ex. No. 2, p. 43. Mr. Brosch also noted that, since the 2002 implementation of the Joint Generation Dispatch Agreement, PSI's off-system sales have generally been limited to system energy transfers of surplus hourly energy to CG&E, which in Mr. Brosch's view insulates PSI from market and profitability risks. Finally, Mr. Brosch stated his opinion that there is simply no shareholder entitlement to additional returns, since shareholders are not "at risk" for plant production costs. Pub. Ex. No. 2, p. 44.

Mr. Endris also testified that PSI does not need any further incentives to maximize profits from off-system sales. Pub. Ex. No. 6, pp. 16-19. PSI has engaged in off-system sales activity in every year subsequent to the Commission's order in Cause No. 40003, without any special treatment tracking off-system sales. One can only conclude based upon actual results that the current traditional method, with 100 percent retention of all changes in profits, provides adequate incentive to PSI to engage in reasonable off-system sales effort. Pub. Ex. No. 6, p. 23. Mr. Endris also claimed that the dollars, volumes, and types of sales to be included in the proposed sharing mechanism are difficult to reconcile with actual historical results. *Id.* at 9. This kind of confusion, he maintained, should lead the Commission to reject PSI's proposal and instead determine that test period off-

system sales profits of $18.7 million, or some other reasonable *pro forma* projection, should be reflected as a credit to revenue requirements." *Id.* at 16.

Mr. Endris was also concerned that the transaction documentation and analysis involved in determining off-system sales profits is voluminous, complex and contentious and will lead to frequent and difficult litigation. Pub. Ex. No. 6, p. 26. He believed the required audits would be costly and resource-intensive, which costs, he suspected, would be borne by the ratepayers, either as a drain on the very profits to be shared or as an expense hitting the FAC earnings test. *Id.* at 26-27. He concluded, as Mr. Brosch did, that PSI should "receive traditional ratemaking treatment of appropriate off-system sales profits as a reduction to revenue requirements and let PSI retain 100% of profits thereafter." Pub. Ex. No. 6, p. 32. Such treatment, he contended, would provide PSI "its desired incentive to maximize the use of the PSI generating resources to achieve off-system sales margins while not subjecting ratepayers to this insufficiently-supported sharing mechanism." *Id.*

The OUCC's alternative was to propose that a base amount of expected purchased power costs and off-system sales profits, such as the $2 million of Summer 2003 purchased power costs and the $18.7 million of test period off-system sales profits, be included in base rates, and that PSI shareholders and customers share in costs and profits above or below this amount, with 90% going to PSI's customers and 10% to its shareholders, on an annual basis. This alternative approach, the OUCC claimed, would properly credit customers for the burden of capacity costs included in base rates, as well as incentivize PSI to economically maximize the pursuit of both purchased power and off-system sales profits. Pub. Ex. No. 1, p. 37; Pub. Ex. No. 2, p. 61.

Intervenor PSI-IG was supportive of the continuation of PSI's purchased power tracker, but opposed tracking PowerShare® costs above or below the level included in base rates. PSI-IG Ex. No. 1, p. 25. As for the off-system profits component of the Summer Reliability Tracker, Mr. Phillips took the position that customers should be credited with the profits from off-system sales in PSI's base rates, because PSI is allowed to earn a return on all of its generating stations. *Id.* Mr. Philips also testified that eliminating any off-set for off-system sales from base rates shifts all of the risk to the customers and provides PSI with no incentive to make such sales. He said that to the extent PSI earns more from off-system sales than the amount included in its base rates, the profits should be shared with its customers through a tracking mechanism separate from the Summer Reliability Tracker. Mr. Phillips recommended that this Commission approve only the minimum recovery of purchased power costs in the tracking mechanism without the PowerShare® credits or other provisions PSI has requested. *Id.* at 26.

Intervenor Kroger took issue only with the off-system profits component of the Summer Reliability Tracker, and specifically the incentive sharing mechanism. Kroger witness Kevin C. Higgins testified that, assets that are being used to make these profits possible are being fully funded by ratepayers — and ratepayers should receive a significant share of any benefit. The Company's share should be limited to the amount needed to provide it with adequate incentive to make profitable off-system sales transactions. He proposed that the $18.7 million in profits from off-system sales during the test period be credited against base rates for the rate-effective period and on either side of this $18.7 million there should be a reasonably-sized deadband. Mr. Higgins proposed that as long as the annual amount of off-system sales profit remained within the deadband, no further rate adjustments would be made. In the event that profits from off-system sales fall below or rise above the deadband, he recommended that some sharing of incremental benefits or decremental shortfall take place, implemented through a tariff rider. Mr. Higgins proposed a 50/50 sharing of incremental benefits or decremental shortfall outside the deadband and a deadband of + or -$3 million. This approach, Mr. Higgins claimed, fully aligns the interests of shareholders and ratepayers, and provides the

Company with ample incentive to make profitable off-system sales. Kroger Ex. No. 1, pp. 6-8.

Intervenor CAC opposed certain aspects of the Summer Reliability Tracker. CAC witness Brace E. Biewald contended that the proposed tracker will reduce or eliminate the incentive for the Company to manage costs and risks associated with the tracked costs. Mr. Biewald also predicted a net cost to customers from the proposed Summer Reliability Tracker beginning in 2004, and he claimed that the system for accounting and tracking of transactions is complex and prone to abuse. More specifically, Mr. Biewald recommended that this Commission disallow the Summer Reliability Tracker's off-system sales profit sharing mechanism and require the Company to credit all such profits to customers. Mr. Biewald recommended that this Commission approve a modified version of the Summer Reliability Tracker that allows customers to retain 100 percent of off-system sales profits in all months of the year. Modifying the tracker in this manner, he claimed, would greatly increase the probability that customers would indeed receive a net credit from the tracker. CAC Ex. B, pp. 4-5, and 20.

Testifying on behalf of the Commission's Testimonial Staff, Dr. Borum and Ms. Cvengros indicated that they were generally supportive of PSI's proposed Summer Reliability Tracker. Ms. Cvengros observed that, while somewhat unwieldy as packaged together as a single tracker, the components of the Summer Reliability Tracker are all well-defined elements. IURC Staff Ex. No. 2, p. 28. Both Dr. Borum and Ms. Cvengros agreed that tracking treatment for PSI's summer purchased power costs was appropriate, so long as the tracker procedures called for upfront Commission scrutiny and approval of PSI's purchased power decisions, and as long as the tracker included a mitigation credit feature, whereby customers can be credited with profits derived from off-system sales made from the purchased power capacity. The Testimonial Staff believes that PSI's proposed Summer Reliability Tracker contains these essential elements and is an acceptable purchased power tracking mechanism. IURC Staff Ex. No. 2, p. 31.

On the subject of purchased power cost tracking, Dr. Borum characterized the costs to be tracked as largely outside of the control of management. In Dr. Borum's view, purchased power is a primary example of such uncontrollable costs. Dr. Borum opined that the use of trackers "reduces regulatory lag, and thus limits the utility's incentive to keep costs low." However, he observed, continuation of a pre-approval process for forward power purchases is necessary to meet PSI's summer reliability requirements and continuation of the pre-approval regulatory process connected with the Summer Reliability Tracker will reduce financial uncertainty and risks for PSI, in return for an up-front review and input by interested groups in the resource planning and acquisition processes implemented by PSI. Staff, he said, believes that treating forward purchases similar to the regulatory treatment of building additional generation capacity will promote a resource portfolio planning process in which forward purchases are appropriately considered. Additionally, Staff witness Cvengros noted that, while PSI's purchased power needs in the near term may be relatively small when compared to previous years, PSI's growing customer load will require increasing quantities of purchased power at about the time an order would be expected in this Cause. As a consequence, denying PSI's proposed Summer Reliability Tracker on the grounds that PSI does not currently have to make substantial purchases would probably require the Company to file another petition for a purchased power tracker shortly after an order is issued in this Cause. IURC Staff Ex. No. 3, pp. 5, 13, 17, IURC Staff Ex. No. 2, p. 28.

With regard to the PowerShare® component of PSI's Summer Reliability Tracker, Ms. Cvengros opined that the PowerShare® costs above or below the amount to be included in PSI's base rates are not likely to be excessive and PSI would not suffer a financial hardship were they to be excluded from the Tracker. On the other hand, she explained that Staff views the PowerShare® program as being analogous to a purchased power option contract, whereby

the Company pays an upfront demand premium in exchange for the right to have access to power when needed at specified prices. The only difference is that PowerShare® provides curtailable power, instead of deliverable power — but both have the same effect in maintaining an adequate reserve margin during peak periods. In sum, Staff believes the PowerShare® program costs are legitimate expenses that should be recovered by the Company, and the Summer Reliability Tracker provides an acceptable, but not the only, method of recovering such costs. IURC Staff Ex. No. 2, pp. 28 and 29.

With regard to the off-system profits component of the Summer Reliability Tracker, Staff witness Cvengros explained that Staff views the off-system sales profit sharing component as an expansion of the mitigation credit that has been employed in connection with PSI's existing purchased power tracker. In Ms. Cvengros' view, PSI's sharing proposal explicitly addresses a sharing of off-system sales profits, in contrast to the implicit sharing that occurs today with a base level of off-system profits included in rates. Staff believes that an explicit sharing mechanism provides a better incentive to the utility to make economically efficient off-system sales, as well as easier review and monitoring of the shared profits. IURC Staff Ex. No. 2, p. 28.

While not opposed to PSI's proposed off-system sales sharing mechanism, Ms. Cvengros did offer some alternatives for the Commission's consideration. For example, if the Commission believes that the proposed 50%/50% sharing of off-system profits is inadequate, Ms. Cvengros noted that an adjustment of the shared portion of profits between 50%/50% and 80%/20% to customers' favor would be reasonable, and should not cause a financial hardship on the Company. Alternatively, Ms. Cvengros noted that the Commission could include a base amount of off-system sales in PSI's rates, with or without some sharing of profits above that base amount. Based on PSI's estimate of its test period off-system profits without an explicit sharing mechanism, Ms. Cvengros recommended $13 million as an appropriate base amount of off-system profits to be included in rates should the Commission prefer that approach. IURC Staff Ex. No. 2, p. 31, Attachment K.

In response to other parties' criticisms concerning the complexity of identifying off-system sales profits for purposes of sharing, Ms. Cvengros agreed that the process is complex, but noted that the process for determining off-system profits is the same process necessary for determining fuel costs for the FAC. Dr. Borum concurred on this point, explaining that the JGDA dictates how off-system sales costs and revenues must be allocated between PSI and its affiliate, CG&E. IURC Staff Ex. No. 1, pp. 26-33; IURC Staff Ex. No. 2, p. 27.

(e) *PSI Rebuttal.* Mr. Esamann testified that PSI continues to believe that cost tracking mechanisms are appropriate for costs that are substantial, variable or volatile, and largely outside of the control of management. Just as important, he said, PSI continues to believe that cost tracking mechanisms benefit both customers and the company in numerous ways — by allowing the utility to recover its prudently-incurred costs of providing service, no more and no less; by helping to level the playing field between competing options (capital versus expense options), thus encouraging the most economic choices; by eliminating artificial disincentives to pursuing the most economic choices (again, capital versus expense options, or forward versus spot market choices); by encouraging advance planning and hedging as opposed to reliance on volatile spot markets, thus aligning customer and company interests in reliability and price certainty; and by allowing the utility to defer the need for repeated general rate cases. Pet. Ex. DD, p. 17.

He maintained that PSI's purchased power and PowerShare® costs are collectively significant, variable, and largely outside of its control — similar to fuel costs. Tracking treatment, he said, assures that the utility will recover these costs of providing service on a timely basis, no more and no less, while base rate treatment, alone, of these cost items would inevitably result in an over or under recovery. Pet. Ex. DD, pp. 17-18.

He emphasized that tracking treatment goes a long way toward leveling the playing field between capital and expense options — maintaining that a utility can mitigate its purchased power and peak load management risks by building additional "iron-in-the-ground" capacity, and if the reserve margin is large enough, the utility can virtually eliminate the need for any reliance on purchased power or peak load management programs. But, he said, a total long-term reliance on on-system generation may not be the most economic option for the utility's customers. A purchased power and PowerShare® tracking mechanism gives the utility the flexibility to rely on the power market when appropriate and encourages the utility to make the most economic choice, by allowing the utility an opportunity to recover its out-of-pocket purchased power and peak load management costs. Pet. Ex. DD, pp. 17-18.

Mr. Esamann criticized the OUCC's proposed level of purchased power expense to be reflected in PSI's base rates as an alternative to PSI's proposal. He observed that the Company's 2003 purchased power costs were by far the lowest level of forward reliability purchased power costs experienced by PSI since prior to 1999 (less than $2 million), *Id*, at 18-19. Moreover, he said, this low level of purchased power expense is likely to be temporary, given the expected gradual increase in wholesale power prices and the approximately 100 MWs of annual demand growth PSI is experiencing on its retail system. *Id at* 19. Accordingly, he said, if this Commission were to include a base amount in PSI's rates, he would recommend that this Commission use an average of the last two years' forward reliability purchased power costs, which amounts to $10.5 million. That level, he noted, is still lower than PSI's estimated annual purchased power costs over the next few years. *Id.*

To the OUCC's argument that tracking treatment is not necessary for off-system sales profits and, instead, off-system sales profits of $18 million should be included in base rates, Mr. Esamann pointed to the variability associated with off-system sales profits — a variability that is in large part outside of PSI's control and dependent, instead, on market prices, weather and customer demands. He added that the test period level of $18 million in off-system sales profits experienced by PSI was by far the highest level of off-system sales profits earned by PSI from 1996 through the test period. However, he said, if the Commission decides to include a level of off-system sales profits in base rates, PSI believes that a reasonable level of trading expenses should also be included in PSI's base rates. In its case-in-chief PSI excluded certain of its trading expenses from its rate increase request, essentially in exchange for an explicit off-system sales sharing mechanism. Pet. Ex. DD, pp. 19-20.

With respect to the OUCC's contention that PSI needs no special incentive to make off-system sales, Mr. Esamann testified that PSI continues to believe that incentivizing it to maximize off-system sales profits through a sharing mechanism makes sense for both customers and the Company. In Mr. Esamann's view, an incentive sharing mechanism will increase the overall size of the "pie" (the off-system sales profits), with benefits created for both customers and the Company. Pet. Ex. DD, pp. 20-21. Mr. Esamann observed that although it is easy to say that a utility should always seek to maximize off-system sales profits for the benefit of native load customers, it is important to keep in mind that there are costs and risks associated with maximizing such sales profits. If the utility has no upside opportunity, there will naturally be a disincentive for the utility to incur those incremental costs and risks. Pet. Ex. DD, p. 21.

He emphasized that there are incremental costs and risks associated with having and keeping the Company's generation available for off-system sales opportunities, even when it is not anticipated to be needed for native load customers' demand requirements. There are, he said, different levels of costs that are incurred to serve anticipated native load customer demands, versus serving anticipated native load customer demands plus anticipated off-system sales opportunities. Such costs include costs associated with committing, ramping up, and dispatching the units — and different levels of these costs will be incurred to serve anticipated

native load customer demands, versus serving anticipated native load customer demands plus anticipated off-system sales opportunities. There are also costs associated with maintaining and repairing the utility's power production facilities that may not need to be incurred for native load customers purposes. If PSI concluded that sufficient off-system sales opportunities were available, and if PSI were incented to get that unit back on-line and running in order to capitalize on wholesale market opportunities, PSI would likely incur such extraordinary O&M costs, he said. Pet. Ex. DD, pp. 21-22.

Mr. Esamann went on to explain why there is likely to be a difference in the level of off-system sales achieved with and without an incentive sharing mechanism, observing that if PSI lacked a meaningful incentive opportunity in this area, PSI would likely commit its system differently than it does today. It would of course continue economic dispatch, but would commit its units to meet anticipated native load requirements, rather than to meet native load requirements plus wholesale market opportunities. In any given hour, he said, PSI may have surplus energy available to sell into the wholesale market, depending on actual native load demands versus the level of demand anticipated the day-before. Nevertheless, he estimated that this difference in unit commitment would result in a decrease in off-system sales profits on the order of magnitude of $4 million annually. Pet. Ex. DD, p. 23.

Moreover, Mr. Esamann emphasized that there are other benefits to native load customers associated with having PSI's generating units committed to meet native load demands plus wholesale market opportunities. If native load demands should exceed expectations, or if PSI experiences a generating unit outage, the "market-committed" generation can instantaneously be used to meet native load customer demands, because that generation is already ramped up and running and native load customers have "first call" on PSI generation. Under the alternative, "native load only" commitment scenario, however, native load customer demands would need to be partially met through potentially higher cost hourly market purchases until such time as incremental PSI generation could be ramped up and committed. Pet. Ex. DD, pp. 22-24.

(f) *Commission Discussion and Findings.* Pursuant to IC 8-1-2-42(a), this Commission has the legal authority to approve tracking mechanisms for fluctuating costs. As a general rule, IC 8-1-2-42(a) states that: "A public, municipally owned, or cooperatively owned utility may not file a request for a general increase in its basic rates and charges within fifteen (15) months after the filing date of its most recent request for a general increase in its basic rates and charges . . ." *Id.* However, this section goes on to indicate that: "The phrase 'general increase in basic rates and charges' does not include changes in rates related solely to the cost of fuel or to the cost of purchased gas or purchased electricity or adjustments in accordance with tracking provisions approved by the commission." Ind. Code § 8-1-2-42(a). The proposition that the Commission has the authority to approve the tracking of certain costs has also been affirmed by the courts. *See, City of Evansville v. SIGECO*, 339 N.E.2d 562, 593 (Ind. Ct. App. 1975); *L.S. Ayres v. Indianapolis Power & Light Co.*, 351 N.E.2d 814, 838-39 (Ind. Ct. App. 1976).

Against this legal and regulatory backdrop, we will now consider the evidence regarding tracking treatment of PSI's purchased power and PowerShare® costs. The evidence in this case establishes that the wholesale market continues to exhibit the potential for volatility, that it is reasonable to consider PSI's purchased power and PowerShare® costs collectively given their analogous functions, and that PSI's collective purchased power and PowerShare® costs are potentially significant. Moreover, the evidence indicates that even with the addition of incremental generating capacity in 2003, PSI continues to have a need for purchased power in order to maintain an adequate reserve margin, and that PSI's retail load continues to grow. While PSI's Summer 2003 purchased power costs were relatively low, the evidence suggests that PSI's purchased power needs and costs are likely to increase over time given PSI's load growth and expected wholesale market price increases and volatility.

Importantly, as we concluded in both our April 2001 Order in Cause No. 41448-S1 and our June 2003 Order in Cause No. 42200, a number of regulatory policy rationales support the continued use of purchased power tracking mechanisms. A utility should have a reasonable opportunity to recover prudently incurred costs associated with meeting its obligation to provide adequate and reliable service to its customers. Additionally, credit quality is of importance to both utilities and their customers, and there is a recognized connection between the periodic review and adjustment of rates and positive credit quality. Last, but not least, a purchased power tracking mechanism is consistent with our goal of leveling the playing field among resource options and thereby encouraging pursuit of the most cost-effective options. We concluded in 2001 and 2003, and we conclude today, that continuation of a purchased power tracker mechanism for PSI will align the mutual interests of PSI's customers and shareholders in reliable and cost-effective electric utility service.

Notably, these same regulatory policy rationales support approval of tracking treatment for PSI's PowerShare® costs, albeit to varying degrees. We believe that approval of the PowerShare® component of the Summer Reliability Tracker will allow the recovery of prudently incurred costs associated with providing reliable electric service, and will provide PSI with an incentive to maximize the usefulness of its PowerShare® program. In sum, the law, the evidence, and regulatory policy all support approval of a tracking mechanism for PSI's purchased power and PowerShare® costs. Accordingly, we hereby approve the purchased power and PowerShare® components of PSI's proposed Summer Reliability Tracker. We also approve PSI's corresponding accounting request for authority to defer for subsequent recovery via the Tracker, its June through September purchased power and PowerShare® costs.

With respect to the off-system sales profit component of the Summer Reliability Tracker, the Commission recognizes that a number of options were presented to us for consideration by the various parties. In undertaking our review of this issue, the Commission recognizes that fair and reasonable asset optimization programs, that present corresponding benefits to ratepayers, should be encouraged. While the utilization of ratepayer funded resources in the pursuit of off-system sales profits should result in a corresponding reward to ratepayers for the risk being borne, the Commission is cognizant that PSI should have an appropriate incentive to optimize its generation assets. The Commission believes that balancing the interests of PSI and its ratepayers is appropriate and, if done properly, will provide a benefit that might not otherwise be possible.

In the present case, PSI achieved $18.7 million of such profits during the test period and a significantly larger amount during calendar year 2002. Yet, Mr. Esamann testified that PSI projects *losses* in the area of off-system profits for both 2003 and 2004. We agree with PSI that off-system sales revenues are potentially significant, volatile or variable, and largely outside the control of the utility and may therefore be tracked. In reaching this conclusion we find that tracking off-system sales profits does not appear to be overly complicated and administratively burdensome. As Ms. Cvengros and Dr. Borum both pointed out, the same information that will be necessary to track off-system sales profits is already captured and analyzed in connection with PSI's fuel adjustment charge proceedings.

While we are granting approval to track off system sales profits, we do not believe that the 50%/50% sharing proposal put forth by PSI presents the optimum approach to addressing this issue. In presenting several options for our consideration, we note that Ms. Cvengros indicated that the Commission could include a base amount of off-system sales in PSI's rates, with or without some sharing of profits above that base amount. This approach was also recommended by the OUCC, Kroger, and PSI-IG. We are persuaded by the recommendation that we include a level of off-system sales profits in base rates and find that this should be done in conjunction with the use of a 50/50 sharing mechanism.

In adopting this approach, we are cognizant of PSI's concern that the amount included should reflect a reasonable level of trading expenses which were not included in the explicit sharing proposal advocated by PSI in this Cause. While we are persuaded by the OUCC's proposal that we include $18.7 million in rates for this purpose, this amount does not reflect trading expenses. Therefore, consistent with our earlier findings, we find that $18.7 million of test-period off-system sales profits, minus $3,953,000 for trading expenses, for a net value of $14.747 million, should be included in base rates to reflect the test-period. We further find that off-system sales profits should be tracked from this amount and shared 50/50 between PSI and ratepayers. We also find that tracking should be above and below the net amount in base rates; PSI may not apply a net annual off-system sales profit of less than zero to the tracker; and, all off-system sales net income should be included as jurisdictional income for purposes of the FAC earnings test. In addition, PSI's corresponding request for accounting relief is also approved.

(2) *NO_x Emission Allowance Tracker.*

[85-88] (a) *PSI's Testimony.* PSI witness Farmer testified that Petitioner's proposed NO_x emission allowance rider provides a rate mechanism for the recovery of charges to operating expense resulting from PSI's use of NO_x emission allowances ("EA") in order to comply with the federal and state NO_x SIP Call requirements. He explained that beginning in May 2004, PSI will be required to substantially reduce the amount of NO_x emitted from its power plants. Emission allowances will be consumed for each ton of NO_x emitted into the atmosphere during the months of May through September. Even though PSI will receive various allocations of zero cost NO_x emission allowances from the Indiana Department of Environmental Management ("IDEM"), PSI's future NO_x SIP Call compliance strategy includes the possibility of purchasing or selling NO_x emission allowances in order to minimize the cost of compliance to retail customers. PSI's proposed Standard Contract Rider No. 69 would allow for cost recovery of NO_x emission allowances as such allowances are consumed. Pet. Ex. CC, p. 10.

Mr. Farmer explained that the concepts incorporated within the Company's proposed NO_x Emission Allowance Adjustment are similar to the concepts embodied within its SO_2 Emission Allowance Adjustment, approved by the Commission in Cause Nos. 39584 and 39584-S2. Both riders, he said, are "zero based" riders, meaning that there are no costs being recovered in base rates. Both riders provide for the recovery of costs of emission allowances consumed due to the operation of the Company's own generating units used to serve native load customers, as well as the cost of emission allowances included in the cost of power purchased or transferred for economy, reliability, or operating purposes, to the extent such costs are specifically identified or can be reasonably estimated. Costs under both riders are allocated to retail customers based on kilowatt-hour sales. According to Mr. Farmer, both riders provide for the recovery or crediting of net gains and losses from the sale of emission allowances that have been allocated to the Company by the environmental agencies or emission allowances purchased by the Company on behalf of native load customers. Pet. Ex. CC, p. 11.

PSI initially proposed that Standard Contract Rider No. 69 provide for the sharing of net gains and losses associated with NO_x EA sales at a ratio of 80% to customers and 20% to the Company. However, in response to concerns raised by other parties, in rebuttal PSI modified its NO_x emission allowance cost tracking proposal in two ways: First, PSI changed its initial proposal to provide customers with 100% of net emission allowance sales proceeds; and second, PSI proposed to incorporate the NO_x emission allowance tracking features into PSI's existing SO_2 emission allowance rate adjustment mechanism (Standard Contract Rider No. 63). Pet. Ex. CC, pp. 10-22; Pet. Ex. QQ, p. 42.

(b) *OUCC's, Intervenors', and Testimonial Staff's Testimony.* The OUCC's only objections to the proposed NO_x emission allowance tracker involved the 80%/20% sharing feature, and the use of a mechanism separate and apart from PSI's existing SO_2 mechanism. As mentioned above, PSI addressed both of these concerns in its rebuttal testimony.

Intervenor PSI-IG took the position that PSI should propose this tracker, if appropriate, if and when the costs are of significant magnitude to warrant another adjustment to customers' bills. Alternatively, PSI-IG was of the opinion that the NO_x emission allowance tracker should be treated the same as PSI's SO_2 allowance cost tracker (i.e., 100% of net sales proceeds should be credited to customers). PSI-IG Ex. No. 1, p. 27.

Testimonial Staff generally supported approval of rate adjustment mechanisms for the recovery of SO_2 and NO_x emission allowance costs incurred providing service to jurisdictional retail customers. Dr. Borum testified that Staff has no objection to the costs of NO_x emission allowances being passed to ratepayers through a tracker similar to the one being proposed by PSI for SO_2 allowances, but had concerns regarding the proposed 80/20 sharing between the Company and ratepayers of gains or losses from selling NO_x emission allowances. Staff recommended that the NO_x tracker be consistent with the SO_2 tracker, with all gains or losses from sales of the emission allowances going to ratepayers, rather than an 80/20 split. IURC Staff Ex. No. 3, p. 26.

(c) *Commission Discussion and Findings.* With PSI's rebuttal modifications to its NO_x emission allowance tracking proposal, there appears to be very little dispute among the parties on this topic. We conclude that it is reasonable to authorize PSI to track and recover NO_x emission allowance costs incurred in connection with providing retail electric service, and to authorize PSI to credit customers with 100% of net proceeds associated with any sales of jurisdictional NO_x emission allowances. Accordingly, we approve PSI's NO_x emission allowance proposal as modified in its rebuttal testimony.

(3) *Midwest ISO-Related Cost and Revenue Adjustment Mechanism.*

[89-91] (a) *PSI's Testimony.* PSI also requested approval of a new Midwest ISO Management Cost And Revenue Adjustment Standard Contract Rider ("Midwest ISO Rider") to track, for recovery or credit, changes in the amount of PSI's Midwest ISO Management Costs and Revenues included in base rates as a result of this proceeding. PSI is proposing to track (i) costs billed to PSI by the Midwest ISO under Schedule 10 (ISO Cost Recovery Adder), or a successor provision (including Schedule 10-FERC), of the Midwest OATT, or any successor Tariff for the Midwest ISO; (ii) costs billed to PSI by the Midwest ISO under Schedule 16 (Financial Transmission Rights Administrative Service Cost Recovery Adder), or a successor provision, of the Midwest OATT, or any successor Tariff for the Midwest ISO; (iii) costs billed to PSI by the Midwest ISO under Schedule 17 (Energy Market Support Administrative Service Cost Recovery Adder), or a successor provision, of the Midwest ISO OATT, or any successor Tariff for the Midwest ISO; (iv) costs billed to PSI by the Midwest ISO for standard market design or other government mandated transmission costs PSI is required to pay on behalf of its Indiana retail electric customers; and (v) certain Midwest ISO transmission revenues assigned to PSI by the Midwest ISO. Pet. Ex. Z, pp. 30-31; and Pet. Ex. RR, pp. 13-14.

PSI proposed to include in its base retail rates \$5.554 million for Schedule 10 costs. As there are no current charges billed under Schedules 16 and 17, such Schedule 10 costs are the only costs that PSI proposed to include in base retail rates. PSI also proposed to include in the fixing of base rates Midwest ISO transmission revenues of \$10.905 million as a revenue credit, thus reducing base retail rates. The net of these two items resulted in a reduction in PSI's proposed base rates of \$5.351 million. Pet. Ex. Z, p. 31.

Mr. Freeman said that under the Midwest ISO Rider, the total of these cost categories would be added together and the transmission revenues subtracted to determine the net amount for each quarter. The difference between this net amount and \$1.337 million (one quarter of \$5.351 million) would be recovered or credited, whichever is applicable, to the customers through the Midwest ISO Rider. Mr. Freeman said that the annual retail electric jurisdictional costs to be incurred by PSI under Midwest ISO Schedules 16 and 17 are estimated to be approximately \$2.1 million. Consistent with PSI's Fuel Cost Charge Standard Contract Rider and PSI's Emission Allowance Charge Standard Contract Rider, PSI proposed to adjust the Midwest ISO Rider on a quarterly basis. To the extent that any costs to be recovered under the Midwest ISO Rider are not billed by the Midwest ISO to PSI pursuant to Midwest ISO Schedules 10, 16 or 17, PSI will demonstrate in its quarterly filing the amount and reasonableness of such costs. Pet. Ex. Z, pp. 31-33.

PSI witness Ronald R. Jackups emphasized that the proposed Rider addresses costs and revenues that are variable, substantial, and outside the control of PSI, but which result from PSI taking transmission service under the Midwest ISO OATT to serve PSI's retail electric customers. More specifically, Mr. Jackups explained that the costs and revenues covered by the proposed Rider are: (1) the result of the decisions of the FERC; (2) variable in amount from year to year; (3) variable as to timing; (4) substantial in individual and aggregate amounts; and (5) outside the control of PSI (*i.e.*, dependent upon the actions of the FERC, the Midwest ISO, customers and loads, etc.). Further, as federally set and imposed charges at retail, necessary in order to provide retail service, Mr. Jackups testified that the costs to be incurred are just, reasonable and necessary. Pet. Ex. M, pp. 46-48.

(b) *OUCC, Intervenors', and Testimonial Staff's Testimony.* The OUCC opposed PSI's proposed Midwest ISO Rider because such costs failed to meet the five (5) rate tracking criteria recommended by OUCC — including its view that PSI's Midwest ISO's costs are relatively stable and insignificant in the context of PSI's overall O&M expenses (only 0.678%, before tax). Although Mr. Carver's testimony specifically addressed the \$5.761 million of MISO Schedule 10 costs, the MISO charges are still immaterial even after considering the additional \$2.1 million estimated by PSI witness Freeman (Pet. Ex. Z, pp. 31-33) attributable to MISO Schedules 16 and 17. In lieu of PSI's proposed Midwest ISO rider, OUCC would alternatively recommend the continuation of the deferral mechanism previously authorized by the Commission — to the extent PSI does not separately recover any increased administrative costs through increased transmission revenues, MISO related efficiencies or through retail base rates. Pub. Ex. No. 1, pp. 57-59.

Intervenor PSI-IG opposed the tracking of Midwest ISO-related costs above or below the amount to be included in base rates, and opposed PSI's proposed Midwest ISO Rider as premature and probably inappropriate. PSI-IG witness Phillips said that PSI can request approval of this mechanism, if appropriate, when all matters regarding the MISO, costs, operations, rules and regulations are known. PSI-IG Ex. No. 1, p. 26.

Testimonial Staff endorsed PSI's proposed tracking of Midwest ISO related costs and revenues, including costs that are (1) the result of decisions by the FERC; (2) variable in amount from year to year; (3) variable as to timing; (4) substantial in individual and aggregate amounts; and (5) outside the control of PSI. Dr. Borum testified that, Staff agrees that these MISO-related revenues and MISO-related costs are appropriately recovered through a tracker, in that "PSI's proposal is balanced . . . designed to flow through to ratepayers MISO-related transmission revenues received by PSI . . ." Dr. Borum noted that PSI has very little control over these costs or revenues since they are incurred through MISO tariffs and schedules approved by the FERC. Staff Ex. No. 3, pp. 23-24.

(c) *PSI Rebuttal Testimony.* In rebuttal, PSI witness Freeman testified that the Midwest ISO Rider: (1) is not limited to just PSI's Schedule 10 costs; (2) covers costs that PSI is currently incurring and revenues that PSI is currently receiving; and (3) covers costs and revenues that have shown a significant variance (for example, an eight-month variance of over \$10 million in transmission revenues). Pet. Ex. RR, pp. 5-7.

(d) *Commission Discussion and Findings.*

We find reasonable PSI's proposal to track Midwest ISO related costs and revenues, including costs that are: (1) the result of decisions by the FERC; (2) variable in amount from year to year; (3) variable as to timing; (4) substantial in individual and aggregate amounts; and (5) outside the control of PSI. PSI's proposal is balanced and designed to flow through to customers Midwest ISO-related transmission revenues received by PSI. Therefore, we find that PSI's proposal to track Midwest ISO related costs should be approved.

[92, 93] (4) *Modifications to PSI's Existing SO_2 Emission Allowance Tracker*. Separate and apart from its rebuttal proposal to incorporate NO_x emission allowances into its existing SO_2 emission allowance tracker (Rider 63), PSI also proposed a minor modification of its current Rider 63 SO_2 Emission Allowance Adjustment (originally approved in IURC Cause No. 40003). The purpose of this minor modification is to conform to the manner in which costs applicable to native load customers are captured today. Mr. Farmer explained that this proposed conforming modification does not involve any substantive changes. The primary reason for the modification, he said, is the fact that the Company has various processes in place that are used to specifically identify emission allowance costs applicable to native load customers. Pet. Ex. CC, pp. 12-13.

No party objected to PSI's proposed modification to its SO_2 emission allowance tracking provisions, and as mentioned above, IURC Testimonial Staff supported continuation of SO_2 tracker. Accordingly, we accept PSI's proposed modifications and approve PSI's proposed modified Standard Contract Rider No. 63.

[94] (5) *Modifications to PSI's Existing Fuel Adjustment Charge Mechanism.* PSI also proposed minor modifications to its existing fuel adjustment charge mechanism, Standard Contract Rider No. 60. Mr. Farmer explained that, since PSI's last retail rate case, there have been several significant proceedings relating to the fuel adjustment charge, such as this Commission's generic FAC case, Cause No. 41363, and cases interpreting the generic FAC case, such as SIGECO's and NIPSCO's FAC45 cases, and PSI's FAC56 case. PSI simply proposed to update Rider 60 to reflect current practices. Pet. Ex. CC, pp. 13-14. No party objected to these minor proposed changes to PSI's Rider 60. We find such changes to be appropriate in light of our various FAC orders issued since PSI's last rate case, and we hereby approve PSI's proposed modifications to its Standard Contract Rider 60.

B. *Real Time Pricing ("RTP")*.

[95] (1) *PSI Proposal.* PSI proposed to terminate its RTP program (Standard Contract Rider No. 21), which consists of a two-part rate — an access charge for the customer's historic load ("CBL"), which is billed at standard tariff rates, and an energy charge for the customer's incremental or decremental energy usage that is billed at a real time price. Currently, 57 PSI customers participate in RTP, with an expected peak load reduction of about 15 MWs. Pet. Ex. AA, p. 15.

PSI witness Jeffrey R. Bailey testified that PSI began its RTP Program in 1996. Its primary objectives were to elicit load responses by customers in response to changes in price. To that end, it was reasoned that customers would reduce load during high priced periods and thereby produce demand savings to PSI. Similarly, customers could shift load to, or grow their load during, lower priced periods, creating demand savings or incremental revenue growth. *Id.* at 16. The Company's analysis, after more than seven years of experience, however, revealed that, on average, RTP customers were receiving a nearly 40% discount from tariffed rates for the RTP portion of their bills (*i.e.*, load above the CBL). For some customers the discount was even higher. Absent any modification of the RTP Program, this subsidy by PSI's other industrial and commercial customers would continue, Mr. Bailey observed. *Id.* As a result, he said, PSI has concluded that it and its other industrial and commercial customers were not receiving a proportionate amount of value from these RTP customers relative to other demand response programs. PSI's conclusion was to

eliminate its RTP Program, effective with a final order in this Cause. *Id.*

Mr. Bailey testified that while the Company's analysis confirmed that *some* customers do respond to high prices, about two-thirds of the customers on the RTP program were only minimally responsive or not responsive at all. *Id.* at 17. Over the last couple of years, he said, market prices have been very low. Because the RTP commodity price is the lesser of the market price or PSI's marginal generation costs, PSI's low generation costs, combined with low market prices, has meant that customers have generally received low price signals and have not had an incentive to shift their load to lower priced, off peak periods. *Id.* So, he observed, while customers are receiving a big discount from tariff rates, PSI is not receiving the proportionate value created when customers shift load to off-peak periods. In essence, he said, the program is not cost-effective. *Id.*

Mr. Bailey said that PSI had investigated various potential ways to modify the program, including putting "fixed adders" on the commodity portion of the price and demand charges on the T&D portion of the price to improve cost recovery from the RTP customers, but that ultimately the Company determined that these actions were drastic enough to impact RTP customers nearly as much as termination of the program, altogether. Even after such changes, he observed the Company could not be certain the pricing mechanism would function satisfactorily. *Id.*

He added that the credits for load reductions under PowerShare® were far less than the discounts generated under RTP. *Id.* The Company concluded that a more appropriate valuation (*i.e.* credit or discount commensurate with value created) would be achieved through PowerShare®, either through its CallOption or QuoteOption components. *Id.* Additionally, he said, PowerShare® has other features that make it preferable to the RTP program, including greater certainty in the amount of peak load reduction (customers contract to reduce a certain amount under CallOption). *Id.* In contrast, the Company under RTP must rely on the customer to reduce load voluntarily in response to price signals, with no upfront estimate of the load reduction the customer may be able to produce. *Id.*

As for the impact of termination of the program on customers, Mr. Bailey testified that, on average, customers will experience bill increases of about 8% before the increase requested in this cause. *Id.* at pp. 8-9. He added that a small number of customers will see bill increases exceeding 20% before the rate increase requested. *Id.* Recognizing that this is a potential hardship for customers, the Company proposed to phase-out the RTP program over a two-year period. *Id.*, p. 20-21. The Company calculated the benefits received by customers under the RTP program relative to its base tariff and proposed to offer these benefits as credits on each RTP customer's electric bill during the phase out period. The initial credits, he said, would be based on 67% of the savings from the base tariff — as defined during the test period — at the time new tariffs are approved (Phase I), and would be reduced to 33% at the end of the first year (Phase II). At the conclusion of the second year, the credits would cease (Phase III). Pet Ex. BB, p. 9.

PSI proposes that its Rate LLF and HLF customers that are not on the RTP program provide a subsidy necessary to fund the bill credits during the two-year phase out period. Accordingly, PSI would file three consecutive sets of tariffs for Rates LLF and HLF — Phase I, Phase II, and Phase III. The amounts of the subsidies required would be as follows:

RTP Credits

	Total	*Phase I*	*Phase II*
Applicable to HLF	$7,492,263	$5,019,816	$2,472,447
Applicable to LLF	$ 187,694	$ 125,755	$ 61,939
Total	$7,679,957	$5,145,571	$2,534,386

Id. at 9-10.

The Company proposed to transition RTP customers that do have the capability of curtailing usage to its PowerShare® program, and they would be eligible for the program even while they are getting bill credits from the RTP program phase-out. Pet Ex. AA, p. 21. Mr. Bailey observed that the Company's Time-Of-Use rate is another option that may be a good fit for some RTP customers.

Mr. Bailey added that there may be some customers who can create additional value by the nature of operations they adopt, citing as an example a customer that can consistently reduce its load during peak hours, which may create value for PSI that is in excess of the PowerShare® CallOption premiums. For these customers, he said, the Company will entertain a special contract, subject to Commission approval. *Id.*

(2) *PSI-IG Position.* The PSI-IG opposed elimination of the RTP rate. It argued that the rate is theoretically sound and accurately sets forth hourly rates based on PSI's hourly costs. PSI-IG Ex. No. 1, p. 21. To PSI's point that RTP customers do not adequately shed load at the time of PSI's summer peak, witness Phillips argued that the RTP rate should not be discontinued for that reason, arguing that their rate is not an interruptible rate, but a rate that charges customers an accurate price for each hour of the year. *Id.* He added that the customer has the option of paying an extremely high price during high cost hours or reducing purchases based on operational and economical considerations and that PSI should not be allowed to eliminate this rate because it does not agree with the choice made by its customers. *Id.* at 21-22.

Mr. Phillips argued that the current RTP has a 10% adder to hourly costs for HLF and a 25% adder to hourly costs for Rate LLF, which, he said, means that PSI always recovers actual hourly costs, plus a 10% to 25% adder to those actual hourly costs. So, he said, it is impossible for PSI to lose money with respect to the cost to serve its RTP customers. *Id.* at 22. He concluded that the elimination of this rate structure would be viewed as a backward step for providing customers with accurate price signals and an economic choice. *Id.*

(3) *Kroger Position.* Kroger disagreed with PSI's proposal to have rates HLF and LLF customers fund a subsidy to former RTP customers migrating to those rate schedules. Kroger witness Higgins observed "the irony of this situation is that the purpose of the subsidy is to shield the RTP customers from the immediate pain of paying these very same HLF and LLF rates; so the customers who are already on these 'painful' rates are asked to pay even more, in order to 'ease the pain' of the RTP customers that are now joining them." Kroger Ex. No. 1, p. 22. Accordingly, Mr. Higgins recommended that PSI's subsidy proposal be denied, arguing that if Rates HLF and LLF are found to be just and reasonable, then there is no compelling reason to shield RTP customers from the pain of being on these rates. *Id.* at 23. Alternatively, he argued that if the RTP subsidy is adopted, it should be funded, 50% by PSI and 50% by all customer classes, in proportion to each class's base revenue requirement. *Id.*

(4) *Testimonial Staff's Testimony.* Staff witness Dr. Borum stated that the Testimonial Staff is not convinced that the RTP program should be terminated, rather than continued or modified. IURC Staff Ex. No. 3, p. 35. The problems cited by PSI, he maintained, are

essentially financial. *Id.* He said that wholesale market prices have been low for the past few years and as PSI's on-system incremental costs are also low, RTP customers have not shifted load in response. *Id.* Thus, he observed, if PSI is getting no value from load shifting, putting these customers on regular tariffs allows the Company to collect more revenues. *Id.* In essence, he said, PSI wants to terminate the program because it is not receiving enough financial benefit in today's low price environment. PSI's financial concerns do not mean that the RTP program has no value, he argued. *Id.*

Dr. Borum said that he is convinced that retail prices that are designed to better reflect actual hourly wholesale market costs will benefit both customers and utility companies. Over time, he argued, customers shifting loads in response to these hourly wholesale market costs would benefit both the RTP program participants and the utility with lower overall costs. Thus, Staff believes PSI has put undue emphasis on immediate results and under-valued the likelihood of significant effectiveness of the RTP program over time. *Id.*

Dr. Borum noted that this Commission, in approving a previous version of PSI's purchased power tracker, directed PSI to explore all possible methods and resources of providing efficient and economical energy to its customers, including "innovative rate options." *Id.* at 35-36. As a result, he said, Staff recommended that "approval of the purchased power tracker be conditioned on PSI entering into a collaborative process with Staff and other interested groups to not only explore whether and how the RTP program should be modified, but to actively evaluate the feasibility of implementing other innovative rate options." *Id.* at 36.

(5) *PSI Rebuttal.* PSI's witness Bailey testified in response to Mr. Phillip's claim that the Company's proposals on the RTP and PowerShare® Programs would be reviewed as a backward step for providing customers with accurate price signals and an economic choice. He said that the Company's proposal to eliminate the RTP rider and transition its customers to special contracts or to the newly enhanced PowerShare® program would constitute an appropriate course to maximize the value of its peak load management program. Pet Ex. SS, p.2.

Responding to Mr. Borum, Mr. Bailey testified that PSI's track record shows continued experimentation with innovative rate and demand-side management options, and demonstrates that the Company is committed to the goal of reducing the need for additional generating capacity. He said that the Company is certainly willing to discuss with Staff and interested parties real time pricing and other innovative rate options for the future. However, he believes that the current RTP program is so flawed that the only feasible option is termination. There is no clear solution, he said, to improve price signals from a market that currently does not adequately reflect the long-term cost of capacity. *Id.* at 3.

Regarding the contention that PSI's request to terminate the RTP is largely motivated by short-term financial concerns, Mr. Bailey responded that PSI's revenue requirement is derived completely independently of any of its optional rate programs, and would remain the same if the RTP program is retained or terminated. *Id.* PSI's direction, he said, is not motivated by financial self-interest, but rather by the fact that the program is not cost effective. *Id.* He added that retention of the program would cause other customers to bear the burden of a program that produces no tangible value for them. *Id.*

As to Mr. Phillip's complaint that PSI appears to be driven by some notion of revenue neutrality in its RTP proposal, Mr. Bailey responded that PSI *is* driven by the notion of revenue neutrality, pointing out that one only needs to read the RTP rider (Standard Contract Rider No. 21) to see that the design of the RTP program was to make customers "bill neutral" with respect to their historical usage. *Id.* Customers could then respond to real time prices accordingly, he said. *Id.* With respect to Mr. Phillip's contention that because PSI charges an adder to hourly costs, it is impossible for PSI to lose money with respect to the cost to serve its RTP customers, Mr. Bailey responded that even if PSI recovers the incremental costs of generation (*e.g.*, fuel), there is not sufficient remaining margin to support the cost of additional capacity that RTP customers are using. *Id.* at 5.

To Dr. Borum's contention that by eliminating the RTP Program PSI is no longer reducing the disconnect between wholesale and fixed retail prices and Mr. Phillips' opinion that the RTP is theoretically sound and accurately sets forth hourly rates, Mr. Bailey responded that a major point in the Company's case-in-chief is that the price signals being sent to RTP customers are *not* accurate. *Id.* He explained that the RTP pricing mechanism sends a price signal to customers based on the lesser of PSI's internal generation cost or the market. Whatever the signal attempted to be sent from wholesale prices, he said, is negated by a mechanism that allows the customer to always receive the lowest price of generation or market. *Id.* Mr. Bailey testified that the fact that the RTP program is voluntary, not mandatory, substantially influences the long-term cost effectiveness of the program, as customers have no long-term requirement to remain with the program and subject themselves to the volatility of the wholesale market. *Id*, at 5-6.

PSI proposes to terminate the program, he said, because it does not produce its intended goal of price response. *Id.* at 7. A prerequisite, he said, to a customer's being placed on the rider was its ability to shift load from higher cost to lower cost pricing periods and to add new load during lower cost pricing periods. If such load shifting is not occurring, and PSI cannot depend on the program for peak load reduction, then the program is not fulfilling its intended purpose, Mr. Bailey testified. *Id.* Other options, he said, like special contracts or PowerShare®, will save the customer money and produce a benefit to PSI and its remaining customers. *Id.* The Company's position, he said, is that if a customer is going to pay less than tariffed rates, then that customer must bring something of value to the Company, and non-participating customers. However, under the RTP rider, the discount to participating customers is large while the benefit to the Company and remaining customers is small. *Id.* at 7-8.

Mr. Bailey also disagreed with Mr. Phillips' contentions that a separate cost of service study should be done for RTP customers, observing that RTP is a Rider to Rates HLF and LLF, and the customers on RTP are properly HLF and LLF customers who have chosen to participate in a voluntary rider available to those rates. *Id.* at 8. PSI, he observed, has numerous riders each of which is included with its base rate for cost of service purposes, citing examples PSI's Smart $aver® under Rate RS, Optional Commercial Electric Service under Rate CS, Total Electric Commercial Service under Rate LLF, and Time-of-Use options under both Rates LLF and HLF. *Id.* None of these riders, he pointed out, have ever been fully segregated from its base rate for the development of rates.

Defending the Company's proposed phase-out of the RTP credits to affected customers, Mr. Bailey said that the proposed phase-out, to mitigate the large rate increase the RTP customers will incur if the entirety of their load is immediately placed on Rates HLF or LLF, is something the Company has done in the past, with some success. He cited as an example, Cause No. 40003, where the Company used a three-year phase-in approach to mitigate the bill impacts to Rate MLF customers as that rate was combined with Rate HLF. *Id.* He said that while the Company believes that termination of the RTP program is proper, it also recognizes the hardship it may cause customers because of a large increase in their bill all at one time. A gradualism approach, he observed, is common in the industry and, in the Company's opinion, the right thing to do here. *Id.* at 8-9.

(6) *Evidence at Hearing.* On cross-examination by PSI at the November hearings in this Cause, Dr. Borum clarified that his testimony was not intended to call for the continuation of the RTP program as is. Rather, he believes that a collaborative process involving interested parties is the best way to examine the future of the RTP program and other innovative rate programs. He also indicated that a goal of any collaborative process concerning innovative rate options should be to increase the cost effectiveness of the rate options. Tr. at R107-R108.

(7) *Discussion and Findings.* This Commission and its regulated utilities have a responsibility not only to encourage experimental innovative rate options, but also to ensure that programs meet standards of cost effectiveness. Based on the evidence we find that it is apparent that the RTP program, as currently designed, has some serious flaws. No party presented evidence that the program was, in fact, cost effective. However, this Commission believes that innovative rate options such as real time pricing, which encourage customers to react to hourly wholesale market prices, are an important offering.

Consistent with the recommendation of Testimonial Staff, we find that the best venue to deal with the RTP problems would be a collaborative process involving PSI, Staff, and other interested parties. Before this pilot program is discontinued, we feel that the parties should consider ways that it can be redesigned or modified in order to make it an effective program. While the collaborative parties are meeting, the RTP program shall continue in place as is. However, our decision does not prejudge that continuation of the RTP program is necessary or appropriate. Rather, the goal of the collaborative is to design rate options which will be effective while providing value to PSI, its participating customers, and PSI's non-participating customers (these options may or may not include some form of a real time pricing program). Additionally, we find that the collaborative process should be concluded by October 15, 2004. PSI shall file a report detailing the efforts of the collaborative process by November 15, 2004.

Because PSI has met its burden of proof in regards to the termination of the program *as it is currently designed*, we find that the RTP rider, Rider No. 21 should be extended until January 31, 2005, whereupon it will automatically terminate. However, we would expect that it will be replaced by one or more innovative pricing options developed during the collaborative, or that the majority of PSI's RTP customers will be transitioned to PSI's PowerShare® program.

In reaching the foregoing conclusions we also find that phase-out credits proposed by PSI are not necessary or appropriate. While we recognize that in many instances it might be appropriate to phase in the effect of rate changes when certain classes of customers are disproportionately affected by a certain change, we recognize that the very customers we would be seeking to protect through the phase out in this instance have already reaped financial benefits from a program that does not appear to be working as envisioned. As the program will not end until January 31, 2005, and may be replaced by an improved RTP program, current customers will have a sufficient opportunity to prepare for the change. Therefore, we find that phase out credits are not necessary and are hereby denied.

C. *PowerShare® Program CallOption Pricing Change.*

[96, 97] (1) *Background.* PSI's witness Bailey described PSI's PowerShare® program, offered under its Standard Contract Rider No. 23. This program, implemented in January, 2000, is currently a market-based program that provides financial incentives in the form of bill credits to industrial and commercial customers to reduce their electric demand during PSI's peak load times. Customers may choose to participate in either CallOption or QuoteOption.

CallOption requires customers to commit to a pre-selected load reduction, based on historic or usual demand, at a selected strike price. The strike price is selected by the customer based upon the customer's willingness and ability to comply with the call for load reduction. In return for this commitment to reduce when called, CallOption customers receive a monthly premium payment from PSI as a credit to their bill. In addition, when customers are called to reduce load, they receive an energy credit. PSI's standard CallOption product may be exercised by PSI when the next day's market prices are projected to be greater than the customer's selected strike price. The term of the standard CallOption program agreement is four months — June through September. Pet. Ex. AA, pp. 10-11. Mr. Bailey also described the QuoteOption component of PowerShare®, which allows a customer to elect whether or not to reduce its load when called upon by PSI when prices reach a minimum price. No monthly premium is paid to QuoteOption customers since they may elect not to respond when called, but an energy credit is paid for load reductions made in response to PSI's calls.

(2) *PSI Proposal.* Mr. Bailey explained that since inception of the program, PowerShare® has been a market-based program, where the credits provided to customers for load curtailments have been based on the value of those curtailments in the short term wholesale energy market. Because market prices are highly variable, customer credits have varied dramatically from year to year. In 2000 and 2001, customer credits were relatively high and these credits produced excellent customer participation. However, recent low market prices have resulted in low credits for customers that have the ability to curtail load. These low credits have drastically reduced participation it the PowerShare® program, even as PSI has set new peak demand records and has installed additional generating capacity. So, while the PowerShare® program has great potential value to PSI in providing needed capacity, it has been valued less by customers because of the current low market-based credits. *Id.* at 13.

In an effort to reinvigorate the program, and to transition it to a stable program capable of producing consistent capacity value for PSI, the Company proposed to treat PowerShare® CallOption similar to PSI's regulated DSM programs, which are evaluated based upon the long-term avoided costs, rather than on short-term market prices for the summer ahead. In essence, PSI will be giving a long-term capacity value to the CallOption customer's agreement to curtail usage. Under this new pricing methodology, the credits offered to PowerShare® CallOption customers would be based upon the value of avoiding investment in a combustion turbine as opposed to the short-term, highly variable market value. This should, Mr. Bailey said, stabilize the credits PSI can pay customers at an attractive level to customers in exchange for an agreement to reduce their load when called upon. While this would be a material increase over current credit levels, the Company does not anticipate that such credits would exceed half the value of the annual avoided cost of a combustion turbine, he said. *Id.*

Mr. Bailey testified that the test year contains $1,023,000 of expenditures in the form of bill credits related to PSI's PowerShare® CallOption program, and with the transition of this program to more traditional DSM pricing, PSI believes that program expenditures will be at or above this level. The change in philosophy which results in increased credits to customer should, he said, enhance customer participation levels. *Id.* at 14

(3) *Positions of Other Parties and Testimonial Staff.* Testimonial Staff expressed disappointment over PSI's proposal to move to a capacity avoidance cost standard for PowerShare® credits. Staff indicated that it is important that utilities find effective ways to provide price signals to end-use customers. The CallOption program was one means of providing price signals to customers who are sophisticated enough to understand and react to those price signals. Staff noted however, that with low market prices, came lower participation and the Commission should not take a negative view of the program when participation fluctuates widely due to the change in premium payments. IURC Staff Ex. No. 2, p.24. PSI-IG witness Mr. Phillips also recommended maintaining the short-term market pricing of CallOption premiums. He testified that using market prices would increase participation when the market prices were high, precisely when such load reduction is most needed. PSI-IG Ex. No. 1, pp. 23-24.

(4) *PSI Response.* PSI responded that the changes it is proposing to PowerShare® should enhance, rather than detract from the goal of providing price signals that result in changes in customer consumption patterns. Mr. Bailey observed that PSI's proposal merely replaces a short-term, volatile wholesale market price signal with a stable, long-term price signal for the CallOption component of the PowerShare® program. He emphasized that PSI will maintain *short-term wholesale market pricing* through the PowerShare® *QuoteOption* component. This change, he contended, will make Power-

Share® an even more effective rate option than the current structure. Pet Ex. AA, p. 10.

(5) *Discussion and Findings.* We find PSI's PowerShare® proposal reasonable. The CallOption program requires a contractual commitment to reduce load and allows the Company to depend on the load reductions in its Integrated Resource Plan. Under the current proposal, customers would be paid the true value of that reduction. In the current wholesale market, as CallOption is currently structured, it does not appear that customers are getting paid any capacity value. Moreover, the QuoteOption aspect of the PowerShare® program maintains a short term market price based option. Thus, PSI can still benefit when prices are high through higher participation in the QuoteOption program. Therefore we approve the pricing change as proposed by the Company.

D. *Line Extension Advance Deposit ("LEAD") Credit.*

[98, 99] (1) *Evidence.* PSI witness Pefley testified in support of PSI's proposed change in its LEAD credit. Ms. Pefley testified that PSI's Standard Contract Rider No. 52, Line Extension — Advance Deposit, is patterned after 170 IAC 4-1-27(C) ("Rule 27") which provides that PSI will require a line extension advance deposit if the estimated cost of extending its facilities to serve a customer exceeds the estimated revenue from the customer over a period of 2 1/2 years. Pet. Ex. J, p. 11. Ms. Pefley said that the Company has determined that the application of Rider 52 does not provide for a sufficient amount to allow the Company to earn an adequate return on its line extension costs. She pointed out that while the number of customers has increased by 16% since the end of the test period in the last rate case, PSI's net investment to connect such customers to its system has increased by more than twice this amount, with the result that new customers are not bearing the full costs of connecting to PSI's system. In these circumstances, she said, the unrecovered costs are being passed on to existing customers and results in regulatory lag for PSI between rate cases. PSI proposed to replace the 2 1/2 years of revenue credit in Rider No. 52 with a credit equal to the actual net book value of the plant investment required to connect new customers as of the end of the test period in this proceeding. *Id.* at 13. For the residential class, the credit is a fixed dollar amount per customer. Ms. Pefley maintained that PSI's proposed approach is fair because it reflects the connection costs embedded in the distribution rates that the customer will pay.

OUCC witnesses Endris and Brosch opposed PSI's proposed change to Rider No. 52. Mr. Endris had three concerns with the proposal: (1) in his opinion, PSI has not sufficiently demonstrated that it needs the change; (2) PSI's proposal does not adequately reflect the benefits and contributions of new customers; and (3) PSI's proposal would impede economic growth. Pub. Ex. No. 6, p. 39. Mr. Endris argued that PSI provided no historical analysis demonstrating that the experience since the last rate case is any different from the past. He said that Ms. Pefley failed to consider that some of the growth in plant investment is for replacement projects due to deterioration or obsolescence. In addition, Mr. Endris indicated that Ms. Pefley failed to show whether some projects contributed disproportionately to the increase in PSI's net plant investment.

Mr. Endris thought that PSI's proposal ignored the prediction of PSI witness Stevie that the 2003-2008 growth rate in kilowatt-your sales will be greater than the growth rate in peak demand. If this is true, Mr. Endris argued, the new customers will be contributing to fixed cost recovery to a greater extent than their contribution to peak demand capacity requirements. Therefore, he maintained, the capacity cost recovery is likely to contribute to PSI's overall rate of return in a manner that would tend to offset increases in plant investment in the accounts identified by Ms. Pefley. *Id.* at 45.

Mr. Endris went on to testify that the proposed change also upsets the balance of customer and utilities' interests underlying Rule 27. Mr. Endris claimed that if the Commission had intended the line extension rule to result in no increases in rate base, it would not have utilized a revenue basis, but rather something linked to return on investment. Pub. Ex. No. 6, p. 47. Mr. Endris also argued that the Commission's balancing of interests has an impact upon economic development in the form of new housing growth. He said this Commission could have chosen to have the customer pay 100% of the hook-up charges, but instead chose to impose a lesser financial burden. According to Mr. Endris, PSI's proposed change upsets this balancing of interests. *Id.* at 48.

Mr. Brosch asserted that the proposed Rule 27 change ignores the revenues and profits to be contributed by the new customer. Pub. Ex. No. 2, p. 117. He pointed out that a new fixed credit of $856 would be available for a new residential customer regardless of whether the projected revenue from that customer would justify capital expenditure. He also said the proposed credits do not reflect costs, because the net depreciated cost of plant balances used in Ms. Pefley's calculations are not the values included in the revenue requirements. *Id.* at 118. Finally, Mr. Brosch argued that the investments reflected in the depreciated plant accrual balances were made for different reasons, not just to connect new customers. These balances further include, he said, all prior vintages of construction, rather than the current period costs that might indicate what it actually costs to serve customers today. *Id.* at. 119-120.

On rebuttal, Ms. Pefley disagreed with Mr. Endris' concern about PSI's proposal impeding economic development. Ms. Pefley observed that construction costs come in eighth in a list of site selection factors — behind availability of skilled labor and labor costs. Pet. Ex. LL, p. 2. She also did not believe that the proposed Rider 52 change will significantly impact larger commercial or industrial customers locating in PSI's service territory. Ms. Pefley presented an analysis which showed that using PSI's proposed LEAD credit to several actual connections in PSI's Noblesville service territory, only one large commercial or industrial customer would have been required to pay a deposit in the amount of $57. *Id.* at 3. With respect to the possible chilling affect on residential development predicted by Mr. Brosch, Ms. Pefley observed that the increase in the cost of a new home under PSI's proposal would be only approximately 0.5% for the average non-electric space heating customer and 0.9% for the average electric space heating customer.

Ms. Pefley also disagreed with Mr. Brosch's characterization of PSI's proposal as being contrary to sound economic theory. She said that there is no rational economic theory that supports the provision of a credit against distribution construction costs based on fuel cost charge derived revenues that are a dollar-for-dollar pass-through, with no profit margin, as the current rule provides. *Id.* at 4. She observed that Rider 52 as proposed is consistent with the regulatory principle of cost causation, in that it provides a credit to each class of customers based on the distribution-related construction costs reflected in that class's rates. She also stated that Rider 52, if approved, would provide an "apples to apples" standard by crediting constructions costs to connect a customer with construction costs reflected in the rates that the customer will pay. *Id.* at 5. Ms. Pefley also rejected Mr. Endris' claim of a need to perform an analysis of individual work orders, observing that the problem of utility investors and existing customers subsidizing the connection costs of new customers is not new or unique to PSI. *Id.* at 6.

(2) *Discussion and Findings*. In support of her request in this Cause Ms. Pefley directed our attention to two specific provisions in the rule. The first provision is 170 IAC 4-1-27(C) which states as follows:

> Each electric utility shall, upon proper applications for service from overhead and/or underground distribution facilities, provide necessary facilities for rendering adequate service, without charge for such facilities when the estimated total revenue for a period of two and one half (2 1/2) years to be realized by the electric utility from permanent and continuing customers on such extension is at least equal to the estimated cost of such extension.

170 IAC 4-1-27(C)

Ms. Pefley then indicated that PSI is

requesting relief from the Commission under section 170 IAC 4-1-27(H), which states:

> This Rule 25 [this section] shall not be construed as prohibiting an electric utility from (1) making extensions without charge where the cost of the same is greater than is provided in (C) above, or (2) providing an alternate plan to be approved by the commission; provided that in the application of this subsection (H) no discrimination is practiced between customers whose service requirements are similar.

170 IAC 4-1-27(H)

Our line extension Rule 27 permits a utility to collect a line extension deposit when the estimated costs to connect a new customer exceed 2 1/2 years of anticipated revenues from the customer. Thus, a linkage is established between the expected stream of revenues and profits from the customer and the service connection costs required to achieve such revenues and profits. We note that this approach has been applied by Indiana electric utilities for many years.

It is undisputed under Rule 27 that someone must pay for new customer connections and if the new customer does not bring sufficiently compensatory profits to the utility, that new customer must pay a deposit. Alternatively, if a new customer's revenues are expected to be large, the costs to connect and serve the customer will be recovered relatively quickly through regular monthly billings and the new revenue stream, so that no subsidization is caused by new customers. At issue under the Company's new proposal is whether or not a revenue-based framework of evaluation is reasonable, or should be modified in the manner PSI now advocates.

As the modification requested by PSI is properly characterized as a request for variance under 170 IAC 4-1-27(H), the burden of proof is upon PSI to fully support its variance request in order for us to conclude that we may properly deviate from the provisions contained in the rule. We do not have sufficient evidence before us to make such a finding. PSI's proposed changes to Rider 52 reflect a construction credit based upon PSI's construction costs relating to the extension of service, without regard to whether a new customer will generate large streams of revenues and profits or only modest new revenues. The OUCC maintained that the present framework of analysis is valid, and that the Company has not proven otherwise.

We agree with the OUCC on this issue. PSI failed to provide any cost justification for its position. The Company's distribution plant balances include costs of constructing plant for replacement, modernization, highway relocations and reliability enhancement in addition to costs to connect and serve new customers. In order to accurately isolate costs to connect new customers, a special study seems necessary to disaggregate plant costs incurred for this purpose and relate such costs to the profits contributed from new customers. The evidence in this proceeding compels the conclusion that PSI's variance request is not supported by sufficient evidence to allow us to find that we should deviate from the requirements of Rule 27. Therefore, we deny PSI's request to modify the existing LEAD credit mechanism.

[100, 101] E. *Optional High Efficiency Residential Service Rate.* Mr. Brosch testified that PSI had originally proposed to continue a 20 percent discount under Standard Contract Rider 6.3. Pub. Ex. No. 2, p.111. He said that the discount arose during implementation of PSI's Smart Saver program and was intended as an incentive to promote the installation of high efficiency electric heating and cooling equipment. However, during discovery PSI stated that it appeared that the 20 percent discount would not pass the Utility Cost Test, but that a 10 percent discount would. PSI recommended a reduction of the discount to 15 percent, in order to continue to avoid adverse impact to customers currently on the rate. *Id.* at 111. Mr. Brosch testified that the OUCC supported reducing the Rider 6.3 High Efficiency discount to 15 percent. We find this compromise and proposal of the OUCC and PSI reasonable, and it is approved.

[102-104] F. *Customer Connection Charges*. PSI proposed increasing its residential and commercial customer connection charges from $8.15 to $9.90. Mr. Brosch objected to these increases, claiming that PSI's current customer connection charges are higher than Indiana electric utilities. Pub. Ex. No. 2, p.109. However, in describing the cost support supplied by PSI in support of the proposed connection charges, Mr. Brosch admitted that a customer connection charge as high as $11.20 could be justified. *Id.* at 110. Mr. Brosch recommended that the charge remain at $8.15, because this rate recovers a "high percentage" of customer-related fixed costs.

In response to Mr. Brosch's proposition, Mr. Bailey observed that the fixed connection charge is intended to recover fixed costs and if the charge is not large enough to recover such costs, the part not covered is recovered through variable charges, which penalizes large volume users. This result, according to Mr. Bailey, creates an intra-class subsidy issue not considered by Mr. Brosch. *Id.* at 18. In Mr. Bailey's opinion, the cost of connection does not vary with usage and should be recovered through fixed charges.

No party disputed that PSI's proposed connection charge of $9.90 is cost justified. Nor did any party dispute that connection costs do not vary with usage and should be recovered as a fixed charge. PSI has proposed a gradual increase, which will ultimately lead to the goal of cost causation — having customers who cause costs to be incurred be responsible for those costs. This Commission has repeatedly endorsed this fundamental principle of ratemaking. We find the development of PSI's proposed residential and commercial connection charge of $9.90 to be just and reasonable. We authorize PSI to increase the connection charge to Rates RS and CS in the manner described in Mr. Bailey's testimony (Pet. Ex. BB, pp. 2-3), commensurate with the relief granted herein and it is approved.

G. *PSI's Lighting Tariff Proposals.*

[105] (1) *Evidence*. PSI proposed several changes to its lighting tariffs (Rate SL — schedule for street lighting service, rate AL — schedule for area lighting service, and rate OL — schedule for outdoor security lighting) in order to streamline its offerings of lighting equipment by restricting the number of lighting options provided to customers, and decoupling the capital costs of the lighting systems from the tariff. Mr. Bailey indicated that the number of lighting types and fixtures has grown considerably over the years, and this has made the administration of PSI's lighting programs more difficult and time consuming. Pet. Ex. BB, p. 11. PSI proposed to freeze certain rate schedules (SL, AL and OL), and transition customers to an Outdoor Lighting Equipment Service ("OLES") agreement for maintenance and equipment costs, and Rate UOLS — Unmetered Outdoor Lighting Service or Rate MOLS — Metered Outdoor Lighting Service for the energy charges associated with the lighting equipment. *Id.* at 12.

Mr. Bailey explained that customers would benefit from these changes because, the OLES agreement provides a one-on-one equipment contract with the customer where the customer pays the current price of the lighting system. This locks in the customer's equipment purchase price, eliminates future rate increases, and eliminates subsidies to other lighting customers. Customers will have an option to pay for the lighting system up-front or over time, up to a maximum of ten (10) years. At the end of the equipment contract, the customer will no longer have a monthly payment for the equipment. In contrast, under rates SL, AL, and OL customers pay a monthly fee for the equipment as long as they require electric service. *Id.* Mr. Bailey also recommended eliminating several PSI lighting rates that were frozen.

OUCC witness Mr. Brosch commented that he did not object to PSI's proposals to freeze and phase out rates SL, AL and OL, as long as PSI continues to offer rate OLES at reasonable cost-based rates. Pub. Ex. No. 2, p. 113. Mr. Brosch noted that PSI should clarify its proposal for OLES pricing.

In response to Mr. Brosch's testimony, PSI witness Bailey confirmed that future charges under OLES will continue to be cost based.

More specifically, PSI committed to the use of actual cost to acquire and install the lighting systems with appropriate loadings, and will use a rate of return for the computation of levelized fixed charge rates based on the most recent figures approved by the Commission. In brief, the calculations for the recovery of capital related costs will be the same as PSI has used historically in the development of its lighting rates; however, the recovery period will be no longer than ten years, and can be less at the customer's discretion. Additionally, PSI committed that the capital portion of the various lighting rate schedules will not be increased as long as the same lighting system is used by the customer.

(2) *Discussion and Findings*. PSI's proposed changes to its lighting schedules are hereby approved. Under the new rates, customers will pay cost-based rates for the lighting equipment, and a separate kwh charge for the energy used. No party objected to the streamlining of these tariffs and we find the new proposal to be a more workable and efficient method of offering various lighting services to PSI's customers.

H. *General Terms and Conditions for Electric Service*. PSI proposed certain minor changes in the General Terms and Conditions for Electric Service contained in its retail electric rate tariff. Pet. Ex. BB-3. No party objected to any of PSI's proposed changes to its General Terms and Conditions. Based on the evidence presented, and the lack of opposition to the proposed changes, we find that PSI's General Terms and Conditions for Electric Service as contained in its proposed retail electric rate tariff are reasonable and should be approved.

I. *Undisputed Changes to Tariff.* In addition to the changes, deletions and additions to or from PSI's current retail electric rate tariff previously discussed, PSI proposed various other rate schedule changes, deletions and additions which were not disputed in this proceeding. All of such changes, deletions and additions to or from PSI's current retail electric rate tariff that were not disputed are hereby approved, even though they may not be specifically discussed herein.

10. Fuel Cost Adjustment Charge Issues.

[106, 107] A. *New Base Cost of Fuel*. PSI proposed in this proceeding to increase the base cost of fuel to be used in its fuel cost adjustment charge proceedings from 14.112 mills per kWh to 14.484 mills per kWh. Pet. Ex. X, pp. 34-35. No party challenged such proposal. We find that such proposal is reasonable and proper and should be approved. When PSI files its new schedule of rates and charges as ordered below, PSI should file with the Electricity Division of this Commission a new base cost of fuel as approved by this Finding, and a new fuel cost charge as approved on the date of approval of the new rates and charges, modified to reflect the new base cost of fuel.

[108] B. *Authorized Net Operating Income for Fuel Cost Adjustment Charge Purposes*. For purposes of the earnings test contained in the fuel cost adjustment charge statute, and consistent with our return findings in this Order, PSI shall be authorized to earn $267,500,000, prior to any additional return on qualified pollution control property approved by the Commission, pursuant to Ind. Code §§ 8-1-2-6.6 and 6.8, not taken into account in this case as of the August 31, 2003 update of Petitioner's plant for rate base purposes. The Commission also finds that, for purposes of computing the authorized net operating income for IC 8-1-2-42(d)(3), the increased return shall be phased-in over the appropriate period of time that the Petitioner's net operating income is affected by the earnings modification as a result of the Commission's approval of this Order.

[109] C. *OUCC Recommendation to Restate PSI's Books and Records for FAC Earnings Test Purposes*. Mr. Brosch recommended that the Commission recognize that the FAC earnings test is vulnerable to serious distortions due to accounting reclassifications and what Mr. Brosch termed as abusive levels of selective rate tracking and excessive cost deferrals. Pub. Ex. No. 1, pp. 20-23 and 127. In fact, Mr. Brosch asserted that the FAC earnings tests cannot be relied on to backstop inappropriate regulatory policies or the approval of piecemeal rate trackers and accounting deferrals. Mr. Brosch took particular exception to the Company's accounting for mark-to-market valuation adjustments recorded by the Company pursuant to Financial Accounting Standards Board Statements Nos. 133 and 138. Mr. Brosch explained that from late 1997 through November 2001, the Company recorded unrealized gains and losses relating to the market value of certain trading positions above-the-line. Mr. Brosch quoted from Mr. Farmer's prefiled testimony wherein Mr. Farmer stated that PSI began recording mark-to-market gains and losses below-the-line in December 2001 in response to an accounting directive from the Chief Accountant of FERC that was received in August 2001. *Id.* at 122. The effect of this accounting change was that such revaluations would not thereafter be included in reported utility operating income.

Mr. Brosch objected to the inconsistency between the accounting policy before and after the FERC directive. He proposed that this Commission should direct PSI to restate its books for purposes of the FAC earnings test, to reflect the application of either an above-the-line or below-the-line classification of mark-to-market gains and losses across all relevant reporting periods. Mr. Brosch sponsored an attachment to his testimony (MLB-3) which purported to show that if mark-to-market gains and losses had been excluded from jurisdictional above-the-line income, PSI's cumulative earnings differential through the relevant period in PSI's FAC58 would have shown a cumulative earnings excess of $58.3 million rather that the cumulative earnings deficit of $6.6 million reported by PSI.

PSI witness Farmer urged this Commission to reject the OUCC's invitation to retroactively restate its FAC earnings test results due to the fact that the FERC now directs utilities to account for mark-to-market gains and losses below-the-line. He observed that, with one exception related to the accounting for PSI's Marble Hill related costs, which by order of the Indiana Supreme Court were directed to be excluded from ratemaking processes, the FAC earnings test has always been calculated by reference to a utility's actual books and records. Pet. Ex. QQ, p. 44. Mr. Farmer testified that PSI has faithfully calculated its earnings test results by reference to its actual books and records, complying with FERC-mandated accounting requirements, including the directive to record mark-to-market gains and losses below-the-line, beginning in 2001. *Id.* It was Mr. Farmer's view that the Indiana custom and practice of following actual books and records should not be changed retroactively to produce a different result from that shown by the Company's books and records.

D. *Discussion and Findings on this Issue.* We are mindful of the fact that accounting principles represent a dynamic rather than a static set of rules, and that changes in accounting principles are typically applied on a prospective as opposed to a retroactive basis. We also recognize that there will likely be many such changes in the future. An important principle of regulation is that a utility maintain its books and records in accordance with generally accepted accounting principles and orders of the bodies that regulate the utility. There is no suggestion here that PSI has done anything other than act in accordance with this principle. We do not believe it would be good policy to require a utility to restate its income in a way that does not reflect its actual books. For the reasons stated above, we reject the OUCC's recommendation that PSI adjust and retroactively restate its books for FAC earnings test purposes.

11. Purdue University Issues.

[110, 111] A. *Evidence.* Intervenor Purdue University ("Purdue") witnesses, Mr. Van Meter and Ms. Haase suggest Rider 67 — and its successor Rider 70 — should not be applied to Purdue because it is unfair for Purdue to pay costs to meet PSI's peak demand when Purdue has self generation that can meet Purdue's peak load requirement. Purdue has a special contract with PSI. Ms. Haase also complains that PSI failed to update the proportionate contribution to peak demand, noting that Purdue installed significant self generation after entering into its contract with PSI. Purdue Ex. No. 2, pp. 8-9. For this reason, Ms. Haase recommends that PSI update its load calculations when costs are

updated. *Id.* at 11. Additionally, Mr. Van Meter complains generally about the volatility that trackers provide in Purdue's bill. He noted that trackers make up more than 10 percent of Purdue's bill to PSI, and cause great fluctuation in Purdue's bill, making it difficult to budget. Purdue Ex. No. 1, pp. 9-10.

In response, PSI witness Bailey stated that whatever load Purdue places on PSI's system during peak load conditions contributes to PSI's peak. In addition, in accordance with operating criteria, PSI must carry spinning and supplemental reserves associated with whatever Purdue load it is experiencing. The stability and predictability of Purdue's load is immaterial to this process. Pet. Ex. SS, pp. 12-13. Therefore, PSI must carry, and plan for, sufficient reserves attributable to meeting the load that Purdue imposes on PSI's system.

Mr. Bailey explains that Ms. Haase's contention, that PSI has failed to update the proportionate contribution to peak demand, is simply incorrect. As the lead negotiator of the Purdue contract, Mr. Bailey noted that PSI recognized that Purdue's load would change as a result of their additional generation. In the development of the allocators in Cause No. 40003, PSI made a *pro forma* adjustment to reflect the amount of load Purdue expected to take from PSI following the addition of its new generating equipment. *Id.* at 13. In response to Ms. Haase's contention that PSI should update its load calculation when costs are updated, Mr. Bailey explained that while the loads of Purdue are readily ascertainable, the class loads for PSI's major rate schedules are not. Allocators for PSI's major rate schedules are derived through load research and require an extensive study. Mr. Bailey comments that it is not practical or cost effective to update them outside the context of a rate case. *Id.*

In response to Mr. Van Meter's concern about the volatility that rate tracking mechanisms produce for Purdue, PSI indicated that it understands the concern, but that Purdue probably has more certainty in its electric bill than any other PSI customer, due to its special contract. Mr. Bailey noted that Purdue's electric bill from PSI was only 0.78% of its budget for 2002-2003. *Id.* at 14.

At the evidentiary hearing Purdue entered into three stipulations, namely: (1) Purdue places load on PSI's system during PSI peak load conditions; (2) PSI must carry and plan for reserves attributable to meeting all of its anticipated load, including the load associated with Purdue's contract; and (3) there are expenses other than purchased power that Purdue has difficulty accurately budgeting.

B. *Discussion and Findings.* As to the applicability of PSI's Summer Reliability Tracker to Purdue, we find that it is appropriate. Purdue concedes that it placed load on PSI's system at times of peak demand, and that PSI must carry and plan for reserves, including reserves to meet Purdue's needs. Purdue's self generation does not change the fact that it contributes to PSI's peak and should pay its fair share of purchased power costs — both energy and demand components. Concerning Purdue's complaint that PSI failed to update Purdue's contribution to peak demand to account for its additional generation, we find that not to be the case. Mr. Bailey explained that PSI took the additional self generation into account when calculating Purdue's contribution to peak demand. Additionally, we find that there is no basis for updating demand allocators every time costs are updated as proposed by Purdue. We agree with Mr. Bailey, that updating demand allocators outside of a rate case is not practical or cost effective.

Finally, concerning the volatility of trackers, while we understand the concern, the record reflects that trackers were 10% of Purdue's bill, and electricity makes up less than 1% of Purdue's budget. Based on the evidence presented in this Cause, we do not find the volatility of trackers to be overwhelming to Purdue.

12. Holding Company Issues.

[112] A. *Evidence.* CAC witness Christopher Williams testified that Cinergy's holding company and business unit structure lends itself to abuse and conflicts of interest, claiming that the organizational structure, operating policies and executive pay and performance programs of

Cinergy since the merger between PSI and CG&E in 1994 have had the effect of "hollowing out" PSI, significantly compromising the corporate integrity of PSI in performing its public service role in order to serve the total shareholder return goals of Cinergy. CAC Ex. A, p 7.

CAC witness Michael Sheehan also indicated that PSI has been "hollowed out" as Cinergy has been gradually dismantling PSI's management control over its utility business and operations and transferring that control to one or another of Cinergy's unregulated subsidiaries. CAC Ex. C. p. 36. He said that this was so with respect to control over PSI's operations, the division of loyalties in management, and the structure of incentive pay for executives. Dr. Sheehan pointed out that PSI managed much of its operations via service agreements with affiliates, which are unregulated and which, in his view, have their own interests to maximize. *Id.* at 37-40. He also pointed out that many of the management positions "ostensibly working for PSI and having loyalties to PSI and its function as a regulated utility are employees of, or hold positions with, one or another of Cinergy's unregulated subsidiaries." *Id.* CAC witness Mr. Biewald claimed that the JGDA was extremely complex and subject to manipulation. CAC Ex. B, pp. 22-23. He said that each of the 14 PSI officers listed in Cinergy's 2002 Annual Report on Form 10-k is an officer of at least one other unregulated Cinergy subsidiary or Cinergy itself, and none is actually employed by PSI, but rather, by Cinergy Services Inc., or Cinergy Power Generation Services Inc. *Id.* at 41.

Dr. Sheehan also claimed that the structure of executive incentives at Cinergy predominantly favor improving the financial condition of Cinergy, as opposed to PSI. Dr. Sheehan concluded that Cinergy's executive incentive programs serve to direct the attention of PSI's executives and affiliate executives working at PSI away from PSI's public utility goals and responsibilities and focus it, instead, on Cinergy's goals, which are largely directed to its unregulated companies and operations. *Id.* at 43. As to what should be done about this, Dr. Sheehan recommended that this Commission establish a separate docket to investigate the ongoing dismantling of PSI via Cinergy's structural changes, and the accounting ramifications of the resulting already dense web of inter-affiliate, less than arms length transactions, claiming "there is too much smoke here to safely ignore." *Id.* at 44.

Both CAC and the OUCC also urged this Commission to initiate a separate investigation into PSI's implementation of the 2002 Joint Generation Dispatch Agreement, citing concerns with PSI's implementation protocols. OUCC witness Mr. Endris testified that an investigation was needed to fully understand the tremendous complexity of intra-company energy transfers and to ensure that customers have not been short-changed. Pub. Ex. No. 6, p. 52.

PSI witnesses Esamann and Reising disagreed with CAC's claims. Mr. Esamann observed that there are numerous safeguards in place to guard against abuse and conflicts of interest, and pointed out that many benefits and synergies (cost savings) accrue to PSI by virtue of its participation in a holding company, service company and business unit structure. The safeguards in place, he said, include federal and state laws; SEC, FERC and IURC oversight; PSI's own affiliate guidelines; FERC code of conduct requirements; the provisions of Cinergy's own service agreements; and, the provisions of agreements such as the 2002 JGDA and the Joint Transmission System Agreement ("JTA") between PSI and CG&E. Pet. Ex. DD, p. 36.

Mr. Esamann pointed out that the Cinergy merger has also allowed PSI and CG&E to share their best practices in a variety of areas that benefit customers, such as power production operations, T&D system operations, and customer service operations. Being part of a merged, holding company structure, he added, also allows PSI and CG&E to share both operating and financial resources. Important to customers, he said, is the fact that PSI has access to CG&E operating resources — such as CG&E generation through the JGDA, CG&E line trucks and line crews for storm restoration purposes, and a variety of expertise shared between the Cinergy companies. *Id.* at 37-38.

Expanding on Mr. Esamann's observation, Mr. Reising gave examples of protective financial safeguards in place, consistent with the legal separation between PSI and Cinergy. For example, the creditors of PSI clearly have the priority claim on the assets of PSI. Further, PSI is legally prohibited by the Public Utility Holding Company Act of 1935 ("PUHCA") from loaning money to Cinergy. PSI is also prohibited from guaranteeing the debt of Cinergy. Finally, there are no cross defaults between Cinergy debt and PSI; in other words, if there would be a default on Cinergy debt, that default would not trigger a default on PSI debt. Pet. Ex. EE, pp. 12-14.

Mr. Reising pointed out the financial support that Cinergy and the holding company structure have provided to PSI. For example, PSI's dividend payout ratio averaged only 31% for the four-year period from 1999 to 2002. By virtue of being a part of the Cinergy holding company structure, PSI was able to rely on its affiliates to fund the majority of Cinergy's dividend payout during this period. PSI's lower dividend payout ratio allowed PSI to improve its liquidity by almost $240 million versus what it would have been if PSI had met a standard 70% dividend payout ratio in each of those years.

Mr. Esamann disagreed with CAC's contention, and that of the OUCC, that the Commission should initiate a separate investigation into Cinergy's implementation of the JGDA. He observed that since April, 2002, PSI has worked hard to implement the JGDA in a manner consistent with both the spirit and letter of the agreement, working to fashion a number of business rules to implement the JGDA in a fair and objective manner. The Company's primary business rules, and the system energy transfers that take place under the JGDA, he observed, have been presented to the Commission in PSI's various FAC proceedings. Additionally, consistent with the terms of the JGDA and the underlying Indiana settlement agreement, he pointed out, the hourly market prices at which system energy transfers are priced are regularly audited by an independent audit firm, Jefferson Wells, and the related audit reports have also been presented to the Commission and to the OUCC in connection with PSI's FAC proceedings. *Id.* at 38-39.

Mr. Esamann further emphasized, as did Staff witness Borum, that the 2001 Indiana settlement agreement that accompanied the JGDA required PSI to meet with the Indiana signatory parties in January 2004, to assess the feasibility, efficacy and equity of continuing joint system dispatch and system energy transfers. Subsequently, in March 2004, PSI must initiate a proceeding before the Commission to begin a formal assessment of the functioning of the JGDA. *Id.* at 39.[11] Given these commitments and PSI's ongoing presentation of information concerning JGDA system energy transfers in its quarterly FAC proceedings, Mr. Esamann saw no reason for a separate Commission investigation into JGDA issues. *Id.*

B. *Discussion and Findings*. We believe that the record has adequately established numerous benefits of its merger — financial, operational, and synergistic — with CG&E, as well as the continuing presence of safeguards in place to protect against abuses. As for the JGDA, that Agreement will be the subject of our further review, under Cause No. 41954. Therefore, it would be premature for this Commission to establish an investigation into the JGDA at this stage of the proceedings. As for allegations that PSI has been "hollowed out" we do not believe that the evidence supports such a claim. This Commission is satisfied that PUHCA, in conjunction with additional safeguards, including the Commission's full jurisdiction over PSI's operations, remains in place. Therefore, based on the evidence presented on this issue we do not believe an investigation is warranted on this issue and hereby deny all requests for such an investigation.

13. Environmental Planning.

[113, 114] A. *Testimony Presented by the CAC*. CAC witness Chris Williams stated that the CAC is concerned that PSI has essentially adopted a policy of making capital investments to address environmental risk only to the extent and at the times required by law. CAC Ex. A, p. 8. CAC witness Mr. Bruce Biewald also noted that PSI's actions reflect an approach of doing the minimum required. According to Mr. Biewald, PSI has reduced its DSM expenditures, is too reliant on coal, and doesn't promote renewables. CAC Ex. B, pp. 37-43.

Mr. Biewald indicated that he believes there is a disparity between the way Cinergy/PSI manages its financial risk versus the way it manages environmental risk, arguing that PSI could more actively address its environmental risks. He conceded PSI has made some effort to diversify its generation mix, to reduce emissions from its existing plants, and to implement demand-side management programs. Mr. Biewald cited EPA data ("eGRID") showing Cinergy's generation mix in the year 2000 was 98% coal. Cinergy's emissions of CO2, SO_2, and NO_x in 2000 were 67 million tons, 560 thousand tons, and 154 thousand tons, respectively. According to Mr. Biewald, PSI's share of Cinergy's generation was about 59% in 2000 amount. PSI's share of CO2 emissions was also 59% of the total. For SO_2, PSI's share was higher (66% of total) and its NO_x share was lower (53% of total). These shares are based upon EPA's eGRID data. Mr. Biewald concluded that PSI should serve its customers with low cost, reliable power in a way that also diversifies the resource mix, cleans up the existing fleet of plants, and expands energy efficiency programs.

Mr. Biewald recognized that Cinergy has made investments in selective catalytic reduction ("SCR") to control NO_x emissions. He also noted that the repowering of Noblesville has increased the station's capacity and switched its fuel from coal to gas. This represents progress toward improving the efficiency of Cinergy's generating mix, and diversity of its fuel supply, but Noblesville represents just 300 MW of capacity in a system of about 12,000 MW. Mr. Biewald noted that PSI progress in diversifying it resource mix is very gradual, and not designed to meet environmental mandates that are not yet in place. Carbon dioxide emissions, fine particulates, and toxics such as mercury will likely need to be addressed by Cinergy in the near future.

Mr. Biewald also testified that demand side programs and renewable generating resources will be essential components of a low cost and prudent strategy to manage these emissions and associated risks. Given the Company's heavy reliance on coal generation and its pronounced vulnerability to new environmental regulations, Mr. Biewald suggests that aggressively pursuing DSM would seem to be a prudent environmental risk management policy that the Company should not overlook. In addition, Mr. Biewald testified that if PSI were to utilize an increased share of renewable generating capacity, this would also serve to reduce its exposure to environmental risks at costs that could reasonably be borne by customers. Mr. Biewald concluded his testimony by recommending that PSI should aggressively develop and implement cleaner generating resources and energy efficiency programs, in order to better serve its customers.

B. *PSI Testimony*. PSI witnesses agreed that environmental compliance planning is complex and that a utility the size of PSI cannot wait until the last minute, or until all requirements are fully known to begin such planning. Mr. Roebel testified that even after environmental compliance equipment is installed there remain operating challenges that must be addressed. He also described how PSI had to begin construction of, not just plan for, SCRs for compliance with the NO_x SIP Call while a court order staying those requirements was still in place. Mr. Roebel went on to explain that PSI has been actively planning and evaluating options for compliance with what the Company believes will be more stringent environmental requirements in the near future. Pet. Ex. KK, p. 4. Similarly Mr. Esamann explained that he believed that it is good public policy to encourage utilities such as PSI to present their environmental compliance plans to regulators and interested customer groups. Mr. Esamann went on to state that with mercury rules imminent the Company anticipates that it will be submitting an environmental compliance and cost recovery

plan to the Commission in 2004. Pet. Ex. DD p. 35.

C. *Discussion and Findings*. It is very clear for the record in this proceeding that major coal burning utilities such as PSI face significant environmental compliance costs and challenges. We agree with the CAC that it is prudent for PSI to begin evaluating options and planning to address environmental compliance issues well before the specific requirements are known with absolute certainty. Due to PSI's reliance on coal, the development of an improved resource mix, including the implementation of cleaner generating resources in conjunction with the utilization of energy efficiency programs, must be undertaken by PSI in order to ensure long term benefits to its customers. Accordingly, we anticipate and expect that future environmental compliance issues will come before us for review, and anticipate that PSI will take the steps necessary to address environmental compliance issues in a proactive manner consistent with our findings herein.

[115-118] *14. The FERC-Seven-Factor Test*. PSI witnesses Ronald R. Jackups and Edward F. Kirschner explained the FERC Seven Factor Test for classifying PSI's facilities as transmission or distribution and why PSI is seeking this Commission's approval of such classification in this case. Mr. Jackups testified that the FERC's Seven-Factor Test provides specific criteria to determine whether facilities should be classified as transmission facilities or distribution facilities under the Uniform System of Accounts. Pet. Ex. M, p. 63. Mr. Kirschner described in detail each of the tests. Pet. Ex. N, pp. 8-13.

Mr. Jackups said that the Midwest ISO Agreement requires that, prior to the end of the fourth year of the transition period of the Midwest ISO, each transmission owner shall file a request with the appropriate regulatory authority for a determination as to which of its electric system facilities are transmission facilities and which are distribution facilities, in accordance with the FERC's Seven-Factor Test. Pet. Ex. M, pp. 63-64. Mr. Jackups explained that because of the potential for changes in the transmission and distribution components of PSI's retail electric rates when the FERC's Seven-Factor Test is implemented, PSI elected to request this Commission's review of the Company's implementation of the FERC's Seven-Factor Test in this proceeding, so that any changes ordered by this Commission could be implemented within the context of this general rate case. Pet. Ex. M, p. 64.

Mr. Kirschner testified that the application of the FERC Seven-Factor Test resulted in the determination that all of PSI's electric delivery system facilities rated 69 KV and above, networked or radial, should be classified as transmission, and that all of PSI's electric delivery system facilities rated below 69 kV should be classified as distribution. Pet. Ex. N, p. 8 This represented no change from PST's previous classification of its facilities. Pet. Ex. N, pp. 8 and 14.

No party contested these classifications or objected to PSI's implementation of the FERC's Seven-Factor Test in this proceeding. We find that PSI has properly implemented the test and has appropriately determined which of its facilities should be classified as transmission facilities and which should be classified as distribution facilities for purposes of the FERC Seven-Factor Test.

[119-122] *15. Compliance with Hold Harmless Commitment*. PSI witness John P. Steffen submitted testimony regarding the Company's compliance with the "hold harmless" provisions of the Indiana Settlement Agreement as approved by this Commission in its March 29, 1994 Order in Cause No. 39897. Mr. Steffen testified that under the terms of the Settlement Agreement as approved by the March 29, 1994 Order, PSI was required to make affirmative showings with respect to net merger production capacity savings, net merger production cost savings and net merger non-fuel O&M cost savings Pet. Ex. C, p. 28. Mr. Steffen also said that the March 29, 1994 Order also required PSI to submit, as part of certain post-merger general rate case proceedings, information regarding 16 different categories. Mr. Steffen sponsored an exhibit that set forth this required information.

Id. at 27-31; Pet. Ex. C-8.

As to production capacity savings, Mr. Steffen said that Ms. Diane Jenner's direct testimony shows that PSI has used a target planning reserve margin of less than 20%, PSI's previous standalone margin, since the 1994 merger. Pet. Ex. C, p. 31. With respect to production cost savings, Mr. Steffen noted that under the 2002 Joint Generation Dispatch Agreement and as part of the Indiana Settlement Agreement in Cause No. 41954, PSI committed to provide its retail electric customers with $7.3 million in annual joint dispatch savings rate credits through 2004. Mr. Steffen testified that since April, 2002, PSI has implemented these credits through its fuel adjustment clause. *Id.* at 32. As to non-fuel O&M costs, Mr. Steffen sponsored an exhibit which showed that O&M costs for this proceeding would have been an estimated $8.3 million higher but for the merger. Pet. Ex. C-9. Mr. Steffen said that converting the non-fuel O&M costs to a per customer basis shows that PSI's annual non-fuel O&M cost per customer today is $579, compared to an indexed PSI annual non-fuel O&M per customer of $583 in 1992. Pet. Ex. C, p. 37.

Mr. Steffen testified that the non-fuel O&M savings produced by the merger exceed the cost of the merger and, therefore, PSI's customers have been held harmless from the effects of the merger and are clearly better off as a result of the merger. *Id.* at 38. Mr. Steffen added that it was noteworthy that this demonstration was made by referencing only non-fuel O&M savings, without any consideration given to the savings produced by deferred capacity, and joint dispatch and financing and fuel cost savings.

No party disputed Mr. Steffen's testimony regarding PSI's compliance with the "hold harmless" provisions of the Settlement Agreement in Cause No. 39897. We find that PSI has complied with the provisions of that settlement and the terms and conditions of the March 29, 1994 Order approving it.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. PSI shall be, and hereby is, authorized to place into effect rates and charges for retail electric utility service rendered by it in the territories served by it in the State of Indiana in accordance with this Order, including an annual increase to its rates and charges of $107,344,000 which represents an increase in operating revenues of 8.36%. Said rates will produce total jurisdictional electric operating revenues of $1,406,596,000 and, on the basis of annual jurisdictional electric operating expenses of $1,139,096,000, will result in annual jurisdictional electric utility operating income $267,500,000. PSI is hereby authorized to file with the Commission a new schedule of rates and charges which will properly reflect, establish and provide the operating revenues herein authorized. Said schedule of rates and charges should be in accordance with this Order.

2. PSI shall file with the Electricity Division of this Commission, appropriate tariffs using the rate design criteria specified in Finding No. 9 of this Order, including the rates and charges authorized herein for Phase I. Such Phase I rates and charges shall be effective upon such filing, subject to refund, pending review and approval by the Commission's Electricity Division. For Phase II, PSI shall file with the Commission's Electricity Division appropriate tariffs for such phases, including the applicable rates and charges authorized herein, at least forty-five (45) days before their respective implementation dates in order to allow sufficient time for review and approval. The rates and charges for Phases II shall be effective upon approval of the filed tariffs.

3. PSI's filing of its new Phase I rates and charges with the Commission's Electricity Division shall be accompanied by a simultaneous refiling of: (a) its fuel cost charge in effect on the date of the approval of such new rates and charges, modified to reflect the new base cost of fuel provided for in Finding No. 10A of this Order; (b) its Clean Coal Operating Cost Revenue Adjustment, Standard Contract Rider No. 71 to reflect the effect of costs that will be contained in base rates in accordance with the provision of this Order; and (c) its Qualified Pollution Control Property Revenue Adjustment, Standard Contract Rider No. 62 to reflect the effect of costs that will be contained in base rates in accordance with the provision of this Order.

4. PSI shall be, and hereby is, authorized to recover in its retail electric rates its deferred Dynegy buyout costs, as determined in accordance with Finding No. 6D(13)(a) of this Order, and to continue to defer, for subsequent recovery in its retail electric rates, the unamortized balance of its deferred Dynegy buyout costs, as determined in accordance with that same Finding.

5. PSI shall be, and hereby is, authorized to recover in its retail electric rates its deferred transaction costs and costs to achieve benefits associated with the 1994 Cinergy merger, as determined in accordance with Finding No. 6D(13)(b) of this Order, and to continue to defer, for subsequent recovery in its retail electric rates, the unamortized balance of its deferred transaction costs and costs to achieve benefits associated with the 1994 Cinergy merger, as necessary.

6. PSI shall be, and hereby is, authorized to: (a) recover in its retail electric rates its Midwest ISO-related deferred administrative costs, all as determined in accordance with Finding No. 6D(13)(c) of this Order; and (b) to continue to defer, for subsequent recovery in its retail electric rates, the unamortized balance of its Midwest ISO-related deferred administrative costs, all as determined in accordance with that same Finding.

7. PSI shall be, and hereby is, authorized to recover in its retail electric rates its post-in service deferred depreciation and AFUDC, as determined in accordance with Finding No. 6D(13)(d) of this Order, and to continue to defer, for subsequent recovery in its retail electric rates, the unamortized balance of its post-in service depreciation and AFUDC, all as determined in accordance with that same Finding.

8. Commencing with the first day of the month coincident with or immediately following the effective date of this Order, PSI is hereby authorized to place into effect the depreciation rates approved in Finding No. 6D(1) of this Order.

9. PSI's proposed classification of its electric delivery system facilities as transmission facilities and distribution facilities, as described in Finding No.14 of this Order, shall be, and hereby is, approved for purposes of the FERC Seven-Factor Test.

10. PSI shall be, and hereby is, authorized to implement the charges and credits for the payment of its Indiana property taxes incurred after the effective date of this Order in the manner provided in Finding No. 6D(11) of this Order.

11. PSI shall be, and hereby is, authorized to implement the Summer Reliability Standard Contract Rider, NO_x Emission Allowance Standard Contract Rider, and Midwest ISO Cost and Revenue Adjustment Standard Contract Rider, all as determined in Finding No. 9A of this Order.

12. PSI shall be, and hereby is, directed to participate in a collaborative process involving Commission Staff and other parties concerning PSI's RTP Program, all as provided in Finding No. 9B of this Order.

13. This Order shall be effective on and after the date of its approval.

APPROVED: MAY 18, 2004

FOOTNOTES

[1]Dr. Morin stated that all of his market-based estimates (CAPM, RP and DCF) include an adjustment for flotation costs, as these costs are incurred but not expensed at the time of issue, and therefore must be recovered via a rate of return adjustment. Pet. Ex. G, p. 42. Flotation costs include a direct component in the form of compensation to the security underwriter for its marketing/consulting services, for risks involved in distributing the issue, and for operating expenses associated with the issue. Flotation costs also include an indirect component in the form of downward pressure on the stock price as a result of the increased supply of stock from the new issue, the latter frequently referred to as market pressure. Pet. Ex. G, p. 42, and Pet. Ex. G, Appendix A.

[2]Mr. Kaufman stated that he had not quantified a specific basis point adjustment to his recommended 9.25% cost of equity for PSI if this Commission approved any combination of those three proposed trackers. Tr. at Q98-Q100. Mr. Kaufman also stated during cross examination that he had asked PSI to quantify the value of PSI's proposed trackers in a data

request and that PSI had failed to provide him with a response on that issue. Tr. at Q98.

[3]Mr. Kaufman noted that the Commission has accepted the quarterly dividend adjustment in prior cases, but indicated that he believes that if this approach is utilized a corresponding downward adjustment should be made to account for the timing of how a utility earns its profits (and invests them during the year). Pub. Ex, No. 8, pp. 48-49.

[4]However, this changed in Dr. Morin's October 2003 update which showed that his October 2003 DCF results were below his October 2003 CAPM and RP results. Pet Ex. G, p. 46; and Pet. Ex. TT, p. 3.

[5]We note that this August 1, 2003 decision was premised, in large part, in response to quality of service problems of the utility and that the 9.5% was only put into effect on an interim basis. *See*, 2003 N.J. PUC LEXIS 253 and 2003 N.J. PUC LEXIS 243.

[6]The Petitioner's rebuttal evidence did include such a 75% scenario. Pet. Ex. HH, pp. 4-5; Pet. Ex. HH-1; Pet. Ex. GG, pp. 6-10; and Pet. Ex. EE, pp. 5-6.

[7]Only the ECAPM remains as a model subject to any meaningful criticism from the experts in this Cause.

[8]Mr. Bailey observed that for a customer to be considered in the Company's migration analysis, the customer must be able to save at least five percent on its annual bill or have the potential to save at least $600 annually. *Id.* at 8. Mr. Bailey testified that the Company planned to notify customers following an order in this Cause detailing the potential bill savings. It will follow this letter with a personal telephone call if needed and a personal visit in some cases. *Id.*

[9]Mr. Selecky proposed a 10-year average, while Mr. Majoros used a 5-year average. Mr. Majoros made the same proposal with regard to production plant.

[10] With respect to another area of contention related to average service lives for a few accounts, Mr. Majoros proposed longer lives than those used by Mr. Spanos for six accounts. We find Mr. Spanos' testimony provides an adequate explanation on this issue and we decline to substitute the calculations of Mr. Majoros for only those few accounts.

[11]The initiation of discussions, as agreed in Cause No. 41954 (*Ind. Util. Reg. Comm'n*, September 11, 2001), was extended at the request of the parties until June 1, 2004.

EDITOR'S APPENDIX

PUR Citations in Text

[IND.] Re Indiana Michigan Power Co. dba American Electric Power, 216 PUR4th 257, Cause Nos. 42032, 42027, Dec. 17, 2001.

[IND.] Re Indiana-American Water Co. Inc., 169 PUR4th 252, Cause No. 40103, May 30, 1996.

[IND.] Re Peoples Gas & Electric Power Co., 138 PUR4th 320, Cause No. 39315, Oct. 21, 1992.

[IND.] Re PSI Energy Inc., 173 PUR4th 393, Cause No. 40003 Sept. 27, 1996.

[IND.] Re Treatment of Purchased Power Cost in Summary Fuel Adjustment Clause Proceedings, 196 PUR4th 155, Cause No. 41363, Aug. 18, 1999.

{IND.Sup.Ct.] Columbus Gas Light Co. v. Pub. Service Commission, 193 Ind. 399, P.U.R. 1923E 602, 140 N.E. 538 (1923).

[IND.Sup.Ct.] Indiana Pub. Service Commission v. City of Indianapolis, 235 Ind. 70, 12 PUR3d 320, 131 N.E.2d 308 (1956).

[U.S.Sup.Ct.] Bluefield Water Works & Improv. Co. v. West Virginia Pub. Service Commission, 262 U.S. 679, PUR1923D 11, 67 L.Ed. 1176, 43 S.Ct. 675 (1923).

{U.S.Sup.Ct.] Federal Power Commission v. Hope Nat. Gas Co., 320 U.S. 591, 51 PUR NS 193, 88 L.Ed. 333, 64 S.Ct. 281 (1944).

Re The District of Columbia Natural Gas, a Division of The Washington Gas Light Company

Formal Case No. 874
Order No. 13221

District of Columbia Public Service Commission
June 15, 2004

ORDER removing the cap of ten-percent of projected annual sales volume from the hedging program of a natural gas local distribution company (LDC), leaving the LDC free to make whatever hedging decisions it believes are prudent, subject to its current limits for operational flexibility and the possibility of a future prudence review. Commission also directs the LDC to undertake a simulation for the next hedging season and track the effects of a hypothetical derivative hedging program for the same volume of gas that is currently hedged by the LDC.

In 2001 the commission adopted a pilot hedging program for the purpose of determining whether hedging would provide consumers with some protection against wholesale gas price volatility. The pilot included a ten-percent cap to insure that the LDC did not over-commit to a hedge volume in excess of customer needs — a circumstance that could have forced the LDC to sell gas at a loss. However, the commission finds that the cap no longer serves its purpose inasmuch as the LDC limits its system-wide hedging volume based on the amount of gas that the LDC believes it can consume.

Commissioner Rachal dissents, arguing that the majority should send a clear signal to the LDC indicating that more should be done with respect to hedging. He favors raising the cap to 15-percent, claiming that eliminating the cap does not provide any guidance to the LDC regarding whether or not the commission supports efforts to hedge. Increasing the cap, Commissioner Rachal asserts, would definitively and affirmatively indicate to the LDC that more hedging should be done if the LDC finds hedging to be prudent under the relevant circumstances. Removing the cap entirely, he contends, has a chilling effect on hedging inasmuch as the uncertainty over what may be deemed appropriate after a prudence review looms larger without any guidance.

1. GAS, § 7

[D.C.] Procurement of supply — Acquisition strategies — Reducing price volatility — Hedging — Removal of 10-percent cap — Local distribution company.
p. 130.

2. AUTOMATIC ADJUSTMENT CLAUSES, § 32

[D.C.] Natural gas procurement — Local distribution company — Acquisition strategies — Hedging activities — Denial of preapproval or presumption of prudence — Local distribution company.
p. 130.

3. EXPENSES, § 126

[D.C.] Natural gas local distribution company — Cost of gas — Hedging activities — Denial of preapproval or presumption of prudence — Local distribution company.
p. 130.

4. GAS, § 7

[D.C.] Procurement of supply — Acquisition strategies — Reducing price volatility — Hedging — Denial of preapproval or presumption of prudence — Local distribution company.
p. 130.

5. GAS, § 7

[D.C.] Procurement of supply — Acquisition strategies — Hedging activities — Simulated derivative hedging program — Reporting requirements — Local distribution company.
p. 130.

6. GAS, § 7

[D.C.] Procurement of supply — Acquisition strategies — Reducing price volatility — Hedging activities — Local distribution company — Lack of guidance from commission — Dissent.
p. 131.

7. GAS, § 7

[D.C.] Procurement of supply — Acquisition strategies — Hedging activities — Simulated derivative hedging program — Local distribution company — Dissent.
p. 131.

8. EXPENSES, § 126

[D.C.] Natural gas local distribution company — Cost of gas — Hedging activities — Denial of safe harbor — Local distribution company — Dissent.
p. 131.

9. GAS, § 7

[D.C.] Procurement of supply — Acquisition strategies — Reducing price volatility — Hedging — Denial of safe harbor — Local distribution company — Dissent.
p. 131.

Tab C

from qualifying facilities that are dispatched by the utility will be adjusted in accordance with § 4(C)(7)(c);

c. rates established for purchases from qualifying facilities that coordinate their maintenance schedule with a utility will be adjusted in accordance with § 4(C)(7)(d); and

d. rates established for purchases will be adjusted in accordance with § 4(C) with § 4(C)(7)(e).

2. Any party may allege that any or all of the above standards are unreasonable as applied to a specific set of facts. Any party so alleging shall propose an alternative set of standards and shall have the burden of proving that (a) the application of the standards set forth above is unreasonable, and (b) the party's proposed standards are reasonable.

OHIO PUBLIC UTILITIES COMMISSION

Re Toledo Edison Company

Intervenors: Office of Consumers' Counsel, City of Toledo, General Motors Corporation, and Board of County Commissioners of Lucas County

Case No. 80-377-EL-AIR
April 9, 1981

APPLICATION *for authority to increase rates; granted in entirety. Amount of authorized increase limited to size of rate request.*

Valuation, § 25 — Rate base determination date.

[OHIO] Property not actually owned by a utility at date certain (the rate case valuation date) may not be included in rate base. [1] p. 574.

Commissions, § 19 — Jurisdictional conflicts — Nuclear power — Federal preemption.

[OHIO] The federal government has clearly preempted state regulatory authority over nuclear power. [2] p. 575.

Valuation, § 222 — Plant out of service — Rate base treatment.

[OHIO] When an electric utility's nuclear plant was out of service for 227 days during the test year and on the date certain (rate case valuation date), it was held more appropriate to normalize test-year plant operations than simply to remove the plant from rate base. [3] p. 575.

Valuation, § 96 — Accumulated depreciation — Rate base deduction.

[OHIO] The amount of depreciation expenses which has or has not been recovered through prior rates is irrelevant for purposes of determining a proper depreciation reserve to be deducted from rate base for rate-making purposes. [4] p. 579.

Valuation, § 224 — Construction work in progress — Rate base allowance.

[OHIO] The commission in its discretion may include construction work in progress in rate base, but only for projects at least 75 per cent complete and only so that the amount included does not exceed 20 per cent of the remainder of rate base. [5] p. 580.

Valuation, § 301 — Working capital allowance — Fuel inventories.

[OHIO] A 75-day coal and oil inventory requirement was approved for the purpose of computing a working capital allowance. [6] p. 580.

Valuation, § 202 — Canceled construction — Unamortized costs — Rate base treatment.

[OHIO] Unamortized expenses associated with canceled construction projects were excluded from rate base. [7] p. 584.

Expenses, § 95 — Payroll costs.

[OHIO] Payroll expenses were allowed on the basis of budget projections for future employee levels. [8] p. 587.

Expenses, § 89 — Regulatory compliance — NECPA — Energy audits.

[OHIO] The estimated cost of compliance with the National Energy Conservation Policy Act, and its requirement that electric utilities perform residential energy audits, was allowed for rate-making purposes. [9] p. 588.

Expenses, § 104 — Preoperational training costs.

[OHIO] Preoperational training costs incurred in connection with a nuclear power plant placed in operation during the test year were excluded from cost of service. [10] p. 589.

Expenses, § 35 — Cancellation costs — Amortization — Cost-of-service allowances.

[OHIO] The standard to be applied in determining whether to include in cost of service an allowance for amortized plant cancellation costs is whether such costs were reasonably and prudently incurred. [11] p. 589.

Expenses, § 35 — Cancellation costs — Amortization — Cost-of-service allowance.

[OHIO] Amortized plant cancellation costs were allowed for rate-making purposes. [12] p. 589.

Expenses, § 35 — Cancellation costs — Amortization — Cost-of-service allowance.

[OHIO] A rate-making allowance for amortized plant cancellation costs should include recovery of all costs reflected in allowance for funds used during construction. [13] p. 589.

Depreciation, § 7 — Expense allowance — In-service date.

[OHIO] A depreciation expense allowance related to plant placed in service during the test year, but after the rate base valuation date, was recognized for rate-making purposes. [14] p. 591.

Expenses, § 26 — Advertising — Employee strike — Back-to-work offers.

[OHIO] Costs associated with utility advertisements which were aired during an employee strike and which extolled the fairness of offers made by the company to the striking employees were disallowed for rate-making purposes. [15] p. 592.

Expenses, § 26 — Advertising — Customer services — Energy studies.

[OHIO] Costs associated with utility advertisements which advised prospective industrial customers that the company provided energy requirement studies and site selection services were allowed as part of cost of service, although the company conceded that the purpose of the advertising was to attract new industrial load. [16] p. 592.

Expenses, § 92 — Rate case costs — Amortization.

[OHIO] A two-year period for amortization of rate case expenses was rejected. [17] p. 593.

Expenses, § 10 — Inflation adjustment.

[OHIO] A proposed attrition allowance in the form of an across-the-board post-test-year inflation adjustment to reflect projected future expenses was rejected where the utility's financial integrity was not threatened. [18] p. 594.

Return, § 87 — Electric company.

[OHIO] An electric utility's overall rate of return was set at 11.44 per cent, that being the rate of return produced by approving the entire amount of the company's proposed rate increase, where rate of return evidence presented by company and staff witnesses had supported overall return rates of (1) 12.02 per cent and (2) between 11.36 per cent and 11.69 per cent. [19] p. 597.

Rates, § 253 — Application for increase — Form and contents.

[OHIO] The term "substance of the application," as used in a state statute outlining the required contents of a notice of application for a rate increase, implies, among other things, the amount of rate relief requested. [20] p. 598.

Rates, § 645 — Application for increase — Scope of proceedings — Amount of increase — Maximum limit.

[OHIO] The maximum amount of increase in rates which may be approved for a public utility is limited, as a general rule, by the amount of rate relief requested by the company in its filed notice of application for a rate increase. [21] p. 598.

Rates, § 81 — Jurisdiction — State commissions — Customer charge.

[OHIO] The commission has authority to approve a customer charge. [22] p. 600.

Rates, § 304 — Connection charges — Account activation charge.

[OHIO] A customer account activation charge was approved. [23] p. 602.

Rates, § 354 — Elective service — Appliances — Water heating rate.

[OHIO] Tariff language limiting eligibility for a special water heating rate to customers served as of an earlier date was interpreted as "grandfathering" individual customers, rather than service installations. [24] p. 603.

Before Newcomb, chairman, and Pines, commissioner.

By the COMMISSION:

Opinion and Order

The commission, coming now to consider the above-entitled permanent rate application filed by the Toledo Edison Company pursuant to § 4909.18 Revised Code, the staff report of investigation issued pursuant to § 4909.19 Revised Code; having appointed its attorney examiner, Barth E. Royer, pursuant to § 4901.18 Revised Code to conduct a public hearing and to certify the record thereof directly to the commission; having reviewed the testimony and exhibits introduced into evidence at the public hearing commencing February 19, 1981, and concluding March 9, 1981, and being otherwise fully advised in the premises, hereby issues its opinion and order.

History of the Proceedings:

The Toledo Edison Company, the applicant herein, is an Ohio corporation authorized to engage in the business of supplying electric service within this state. The company provides retail service to approximately a quarter million customers in a 2,500 square mile service territory which encompasses the greater Toledo area as well as all or parts of ten northwestern Ohio counties. As a public utility and an electric light company within the definitions of §§ 4905.02 and 4905.03(A)(4) Revised Code, applicant is subject to the jurisdiction of this commission pursuant to §§ 4905.04, 4905.05, and 4905.06 Revised Code. The company's present rates for electric service were established by this commission's order of February 29, 1980, in Case No. 79-143-EL-AIR (36 PUR4th 209), and became effective March 5, 1980.

On April 3, 1980, the Toledo Edison Company served and filed a notice of its intent to submit a permanent rate increase application pursuant to § 4909.18 Revised Code as required by § 4909.43(B) Revised Code and Rule 4901-1-36 Ohio Administrative Code. As a part of this prefiling notification, applicant requested that July 1, 1980, be fixed as the date certain for the valuation of property and that the twelve months ending December 31, 1980, be established as the test period for the analysis of accounts. The commission approved the proposed date certain and test year by entry of April 30, 1980. By motion of June 3, 1980, applicant requested waiver of certain of the commission's standard filing requirements. This motion was granted by commission entry of June 24, 1980. The application was submitted on July 3, 1980, and was accepted for filing as of that date by commission entry of July 31, 1980. The form of the legal notice proposed by the company was also approved, subject to minor modifications.

In accordance with the provisions of § 4909.19 Revised Code, the staff of the commission conducted an investigation of the matters set forth in the application and the related filings. A written report of the results of the staff investigation was filed January 14, 1981, and was served as provided by law. Objections to the staff report were timely filed by the applicant, and by the Office of Consumers' Counsel and General Motors Corporation who had been granted leave to intervene.

Pursuant to the commission's entry of January 28, 1981, the public hearing of this matter commenced February 19, 1981, before attorney examiner Barth E. Royer. The first day of hearing was held at city council chambers in Toledo, Ohio, to afford members of the public affected by the application the opportunity to present statements concerning the proposed increase. Subsequent sessions were held at the offices of the commission, 375 South High Street, Columbus, Ohio. Leave to intervene was granted to the city of Toledo and the board of county commissioners of Lucas county, Ohio, at the outset of the hearing, but these parties filed no objections to the staff report, nor did they actively participate in any phase of the proceedings. The recorded transcript of the proceeding and the exhibits admitted into evidence during the eleven days of hearing have now been certified to the commission by the examiner for its consideration.

APPEARANCES: Messrs. Fuller, Henry, Hodge, and Snyder, by Paul M. Smart and Fred L. Lange, Toledo, and Thomas R. Sheets, senior attorney, Toledo Edison Company, Toledo, on behalf of the applicant, the Toledo Edison Company; William J. Brown, attorney general of Ohio, by Jon Heller and Donn Rosenblum, assistant attorneys general, Columbus, on behalf of the staff of the public utilities commission of Ohio; William A. Spratley, consumers' counsel, by Margaret Ann Samuels and Timothy Jochim and Bruce J. Weston, associate consumers' counsel, Columbus, on behalf of the Office of Consumers' Counsel; Messrs. Bell and Clevenger, L.P.A., by Langdon Bell, Columbus, on behalf of General Motors Corporation, intervenor; Anthony F. Pizza, Lucas county prosecutor, and Nick Batt, assistant county prosecutor, Toledo, on behalf of the board of county commissioners of Lucas county, Ohio, intervenor; Frank P. Pizza, director of law, and Joseph Goldberg, assistant director of law, Toledo, on behalf of the city of Toledo, intervenor.

Commission Review and Discussion:

This case comes before the commission upon the application of the Toledo Edison Company, pursuant to § 4909.18 Revised Code, for authority to increase its rates and charges for electric service to jurisdictional customers. Applicant alleges that its existing rates are insufficient to provide it reasonable compensation for the service it renders, and seeks commission approval of rate schedules which would yield some

$64,527,000 in additional gross annual revenue based on its analysis of test-year operations. Although the rates noticed in connection with the proceeding would produce additional revenues in the stated amount, applicant's subsequent filings and updating adjustments would support an increase substantially in excess of $81 million, were the company to prevail on all contested issues in the case.[1]

The commission staff's initial recommendation, as set out in its report of investigation, was for an increase in the range of $58 to $64 million. However, the staff also revised and updated certain elements of its analysis, and were the commission to adopt the staff's present position on each controverted question, a pro forma revenue deficiency under existing rates in the range of approximately $63 to $69 million would result. Finally, were it not for its stance on the question of the proper rate-making treatment for the Davis-Besse nuclear unit and the costs associated with certain CAPCO project cancellations, the analysis presented by consumers' counsel, when adjusted to give effect to staff revisions in those areas where intervenor's witnesses accepted the staff approach, would support the need for a substantial percentage of the revenue increase requested by the company.

The commission is well aware that Toledo Edison received rate relief only a little over one year ago, and that the 18.25 per cent increase requested at this time is substantial. However, as the foregoing comments suggest, there are indications that the present request is conservative in light of the economic conditions now confronting this utility.

Rate Base

The applicant, the commission staff, and consumers' counsel each offered testimony and submitted exhibits in support of its respective rate base proposal in this proceeding. The following table compares the company and staff estimates of the value of applicant's property used and useful in rendering the service affected by the application as of the date certain of July 1, 1980. Adjustments to these proposals recommended by consumers' counsel will be discussed on an item-by-item basis below.

JURISDICTIONAL RATE BASE

	Applicant[1]	*Staff*[2]
Plant in Service	$ 963,963,881	$ 949,149,893
Depreciation Reserve	(186,008,556)	(184,721,729)
Net Plant in Service	$ 777,955,325	$ 764,428,164
CWIP	108,572,840	106,495,278
Working Capital	34,095,024	26,978,522
Other Items	24,553,550	-0-
Customer Advances	(44,763)	(94,063)
Deferred Taxes and Tax Credits	(43,541,699)	(40,066,354)
Jurisdictional Rate Base	$ 901,590,277	$ 857,741,547

[1]Applicant Exh 4, Schedule B-1.
[2]Staff Second Revised Schedule 7.

[1]This figure reflects the revenue deficiency shown on the company's six-and-six filing, and does not include applicant's revised rate of return recommendation or certain other adjustments proposed at hearing.

Jurisdictional property allocations are not in dispute in this proceeding. Thus, the disparity in the plant in service recommendations is attributable to the respective positions of the applicant and the staff on the eligibility of certain items for rate base consideration.

Land and Land Rights:

Consistent with its customary practice, the staff selectively sampled a number of land parcels owned by the applicant in order to determine if the property in question satisfied the statutory used and useful criteria. The inspection in this case produced a recommendation that adjustments be made for two parcels. Applicant objected only to the exclusion of $25,250 associated with its Bryan substation site. Upon review, the staff determined that it had excluded the parcel in question based on an erroneous entry in a company response to a staff data request, and withdrew the recommendation. Accordingly, the commission finds that this amount should be restored to rate base, and that the balance of the staff's land and land rights adjustment should be adopted.

Edison Plaza:

In arriving at its plant in service determination, the staff excluded a portion of applicant's investment in Edison Plaza, the company's 16-story office building located in downtown Toledo. Applicant does not currently require the entire structure for its operations, and leases office space on eight of the floors to private tenants. As the commission found in the company's last rate case, this leased space cannot properly be considered "used and useful" utility property within the meaning of the term as employed in § 4909.15 Revised Code, and the staff adjustment is consistent with this prior decision (Re Toledo Edison Co. [1980] 36 PUR4th 209). Applicant objected to this exclusion, but has presented nothing which would persuade the commission that our previous decision with respect to the legal question involved was in error.

By way of an alternative objection, applicant argues that if the commission is to accept an exclusion to reflect the leased portion of Edison Plaza, it should calculate the amount of the adjustment on an incremental basis rather than through the square footage allocation proposed by staff. As a review of our earlier order will indicate, the commission agreed with the theoretical merits of an incremental approach, but found the specific analysis presented by the company in that case to be deficient. Applicant had based its allocation on the differential in the estimated cost, in vintage dollars, of the construction of an eight-story building versus the estimated cost of the structure actually built. The commission's rejection of this method was based on a concern arising from the degree by which actual construction costs had exceeded the estimate, as it was obvious that the overrun was at least partially attributable to the construction of what became the leased portion of the 16-story building. Thus, it appeared that the company's method would necessarily understate the exclusion.

In the instant case, applicant has presented an incremental analysis in which this defect has been remedied. As anticipated, when actual construction cost data was utilized, the amount of the exclusion increased to 29.83 per cent. The commission finds the adjustment, as proposed by the company, to be reasonable, and will adopt applicant's calculation for purposes of our plant in service determination. In accordance with this finding, we will also adopt the company's adjustment to operating income necessary to reflect the exclusion of the leased property in lieu of that proposed by the staff.

Unused or Missing Items:

The staff recommends the exclusion from rate base of the jurisdictional net original cost of seven items of property which, as a result of its investigation, the staff concluded were not used, were missing, or had been retired from service prior to date certain. Applicant objected to the exclusion with respect to five of the items, and presented evidence in support of its argument that they should be restored to rate base. The commission has already considered the question of the coal docks at applicant's Bay Shore and Acme power stations, finding them to be properly regarded as used and useful property (Re Toledo Edison Co. Case No. 76-1174-EL-AIR, June 9, 1978). We sustain applicant's objections to the exclusion of these two items. The commission also sustains the company's objections to the staff's exclusion of a Dietz trailer and an air compressor whose existence the staff was unable to verify during its inspection. The evidence shows that the items were, in fact, in service, but were at remote job site locations at the time of the staff audit. We overrule, however, the objection to the exclusion of miscellaneous office furniture in storage at date certain. Although the amount in question is relatively small, inventory items of this type, assuming all other standards are met, are more properly considered in the working capital allowance than as plant in service.

In connection with this aspect of its investigation, the staff expressed the view that applicant should be required to shorten the interval between the physical inventories it conducts of its general plant assets. Applicant opposes this recommendation, explaining that its procedure is to undertake a field inventory of 20 per cent of general plant equipment accounts on a yearly basis, and that, given the relative magnitude of these assets to total plant investment, annual field inventories are not warranted from a cost standpoint. The commission will continue to monitor applicant's practices with respect to field inventories, but will not mandate a change in current procedures at this time.

Davis-Besse Common Facilities:

[1] As addressed in detail later in this discussion, CAPCO member companies have terminated certain nuclear generation projects including the planned construction of Units 2 and 3 at the Davis-Besse station. As a result of this decision, applicant seeks rate base recognition for land and common facilities at the Davis-Besse site heretofore allocated to the planned additional units. The staff opposes this adjustment, pointing out that the terms of the "buy back" of these facilities are still in negotiation and that the property in question was not owned by applicant at date certain. The staff did, however, include in rate base Toledo Edison's existing share of the common facilities based on its agreement with applicant's proposition that this property should now be considered used and useful in connection with the existing Davis-Besse unit, Unit 1. Applicant objects to the staff exclusion of the balance of the common facilities.

The commission decision on this issue is clear cut in light of the plain language of § 4909.05 Revised Code. The common facilities excluded by the staff were not the property of applicant at date certain and may not be considered in the rate base valuation. Applicant's objection is overruled. The commission does agree, however, that the proper amount of the exclusion is that shown in the text of the staff report, or $6,459,000, rather than the figure used by the staff in its original rate base calculation.

Davis-Besse Nuclear Plant:

[2, 3] The Davis-Besse nuclear plant is a generating facility co-owned by the applicant and the Cleveland Electric Illuminating Company. The plant commenced commercial operation in 1977 and has been the subject of considerable controversy in every rate proceeding instituted by the two companies since that date. There appear to be several principal causes for the furor the very mention of the name, Davis-Besse, seems to engender in these cases, and the commission, by way of preface to its discussion of the issue in this case, believes it appropriate to list and briefly comment on those that we can identify.

First, there is a genuine concern among many individuals, and we include ourselves in this number, as to the risks associated with nuclear generation generally, and the safety of Davis-Besse in particular. However, this is an area in which the federal government has clearly preempted state regulatory authority. Northern States Power Co. v Minnesota (CA8th 1971) 90 PUR3d 401, 447 F2d 1143, affd (1972) 405 US 1035; Stebbins v Ohio Pub. Utilities Commission (1980) 62 Ohio St 2d 431, 406 NE2d 525. We do not intend to indicate through this observation that we believe Davis-Besse to be unsafe. Indeed, the record in this case clearly indicates, just as it has in other cases wherein we have considered the unit's operations, that in each instance where a potential problem forced the unit off line, the problem was identified, reported, and remedied to the satisfaction of the Nuclear Regulatory Commission, the agency that does have authority in this area. As we pointed out in our decision in Re Cleveland Electric Illum. Co. (1980) 38 PUR4th 494, this plant has been subject to NRC scrutiny since the time it was on the drawing board and it was and is licensed to operate. Thus, while the risks associated with the plant's operation may be a very real concern in some sectors, this commission is not the appropriate forum in which to debate the question, a point which apparently has never really been fully recognized.

A second cause of the controversy surrounding Davis-Besse is the impact that inclusion of the plant in rate base has had on customer bills. Due to the rate of inflation during the period of its construction, the significant lag between the in-service date originally projected and the actual in-service date, and certain required design modifications, the plant ended up costing the company several times the original estimate. In this case, the Toledo Edison share of the net investment in Davis-Besse represents roughly one-third of the company's total rate base. The full rate impact hit the consumer in the midst of the post-1974 energy cost spiral, when customer frustration over repeated electric rate increase requests was already beginning to swell. The fact that Davis-Besse, in terms of production expense, is by far the cheapest source of energy available to either Toledo Edison or Cleveland Electric Illuminating Company provides little solace to those customers upon whom rate increases work such great hardships.

Next, we come to the matter of the unit's disappointing performance, the issue that has generated pages and pages of transcript in recent Toledo Edison and Cleveland Electric Illuminating Company rate cases. As consumers' counsel was so fond of reporting during this hearing, Davis-Besse has exhibited a cumulative capacity factor through year-end 1980 which ranks it among the lowest of all nuclear power plants with respect to this measure of performance. Although the commission has, for rate-making purposes, always normalized Davis-Besse operations so that base rates established will be based on a more reasonable level of operation, this does not insulate the customers from the higher fuel charges incurred when the unit is not running.

Finally, the commission must observe that there is an intangible aspect to the Davis-Besse controversy, which is, in part, a product of the other factors we have recited. Davis-Besse has, in effect, become somewhat of a symbol to those whose opposition to utility rate increases may not be tied strictly to legal considerations or sound regulatory theory. Its visibility lends itself to this use, and the commission has long recognized that in dealing with this issue we must peel away the rhetoric and take an unimpassioned look at the facts.

During 1980, the test period in this proceeding, Davis-Besse was out of service a total of 227 days and was not in service on the date certain. In the two prior Cleveland Electric Illuminating Company rate cases, Case No. 78-677-EL-AIR (May 2, 1979) and Case No. 79-537-EL-AIR (July 10, 1980), roughly similar outage rates prompted various parties to argue that the plant should not be included in rate base on the theory that it was not "used and useful" within the meaning of that term in § 4909.15(A)(1) Revised Code. The commission rejected these contentions and, in the earlier of the two cases, its decision on the point was specifically affirmed by the supreme court. City of Cleveland v Ohio Pub. Utilities Commission (1980) 63 Ohio St 2d 62, 406 NE2d 1370. Our initial review of the objections filed by consumers' counsel in the instant proceeding led us to anticipate that this same theory would be advanced again in this case, but upon review of the record relative to the Davis-Besse question, we are not clear as to exactly what it is that consumers' counsel is proposing. However, as the filed objection does begin by taking exception to the staff's failure to exclude the unit from net plant

in service, we will begin our examination at that point, and will attempt to treat all aspects of intervenor's position within this portion of the opinion and order.

The only reference to this objection contained in the prefiled testimony presented by consumers' counsel witnesses is a brief passage in the prepared testimony of Mr. Heithoff which indicated that consumers' counsel is proposing that an adjustment to the revenue requirement be made to disallow a return on the net investment in Davis-Besse. This is followed by a disclaimer with respect to any legal interpretations which might be involved, and the statement that consumers' counsel will deal with the legal aspect of the adjustment. When we turn to the transcript, we find that what the witness contemplated in these few lines was what he terms an "earnings penalty" which, in effect, is a denial of a rate of return on the unit in the proportion by which the commission anticipates that generation for the period for which rates are being set will be below a level deemed to be reasonable. The witness agreed that elimination of the plant from rate base would require complex adjustments designed to show the effect on system operations had the plant been totally unavailable (see Re Cleveland Electric Illum. Co., *supra*). Leaving aside the fact that denying a return on a portion of the rate base is tantamount to excluding property from the rate base and the fact that the promised legal interpretation which was reputed to support this earnings penalty has never materialized,[2] the witness specifically declined to offer any judgment as to what the earnings penalty should be as he had conducted no study of the matter.

Despite the fact that its witness emphasized that the adjustment he was proposing related to what should reasonably be anticipated in the way of future performance, consumers' counsel directed its entire attention to the past performance of Davis-Besse. Intervenor apparently places great faith in the res ipsa loquitor doctrine, as it asks the commission to find that the unit's disappointing performance to date can only be the product of management inefficiency and imprudence without presenting any evidence which would actually support such a conclusion. To be sure, consumers' counsel did pick its way through various NRC reports pointing out any negative aspect it could find, but when we look at the ultimate conclusions reached by the NRC inspectors, a totally different position emerges. The latest NRC management inspection report is a case in point. Consumers' counsel cites a passage indicating that in the area of procurement, which deals with material storage and handling, the company received a "poor" rating. However, a review of the entire document reveals that of the nine areas inspected and evaluated, the company received a "good" rating with respect to its training program, and an "average" rating in the other seven areas. This was the most favorable report issued to date in Region III. Of particular interest for the purposes at hand are the following excerpts.

"The generally favorable evaluation is considered a reflection of the efforts and resources applied by the Toledo Edison Company toward problems that were

[2]On brief, consumers' counsel did rewrite certain Ohio statutes in an attempt to provide authority for its position, but has yet to present any cognizable legal justification for this measure.

recognized earlier by the NRC Region III office and Toledo Edison management.

"As documented in previous NRC correspondence, the past regulatory and operating performance of the Davis-Besse nuclear power plant had been less than desired. However, it was the performance appraisals section's judgement that actions initiated by Toledo Edison Company since late 1979, partly in response to the inspection and enforcement efforts of Region III, have been responsive to identified concerns and should provide for improved future performance. These actions include a corporate reorganization which has increased emphasis in activities affecting the Davis-Besse plant."

Thus, even if we were to accept the earnings penalty concept advanced by witness Heithoff, which we do not, there would be no basis for such a penalty here under the test he proposes. Moreover, if we construe intervenor's repeated references to management imprudence as an attempt to invoke the provision of § 4909.154 Revised Code which requires that the commission disallow operating expenses incurred through imprudent management, we are still no closer to finding support for any additional adjustment in this case. The fact that operations are normalized for the purpose of setting future rates automatically brings the commission into compliance with the statute, as the actual cause of the reduced capacity factor which makes normalization necessary would be totally irrelevant.

Rather than accept consumers' counsel's unsupported assertions as to the reasons for Davis-Besse's low capacity factor, the more constructive approach is to examine the testimony and exhibits presented by Mr. Johnson, Toledo Edison Company's president and chief operating officer wherein he details the duration and cause of every outage experienced at Davis-Besse since the unit went on line in 1977, and the steps taken to bring the unit back into service. It is obvious that the bulk of these outages relate to circumstances which were beyond the control of the company. Mr. Johnson readily concedes that the performance of the unit to date has not been what the company would have liked, and describes the steps taken to improve its availability, including the retention of outside consultants and the formation of an in-house group designated as the nuclear mission.

Perhaps one of the most telling points with respect to the commitment of Toledo Edison management in the power plant production area is one that has been largely overlooked in this proceeding. Although we would certainly not suggest that the operation of a coal-fired unit is parallel to the operation of a nuclear plant, the performance of the company's fossil units certainly speaks, to some degree, to management's attitude toward power plant productivity. The fact is that the company's overall heat rate efficiency for its coal-fired generation system ranked 19th among the top 100 electrics in 1979, and Bay Shore station ranked in the top ten in the country. Bay Shore's capacity factor was well above the industry average.[3]

On March 23, 1981, consumers' counsel filed a motion with the commission requesting that we order an audit of Toledo Edison Company's management of the Davis-Besse nuclear power plant. In support of the motion, consumers' counsel rehashes many of the same arguments advanced on brief in support of their proposed but still undefined rate case adjustment. These arguments are equally ineffectual in this context. Quite apart from the question of the commission's authority to require such an audit, the more pertinent question is why we should do so in light of the evidence we have just recounted. The NRC reports indicate that the company has been responsive in remedying identified problems. The company has already retained outside consultants to assist it in the area of Davis-Besse productivity, and the company has submitted a report from its nuclear mission outlining the major steps which have and will be taken to respond to some of the items which have adversely impacted on the unit's availability. The motion should be denied.

The final component of consumers' counsel's Davis-Besse package is the novel proposal advanced by its witness Noack at hearing for the recovery of depreciation and nuclear fuel disposal expense associated with Davis-Besse generation through a customer surcharge rather than through base rates. As these costs are booked only when the unit operates, the witness theorizes that such a device would result in an equitable treatment for ratepayers, who would not be charged for the expense when the unit was not on line. There is certainly some logic in this proposal, but it is clear that there are a number of practical constraints which the witness did not fully consider. As we believe the record supports the use of normalized Davis-Besse operations as a basis for other cost-of-service elements, we will accord these items their customary treatment as well.

Depreciation Reserve:

[4] Section 4909.05(H) Revised Code requires that the commission determine the proper and adequate reserve for depreciation to be deducted from the original cost of applicant's used and useful property. The staff, in the course of its investigation, tested applicant's booked reserve against a theoretical reserve study and found the correlation satisfactory to support the use of the actual booked reserve as a starting point for its analysis in this area. The disparity in the reserve recommendations of the applicant and the staff is attributable, in part, to their respective positions on the plant in service issues previously discussed, but an additional adjustment recommended by the staff also accounts for a portion of the difference.

As a result of two company applications, this commission recently authorized Toledo Edison to revise its depreciation accrual rates (Case No. 80-529-EL-AAM, Case No. 80-1037-EL-AAM). Pursuant to commission order, the new accrual rates are to take effect May 1, 1981. The staff relied on the new rates in determining the depreciation expense allowance it recommends for purposes of this proceeding and, accordingly, restated the reserve to give effect to the change in rates. Applicant objected to the staff treatment, arguing that the resulting increase in the reserve serves to reduce rate base without recognizing that the increment attributable to the adjustment has never been funded through rates.

[3]Consumers' counsel, of course, did not propose an "earnings reward" to reflect this fact.

The commission's responsibility under § 4909.05(H) Revised Code is to establish a depreciation reserve for rate-making purposes in an amount "determined to be reasonable." The commission held on a number of prior occasions, including this company's last rate case, that this provision clearly contemplates adjustments to booked reserve in appropriate circumstances (Re Toledo Edison Co. [1980] 36 PUR4th 209; Re Oxford Nat. Gas Co., Case No. 78-1404-GA-AIR, Jan. 28, 1980; Re Pike Nat. Gas Co., Case No. 77-615-GA-CMR, July 6, 1978). The staff adjustment is designed to produce a match between its depreciation expense recommendation and date certain net plant, an objective we have identified as proper (Re Ohio Bell Teleph. Co. Case No. 79-1184-TP-AIR, Dec. 3, 1980). The amount of depreciation expense which has or has not been recovered through prior rates is irrelevant for purposes of determining a proper depreciation reserve for rate-making purposes (Re Toledo Edison Co., *supra*; Re Oxford Nat. Gas Co., *supra*; Re Pike Nat. Gas Co., *supra*). The commission's concern is to afford applicant a reasonable future earnings opportunity, not to second-guess past judgments which were assumed to be appropriate at the time they were made (Re Oxford Nat. Gas Co., *supra*). Depreciation, by its very nature, presents a moving target, and rates should be based, to the extent possible, on current perceptions of what the future will hold. Moreover, as we have repeatedly emphasized, the view that rates are designed to recover specific past expenses, or that these expenses are somehow traceable to actual dollars of revenue generated by those rates, completely mistakes the nature of the rate-making exercise (see, e.g., Re Ohio Edison Co., Case No. 77-1249-EL-AIR, Nov. 17, 1978; Re Columbus & Southern Ohio Electric Co. [1978] 24 PUR4th 261). Applicant's objection is overruled. After adjustments necessary to reflect our decisions with respect to other rate base issues, the commission is of the opinion that a depreciation reserve of $185,265,041 is proper and adequate for purposes of this case. Deducting this amount from the original cost of includable property results in a finding of jurisdictional net plant in service of $766,043,934.

Construction Work in Progress:

[5] Section 4909.15(A)(1) of the Revised Code provides that the commission may, in its discretion, include in its rate base determination a reasonable allowance for construction work in progress. The statutes limit eligibility for the allowance to projects which are at least 75 per cent complete, and further provide that the allowance may not exced 20 per cent of the remainder of the rate base. Applicant's proposed construction work in progress allowance of $108,572,840 reflected the jurisdictional date certain cost of nine construction projects. As a result of its investigation, the staff determined that four of the projects proposed for consideration did not meet the statutory eligibility criteria, and recommended an allowance of $106,495,278. No party objected to this staff recommendation, and the commission will adopt the staff's finding as the construction work in progress allowance for this case.

Working Capital:

[6] The applicant, the staff, and consumers' counsel each proposed an allowance for working capital to be included in the rate base valuation in accordance with the provisions of § 4909.15(A)(1) Revised Code. All three estimates were derived through the use of the formula approach and only a few issues have been raised through filed objections.[4]

Both the applicant and consumers' counsel objected to the staff's calculation of the fuel inventory component. Not surprisingly, the company claims that the resulting allowance is too low, while intervenor contends that it is too high.

There are a number of acceptable methods for determining the appropriate fuel inventory component of the working capital allowance, and the commission has, from time to time, employed different techniques for purposes of this calculation (Re Ohio Edison Co. [1980] 33 PUR4th 435). In this proceeding, applicant based its proposed total fuel inventory of $25,987,593 for coal and oil on the average of the 13 month-end balances in these accounts. The staff agreed, for reasons discussed below, with the use of this approach in connection with the oil inventory, but determined its recommended allowance for coal by first establishing what it believed to be an adequate supply, here seventy-five days, and then multiplying by the weighted cost of the average daily burn at the major generating stations. The resulting recommendation, which was revised to reflect necessary corrections identified by consumers' counsel witness Haskins, is $18,556,163. Consumers' counsel agreed with the staff's coal inventory calculation, as revised, but argues that the allowance for the oil inventory should be calculated with reference to the same 75-day assumption. Intervenor's recommended allowance is $16,863,281.

The commission begins its examination of the fuel inventory question with the general observation that, absent special circumstances, a company's actual inventory level provides a fairly solid clue as to what the applicant really considers to be an adequate inventory. Thus, the commission tends to be more skeptical of company claims for an allowance based on an alleged days' supply requirement that substantially exceeds that evidenced through its actual procurement practice, than in circumstances such as in the instant case where the company's experienced inventory levels provide the basis for the requested amount. However, the reasonableness of the days' supply represented by existing inventories must still be examined.

Applicant's witness Busby testified that, with respect to the coal inventory, the company endeavors to maintain a 60- to 90-day supply. The staff and consumers' counsel's 75-day recommendation falls at the midpoint of that range. In considering this issue in the company's last rate case, the commission agreed with applicant's position that the 80- to 85-day supply represented by the actual inventory was reasonable for purposes of the coal inventory allowance in light of special factors impacting on Toledo Edison, such as the distance of certain of its units from sources of supply (Re Toledo Edison Co. [1980] 36 PUR4th 209). However, based on the

[4]Consumers' counsel did object to the cash element utilized by the staff; but this objection is tied to its position on various expense and tax issues, not to the method of calculation.

staff's calculation, the actual inventory in this case represents a level far in excess of the days' supply found adequate in the prior proceeding. Applicant alleges that this is a function of the staff's method of computing average daily burn, which the company believes to be unreasonable.

For purposes of this proceeding, the staff considered only data from the last three months of the test year in determining the average daily burn for applicant's Bay Shore and Acme units. Daily burn for Bruce Mansfield Unit 2 was calculated with reference to consumption for September, October, and December of 1980. September consumption was, in effect, substituted for November, since the unit was off-line during that month. Average daily burn for Bruce Mansfield Unit 3 was computed using the capacity ratio of the two Mansfield units. The staff's objective in looking only to the last three months of the test year was to recognize the effect on fuel consumption attributable to the commencement of Bruce Mansfield Unit 3 commercial operations in the fall of 1980. Because a hypothetical system redispatch assuming the new unit was in service for the entire year was unavailable, the staff considered the last three-month experience as a reasonable surrogate, on the basis that the average kilowatt-hour generation during the last quarter was almost identical to the average kilowatt-hour generation for the entire year.

Applicant observes that this approach ignores the impact of scheduled outages at several of the company's most efficient and reliable units during the three-month budget period examined by staff, and points to the inconsistency in the staff excluding November results from Bruce Mansfield Unit 2 as unrepresentative while making no adjustment for outages at other units on the system. The commission concedes that the staff's calculation of the day's supply represented by applicant's existing coal inventory may suffer from certain infirmities, but given the state of the record relative to this subject, concludes that coal inventory allowance sponsored by the staff and consumers' counsel should be adopted.

The failure of applicant to introduce any supporting detail into evidence precludes the commission from performing any independent calculation or analysis with respect to this days' supply question. This becomes especially critical in this case due to the related issue of the appropriate cost to be assigned in pricing the Bruce Mansfield fuel inventory. In the company's last fuel adjustment case, the commission restricted the passthrough of the cost of the Quarto coal used at Bruce Mansfield to the generally prevailing market price of approximately $35 per ton, although the actual cost is substantially in excess of that amount. (Re Toledo Edison Co. Case No. 80-241-EL-FAC, Jan. 28, 1981. See also Re Ohio Edison Co. Case No. 80-235-EL-FAC, Dec. 23, 1980.) Although the commission made no finding of imprudence in connection with the Quarto issue in that proceeding, the same considerations which prompted our decision in that case are of equal force here. The purpose is to establish a reasonable allowance for the fuel inventory, and this purpose will not be served if the actual prices paid for Quarto coal are used. Both the staff and consumers' counsel have recognized this in their calculations. As indicated above, applicant's record presentation on the

coal inventory question is such that we cannot break out the Quarto coal element from its proposed allowance, nor can we determine the impact of the annual availability of Bruce Mansfield Unit 3. The commission, therefore, finds that the coal inventory allowance recommended by the staff and consumers' counsel to be best supported by the evidence and will employ that figure for working capital purposes in this case.

Staff witness Heffner testified that the staff was originally inclined to use a similar 75-day supply level in connection with its determination of the proper allowance for the oil inventory, but, due to other considerations, ultimately recommended acceptance of the results of applicant's average 13 month-end balance method. Mr. Heffner readily acknowledged that basing the oil allowance on actual inventories resulted in a total available days' supply greatly in excess of the 75-day standard, but argued that, given the uncertainties attending oil supply and the rapid escalation in its price, maintaining the oil inventory at this level was a sound management practice. He offered a calculation showing the benefit to both the company and its customers of carrying this inventory, thereby forestalling the need to replace it, as opposed to incurring greater replacement costs at anticipated future prices for the commodity. Under the circumstances, we find the staff rationale persuasive, and will adopt the staff recommendation that existing oil inventory levels be considered reasonable for purposes of this proceeding. Consumers' counsel's objection is overruled.

In accordance with the working capital formula, the applicant, the staff, and consumers' counsel each proposed a tax offset in determining its recommended allowance and also reduced the allowance to reflect customer deposits. True to form, consumers' counsel, through its witness Heithoff, has proposed to offset the working capital requirement otherwise established by what it claims are additional sources of so-called "noninvestor"-supplied capital. The commission has explained time and time again why it is inconsistent with the use of the formula approach to single out specific balance sheet accounts for specialized treatment and we see no purpose to be served by going through the explanation in detail again, particularly since intervenor will apparently ignore it in any event. (See e.g., Re Ohio Edison Co. [1980] 33 PUR4th 435.) In this case, consumers' counsel's own witness agreed that if such offsets are to be made, it would be appropriate to also augment the allowance to recognize items such as prepayments, license fees, and rentals which serve to increase the working capital requirement. Indeed, the witness acknowledged that he, himself, has recommended an allowance for prepayments and compensating bank balances in cases in other jurisdictions. Further, applicant's counsel's cross-examination of the witness clearly reveals that his position in a given case generally conforms to the treatment previously authorized in the jurisdiction in question. In fact, his response to an inquiry by the presiding examiner strongly suggests that he would not have recommended the offsets for contract payments withheld, accrued bond interest, or the provision for injuries and damages had he known of this commission's prior rulings on these subjects. We do not refer to this testimony in any sort of attempt to embarrass the witness. In fact, we find his candor refreshing and hope only that the sponsoring party will finally get the message. The offset proposed by consumers' counsel must be rejected.

The following schedule presents in summary form the commission's determination of the allowance for working capital to be included in rate base for purposes of these proceedings. These figures take into account revisions necessary to reflect the disposition of other issues which affect the allowance.

JURISDICTIONAL WORKING CAPITAL ALLOWANCE

Cash Element (One-eighth of Adjusted Operation and Maintenance Expense, Excluding Fuel and Purchased Power)	$ 9,808,000
Materials and Supplies	6,729,653
Fuel Inventory	18,556,163
Tax Offset (One-fourth of Adjusted Taxes, Excluding FICA and Deferred FIT)	(8,174,188)
Customer Deposits	(491,158)
Jurisdictional Working Capital Allowance	$ 26,428,470

Unamortized Terminated Unit Costs:

[7] The January 23, 1980, CAPCO decision to terminate the Davis-Besse Units 2 and 3 and the Erie Units 1 and 2 nuclear projects has given rise to another rate base issue in this proceeding. In earlier rate orders involving other CAPCO member companies, the commission has permitted an amortization of costs incurred in connection with these canceled projects (Re Cleveland Electric Illum. Co. [1980] 38 PUR4th 494; Re Ohio Edison Co. Case No. 80-141-EL-AIR, Feb. 11, 1981). Toledo Edison seeks similar rate treatment for these expenditures, but also proposes rate base recognition for the unamortized balance of these costs. The commission rejected a rate base adjustment of this type in Ohio Edison, *supra*, and must do so again here. We need not reach the theoretical arguments addressed in support of this proposal, as the decision is clearly controlled by Ohio law. Pursuant to § 4909.15 Revised Code, only property used and useful in providing service at date certain may be included in the rate base valuation. Applicant acknowledges that these unamortized costs do not represent such property, and its objection to the staff's exclusion of the unamortized net-of-tax balance of $24,553,550 from rate base is overruled.

Customer Advances:

The staff reduced rate base by $94,063, which represents jurisdictional customer contributions in aid of construction. There were no objections to this recommendation and the commission will adopt the staff deduction in accordance with § 4909.05(I) Revised Code.

Accumulated Deferred Taxes and Tax Credits:

The staff's recommended rate base deduction for jurisdictional accumulated deferred taxes and tax credits drew only two objections. Applicant took exception to the staff's calculation of the deduction for the investment tax credits, pointing out that the staff had ignored the fact that the company had reversed certain prior years' credits during the test year as a result of the 1980 net operating loss reported for federal income tax purposes. At hearing, the staff acknowledged that it had failed to take into account the post-date certain ratable recording of the reversals, and revised its calculation accordingly. The commission, therefore, finds the rate base deduction now sponsored by the staff to be reasonable and will adopt the staff's revised recommendation for purposes of this proceeding.

Consumers' counsel objects to the staff's failure to recommend an additional rate base deduction to recognize the tax effect portion of any amortization permitted in connection with the terminated CAPCO projects. After a review of the record relative to this subject, we remain at a loss to understand the basis of this objection, or of the adjustment proposed by consumers' counsel witness Heithoff relating to it. The tax effect under discussion is the federal income tax deduction for the loss resulting from the cancellation of the projects, and is not a tax timing difference of the type that would support a legitimate rate base adjustment. The staff properly recognized this deduction in its cost-of-service analysis by reducing operating income upon which federal income tax expense was calculated by the gross amount of the annual amortization expense. Simply stated, the tax effect has been fully considered, and there are no resulting accumulated deferrals which represent a source of capital to the company. If we interpret the objection to refer to the tax effect relating to the unamortized balance, the proposed adjustment would still be inappropriate. The loss carried forward is net of tax, as the tax effect increment was amortized under the staff's calculation. Had the commission accepted applicant's proposal to include this unamortized balance in rate base, a deduction may well have been proper. However, because this company proposal was rejected, there is no rate base investment against which the tax effect can be offset. The objection is overruled.

Rate Base Summary:

In light of the foregoing, the commission finds the jurisdictional statutory rate base as of the date certain, July 1, 1980, to be as set forth on the following table:

JURISDICTIONAL RATE BASE

Plant in Service	$ 951,308,975
Depreciation Reserve	(185,264,041)
Net Plant in Service	$766,043,934
CWIP	106,495,278
Working Capital	26,428,470
Customer Advances	(94,063)
Deferred Taxes and Tax Credits	(40,066,354)
Jurisdictional Rate Base	$ 858,807,265

Operating Income

Applicant and the commission's staff each submitted an analysis of test-year accounts reflecting the results of operation under the company's present rates.

Consumers' counsel also presented evidence in support of proposed adjustments to staff's findings.

Operating Revenue

The staff determined that applicant would have realized gross annual operating revenues of $349,256,000 had its present rates been in place throughout the test period. Consumers' counsel raised several objections with respect to the staff's findings. The first of these, that the staff failed to adjust residential customer projections for the budget portion of the test year, requires little discussion. Staff witness Merrick indicated that the staff viewed the projections as reasonable, and also pointed out that the actual results for the test year showed that the company had, in fact, experienced lower residential sales than presented in its six-and-six case. Consumers' counsel did not pursue the matter on brief, and the commission will overrule the objection.

Due to the operation of the company's fuel adjustment clause, the determination of the proper level of the adjusted gross annual revenue turns, in part, on the treatment accorded fuel expense. All the parties agree that fuel costs should be annualized to year-end levels for purposes of determining adjusted revenues, but consumers' counsel takes issue with the specifics of the staff's method. The staff agreed with consumers' counsel's objection relative to the recognition of the commission's findings with respect to Quarto coal costs at Bruce Mansfield Units 2 and 3 in Re Toledo Edison Co. Case No. 80-241-EL-FAC, Jan. 28, 1981, noting that the decision had issued subsequent to the filing of the staff report. Review of the revised staff schedules distributed at the conclusion of the hearing indicates that the expense aspect of the adjustment was not properly carried forward to the summary schedule. Our findings incorporate the proper adjustment for this item.

Consumers' counsel also contends that the annualization of fuel revenues should be computed on a cents per MMBtu basis rather than the dollars per mwh basis which the applicant and the staff utilized for purposes of the adjustment. Consumers' counsel witness Haskins argues that the staff method implicitly recognizes relative efficiencies of the company's generating units, while the cents per MMBtu approach tends to even out this effect. On brief, consumers' counsel also notes that the staff used a cents per MMBtu method in the pending Cleveland Electric Illuminating Company rate case, Case No. 80-376-EL-AIR.

There are several observations to be made in connection with this consumers' counsel objection. First, the choice of the method to be used has relatively little practical effect on net operating income because the adjusted test period fuel revenues will correspond to the adjusted test period fuel expense. Further, as the company will be directed to adjust the base average cost of fuel in its new rates to the average cost experienced in the most recent period prior to the issuance of this opinion and order, this matching will continue to be preserved. Second, the method used by the staff in this case is identical to that approved in prior Toledo Edison cases and the fact that the staff may have recommended an alternative method in another case involving another company is evidence only that either method may be considered reasonable. Finally, we note that a cents per MMBtu approach is actually not any more responsive to the unit relative efficiency question than the dollars per mwh calculation, as the actual bill to an individual customer will always vary depending on the efficiencies of the unit on line when service is received. The commission is of the opinion that the staff's calculation of the annualized fuel revenues and expenses, subject to the revision with respect to the Quarto coal costs, should be adopted. After the additional adjustment to other income to reflect our decision on the Edison Plaza issue, the commission finds applicant's adjusted test-year operating revenue for purposes of this proceeding to be $349,186,000.

Payroll Expense:

[8] The applicant and the staff each based its recommended allowance for test-year payroll expense on the company's budget projections. Consumers' counsel objected to the use of the budget estimates for purposes of this calculation, pointing out that the actual number of employees in the projected portion of the test year was somewhat below the level in the budget forecast. From this data, intervenor concludes that the budgeted payroll expense overstates labor costs, and, therefore, does not serve as an appropriate guide for determining the allowance for this item. The commission must disagree.

As we have pointed out in previous discussions concerning the projected portion of the test year, forecasted results of operations provide an appropriate basis for establishing rates, in that the projections, if properly performed, may provide a more representative protrayal of the company's ongoing experience than do actual figures for the balance of the test year which may contain short-term aberrations (Re Columbus & Southern Ohio Electric Co. [1978] 24 PUR4th 261). We find nothing in this record to suggest that the use of projected employee levels in determining allowable payroll expense will lead to a unreasonable result. Although the actual experience in terms of number of employees was down from the forecast, employee man-hours and actual labor dollars expended were slightly higher than the estimates upon which the applicant and the staff relied in determining payroll expense. Consumers' counsel suggest that this phenomenon is attributable to significant overtime required in the second six months of the test year due to the extended Davis-Besse outage and heavy maintenance schedule. However, the close correlation between budgeted man-hours and actual man-hours will also yield to the interpretation that the company merely decided, for legitimate reasons, to fulfill its anticipated man-hour requirement during this period through a different mix of straight time and overtime. As applicant's witness Busby explained, total man-hours represent the critical figure in the calculation of the allowance because this is the figure that relates to total labor expense. We further note that the employee level used by the staff as a result of its reliance on applicant's six-and-six filing exceeded by only ten the total number of electric employees at date certain. Under these facts, there is no basis for a finding that payroll expense as determined by the staff should be adjusted. The commission overrules the objection.

Nuclear Fuel Disposal Expense:

This commission has addressed the

question of the proper rate-making treatment to be accorded the costs which will eventually be incurred in connection with the disposal of spent nuclear fuel on several prior occasions, including this company's last rate case (Re Toledo Edison Co. [1980] 36 PUR4th 209). In Re Ohio Edison Co. ([1980] 33 PUR4th 435), we observed that although a good deal of uncertainty attends the future of nuclear fuel disposal, our primary consideration is that disposal costs be reflected in the rates of those customers who receive the benefit of nuclear generation. To ignore these costs currently would unfairly burden future customers and would saddle future commissions with a most difficult problem. No party to this proceeding has suggested that this cost should not be recognized, but an issue does exist with respect to the calculation of the cost.

The staff based its original recommendation for this item on the per kwh price approved by the commission in Case No. 79-143-EL-AIR, *supra*. That figure reflected the $232 per kg estimate contained in a 1978 Department of Energy study upgraded to 1979 dollars. Applicant objected to the use of this same factor without any additional allowance for subsequent inflation. The company incorporated an inflation adjusted figure of $288 per kg in calculating its requested disposal expense allowance, and points to the recently revised DOE estimate of $371 per kg in support of the reasonableness of this estimate. Upon review of this new information, the staff agrees that, at a minimum, the company's inflation adjusted figure should be employed for purposes of this calculation, and the commission so finds. Consumers' counsel's objection relative to this subject has been disposed of by our earlier discussion of the Davis-Besse question.

Nuclear Electric Insurance Expense:

Consumers' counsel objected to a staff adjustment to recognize the cost of nuclear electric insurance which was payable in the second half of the test year, but which was not budgeted at the time of the filing of the company's six-and-six case. The commission approved a similar adjustment in Re Ohio Edison Co. Case No. 80-141-EL-AIR, Feb. 11, 1981. Consumers' counsel did not address the subject on brief, and the commission does not find the reasons offered by consumers' counsel witness Noack for rejecting the adjustment to be persuasive. Indeed, the witness' rationale is somewhat contradictory, for he agrees that cost changes of this type should normally be reflected in the rates authorized, then argues that no recognition should be accorded the item on the ground that budgeted data should not be adjusted. The objection should be overruled.

Residential Energy Audits:

[9] The commission, in several recent rate orders, has authorized an adjustment to cost of service to reflect the estimated cost of compliance with the National Energy Conservation Policy Act mandate that electric utilities perform residential energy audits upon the request of its customers (Re Ohio Power Co., Case No. 80-367-EL-AIR, April 1, 1981; Re Cincinnati Gas & E. Co. [1981] 42 PUR4th 252; Re Ohio Edison Co. Case No. 80-141-EL-AIR, Feb. 11, 1981). The staff recommended such an adjustment in this proceeding. Consumers' counsel has objected, contending that the costs involved are speculative and should not be recognized in fixing rates. We have fully considered this argument in the above-cited decisions, and will stand on our previous pronouncements on this subject as expressed therein. The objection should be overruled.

CAPCO Preoperational Training Costs:

[10] Applicant incurred preoperational training costs in the amount of $68,000 in connection with the commencement of the commercial operation of Bruce Mansfield Unit 3 during the fall of the test year. Consumers' counsel objected to the staff's failure to exclude this item from cost of service, and contends that it should be eliminated on the ground that it represents a nonrecurring expenditure. Applicant and the staff concede that this particular cost is nonrecurring, but argue that similar costs will be experienced in future years as other new units come on line. The commission is not persuaded by these arguments. On brief, applicant and the staff roundly criticize consumers' counsel witness Noack, the sponsor of the adjustment, for this lack of familiarity with future CAPCO generation plans, but neither the applicant or the staff produced any affirmative evidence in support of their position that the costs should not be viewed as nonrecurring. Consumers' counsel's objection should be sustained, and the cost of service will be adjusted accordingly.

Deferred Maintenance Adjustment:

Both the applicant and the staff adjusted production plant maintenance expense to reflect the deferral of maintenance originally scheduled for the first six months of 1980 to the last half of the test year. Consumers' counsel objects to the adjustment but we cannot accept the logic that underlies intervenor's position on this matter. Consumers' counsel witness Noack agrees that maintenance was, in fact, deferred from the first half of 1980, but contends that to allow the adjustment would be to permit the company to use twelve months of expected maintenance cost and ignore the actual results from the first six months. If, as the witness agrees, the purpose of the test-year analysis is to establish representative levels for particular expense items, why is it appropriate to use actual results for a period where production maintenance could not be carried out as expected? We have recognized similar adjustments for deferred maintenance in other decisions, and will do so again here (see, e.g., Re Cleveland Electric Illum. Co. [1980] 38 PUR4th 494).

Terminated CAPCO Generating Units:

[11-13] As indicated earlier in this discussion, applicant seeks an adjustment to amortize, over ten years, the costs incurred to date in connection with four canceled CAPCO nuclear units, Davis-Besse Units 2 and 3, and Erie Units 1 and 2. The staff supports the adjustment, but consumers' counsel objected to the amortization.

The commission has considered this issue in two recent cases involving other CAPCO member companies, and, in each instance, has found the amortization of these costs to be appropriate (Re Cleveland Electric Illum. Co. [1980] 38 PUR4th 494; Re Ohio Edison Co. Case

No. 80-141-EL-AIR, Feb. 11, 1981). Consumers' counsel's argument that the commission is legally precluded from authorizing this adjustment need not detain us, as we have addressed this aspect of the objection in the above-cited decisions. As in the earlier cases, there is no dispute that the costs in question do not represent rate base property, or that the projects will never provide service to customers. However, as we have previously stated, these facts are irrelevant, as this is not a rate base question. What the company seeks through this amortization is the recovery of costs incurred on behalf of the customers to assure that adequate service could be maintained. The standard to be applied, as in the case of any cost-of-service question, is whether the costs incurred were reasonable and were prudently incurred. As consumers' counsel's own witness, Mr. Heithoff, testified, if the commission determines that the initial decision to embark on the projects was prudent, and if the costs incurred to date are reasonable, and if it is determined that the units should not have been abandoned at a much earlier date, then the costs would properly be subject to amortization.

The record on this subject indicates that the above conditions have been satisfied. Consumers' counsel has not challenged the prudence of the initial decision to construct the units, nor has intervenor argued that costs incurred were unreasonable. The only question consumers' counsel has attempted to pursue is whether the decision to cancel the projects should have been made at an earlier point in time, specifically, March of 1979, although the significance of this date, apart from the fact the Three Mile Island incident occurred during this month, is somewhat lost on us. The testimony of Toledo Edison's board chairman and chief executive officer, Mr. Williamson, provides a detailed review of the circumstances leading to the initial decision to build the units, the deferrals of the various in-service dates in response to changing perceptions of future capacity requirements, and the ultimate decision to terminate construction. There is absolutely no evidence of imprudence with respect to any of these decisions, only the bizzare suggestion by consumers' counsel that upon receipt of a March, 1979, CAPCO planning committee report showing a further decline in the projected load growth of the member companies, CAPCO should have instantaneously made the billion dollar decisions to cancel the four units. Obviously, the information contained in this report had a bearing on the ultimate decision to cancel the projects, but much more had to be considered. Even if we were to attach the significance to this report that consumers' counsel erroneously implies is justified, can it be seriously argued that the interval between March of 1979 and January of 1980 is evidence of imprudence given the irreversible nature of the termination decision and the extension lead time now involved with the construction of additional capacity? The answer is clearly in the negative.

Consumers' counsel argues that if the cancellation costs are to be amortized, the equity portion of the AFUDC component should be eliminated from the adjustment on the theory that recognition of this item represents a return on the funds supplied by investors for these projects, which the commission has indicated it will not allow. The mere fact that consumers' counsel witness Heithoff

apparently believes that there is some meaningful difference between the so-called "equity" AFUDC and "debt" AFUDC is fairly conclusive evidence that he does not understand the concepts involved. That no such distinction exists is so obvious that no further comment is warranted. Further, the AFUDC associated with the units is properly regarded as an integral part of the cost of the projects, and should be included in the amortization. Consumers' counsel's objections to the staff's adjustment for the terminated unit costs are overruled.

Bruce Mansfield Unit 3 Adjustment:

[14] Toledo Edison has an ownership interest in Unit 3 at the Bruce Mansfield generating station. As previously indicated, this unit was placed in commercial operation in the fall of 1980, some three months subsequent to the date certain in this proceeding. Thus, although the investment in the unit has been recognized to the extent permitted by the applicable statutes through the working capital allowance approved in this case, it does not actually represent rate base property. The staff incorporated the income and expenses attributable to the plant's operation during the final quarter of 1981 in its cost-of-service analysis. As a part of this adjustment, the staff included an amount to reflect the depreciation expense associated with the unit during the last three months of the test year. Consumers' counsel objects to this component of the adjustment, claiming it does violence to the principle that depreciation expense should be related to the depreciation reserve adopted for rate base purposes. The staff recognizes this principle, but considers this adjustment a necessary adjunct to the recognition of the income effect of bringing Bruce Mansfield Unit 3 on the system. The commission has previously approved such an adjustment involving the same unit in Re Ohio Edison Co. Case No. 80-141-EL-AIR, Feb. 11, 1981.

In considering this question, the commission is confronted with a conflict between two valid rate-making concepts. We would agree with consumers' counsel that the fact that the staff has not treated Bruce Mansfield Unit 3 depreciation expense as a part of the depreciation allowance, but as a separate adjustment to the cost of service, may not change the essential character of this cost component. However, we believe that, in this instance, our judgment should come down on the side of recognizing all forms of expense associated with the revenues realized through the unit's operation. Assume for the moment that we were faced with a somewhat different scenario, one in which a major unit was retired from service after date certain. In such a circumstance, the commission would undoubtedly be asked to consider the argument that none of the costs associated with unit, including depreciation expense, should be recognized in test-year expense, on the grounds that without such an adjustment the test-year expenses would not provide a representative basis for fixing future rates. We would, of course, be receptive to such an argument, particularly as it relates to the depreciation question, for while there would still be depreciation accruals after date certain, and these would still be related to rate base depreciation reserve, there would be no future accrual requirement associated with the unit. The same factors which would support a rate-making adjustment to recognize the future unavailability of the unit, are operative here where depreciation expense, like other associated expenses, are incurred in connection with the unit's present and future availability. The objection should be overruled.

Advertising Expense:

[15, 16] In City of Cleveland v Ohio Pub. Utilities Commission (1980) 63 Ohio St 2d 62, 406 NE2d 1370, the Ohio supreme court held that an applicant utility's institutional and promotional advertising expenses are not properly includable in allowable test-year operating expenses, unless the company can demonstrate that these expenditures provide a "direct and primary benefit to its customers." City of Cleveland, *supra*, 63 Ohio St 2d at p. 62. Expenses relating to informational advertising and advertising designed to promote conservation were considered by the court to be appropriately included in cost of service.

In accordance with this decision, the staff eliminated general advertising expense in the amount of $82,417 from Account 930.1. Applicant objected to this adjustment, but presented no evidence that any of the dollars involved represented advertisements which would satisfy the standard enunciated by the court. This objection is, therefore, overruled.

Consumers' counsel also objected to the allowance for advertising expense proposed by the staff, contending that there were amounts included in Account 909, which nominally includes informational advertising, which are actually associated with ads which are institutional or promotional in character. Intervenor presented the copy of certain advertisements run by the company during the test year in support of this argument. The costs associated with the ads consumers' counsel considers objectionable is $37,786.

In Re Cleveland Electric Illum. Co. (1980) 38 PUR4th 494, order on rehearing, Jan. 21, 1981, we set out certain guidelines in an effort to assist parties to commission rate proceedings in determining what types of advertising are properly includable in allowable expenses in light of the court's holding in City of Cleveland, *supra*, and our own prior pronouncements on the subject (see Re Ohio Edison Co. [1980] 33 PUR4th 435). We noted that not all advertising was readily susceptible to classification under the categories delineated by the court and offered the following observation:

"All advertising imparts information. The characteristic which distinguishes informational advertising from promotional or institutional advertising as the terms are defined by the court in Cleveland, *supra*, is that the acceptable informational advertisement contains a message which the customer may act on in connection with his usage or prospective usage of the service provided. The critical question is whether the consumer can respond to his benefit, to the message conveyed."

After considering the specific ads introduced by consumers' counsel in light of the above test, the commission is of the opinion that some additional adjustment to advertising expense is warranted. Consumers' counsel Exh 7 groups the ads by type, and, for ease of reference, we will consider them on this basis. Group 1 includes ads which the company contends encourage conservation and load management. Our review indicates that these advertisements clearly serve that function, and, save for several ads dealing with the benefits of the heat pump, consumers' counsel did not pursue their exclusion through argument on brief. Group 2 advertisements, with an associated cost of $4,131, represent ads which applicant maintains are designed to improve employee morale. There is nothing in these ads which the customer can respond to in connection with his usage of service and these expenses should be excluded.

The Group 3 ads which drew objection present a close question. These two advertisements were run during a strike by some Toledo Edison office employees. The ostensible purpose of the ads is to advise customers that customer service operations will remain normal during the strike, but a good deal of the copy is devoted to extolling the fairness of the offers made to the striking employees. Given the fact that these advertisements arose in response to a specific situation, it might well be argued that they should not be considered as representative for purposes of determining an allowance for advertising expense, regardless of whether their primary thrust is deemed to be informational. This factor tips the balance in favor of exclusion and the associated cost of $3,894 should be eliminated from cost of service.

The Group 4 ad at issue is designed to advise prospective industrial customers that applicant provides energy requirement studies and site selection services. The company concedes that the purpose of this ad is to attract new industries to the service territory, but points out the benefit this would have on system load factors. We believe our comments relative to area development expenditures in Re Cincinnati Gas & Electric Co. Case No. 80-260-EL-AIR, March 18, 1981, are equally applicable here and will not exclude the cost of this particular ad.

The advertisements contained in Group 5 are clearly institutional in character as they are designed to influence public opinion on the question of nuclear power and to congratulate the company for its concern for the environment as evidenced by the pollution control equipment voluntarily installed at Bay Shore. These ads do impart information, but not of the type that a customer can respond to in connection with his usage of service. The cost of these ads, $11,504, should be excluded.

Consistent with the foregoing discussion, the commission finds that an adjustment to Account 909 advertising expenses in the amount of $19,529 should be approved for purposes of the proceeding, and that total test-year advertising expense should be reduced by $101,946.

Charitable Contributions:

Pursuant to the decision of the supreme court of Ohio in City of Cleveland v Ohio Pub. Utilities Commission (1980) 63 Ohio St 2d 62, 406 NE2d 1370, and consistent with this commission's interpretation of that decision as set out in Re Cleveland Electric Illum. Co. (1980) 38 PUR4th 494, order on rehearing, Jan. 21, 1981, the staff reversed applicant's proposed reclassification of test-year charitable contributions to operating expenses. Applicant took exception through its filed objections, but presented no evidence or argument in support. The objection is overruled.

Rate Case Expense:

[17] Applicant estimates the expenses associated with the preparation, filing, and prosecution of this rate case at $141,000. The staff agreed with the reasonableness of the requested allowance, but proposed that the amount be amortized over two years. The company objects to the two-year amortization, and cites its recent filing history as well as its avowed intent to submit another permanent application in the very near future in support of the proposition that the entire amount should be recognized in fixing rates in this case. Staff witness Merrick indicated that had he been aware of the company's intention in this regard, he would have been inclined to recommend a one-year write-off. Based on these circumstances, and given the commission's practice of excluding unamortized amounts from prior cases in a current proceeding, we believe that applicant's objection to a two-year amortization should be sustained.

Consumers' counsel again objects to any allowance for rate case expense. The commission again overrules the objection (see, e.g., Re Toledo Edison Co. [1980] 36 PUR4th 209).

Depreciation Expense:

The staff's recommendation relative to the appropriate allowance for depreciation expense is consistent with its determination of adjusted depreciation reserve discussed earlier in this opinion and order. Consumers' counsel did not take issue with the staff's depreciation expense allowance, but did object to a related adjustment through which the staff continued the amortization of a prior depreciation reserve deficiency originally authorized by the commission in Re Toledo Edison Co. Case No. 75-758-EL-AIR. Consumers' counsel witness Noack cites to the depreciation study conducted by Gilbert Associates and submitted as evidence in the company's recent depreciation case, Case No. 80-529-AL-AAM, in support of his claim that the current reserve deficiency is actually less than the remaining unamortized portion of the amount of the previously identified underaccrual recognized by the staff in its adjustment. Mr. Noack has ignored two important points in proposing a revised adjustment consistent with the results of the Gilbert study. First, the Gilbert study sought to remedy past underaccruals through the use of the remaining-life method, a method which was rejected by the commission in the depreciation case. Had we adopted this method rather than the whole-life method we have traditionally favored, the accrual rates, themselves, would have been higher. Thus, the disparity in the reserve deficiencies identified by Mr. Noack is a function of the Gilbert Associates' methodology. Further, as staff witness Fox explained, the deficiency in question relates solely to pre-1975 property, while the Gilbert study considered the adequacy of the existing reserve without regard to the vintage distinction established through the commission's prior approval of the amortization. The record clearly demonstrates that Mr. Noack's adjustment is inappropriate, and the commission overrules consumers' counsel's objection to the staff's treatment relative to continuation of the amortization previously authorized.

Attrition Adjustment:

[18] Applicant seeks commission approval of an allowance of some $7.5 million designed to recognize the effects of

attrition on the sufficiency of the rate relief authorized in this case. The staff opposes such an adjustment. The commission has reviewed a number of company requests for an allowance for attrition in its recent rate decisions. The specific proposals have taken a variety of forms, ranging from an augmentation of the rate of return as presented by this company in its last rate case (Re Toledo Edison Co. [1980] 36 PUR4th 209), to adjustments to cost of service to reflect projected future expenses, the approach at issue here. (See Re Dayton Power & Light Co. [1979] 29 PUR4th 145.) The commission has generally rejected adjustments of this type, finding them to be inconsistent with the test-year concept of rate regulation. (Re Columbia Gas of Ohio, Inc. Case No. 76-704-GA-AIR, June 29, 1977, affd'd sub nom. Franklin County Welfare Rights Organization v Ohio Pub. Utilities Commission [1978] 55 Ohio St 2d 1.) Although the commission does permit the annualization of certain known cost changes which are beyond the control of the company and which can be calculated with reasonable certainty, we have never accepted the wholesale adjustment of all expenses to projected post-test-year levels as is proposed in this case. In those instances where attrition allowances have been approved, the companies involved were facing extraordinary circumstances which threatened their basic financial integrity (see, e.g., Re Columbus & Southern Ohio Electric Co. [1979] 24 PUR4th 261). Here, applicant is not currently operating under emergency rates, nor is it precluded by charter or indenture coverage tests from issuing additional securities. The commission, therefore, rejects applicant's proposed attrition adjustment for those reasons repeatedly stated in those prior orders wherein we have addressed this subject. See, also, Franklin County Welfare Rights Organization v Ohio Pub. Utilities Commission, *supra*; and Masury Water Co. v Ohio Pub. Utilities Commission (1979) 58 Ohio St 2d 1.

Payroll Taxes:

As an accounting matter, applicant currently charges payroll taxes to operation and maintenance expense. The staff recommends that these taxes be charged, instead, to Account 408, and treated the adjusted test-year amount of these items as other taxes for rate-making purposes. Applicant did not object to the reclassification, but identified an error in the staff calculation. The staff revised its adjustment accordingly.

Consumers' counsel's objection to the staff's recommended allowance for payroll taxes is tied to its position on the employee expense question discussed above. As we have resolved that issue against consumers' counsel, the payroll tax objection should also be overruled.

PUCO Maintenance Tax and Consumers' Counsel Assessment:

Pursuant to the applicable statutes, the company's obligation for the PUCO maintenance tax and the consumers' counsel assessment is calculated with reference to total company intrastate gross receipts. The staff, consistent with long-standing commission practice, allocated these items based on jurisdictional intrastate gross receipts. Applicant objects, claiming that the entire obligation should be assigned to customers affected by this proceeding. This argument is without merit. The staff treatment properly tracks the basis upon which these obligations are incurred, as we have repeatedly held (see, e.g., Re Cleveland Electric Illum. Co. Case No. 78-677-EL-AIR, May 2, 1979). No question of "benefit" is involved. Jurisdictional customers should simply not be charged for the liability resulting from gross receipts arising from nonjurisdictional sales. The objection is overruled.

Gross Receipts Tax:

Amended Senate Bill No. 448, which became effective January 1, 1981, provided for a one per cent increase in the gross receipts tax applicable to Ohio utilities for 1981. Applicant's proposed allowance for the gross receipts tax as set out in its filings in this case did not, of course, contemplate this temporary increase in the tax rate. Applicant has, however, requested that an adjustment be made to reflect this change. Staff witness Merrick agreed that it would be appropriate to recognize this increased expense in the rates established in this proceeding, assuming safeguards against a potential overrecovery could be established, or to provide for a recovery through the vehicle of a special surcharge of some type. Consumers' counsel opposes any adjustment for this item.

The commission has pursued the question of the proper treatment of the temporary gross receipts tax in Case No. 80-1245-AU-COI, a generic proceeding in which Toledo Edison has participated. We believe that there are circumstances present in the instant case which render it reasonable to defer our determination of the question as it relates to Toledo Edison to the generic docket. The commission has authorized recognition of the temporary tax increase in base rates in our recent decisions in Re Ohio Edison Co. Case No. 80-141-EL-AIR, Feb. 11, 1980, and Re Cincinnati Gas & E. Co. (1981) 42 PUR4th 252. However, in this case, as will be discussed, *infra*, the commission has authorized the total revenue increase requested by the company and has further determined that the relief granted should not exceed that which would have been generated by the noticed rates. To be sure, had the company known of this change at the time of the instant filing, it would have increased its request accordingly; but given the present posture of the matter, the only way to provide for possible recovery is to take up the Toledo Edison situation in the context of the determination of the generic case. This disposition of the matter is consistent with our recent order in Re Ohio Power Co. Case No. 80-367-EL-AIR, April 1, 1981, wherein we were confronted with similar circumstances.

Operating Income Summary:

Consistent with the foregoing discussion, the commission finds applicant's jurisdictional adjusted operating income for the twelve months ending December 31, 1980, the test period in this proceeding, to be as set forth on the following schedule:

ADJUSTED OPERATING INCOME
(000's OMITTED)

Operating Revenues	$ 349,186
Operating Expenses	
Operation and Maintenance	$ 195,811
Depreciation Expense	32,642
Taxes Other than FIT	31,512
Federal Income Tax	24,338
Total Operating Expenses	$ 284,303
Net Operating Income	$ 64,883

Proposed Increase

A comparison of jurisdictional operating revenues of $349,186,000 with the allowable jurisdictional expense of $284,303,000 indicates that under its present rates applicant realized income available for fixed charges in the amount of $64,883,000 based on adjusted test-year operations. Applying this dollar return to the jurisdictional rate base of $858,807,000 results in a rate of return under present rates of 7.56 per cent. This rate of return is well below that recommended as reasonable by any of the expert witnesses presenting testimony on the subject and, accordingly, the commission must conclude that the company's present rates are insufficient to provide it reasonable compensation for the service rendered customers affected by the application. Rate relief is clearly required at this time.

Under the rates proposed by applicant, additional gross annual revenues of $64,527,000 would have been realized based on test-year operations as analyzed herein. On a pro forma basis, which assumes necessary expense adjustments calculated in a manner consistent with the commission's findings, this proposed increase would have yielded an increase in jurisdictional net operating income of $33,362,000, resulting in income available for fixed charges of $98,245,000. Applying this dollar return to the jurisdictional rate base results in a rate of return of 11.44 per cent. The question then becomes whether a rate of return of 11.44 per cent is reasonable.

Rate of Return

[19] Three witnesses presented testimony to assist the commission in its rate of return determination. The specific recommendations are each based on a cost of capital analysis, and no dispute exists with respect to the capitalization ratios employed or the costs to be assigned the debt and preferred stock components of the capital structure.[5] However, differences in the witnesses' respective positions as to the appropriate cost of common equity produced disparities in the overall rate of return recommendations.

Applicant's witness Nicholson, based on his finding of a cost of equity of 17 per cent, recommends an overall rate of return of 12.02 per cent. Applicant's witness Benore, in testimony filed well in advance of hearing, recommended a return on equity of 16.5 per cent. Although this witness provided no specific updates save with respect to two schedules he relied on, he testified that he believed the cost of equity capital to the company to be substantially higher than at the time his original testimony was prepared. At 16.5 per cent, the overall cost of capital to the company would be 11.85 per cent. Staff witness Wissman, based on his cost of equity determination of 15.06 to 16.05 per cent, concluded the overall cost of capital to be in the range of 11.36 to 11.69 per cent. An alternative calculation offered at hearing would increase the lower bound of this recommended range by one basis point. Consumers' counsel did not spon-

[5]For purposes of determining interest charges for the federal income tax expense calculation, we have adopted the staff's long-term debt ratio and embedded cost finding as set out in the testimony of Mr. Wissman.

sor a rate of return witness, but recommends that the return authorized not exceed the lower bound of Mr. Wissman's recommended range.

As indicated above, the increase requested in this case produces a rate of return on rate base of 11.44 per cent. Because this return approximates the lowest bound of the lowest recommendation for which there is support in the record, the commission sees no purpose to be served by a detailed analysis of the various cost of capital recommendations offered. An increase in the full amount requested is clearly justified and, under these circumstances, the rate of return produced by this requested increase of 11.44 per cent should be deemed fair and reasonable for purposes of this case.

Authorized Increase

[20, 21] Adding the authorized increase of $64,527,000 to the adjusted test-year operating revenues at existing rates of $349,186,000, results in a finding that applicant is entitled to place rates in effect which will generate $413,713,000 in gross annual operating revenues.

On brief, applicant argues that the commission should not limit the rate relief authorized to the amount of its request, claiming that the commission has a statutory duty under § 4909.15(D) Revised Code to fix rates in excess of those proposed if the evidence shows higher rates to be necessary to afford the company reasonable compensation for the service rendered. As certain of the rate of return recommendations in this case would support an increase above that requested, this argument must be addressed.

Both the staff and consumers' counsel contend that the company is bound by its noticed rates as published pursuant to § 4909.19 Revised Code. This statute provides, in pertinent part:

"Upon the filing of any application for increase provided for by § 4909.18 of the Revised Code the public utility shall forthwith publish the substance and prayer of such application, in a form approved by the public utilities commission. . . "

In construing this language in Committee Against MRT v Ohio Pub. Utilities Commission (1977) 52 Ohio St 2d 231, 233, 23 PUR4th 371, 371 NE2d 547, the supreme court of Ohio held as follows:

"While generally the published notice required under RC § 4909.19 need not contain every specific detail affecting rates contained in the application . . . the statute does require that the 'substance' of the application be disclosed; i.e., that the essential notice or quality of the proposal be disclosed to those affected by the rate increases."

This commission has indicated that the term "substance of this application" encompasses the proposed rates, themselves (Re Cleveland Electric Illum. Co. [1980] 38 PUR4th 494), and the court has observed that the purpose of requiring that the published notice contains the "substance of the application" is to enable affected parties to determine "whether to inquire further as to the proposal or intervene in the rate case." Ohio Asso. of Realtors v Ohio Pub. Utilities Commission (1979) 60 Ohio St 2d 172, 176, 398 NE2d 784.

As consumers' counsel aptly points out, to hold that a company is entitled to an increase greater than that requested through the noticed rates would create the possibility that a company could reduce interventions in its rate case by the simple expedient of understating its

published request, then spring a greatly increased rate request on the commission at hearing. We in no way intended to suggest that we attribute such a motive to the applicant in this case, as it is apparent in this instance that circumstances have changed a good deal since the original application was filed. But this argument does demonstrate why the staff's and consumers' counsel's position on the matter must be accepted. In so finding, we do not wish to leave the impression that rates authorized in specific individual tariff schedules may not, on occasion, be revised upward by the commission under certain circumstances, or that there would never be a case where we would authorize an increase greater than that requested, as we can envision extraordinary circumstances where this might be a prudent course. However, no such circumstances are present here, and the commission concludes that the relief authorized in this case should be no greater than that originally requested through the noticed rates.

Tariffs

As part of its investigation in this matter, the commission staff reviewed the rate schedules and the provisions governing terms and conditions of service contained in applicant's proposed tariffs. Although several of the issues arising from objections to the resulting staff recommendations have been eliminated by stipulation entered into by the active parties in the case, a number of questions remain for the commission's determination. We begin with a review of the stipulation.

Revenue Responsibility:

The applicant, consumers' counsel, and General Motors Corporation tendered a stipulation for the commission's consideration which contains a proposed resolution of certain issues relating to the appropriate distribution of revenue between jurisdictional customer classes and within the company's GS-12, GS-16, and PV 44 rate schedules. The staff recommends acceptance. The commission is not bound by the stipulation, but must give careful consideration to such a joint proposal where, as here, it is sponsored by all the active parties to the proceeding (Re Cincinnati Gas & E. Co. Case No. 76-302-El-AIR, May 4, 1977).

The parties agree that the jurisdictional class revenue responsibility reflected in applicant's proposed tariffs is supported by the company's cost-of-service study and results in a reasonable distribution of the revenue requirement. The parties have further agreed that in the event the commission authorizs a total revenue increase which differs from that requested by applicant, the total base (nonfuel) rates contained in the proposed schedules should be adjusted so as to retain the same proportional tariff customer class revenue responsibility reflected in the rate schedules as originally proposed.

With respect to the company's GS-12, GS-16, and PV-44 schedules, the parties have agreed that in assigning revenue responsibility within these tariff classifications, the rate design proposed by applicant should be adopted, subject to the following modifications. Within the proposed GS-12 and GS-16 schedules, the dollar differential between the first and second demand blocks should be adjusted to reflect the proportional relationship of the blocks existing in the current GS-12 and GS-16 schedules, the aggregate two-block revenue responsibility remaining as proposed. Within the demand charge of the proposed PV-44 rate, the spread between the first and second block should be reduced by one-half, or as close thereto as practicable, the combined total revenue responsibility of the first two demand blocks to again remain as originally proposed. Consistent with the joint recommendation as it pertains to interclass revenue responsibility, the parties also agree that any adjustments to these three schedules required by commission authorization of an increase which differs from the proposed should be effected so as to retain the basic proportionality of the components as specified in the stipulation. However, in no event should the customer charge contained in the GS-12, GS-16, and PV-44 schedules be reduced from the level proposed by the company.

Upon review of the stipulation, the commission is of the opinion that the provisions contained therein are, in all respects, reasonable and proper, and that the jointly recommended disposition of each of the issues covered is supported by the record. Because the commission has authorized the full relief requested in the application, certain of the provisions of the stipulation will not be invoked, but we note that those provisions are in keeping with customary commission practice in stipulations where the relief authorized differs from that requested. Applicant is, therefore, directed to conform the rate schedules filed pursuant to this order to the terms of the stipulation.

Customer Charge:

[22] Applicant's present rate schedules incorporate a customer charge which provides for the recovery of a specified dollar amount on a monthly basis without regard to actual customer usage during a given billing period. As a part of the instant application, the company proposed a modest increase in the level of most of these customer charge provisions. The staff accepted the proposed increase in the charge for a number of the company's rate schedules, but recommends that the present customer charge of $4 per month be retained on the residential rate sheets R-01, R-04, and R-07. The staff also opposes an increase in the current $6 customer charge contained in residential demand space-heating schedule, R-06. Applicant objects to these staff recommendations, and urges the commission to approve the $5 charge ($7.50 for R-06) as proposed. Intervenor consumers' counsel originally objected to the staff position on the grounds that the charges were excessive, but has indicated on the brief that it now supports the staff recommendation to continue the present residential customer charges at current levels.

The commission is on familiar ground in considering this question, as the customer charge issue has been before the commission on numerous occasions in recent years. (See, e.g., Re Columbus & Southern Ohio Electric Co. [1978] 24 PUR4th 261; Re Ohio Edison Co. [1980] 33 PUR4th 435; Re Cleveland Electric Illum. Co. [1980] 38 PUR4th 494; Re Cincinnati Gas & Electric Co. [1981] 42 PUR4th 252. As in most prior cases, there has been no challenge to the theoretical merits of including a mechanism in rate design to recognize costs incurred by the company merely by virtue of the fact that a customer is on the system, without regard to usage considerations; nor is there any question

that the commission has the authority to authorize such a charge. City of Cleveland v Ohio Pub. Utilities Commission (1980) 63 Ohio St 2d 62, 406 NE2d 1370. The sole issue for the commission's determination is the appropriate level of the charge.

We begin with our oft-repeated observation that there are a number of acceptable cost allocation methodologies, perhaps as many as there are witnesses to testify on the subject. The results produced through the use of any particular costing method should be viewed only as a guide in rate making, as there are other factors which must be given due consideration in the actual setting of rates. General Motors Corp. v Ohio Pub. Utilities Commission (1976) 47 Ohio St 2d 58. Applicant has recognized this principle in requesting a $5 customer charge for the residential schedules, as the company represents that its method of identifying customer costs would actually support a monthly charge of $10.02. In limiting its request to a $5 charge, the company may have anticipated that the commission would be reluctant to approve a charge of significantly greater magnitude, given the impact such a measure might have on some customers' efforts to control bills through reduced consumption (Re Ohio Edison Co., *supra*).

The staff analysis of customer costs produced an identified customer component strikingly consistent with the current $4 per month residential customer charge. The wide disparity in the results of the two studies stems from the fact that the staff adopted a restricted definition of customer costs in selecting the accounts to be incorporated in the calculation, excluding a number of accounts which have both usage-sensitive and customer-related characteristics. The staff acknowledges that certain of the distribution accounts which applicant apparently included in its calculation reflect some customer-related costs, but believes that the exercise in judgement required to segregate these costs is not in keeping with the basic objectives of the staff methodology for determining an appropriate customer charge.

The commission is of the opinion that the staff recommendation to continue the residential customer charge at present levels should be adopted. First, although we recognize that applicant's "minimum system" approach is an established method for determining customer-related costs in those accounts which are influenced both by the number of customers served and the loads of those customers, the company failed to present any supporting detail as to how it arrived at the $10.02 figure. Ironically, applicant criticizes the staff for basing its rejections of the proposed charge on the degree of judgement involved in its method, but introduces no affirmative evidence upon which the commission can base a decision as to whether its own assumptions were appropriate. Based on our experience in other proceedings, we do not doubt that applicant could support a $10.02 customer cost component, but the company clearly did not do so on this record. Second, as noted at the outset of this discussion, the applicant, in proposing a customer charge at a level half that which it claims could be justified, has implicitly acknowledged that the commission must consider other factors, such as continuity in successive rate schedules, in fixing an appropriate customer charge. Although $5 is closer to $10.02 than is $4, commission approval of a $5 charge would still be a judgement call in every sense of the word. The commission's first concern is that a mechanism be incorporated in the rate schedules to reflect the concept of a customer component, and we are only secondarily interested in the choice between the competing methods. Here, the staff recommendation is supported by its customer cost analysis, and the difference between the two proposals is not so significant that adoption of the staff recommendation will produce a materially different impact on revenue stability than approval of a $5 charge. Finally, the commission is not unmindful of the fact that there is some customer misunderstanding concerning the customer charge, and it is hoped that retaining the existing charge will have some positive influence on customer acceptance.

The revenue shortfall which will result from this alternative to applicant's proposed tariffs should be recovered through proportional adjustments to the remaining portions of the applicable residential rate schedules. In so finding, we anticipate applicant's argument that, as a theoretical matter, this adjustment should be made to only the first rate block. However, we believe that a proportional adjustment is, to some extent, responsive to the concerns expressed by the staff and consumers' counsel with respect to existing step differentials in these schedules.

Account Activation Charge:

[23] Applicant has proposed that an account activation charge of $6 be incorporated in its residential and small general service schedules. The intent of this one-time charge is to provide for the recovery of costs incurred in establishing new accounts or in commencing service at new locations. The company advanced a similar proposal in its last rate case, but the commission rejected the measure based upon concerns expressed by the staff as to the possibility that costs had been included in the account activation charge that had already been accounted for in the calculation of the customer charge (Re Toledo Edison Co. [1980] 36 PUR4th 209). As in the prior proceeding, the staff has again agreed in principle with the concept underlying such a charge, but is apparently still troubled by the manner in which it has been computed.

Based upon a review of the record relative to this subject, the commission is of the opinion that an account activation charge is an appropriate mechanism by which to recognize cost causation in the rates established through this proceeding. The implementation of this charge will serve to reduce the revenue requirement assigned to base rates, as the costs associated with account activation will be charged to those customers for whose benefit they are incurred. The staff concern relative to the calculation of the account activation charge stems from the fact that applicant relied on some of the same accounts in determining the level of this charge that the staff utilized in its computation of the customer charge. Although this minor overlap may produce some theoretical inconsistency, the commission's principal objection in this regard is to assure that there is no double recovery in fact. Given the element of judgement inherent in any cost allocation process, we do not see the problem identified by the staff as a barrier to implementation of the charge. We are satisfied that, in this instance, the total revenue requirement can be spread

to the various rate components without creating the prospect of a double recovery and without doing conceptual violence to cost-of-service principles. The commission accepts, however, the staff recommendation that the charge not be approved for inclusion in applicant's closed rate schedules (R-04, R-07, GS-11, GS-17), for, as discussed, *infra*, there is no prospect that new customers or installations will be served under these rates.

Seasonal Rates:

A number of applicant's present and proposed rate sheets contain separate schedules for summer and winter service. The staff recommends continuation of this seasonal differential, but suggests that a movement toward more uniform seasonal rates would be appropriate in light of the growth in winter peak demand over the past several years. Applicant objects to this latter aspect of the staff recommendation, and presented evidence demonstrating that, when a longer time frame is considered, summer and winter load growth have actually remained quite balanced. Applicant also points out that the staff conclusion with respect to the growth in the winter peak is influenced by its reliance on results from a period partially impacted by the moratorium on new natural gas hookups. The annual peak has occurred in the winter period only twice in the last eight years, and the company's long-range forecasts continue to indicate that, assuming normal weather, Toledo Edison will be a summer-peaking company. As further justification for maintaining the seasonal rate differential at the level reflected in the proposed tariffs, applicant cites to the higher load factors consistently exhibited by the company in the winter months. The commission agrees that the resulting lower per unit cost in the winter period should continue to be recognized in the rates authorized and will sustain applicant's objection to the seasonal revenue shifts which would be produced under the staff's proposed rate design for the residential schedules.

The staff recommends that the two-step feature of the company's present and proposed summer residential schedules be eliminated and that the rate for this service be comprised of a customer charge and a flat energy charge. The staff's position on this matter follows from its general view that uniform rates for a given customer class are appropriate absent a showing that circumstances exist which support some alternative rate design. The commission does not disagree with the staff's basic premise, and has, for some years, continued to move toward "flatter" designs through the elimination of multiblock rates and by decreasing step differentials. However, given the conservative nature of the customer charge approved in this proceeding, the commission believes that the structure of the summer residential schedules proposed by the company is not unreasonable in that the failure to retain two steps in the rate may unduly burden higher use customers with nonusage-sensitive costs. The commission also finds that the first 1,000 kwh per kwh rate block for summer usage under the R-04, R-06, and R-07 schedules should be priced identically.

Water Heating and Space-heating Schedules:

[24] Applicant currently offers special rates for residential water heating (R-04) and space heating (R-07) and for general service space heating (GS-17). Pursuant to commission order, these rates have been closed to new customers since 1975. A number of questions concerning these schedules have been raised by applicant's objections to staff recommendations relative to these rates.

First, the staff has recommended that these rates be eliminated in applicant's next rate case, apparently based on its view that the rates are not cost justified. Although it would be premature to act on this recommendation at this time, the commission would note that applicant did offer evidence in support of the propriety of these rates, and that the same equitable considerations which persuaded the commission to permit the grandfathering of customers served thereunder at the time the rates were closed are still operative.

The commission does agree, however, with the staff position that applicant's interpretation of the tariff language governing the availability of these rates is incorrect. The tariffs provide that these rates are available to the "customers" served pursuant to the rate as of August 1, 1975, or who had contracted for the purchase or installation of the appliances in question prior to that date. Applicant construes this language so as to permit these rates to be offered where the installation, itself, meets the stated criteria, rather than limiting the availability of the schedules to the then-existing customers.

The commission had occasion to consider a very similar situation in Re Cleveland Electric Illum. Co. (1980) 38 PUR4th 494, wherein we found that the adoption of such an interpretation was inconsistent with the very purpose of closing the rate, its eventual elimination through attrition. This process will not proceed at any meaningful pace if installations, rather than customers, are grandfathered. Applicant is, therefore, directed to henceforth conform its policy to the plain meaning of these tariff provisions.

Applicant proposes an amendment to both the residential hot water and the residential space-heating tariffs which would condition the continued availability of these rates upon the customer's participation in a positive load management program involving the installation of load controls on electric water heating and central air conditioning should the company so request. The staff recommends approval of these provisions, contingent upon the commission's decision regarding the elimination of the R-04 and R-07 schedules.[6] In its report, the staff further recommended immediate implementation of a specific load control program and that a reporting requirement be imposed as a part of the applicant's next rate filing. Applicant objected to this aspect of the staff recommendation, indicating that the tariff provision was intended to provide a mechanism by which a load management program could be established, but that the studies necessary to determine the cost effectiveness of any particular program had not yet been undertaken. The staff modified this recommendation at hearing, and now suggests that the company be directed to undertake the required analysis and to report its findings not later than its next rate proceeding. The commission views this course of action as appropriate under the circumstances and, in approving the requested amendment to the R-04 and R-06 schedules, will direct the company to submit a report detailing the steps taken to determine whether actual implementation of the load control program should begin and what form it should take. This report should be presented as part of applicant's supplemental testimony in its next permanent rate proceeding.

[6]The staff initially recommended that a similar provision be incorporated in applicant's optional residential heating rate, but withdrew the recommendation at hearing.

Applicant offers an optional residential heating schedule, R-06, to customers who have demand metering capability. This rate was originally provided pursuant to legislative mandate (§ 4905.70 Revised Code), and the company now serves approximately 6,000 space-heating customers under the optional schedule. The staff proposed an alternative design for this rate, but the commission is persuaded that applicant's present structure should be retained. As the staff conceded at hearing, its R-06 rate design would reduce not only the incentive for customers to avail themselves of the optional rate, but would also reduce customer incentive to control maximum demand, contrary to the energy management aims of the rate, itself. Applicant's objections to the staff recommendations regarding this rate should be sustained.

Employee Discounts:

Consumers' counsel, through its filed objections, questioned the failure of the commission staff to recommend that applicant's practice of extending discounts to its employees be reduced to a written tariff provision. Employee discounts are, of course, specifically permitted by § 4905.34 Revised Code, and are governed by contract or agreement between the company and its personnel. As the staff points out, these discounts are not actually a rate of the type susceptible to incorporation in a filed schedule, but merely represent an employee benefit. Given the narrow applicability of the discounts and the limitations on flexibility including them as a specific tariff item would impose, the commission sees no reason to compel the company to file such a schedule at this time. Through a related objection, consumers' counsel argues that, for allocation purposes, the employee discounts should be charged against all customers of the company, and not assigned only to the residential class as proposed in applicant's cost-of-service analysis. Although consumers' counsel's participation in the stipulation regarding interclass revenue responsibility effectively moots this objection, the commission would observe that applicant has acknowledged that consumers' counsel's position on this subject is theoretically correct and that the company will recognize this principle in the future filings. However, the failure to adjust for this item in this case does not change the commission's view as to the reasonableness of the stipulation because the amounts involved are minimal and because the rate of return component of the residential class revenue requirement would still trail the system average rate of return even if the adjustment were performed.

Terms of Payment:

Each of applicant's proposed rate schedules provides for a 5 per cent late payment service charge if bills are not paid within fourteen days after they are rendered. This charge is not assessed prior to one full day following the nominal due date and, in the case of residential customers, is not assessed unless there is more than one late payment within a 12-month period. The language of these provisions is identical to that contained in the company's present tariffs.

The staff, although agreeing that the charge is appropriate and should be retained, echoes the recommendation it offered in Toledo Edison's last rate case that the period for timely payment be extended from fourteen to twenty-one days. The commission rejected this staff suggestion in Case No. 79-143-EL-AIR (36 PUR4th 209), and must do so again at this time.

The commission agrees with the staff's observation that a 21-day period would be consistent with that generally employed by most other utilities, but believes it improper to mandate such a change without also authorizing some rate adjustment to take into account the impact such a change would have on the company's billing and collection procedures. The benefit to the customer of extending the payment period is somewhat illusory, for while there would be a one-week advantage in the first billing month, the interval between required payments would, thereafter, remain identical to that experienced under the present policy. The burden on the company, however, would be very real; and without some form of rate recognition of the effect of such a change on operations, applicant's objection to the staff recommendation must be sustained.

Billing Format:

Applicant recently redesigned its billing format in an effort to simplify customer bills. Consumers' counsel objected to the staff's failure to recommend a revision in this format, contending that the present bills contain insufficient information to permit the customer to determine how the monthly charge for service is calculated. The commission would observe that it has recently addressed this question in Re Promulgation of Guidelines for Billing Formats, Case No. 79-569-GE-UNC, a proceeding in which the Office of Consumers' Counsel participated. Any specific problems not resolved through that generic csse may properly be pursued through a § 4905.26 Revised Code complaint, as the commission is not disposed to again examine the question within the confines of this rate case.

Public Utility Regulatory Policies Act:

Consumers' counsel also objected to what it alleged to be the staff's failure to evaluate applicant's proposed tariffs in relation to the standards, objectives, and purposes of the Public Utility Regulatory Policies Act of 1978 (16 USC §§ 2601 et seq.).[7] Although intervenor did not pursue this matter on brief, the commission would observe that both the staff and the applicant did offer testimony relative to this subject. Further, under PURPA, the duty to consider the identified standards falls upon the commission itself, not the participating parties. The resolution of the tariff issues and the advertising expense issue as set forth in this opinion and order reflects the extent to which the commission finds the PURPA standards

[7]It should be noted that a federal district court has invalidated certain PURPA provisions, including those cited in this case, on constitutional grounds. Mississippi v Federal Energy Regulatory Commission (DC Miss 1981) 38 PUR4th 284, — F Supp —.

to be appropriate based on the evidence in this proceeding. The objection should be overruled.

Effective Date:

The commission's general practice is to fix the effective date of tariffs filed pursuant to its rate orders as thirty days following the issuance of the entry accepting the tariffs for filing. The purpose of this delay is to afford affected customers notice of the increase authorized through mailings by the company prior to the date the new rates become applicable.[8] The commission continues to believe this to be an appropriate practice, but finds circumstances present in this case which compel a departure from this policy.

Section 4909.42 Revised Code provides that if the commission has not acted upon a rate increase application within 275 days of the date of filing, the applicant utility, upon the filing of an undertaking, may place the proposed rates into effect subject to the condition that amounts collected under rates charged which are in excess of those ultimately determined reasonable by the commission must be refunded. The commission makes every effort to issue its rate orders in advance of the expiration of the 275-day time period in order to avoid the customer confusion which might result should the refund provisions be invoked. Due to unforeseen delays in the issuance of the staff report, this was not possible in this instance. However, applicant has not endeavored to place its proposed rates into effect, and the commission believes that basic principles of fairness dictate that the company not be penalized for its forebearance. The commission, therefore, finds the appropriate course in this proceeding to be to establish the effective date of the tariffs filed pursuant to this order as the date they are approved by commission entry. The customer notification requirement will, of course, be retained, said notice to be mailed to affected customers upon approval of its form by the commission.

Findings of Fact:

From the evidence of record in this proceeding, the commission now makes the following findings:

(1) The value of all of applicant's property used and useful for the rendition of electric service to the customers affected by this application determined in accordance with §§ 4909.05 and 4909.15 Revised Code as of the date certain of July 1, 1980, is not less than $858,807,000.

(2) For the 12-month period ending December 31, 1980, the test period in this proceeding, the revenues, expenses, and income available for fixed charges realized by applicant under its present rate schedules were $349,186,000, $284,303,000, and $64,883,000, respectively.

(3) This net annual compensation of $64,883,000 represents a rate of return of 7.56 per cent on the jurisdictional rate base of $858,807,000.

(4) A rate of return of 7.56 per cent is insufficient to provide applicant reasonable compensation for the electric

[8]In Re Ohio Power Co. Case No. 80-367-EL-AIR, April 1, 1981, the commission afforded the company the option of mailing actual notice to customers upon acceptance of the tariffs for filing. If the company elected this option, it was to be entitled to place the new rates in effect three days following the special mailing.

service rendered customers affected by this application.

(5) A rate of return of 11.44 per cent is fair and reasonable under the circumstances presented by this case and is sufficient to provide applicant just compensation and return on the value of its property used and useful in furnishing the service described in the application.

(6) A rate of return of 11.44 per cent applied to the jurisdictional rate base of $858,807,000 will result in income available for fixed charges in the amount of $98,245,000.

(7) The allowable annual expenses for purposes of this proceeding are $315,468,000.

(8) The allowable gross annual revenue to which the applicant is entitled for purposes of this proceeding is the sum of the amounts set forth in Findings 6 and 7, or $413,713,000.

(9) Applicant's present tariffs should be withdrawn and canceled, and applicant should submit new tariffs consistent in all respects with the discussion and findings set forth above.

Conclusions of Law:

(1) The application herein is filed pursuant to, and this commission has jurisdiction thereof, under the provisions of §§ 4909.17, 4909.18, and 4909.19 of the Revised Code; further, applicant has complied with the requirements of the aforesaid statutes.

(2) A staff investigation has been conducted and a report duly filed and mailed and public hearings have been held herein, the written notice thereof having complied with the requirements of § 4909.19 Revised Code.

(3) The existing rates and charges as set forth in applicant's tariffs governing service to customers affected by this application are insufficient to provide the company with adequate net annual compensation and return on its property used and useful in the rendition of electric service.

(4) A rate of return of 11.44 per cent is fair and reasonable under the circumstances of this case and is sufficient to provide applicant just compensation and return on its property used and useful in the rendition of electric service to its customers.

(5) Applicant should be authorized to cancel and withdraw its present tariffs on file with the commission and to file tariffs consistent in all respects with the discussion and findings set forth above.

Re Cogeneration and Small Power Production

Intervenors: Narragansett Electric Company, Blackstone Valley Electric Company, and Huile Blanch, Inc. et al.

Docket No. 1549
March 20, 1981

GENERIC *order setting rates and regulations regarding cogenerated power.*

Rates, § 265 — Cogenerated power — Standard for purchase — Avoided cost method.

[R.I.] The commission found that the option to negotiate a purchase rate for cogenerated power would exist whether or not the commission set a standard rate, and the commission's guide in setting purchase rates in any case would be the utility's avoided costs rather than a cogenerating facility's characteristics. [1] p. 611.

Rates, § 265 — Cogenerated power — Avoided energy costs — Differential rates.

[R.I.] The commission held that the more a cogenerator's output is on peak the higher the avoided energy costs would be, and therefore the commission established daily and seasonal on-peak and off-peak rates to be applied to purchases of cogenerated energy from qualifying facilities that employed time-of-use meters. [2] p. 612.

Rates, § 265 — Cogenerated power — Administrative cost of purchases — Utility liability.

[R.I.] The commission found that administrative costs associated solely with purchases from qualifying facilities for cogenerated energy, and not otherwise covered by the Federal Energy Regulatory Commission rules, or commission findings and orders, shall be borne by the electric utility. [3] p. 617.

Rates, § 262 — Cost of cogenerated power — Avoided incremental energy cost of wholesaler.

[R.I.] The commission found that the incremental energy cost avoided by an all-requirements retail electric utility as a result of purchases of cogenerated electricity from a qualifying facility was the incremental energy cost avoided by the utility's wholesale supplier. [4] p. 619.

Rates, § 265 — Cogenerated power — Utility excess capacity — Effect on price paid to cogenerators.

[R.I.] The commission held that an electric utility avoided no capacity costs as a result of a purchase from a qualifying facility when the utility has excess capacity. [5] p. 619.

Before Burke, chairman, and Miller and Niven, commissioners.

By the COMMISSION:

Decision and Order

Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (16 USC §§ 2601 et seq.) established definitions, guidelines, and a rule-making process "to encourage cogeneration and small power production." A year ago the Federal Energy Regulatory Commission issued its rules under §§ 201 and 210 (18 CFR Part 292), requiring each state regulatory authority to commence implementation and report

Tab D

Return on Equity:

A Survey of Recent Rate Cases From State PUCs

BY PHILLIP S. CROSS

Fixing an appropriate rate of return on equity (ROE) for electric utility investors marks a fundamental component of the typical cost-of-service rate case conducted across the nation by state public utility commissions (PUCs). The following survey demonstrates the results of such cases, as observed over the past year.

As usual, the debate over ROE centers on current trends in interest rates, plus changes in the overall pattern of industry risk—as affected by on-again, off-again efforts at utility industry restructuring. Consider a recent decision from Connecticut as a good example of the broad range of issues that arise. In a case setting rates for Connecticut Light & Power Co. (CL&P), the state PUC said it was unable to justify the company's then-current ROE allowance of 10.3 percent—last set in Connecticut in a 1998 rate order—since a number of changed circumstances had intervened. It lowered ROE to 9.85 percent—below the 10-plus level often awarded by other states for other utilities during the same period. It cited factors such as:

- Lower interest rates. (20-year T-Bond yields down from 5.5 to about 5.3 percent.)
- Improved financial strength. (Bond ratings up from Ba2 to A2 [Moody's], and from BBB- to A- [S&P]. Equity ratio up from 33.4 to 51.1 percent.)
- Lower business risk. (Divestiture of all generating plants.)
- Lower tax rates. (New federal rate caps of 15 percent on both capital gains and corporate dividends). *See, Docket No. 03-07-02, Dec. 17, 2003 (Conn.D.P.U.C.), reported at 229 PUR4th 380.*

In other words, more equity in capital structure implies less investor risk and undercuts need for a higher ROE. And lower interest rates put downward pressure on what utility stockholders might expect to receive from competing investments.

But another important factor, beyond the simple financial indexes, is the question of intangible industry risk. State regulators worry about events such as last summer's Northeast blackout. They fear that the new market institutions imposed by regional grid operators may fall short of ensuring the degree of reliability of service that customers (and investors) have come to expect.

Consider a second recent decision, from Indiana, setting rates for PSI Energy. *See, Cause No. 42359, May 18, 2004 (Ind.U.R.C.), 234 PUR4th 1.*

In that case, the company argued that the utility industry faces many uncertainties that augment risk: Stricter environmental regulations, changes in ownership, a strained transmission grid, and continuing controversy over wholesale market design and operation. Yet the commission accepted arguments by opposing parties that the numerous cost trackers used by PSI had distinguished PSI from other utilities and mitigated any excessive regulatory risks.

"The inescapable fact," said the commission, "is that trackers reduce risk to a utility and PSI has many more trackers than its peers."

Other changes brought by restructuring may also trim risk.

In the CL&P case cited above, the state PUC stressed that the selloff of power plants (making CL&P a wires-only utility) had enhanced the company's business profile, with management able to turn it focus to the lower-risk transmission and distribution systems. Moreover, as the PUC noted, utilities now collect a higher proportion of distribution costs through fixed charges than in the past.

And lower utility ROEs mirror the general downturn in stock prices seen in the early years of the new century. According to the Connecticut commission, CL&P had reinforced that notion by its own testimony regarding the cost of its pension plan. The decision notes that the company had testified that long-term expectations of returns for its pension plan (with assets devoted

70 percent in equities) should be lowered from 9.25 percent (as in 2002) to 8.75 percent, for the rate case test year.

How the Survey Was Conducted

This year's survey covers determinations of the cost of equity capital as made by state PUCs during the period from Oct. 1, 2003, through Sept. 15, 2004. The survey method remains similar to past years. Requests for information on the results of recent rate proceedings were sent to both regulators and utility financial officials. Direct examination of the commission rate orders, where available, provides additional information.

The traditional cost-of-service rate case remains the most obvious source of information on how utility regulators view the issue of shareholder earnings requirements. Nevertheless, other proceedings may contain findings relative to ROE, and those rulings are reported here as well, including cases that deal with performance-based rate plans, periodic earnings reviews, and special proceedings to determine revenue requirements for restructured electric "delivery-only" utility operations.

Explanatory notes accompany most entries, and citations (volume and page number) are provided for orders published in *Public Utilities Reports, Fourth Series (PUR4th).*

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ARKANSAS									
Arkansas Western Gas Co.	Gas	02-227-U	11/8/02	9/17/03	6/30/02	11.0	4.1	11.0	9.9
CALIFORNIA									
PacifiCorp	Electric	D.03-11-019	12/19/01	11/13/03	12/31/03	11.4	2.8		10.9
Pacific Gas & Electric Co.	Electric	D.03-12-035 230 PUR4th 101	6/1/03	12/18/03	NA	NA[1]	NA[1]	11.2	11.2
Southwest Gas Corp. 232 PUR4th 353	Gas	D.04-03-034	2/13/02	3/16/04	12/31/03	13.9	7.4	11.35	10.90
COLORADO									
Aquila Inc.	Electric	C04-0999	12/29/03	8/25/04	8/31/03	11.3	8.2	10.75	10.25
CONNECTICUT									
Connecticut Light & Power Co. 229 PUR4th 380	Electric	03-07-02	8/1/03	12/17/03	NA[3]	140.1[4]	1.9[5]	10.30	9.85[6]
DELAWARE									
Delmarva Power & Light Co. dba Conectiv Power Delivery	Gas	03-127 231 PUR4th 140	3/31/03	12/09/03	9/30/02	16.79	7.75	12.5[7]	10.5
DISTRICT OF COLUMBIA									
Washington Gas Light Co. 229 PUR4th 177	Gas	Order No. 12986	2/7/03	11/10/03	9/30/02	14.1	5.377	10.6	10.6
FLORIDA									
City Gas Co. of Florida 231 PUR4th 341	Gas	030569-U	8/15/03	2/23/04	9/30/04	10.5	6.7[8]	11.5	11.25
Indiantown Gas Co. 234 PUR4th 497	Gas	030954-60	12/15/03	6/2/04	12/31/04	.307	.132	11.25	11.50[9]
IDAHO									
Idaho Power Co.	Electric	IPC-E-03-13	10/16/03	5/25/04	12/31/03	85.6	28.0	11.0	10.25
ILLINOIS									
Ameren CILCO 230 PUR4th 17	Gas	02-0837	11/22/02	10/17/03	12/31/01	14.0	9.11	11.82	10.54
Ameren CIPS	Gas	03-0008	11/27/02	10/22/03	6/30/02	16.0	7.0	10.65	10.71
AmerenUE	Gas	03-0009	11/27/02	10/23/03	6/30/02	4.0	2.0	10.65	10.46
INDIANA									
Community Natural Gas Co. Inc.	Gas	42452	5/28/03	11/20/03	12/31/02	[illegible]	.280	11.25	10.4
Indiana Natural Gas Corp.	Gas	45454	5/30/03	12/7/03	12/31/02		.293	NA	10.4
PSI Energy 234 PUR4th 1	Electric	42359	12/30/02	5/18/04	9/30/02	142.3	107.3	11.0	10.5[10]
Vectren South	Gas	42596	3/12/04	6/30/04	12/31/02	14.7	5.7	11.25	10.5
IOWA									
Interstate Power & Light Co.	Electric	RPU-04-1	3/15/04	6/11/04	12/31/03	105.6[11]	98.2[11]	11.15	11.15[12]
KENTUCKY									
Kentucky Utilities 234 PUR4th 177	Electric	2003-00434	12/29/03	6/30/04	9/30/03	58.254	46.109	11.5	10.5[13]
Louisville Gas & Electric	Electric	2003-00433	12/29/03	6/30/04	9/30/03	63.764	43.4	11.5	10.5
LOUISIANA									
CenterPoint Energy Arkla	Gas	U-27676	11/14/03	8/6/04	6/30/02	15.633	6.951	11.75	10.25
CenterPoint Energy Entex	Gas	U-26720-A	1/15/03	3/3/04	6/30/02	4.651	2.177	9.92	10.5

Company	Type of Service (Elec/Gas)	Case, Docket or Decision No.	Application Date	Order Date	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
MARYLAND									
Potomac Electric Power Co.	Electric	8995	12/5/03	7/6/04	6/30/03	NA[14]	0[15]	NA	10.1
Washington Gas Light Co.	Gas	8959	3/31/03	10/31/03	12/31/03	35.1	2.9	8.75	10.75
MASSACHUSETTS									
Boston Gas Co.	Gas	DTE 03-40	4/16/03	10/31/03	12/31/02	61.3	23.8[16]	13.25	10.2
MICHIGAN									
SEMCO Energy Gas Co.	Gas	U-13496	11/21/02	5/2/03	12/31/03	10.94	4.05	12.76	11.4*
Wisconsin Public Service Corp.	Electric	U-13688	2/6/03	7/23/03	12/31/03	1.4	.30	11.0	11.4*
MINNESOTA									
Interstate Power & Light Co.	Electric	E001/GR-03-767	5/19/03	7/1/04	12/31/02	5.0	0.6	11.0	11.25
NEVADA									
Nevada Power Co.	Electric	03-10001	10/1/03	3/26/04	5/31/03	133.5	46.3	10.1	10.25
Sierra Pacific Power Co.	Electric	03-12002	12/1/03	5/27/04	7/31/03	87.7	46.7	10.17	10.25
Southwest Gas Corp. (Northern Nevada Div.)	Gas	04-3011	3/8/04	8/26/04	9/30/03	8.6	6.4	10.21	10.50
Southwest Gas Corp. (Southern Nevada Div.)	Gas	04-3011	3/8/04	8/26/04	9/30/03	18.9	7.4	10.64	10.50
NEW JERSEY									
South Jersey Gas Co.	Gas	GR0380683 234 PUR4th 277	8/29/03	7/8/04	2/29/04	52.7	20.0[17]	NA	10.0*
NEW YORK									
Central Hudson Gas & Electric Corp.	Electric	00-E-1273	3/29/04	6/14/04	6/30/02[18]	14.1	(2.0)	10.6	10.3[19]
Central Hudson Gas & Electric Corp.	Gas	00-G-1274	3/29/04	6/14/04	6/30/02[18]	3.6	0	10.0	10.3[19]
Fillmore Gas Co., Inc.	Gas	03-G-0697	3/30/03	11/26/03	12/31/02	.298	.188	–	11.0
Rochester Gas & Electric Corp.	Electric	03-E-0765 233 PUR4th 40	5/16/03	5/20/04	NA[20]	105.5	7.4[21]	11.0	10.0[22]
Rochester Gas & Electric Corp.	Gas	03-G-0766 233 PUR4th 40	5/16/03	5/20/04	NA[20]	25.3	7.21[21]	11.0	9.6[22]
OREGON									
Avista Utilities	Gas	UG 153 227 PUR4th 381	4/10/03	9/25/03	12/31/02	7.5	6.3	NA	10.25*
SOUTH DAKOTA									
MidAmerican Energy Co.	Gas	NG04-001	4/2/04	NA	12/31/03	1.56	1.0	11.0	NA[23]
Montana-Dakota Utilities Co.	Gas	NG02-011	12/30/02	12/17/03	12/31/02	2.2	1.3	11.5	10.075
UTAH									
PacifiCorp	Electric	03-2035-02 230 PUR4th 193	5/15/03	1/30/04	3/31/03	125.0	65.0	11.0	10.7*
VERMONT									
Central Vermont Public Service Corp	Electric	6866[24] 231 PUR4th 113	4/15/03[25]	1/27/04	12/31/02	NA[26]		11.0	10.25[27]
VIRGINIA									
Roanoke Gas Co.	Gas	PUE-2003-00425	9/16/03	3/15/04	6/30/03	1.8	1.54	10.5	10.1
Southwestern Virginia Gas Co.	Gas	PUE-2003-00426	9/17/03	6/3/04	6/30/03	.260	.219	13.25	10.1
Washington Gas Light Co.	Gas	PUE-2002-00364	6/14/02	12/18/03	12/31/01	23.8	10.8	13.0	10.5
WISCONSIN									
Madison Gas & Electric Co.	Electric	3270-UR-112	5/30/03	1/13/04	12/31/04	19.2	11.7	12.3	12.0
Madison Gas & Electric Co.	Gas	3270-UR-112	5/30/03	1/13/04	12/31/04	3.3	1.0	12.3	12.0
Wisconsin Electric Power Co.	Electric[28]	05-CE-130 228 PUR4th 444	1/31/02	11/10/03	NA	NA	NA	–	12.7[29]
Wisconsin Public Service Corp.	Electric	6690-UR-115 230 PUR4th 229	4/1/03	12/19/03	12/31/04	88.9	59.4	12.0	12.0
Wisconsin Public Service Corp.	Gas	6690-UR-115 230 PUR4th 229	4/1/03	12/19/03	12/31/04	15.4	8.9	12.0	12.0
WYOMING									
PacifiCorp	Electric	2000-ER-03-198 232 PUR4th 295	5/27/03	2/28/04	9/30/02	41.8	[30]	10.75	10.75[31]

ENDNOTES

- * Approved settlement agreement.

1. Settlement presented as basis for bankruptcy reorganization plan provides a $7.2 billion ratepayer contribution to utility's unrecovered costs of utility service. Approved agreement also creates a $2.21 billion regulatory asset to be amortized over 9-year period.
2. Reflects reduction to business risk attributable to implementation of balancing account rate mechanism, attrition year rate plan, and accelerated pipeline replacement program.
3. Application for approval of four-year rate plan for distribution and transmission services.
4. Utility requested increases of $140.1, $168.8, $195.6 and $226.3 million for rate plan years 2004 through 2007.
5. Department approved rate increases of $1.9, $25.1, $11.9 and $7 million for rate plan years 2004 through 2007.
6. ROE reflects reduced operating risk following industry restructuring and the divestiture of generation. *(Cont. on p. 57)*

delicate balance that must be struck between protecting the utility customers' energy interests and ensuring that the utility has a reasonable opportunity to achieve financial health if it manages its business in an effective and responsible manner. A more complete disclosure to the regulator of the "facts that matter" by the utility, both in and outside of rate cases, can foster the open discussions and eventual building of trust that can make these ideals a reality.

Regulatory Uncertainty: Here to Stay

The message heard loud and clear from survey respondents is that the concept of regulatory uncertainty is real, that it is here to stay for the foreseeable future, and that it must be better managed. Managing regulatory uncertainty will involve finding new ways to promote: (1) greater clarity in the energy policies of the state and federal governments; (2) more specificity and consistency in how regulators implement such policies, and in their related decisions that impact the operations of regulated utilities; and (3) continuing efforts of utilities to interact with regulators and other stakeholders outside the rate case environment to communicate, educate, and build trust.

And with the increased frequency of rate-case filings expected in the next few years, there will be ample opportunity to explore such remedies. Therefore, the utility, regulator, and other stakeholders must all work hard to establish collective objectives that will point the process in the right direction. With all the other major business uncertainties that exist today in the energy industry that cannot as easily be influenced and managed, it is incumbent upon all interested parties to address this most important issue now to ensure the continued viability of gas and electric distribution utilities to meet the future energy needs of their customers.

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Endnotes

1. Survey respondents represented gas utility companies (52 percent), electric utility companies (13 percent), and combination utility companies (35 percent) from 26 states and 2 Canadian provinces.
2. For example, see the Resolution on Gas and Electric Energy Efficiency adopted by The National Association of Regulatory Utility Commissioners (NARUC) board of directors on July 14, 2004, and the Joint Statement of the American Gas Association and the National Resources Defense Council submitted to NARUC in July 2004.

ROE Survey

(Continued from p. 51)

7. Utility's prior rate case decided 11/23/93.
8. PSC imputed short-term debt rate of 3.9% even though actual short-term loan rate was 7% to account for financial losses attributable to non-utility operations.
9. Approved ROE, which is greater than the 11.25% rate approved by the PSC in two other recent gas rate proceedings, is warranted by the small size and risk profile of the LDC.
10. Authorized ROE reflects finding by commission that utility faces financial risk due to numerous rate adjustment trackers that allow for periodic cost-based adjustments between rate cases.
11. Utility seeks temporary increase as shown and permanent increase of an additional $149.2 million. Board grants temporary increase as shown.
12. ROE from prior rate decision adopted for purpose of calculating temporary revenue requirement. ROE of 12.23% applied to investment in new generating plant pursuant to prior certificate ruling. Iowa UB issues binding rate findings as part of new plant certification process.
13. Utility authorized to reverse a write-down to equity resulting from adoption of Statement of Financial Accounting Standards No. 130 (Reporting Comprehensive Income) which required company to disclose a contingent minimum pension liability.
14. Utility required to file cost of service update pursuant to prior ruling approving a merger to determine if rate reduction is required.
15. PSC finds no rate decrease necessary. Rates capped through 2006 pursuant to prior approved merger agreement.
16. Initial rate increase serves as basis for newly approved performance-based rate plan.
17. Rate increase shown offset by $3.09 million elimination of universal service fund interim rate, $21.68 million gas cost adjustment, $0.73 million transitional energy facility adjustment, $6.78 million temperature adjustment clause rate adjustment, and $6.64 million gas supply service rate roll-in.
18. Three-year rate settlement approved 10/25/01. Commission approved rate plan modification 6/14/04 extending rate for 2 years to 6/06. ROE remains at 10.3% as decided in prior ruling. Prior ruling includes revenue sharing as follows: 100% to shareholders from 10.3% to 11.3% – 50/50 sharing of earnings from 11.3% to 14% – Above 14% 100% to ratepayers.
19. Commission updates revenue sharing plan. New sharing points as follows: 100% to shareholders at 10.3% to 10.5% earnings level – 70% shareholders/ 30% ratepayers at 10.5% to 11.3% earnings – 65% shareholders/ 35% ratepayers at 11.3% to 14% earnings and 100% to ratepayers at 14% and above earnings.
20. Proposed rates filed May 16, 2003. Utility also filed electric rate unbundling plan pursuant to prior order.
21. Multi-year rate plan calls for rate freeze through 2008. PSC approves initial rate increases as shown through implementation of electric retail access surcharge and natural gas merchant function charge.
22. Electric plan requires equal sharing with ratepayers of earnings above 12.25% threshold, while gas plan requires equal sharing above 12%.
23. Rate case was settled - ROE was NOT settled. Staff refused to go higher than 10%. Company refused to go lower than 10.75. In the end, case was settled on dollar amount.
24. Order approving agreement restricting ability of utility to seek future rate increase and reducing allowed ROE.
25. Utility filed cost of service study pursuant to prior ruling.
26. Proceeding follows finding by Department that sale of interest in nuclear facility by utility reduced revenue requirement.
27. Department reduces 10.5% ROE included in settlement agreement finding lower rate better matched existing market conditions.
28. Order approving application for authority to construct new generating facilities.
29. Commission finds it reasonable to set the following financial terms for facility lease: 12.7% return on equity and capital structure of 55% equity and 45% debt.
30. Final requirement unstated.
31. Commission rejected 0.25% "Wyoming-specific" risk premium proposed by the utility to account for past disallowance of deferred power costs.