Attorney General First Set Data Requests
ULH&P Case No. 2005-00042
Date Received: July 29, 2005
Response Due Date: August 9, 2005

AG-DR-03-001

REQUEST:

1. With reference to page 11, footnote 1, please provide a copy of the relevant material from the book.

RESPONSE:

See Attachment AG-DR-03-001.

WITNESS RESPONSIBLE: Roger A. Morin

Chapter 10
Market-to-Book and Q-Ratios

This chapter discusses the Market-to-Book (M/B) Ratio and its relationship with the cost of capital. Section 10.1 establishes the formal relationship between the allowed return on equity, the cost of equity, and the M/B ratio. Section 10.2 demonstrates how the DCF cost of equity figure can be theoretically transformed into an appropriate allowed return on equity, based on a target M/B ratio. The importance of maintaining an M/B slightly in excess of 1.0 is underscored. Section 10.3 discusses the estimation of cost of equity capital based on the multivariate statistical analysis of the determinants of M/B ratios. Section 10.4 describes the Q-Ratio approach to determining the cost of equity capital. Section 10.5 critically evaluates the role of M/B ratios in regulation and concludes that regulators should largely remain unconcerned with such ratios because they are determined by exogenous market forces and are outside the direct control of regulators. M/B ratios are largely the end result of the regulatory process itself rather than its starting point.

In Chapter 1, it was suggested that if regulators set the allowed rate of return equal to the cost of capital, the utility's earnings will be just sufficient to cover the claims of the bondholders and shareholders. No wealth transfer between ratepayers and shareholders will occur.

The direct financial consequence of setting the allowed return on equity, r, equal to the cost of equity capital, K, is that share price is driven toward book value per share. Intuitively, if $r>K$, and is expected to remain so, then market price will exceed book value per share since shareholders are obtaining a return in excess of their opportunity cost. But if $r<K$, and is expected to remain so, market price will be below book value per share since the utility is failing to achieve its opportunity cost. A simple idealized example will illustrate this important point.

EXAMPLE 10-1

Consider a utility with a book value of equity per share of $10, and let us say that the market's required return on equity is 12% for firms in that risk class. If the $10 book value of equity is allowed to earn $1.20 per share, or 12%, the market price will set at $10, since the market's required return at that price will be also $1.20/$10, or 12%. If, on the other hand, the $10 book equity per share is allowed to earn say only 6%, the market price has to fall to $5.00 in order for the market's required return to be 12%, that is, $0.60/$5, or 12%.

10.1 The M/B Ratio and the Cost of Capital in Theory

The theoretical relationship between r, K, and M/B can be demonstrated by a simple manipulation of the standard DCF equation. Starting from the seminal DCF model:

$$P_0 = \frac{D_1}{K-g} \tag{10-1}$$

and expressing next year's dividend, D_1, as next year's earnings per share, E_1, times the earnings payout ratio, $1 - b$, we have:

$$D_1 = (1 - b)\, E_1 \tag{10-2}$$

Substituting the latter equation into Equation 10-1:

$$P_0 = \frac{E_1\,(1-b)}{K-g} \tag{10-3}$$

But next year's earnings per share, E_1, are equal to the expected rate of return on equity, r, times the book value of equity per share, B, at the end of the current year:

$$E_1 = rB \tag{10-4}$$

Substituting Equation 10-4 in Equation 10-3:

$$P_0 = \frac{rB\,(1-b)}{K-g} \tag{10-5}$$

Dividing both sides of the equation by B, and noting that $g = br$:

$$P_0/B = \frac{r\,(1-b)}{K-br} = \frac{r-br}{K-br} \tag{10-6}$$

From Equation 10-6, it is clear that the market-to-book, or P_0/B, will be unity if $r = K$, greater than unity if $r > K$, and less than unity if $r < K$:

$$M/B \;\begin{matrix} > \\ = \\ < \end{matrix}\; 1.0 \text{ as } r \;\begin{matrix} > \\ = \\ > \end{matrix}\; K$$

Solving Equation 10-6 for K, a basic measure of cost of equity adjusted for the prevailing M/B ratio can be obtained:

$$K = \frac{r(1-b)}{M/B} + br \tag{10-7}$$

In words, Equation 10-7 demonstrates that finding a cost of equity that is reconcilable to the book return on common equity requires that the latter be increased or decreased by the M/B ratio in proportion to the fraction of income distributed as dividends. Equation 10-7 provides a method of finding the cost of equity capital that is consistent with the observed M/B ratio.

EXAMPLE 10-2

The market value of a utility's common stock has fallen to 75% of its book value. Realized return on book equity expected by investors is 15%. Earnings are divided evenly between dividends and retentions.

$$b = .50 = (1-b)$$

$$r = .15$$

The cost of common equity reconcilable with the observed M/B ratio is:

$$K = \frac{r(1-b)}{M/B} + br$$

$$= \frac{.15 \, x \, .50}{.75} + (.50 \, x \, .15)$$

$$= .10 + .075$$

$$= .175 \text{ or } 17.5\%$$

Several cautions are in order. First, the expected return on book equity rather than the currently allowed return on equity must be used, because the M/B ratio is determined by what investors expect regulators to do, and not by what the regulators did in the past. A serious circularity problem arises if the current allowed return on equity is used because the numerator of the M/B ratio is stock price, which reflects the expected allowed return and not the currently allowed return.

Second, while straightforward application of the DCF approach will theoretically drive share price toward book value per share, it must also be true that the utility can actually be expected to earn the rate set for regulatory purposes. Several factors can cause the utility to earn more or less than is nominally allowed. Delay in instituting new regulatory proceedings, or regulatory lag, can cause the utility to earn more or less than is prescribed. If cost trends deviate from expectations in the case of a forward test year jurisdiction, or if unexpected future changes in cost and output levels occur, regulatory lag will cause the utility to earn more or less than is allowed.

Third, other external factors impinge on the M/B. Diversification into non-regulated fields may cause the ratio to deviate from 1.0, even though the profitability of the regulated portion is restricted. Even if all the firm's activities are regulated, if assets are excluded from rate base, or if Construction Work in Progress (CWIP) does not appear in rate base and no Allowance for Funds Used During Construction (AFUDC) is allowed on CWIP, rate base will not equal net book value, and the M/B will not equal 1.0.

Fourth, in an inflationary period, the replacement cost of a firm's assets may increase more rapidly than its book equity. To avoid the resulting economic confiscation of shareholders' investment in real terms, the allowed rate of return should produce a M/B ratio that exceeds 1.0, as the subsequent section on Q-ratios will demonstrate.

10.2 Target Market-to-Book Ratios and the Cost of Equity

The previous section developed a method of estimating the cost of equity based on observed M/B ratios. The process can be reversed. This section demonstrates how the cost of equity figure obtained from standard DCF can be translated into an appropriate allowed rate of return on book equity to take into account any sanctioned difference between market price and book value. The magnitude of the adjustment will depend on the choice of target M/B ratio. The technique is labeled the Target Market-to-Book Method.

At least two arguments can be made to the effect that allowed rates of return on book equity should be sufficient to sustain a given market price. First, continued access to the equity capital market requires a market price at, or somewhat above, book value to insure salability of new equity issues. The costs of floating common stock, including the underwriter spread, market pressure, and allowance for market break, have been ignored thus far. The nature and magnitude of issue costs were treated in Chapter 6. To enable a company to attract capital on terms that do not dilute the value of existing shares, the market price must be sufficiently above book value so that the net proceeds after costs of issue from the sale of new stock are greater than book value. The return allowed by the regulator should be such that neither confiscation of old equity nor dilution of new equity occurs.

Second, if the goal of regulation is viewed as duplicating the result that would be obtained in an unregulated competitive environment, this requires a market-to-book premium similar to that which prevails for unregulated firms. This will be discussed further in the Q-ratio section of the chapter.

Capital Attraction and Market-to-Book Ratios

A strong case can be made for a market price at least equal to book value. One of the fundamental indicators of a utility's financial integrity is the ability to raise equity capital under favorable conditions. This is especially crucial in the case of public utilities whose needs for external equity are frequent, inflexible, and large. It is a well known fact noted by several finance scholars that if a company sells stock for less than book value, the book value of the previously outstanding shares will be diluted, and so will the earnings per share, dividends per share, and earnings growth. Moreover, it becomes increasingly difficult to distribute the same dollar dividends on an increased number of shares outstanding, and investors will become increasingly reticent in accepting any further stock issues.

The following numerical example illustrates the adverse consequences for both ratepayers and stockholders of selling stock below book value.

EXAMPLE 10-3

Consider a utility with $500 of plant investments, all equity financed, with 20 common shares outstanding. The book value per share is therefore $500/20, or $25. The allowed rate of return is 10%, and the market's required return is 20%.

Earnings will total 10% x $500 = $50, and earnings per share will be $50/20 = $2.50. The stock price is therefore $2.50/.20 = $12.50, or half of the book value per share since the allowed return is one half of the required return. The M/B ratio is $12.50/$25.00 = .50.

What happens if the utility requires an additional $500 of assets to be financed by a $500 stock issue with each share selling for $12.50? The company is allowed to earn an additional $50 on this incremental investment (.10 x $500), for a total earnings figure of $100. To finance an amount of $500 at $12.50 per share requires the issuance of 40 additional shares, bringing the total number of shares from 20 to 60. Earnings per share decline to $100/60 = $1.67, and the price of each share drops to $1.67/.20 = $8.35 in order for shareholders to continue earning 20%. The book value per share drops from $25 to $1000/60 = $16.67. Summarizing the results in tabular form:

	Before	After
Equity capital	$500	$1000
Number of shares	20	60
Book value per share	$25	$16.67
Earnings (10% of equity)	$50	$100
Earnings per share	$2.50	$1.67
Market price (20% return)	$12.50	$8.35
Market-to-book ratio	.50	.50

Therefore, sale of stock when the M/B ratio is less than 1.0 dilutes the share in ownership of the original holders of the 20 shares. The book value for each share they own declines from $25 to $16.67, since the new equity capital base is now divided among 60 shares. The market price drops by 33% as a consequence of the equity dilution.

The above example does not imply that utilities cannot, in fact, raise capital when share prices are below book value, but that they can only do so at the expense of existing shareholders. When expected earnings are less than investors' requirements and a sale of stock occurs, new shareholders can only expect to gain their return requirement at the expense of the old shareholders. The market recognizes the potential dilution impact and reprices the shares downward as protection of the required return. A regulatory policy of setting the allowed return so as to obtain a M/B ratio of at least 1.0 avoids such deliberate economic confiscation and abides by the financial integrity criterion of the *Hope* case and the financial soundness criterion of the *Bluefield* case. Such a policy is also in the interests of ratepayers. Systematic dilution of equity imposed on shareholders, because of deficient earnings, endangers the success of the next stock issue. Investor uncertainties are raised as to whether reasonable earnings will be allowed are raised, thereby increasing the cost of debt and equity.

Adjustment for Target Market-to-Book Ratio

The allowed return on book equity must be revised to account for any sanctioned difference between market price and book value. This adjustment to the cost of equity capital can be obtained using the annual DCF model. Solving Equation 10-6 for *r*:

$$r = M/B(K - g) + g \qquad (10\text{-}8)$$

Equation 10-8 defines the return on book value required to be earned such that the investor will receive his required rate of return and the target M/B ratio will be maintained.

To illustrate yet another use of the DCF formula, the next example combines the Target Market-to-Book Ratio approach with the Non-Constant Growth model enunciated in Chapter 4.

EXAMPLE 10-4

The cost of equity for a utility is 15%, as determined by the standard DCF process. The growth component of that return is 5%. The commission that regulates the utility is on record as stating that its regulatory intention is to allow a rate of return such that the utility's stock will sell at 1.1 times book value to avoid dilution. The allowed return on book equity follows from Equation 10-8:

$$r = 1.1(.15 - .05) + .05 = .16 \text{ or } 16\% \qquad (10\text{-}9)$$

EXAMPLE 10-5

A regulatory commission advocates an M/B of 1.1. This fact is known to investors, but, at present, the stock is trading at book value exactly. It is assumed that current dividends are $5, book value per share is $76.43, the long-term expected growth is 7%, and that investors expect the recovery of stock price to take place in one period. In other words, regulatory lag lasts one period. From the general Non-Constant Growth Model, also known as the Finite Horizon or Limited Horizon Model, of Equation 4-17 in Chapter 4:

$$P_0 = \frac{D_0(1+G)}{1+K} + \frac{1.1B_0(1+g)}{1+K}$$

$$\$76.43 = \frac{\$5(1+.07)}{1+K} + \frac{1.10 \times \$76.43(1+.07)}{1+K} \qquad (10\text{-}10)$$

from which $K = 24.70\%$. Alternate assumptions on the length of the recovery period can easily be handled by the general model of Equation 4-17.

AG-DR-03-002

REQUEST:

2. With reference to page 12, lines 1-18, please provide a copy of the entire rate of return section of the referenced Indiana decision.

RESPONSE:

See Attachment AG-DR-03-002.

WITNESS RESPONSIBLE: Roger A. Morin

*1995 Ind. PUC LEXIS 162, **

Petition of Southern Indiana Gas and Electric Company for Authority to Increase its Rates and Charges for Electric Service, for Approval of New Depreciation Rates, for Approval of New Schedules of Electric Rates, Rules and Regulations for Electric Service, and for Approval of Accounting and Ratemaking Treatment for Electric Service to Reflect the Impact of Implementation of Financial Accounting Standard No. 106

In the matter of the investigation upon complaint by the office of utility consumer counselor of company

Cause No. 39871, Cause No. 4007S,

Indiana Utility Regulatory Commission

1995 Ind. PUC LEXIS 162

June 21, 1995, Approved

CORE TERMS: fair value, plant, electric, methodology, inflation, rate base, subsidy, cross-examination, depreciation, accrual, customer, ratemaking, reduction, reproduction, energy, peaker, accounting, rebuttal, annual, fuel, jurisdictional, rate of return, peak, non-payroll, generation, classification, write-off, five-year, ratio, valuation

PANEL: [*1]

Mortell, Corban, [Illegible Text], and Ziegner Concur; Klein Absent

OPINIONBY: David E. Ziegner, Commissioner; Abby R. McFeters, Administrative Law Judge

OPINION: FINAL ORDER

On December 22, 1993, Southern Indiana Gas and Electric Company ("Petitioner") filed its Petition with the Indiana Utility Regulatory Commission ("Commission") for authority to increase its electric rates for retail sales and service; setting new approved depreciation rates; establishing new or amended rules and regulations for Petitioner's electric service; approving accounting and ratemaking treatment for electric service to reflect Commission approval for, and Petitioner's implementation of, Statement of Financial Accounting Standards No. 106 ("SFAS 106"); and determining the fair value of Petitioner's electric utility properties used and useful in rendering electric utility service for the convenience of the public.

Pursuant to legal notice, a Prehearing Conference was held in Room E306 of the Indiana Government Center South, Indianapolis, Indiana, at 1:30 p.m. EST, on February 22, 1994, in accordance with 170 IAC 1-1-16. Proofs of publication of the notice of the Prehearing Conference were incorporated into the record **[*2]** and placed in the official files of the Commission. Petitioner appeared and participated. The Petition to Intervene of PPG Industries, Inc. ("PPG"), filed on February 18, 1994, was granted without objection and PPG participated. The Office of the Utility Consumer Counselor ("OUCC" or "Public") also appeared and participated in the Prehearing Conference. No member of the general public appeared.

During the Prehearing Conference, the parties reached an agreement and stipulation for scheduling and procedures governing this Cause. Their oral agreement and stipulation was presented to the presiding Commissioner and Administrative Law Judge ("ALJ"), and incorporated into the Prehearing Conference Order issued on May 11, 1994 (the "Prehearing Order"). The binding findings and order of the Commission governing this Cause include, without limitation, the following:

A. Procedural Schedule. Petitioner's case-in-chief to be pre-filed by May 16, 1994; Public and Intervenors' cases-in-chief to be pre-filed by October 7, 1994; Field Hearing set and noticed for August 11, 1994 at 6:30 p.m. (prevailing local time) at the Vanderburgh Auditorium, Evansville, Indiana; Petitioner's rebuttal evidence **[*3]** to be pre-filed by October 21, 1994; evidentiary hearing of Petitioner's case-in-chief set for August 15, 16 and 17 in Room E306, Indiana Government Center South, Indianapolis, Indiana, commencing at 9:30 a.m. EST; evidentiary hearing on Public and Intervenors' cases-in-chief and Petitioner's rebuttal evidence to be held commencing on November 21, 1994 at 9:30 a.m. EST, in Room E306, Indiana Government Center South, Indianapolis, Indiana and to continue on November 23, 1994 and November 28, 1994, as required. The parties were also required to conduct technical conferences for the open exchange of information and to facilitate the litigation process and evidentiary hearings, with any successful resolution of issues or settlement to be reported to the Commission at a hearing scheduled to be held on August 26, 1994 in Hearing Room E306 at 9:30 a.m. EST, Indiana Government Center South, Indianapolis, Indiana.

B. Accounting Methodology. The Commission ordered the following accounting methodology to be used in this Cause, except for the items listed which resulted from a negotiated settlement and stipulation orally presented by the parties:

"The accounting methodology . . . should **[*4]** adjust for changes that are fixed as to time, known to occur and measurable, subject to reasonably accurate quantification, within one year from the close of the test year except for:

(1) final construction costs for Petitioner's F. B. Culley Units 2 and 3 Clean Air Act Compliance Project, which costs may extend slightly beyond the January 1, 1995 projected in-service date for said Project, and for which commercial operation shall be reported by Petitioner and verified by Commission Engineering staff prior to making effective any change in rates authorized in this proceeding;

(2) final construction costs for certain projects at the F. B. Culley generating station which are being completed in conjunction with the above said Clean Air Act Compliance Project (the "ancillary projects"), which costs may extend to December 31, 1994;

(3) the pro-forma annualized estimated costs of operating and maintaining the above said Clean Air Act Compliance Project and the ancillary projects, and the estimated annual depreciation expense, property taxes and insurance and other costs related to the above said Clean Air Act Compliance Project and the ancillary projects, which will be based on estimated **[*5]** 1995 amounts;"

The parties also agreed the Petitioner would not weather normalize for sales but use its actual electric sales for calendar year 1993 in this proceeding.

C. Test Year and Cut-Off Date. The test year is calendar year 1993. Except for the three items listed above, the cut-off date for accounting and engineering evidence is December 31, 1993.

D. Discovery. Discovery is to be informal, with parties to object or respond within ten (10) days of receipt of a discovery request.

Countrymark Cooperative, Inc. ("Countrymark") petitioned to intervene on May 18, 1994, which Petition was granted without objection by a Commission Entry of June 13, 1994. Countrymark is subject to all provisions of the Prehearing Order, pursuant to the provisions of that Order.

The parties fully complied with the Prehearing Order except that Public obtained an agreed extension to October 11, 1994, for it and Intervenors to pre-file their respective cases-in-chief.

Due to the prospect that no settlement could be achieved as to all issues, the August 26, 1994 hearing to receive results of the technical conferences which were held by the parties, was canceled.

A field hearing was held, as **[*6]** noticed, in Evansville, Indiana, on August 11, 1994. Members of the Petitioner's ratepaying public did appear and present testimonial evidence. Some members of the public also presented written statements which were filed by the Public as its Exhibit FHA and admitted into evidence as a part of the Public's case-in-chief presented at the evidentiary hearing that commenced on November 21, 1994.

Prior to the commencement of Petitioner's case-in-chief on August 15, 1994, Petitioner filed supplemental direct evidence of its witness William Hopkins, which evidence was later admitted without objection.

Petitioner's case-in-chief evidence was submitted on August 15, 16 and 17, 1994, and all of its direct evidence admitted, except for additional supplemental direct evidence of its witness William Hopkins which Petitioner requested leave to correct an inadvertent error in his direct evidence submitted at the August hearing. The October 6, 1994 motion of Petitioner to pre-file its additional supplemental direct evidence of Mr. Hopkins, was granted without objection on November 10, 1994, and that additional supplemental direct evidence was pre-filed on November 18, 1994. It was admitted without **[*7]** objection, shortly after the commencement of the hearing on November 21, 1994.

Also, Public filed its Additions and Corrections to Prefiled Direct Testimony on November 17, 1994. There was no objection to that pre-filing and Public's evidence was admitted during its case-in-chief evidentiary presentation on November 21 and 22.

Intervenors PPG and Countrymark also presented their cases-in-chief on November 21 and 22, 1994.

At the conclusion of the cases-in-chief of Public and each Intervenor, Petitioner commenced the presentation of its rebuttal evidence on November 22, and its case was completed on November 28, 1994. A filing schedule for proposed orders and briefs was then set by the Commission. All of the above proceedings were conducted in accordance with legal notices duly issued and made as required by law. Petitioner also complied with all legal and administrative notice requirements.

Public initiated Cause No. 40078 by its October 12, 1994 filing of a complaint against Petitioner alleging that Public's pre-filed evidence indicated that Petitioner's present retail electric rates should be reduced, instead of increased. Public requested a Commission investigation of Petitioner's **[*8]** rates and consolidation of the two proceedings. Petitioner filed its Motion to Dismiss and Objections to Consolidation on October 25, 1994. By its Entry of November 10, 1994, the Commission denied Petitioner's Motion to Dismiss and Objections and ordered consolidation.

Any objections or motions not specifically ruled upon in the Record or discussed in this final order, should be considered overruled. All contentions and proposed findings or orders submitted by any party which are not specifically addressed herein by the Commission, are rejected. The Commission has considered all of the evidence admitted in this proceeding and the arguments made by the parties in arriving at its findings, conclusions and this Final Order. The Commission, based upon the evidence and applicable law, now finds and orders the following:

1. Commission Jurisdiction, Petitioner's Characteristics, And Nature. Petitioner is an Indiana public utility corporation incorporated in the State of Indiana and subject to the statutory jurisdiction of this Commission. It is engaged in the gas and electric utility business at retail wholly within the State of Indiana. This proceeding involves only its retail electric **[*9]** business which consists of electric generation, transmission, distribution, sales and service to the public in essentially eight (8) counties in southwestern Indiana. Petitioner's principal offices are located in Evansville, Vanderburgh County, Indiana. Petitioner owns and operates generating plants, equipment, transmission and distribution plant and equipment, vehicles and other personal and real property used and useful in the provision of electricity and electric utility service for the public convenience and benefit. It holds certificates of convenience and necessity which are indeterminate permits for the provision of its utility electric sales and service to the public. All legal notice requirements were duly and timely complied with pursuant to law in this Cause. Therefore, the Commission has jurisdiction of Petitioner and the subject matter in this Cause.

2. Relief Requested. A comparison of Petitioner's original Exhibit WRH-1 with its Exhibit WRH-1 (rebuttal) establishes that in its case-in-chief Petitioner requested a jurisdictional electric revenue increase of $ 12,393,104, while on rebuttal its request has been reduced to $ 10,480,077. The major reasons for the reduction **[*10]** of $ 1,913,027 relates to a stipulated agreement on depreciation rates and to a reduction in the final estimated cost of the Culley Clean Air Act Compliance Project. We will address the latter, more current request, and note that revenue requirement request should also be additionally reduced somewhat by Petitioner's agreement, on rebuttal at hearing, to reduce its rate base by an additional $ 193,834, which is the original cost of land it had proposed to use for a landfill related to its Culley Clean Air project. Pursuant to the testimony of Public's witness Osberg, (Public's Exhibit 3, p. 5, lines 7-9, and lines 16-18), Petitioner agreed that it has withdrawn plans for the landfill at the present time, and that the $ 193,834 land cost should be removed from its rate base calculation in this Cause. The accounting and findings contained in this Order remove that $ 193,834 from Petitioner's rate base. Petitioner proposes that the revenue increase be allocated pursuant to a cost-of-service study presented by Petitioner. An updated cost-of-service study using the 4 Coincident Peak ("CP") methodology is contained in Petitioner's Exhibit RDG-2 (Rebuttal). To facilitate the Commission's **[*11]** understanding of the effect of the $ 193,834 adjustment on the Petitioner's requested increase, Petitioner filed, on December 15, 1994, its late filed Exhibits, which amend the cost-of-service studies presented by Petitioner on rebuttal. Petitioner also filed on December 15, 1994, a late filed Exhibit, which is a cost-of-service study assuming original cost rate base, to assist the Commission in its deliberations in this case. Petitioner has also requested new depreciation rates, implementation and ratemaking treatment of SFAS 106 and changes in its rules and regulations for electric service. Petitioner also requests Commission recognition and acceptance of its compliance with the Commission requirements in Petitioner's last general electric rate case (IURC Cause No. 37803, Final Order issued February 5, 1986) that Petitioner prepare and present a cost-of-service study based on the 12 CP methodology and that Petitioner has reduced any subsidy between its rate classes to the Commission's satisfaction (e.g. Paragraph 11, p. 11 of Final Order in Cause No. 37803).

3. Request For New Depreciation Rates. The differences between the Petitioner and Public as to Petitioner's new depreciation **[*12]** rates to be set pursuant to I.C. 8-1-2-19 and 21, was resolved between them by their presentation of a "Stipulation and Agreement ("S & A") as to Depreciation Settlement" (Joint Exhibit 1). The S & A specified that the parties agreed to accept Petitioner's proposed depreciation rates for all of the depreciation accounts except for

eight specific accounts. For each of those eight accounts the S & A assigned a specific, agreed upon depreciation rate. Those agreed upon rates are as follows:

	SIGECO Proposal	Settlement Rate
(1) Account 353	2.43%	2.51%
(2) Account 356	2.47%	2.38%
(3) Account 362	2.66%	3.06%
(4) Account 364	4.41%	3.22%
(5) Account 365	3.88%	2.43%
(6) Account 367	3.73%	3.30%
(7) Account 368	3.87%	2.63%
(8) Account 369	4.99%	6.04%

In its case-in-chief, the Petitioner presented the testimony of Robert J. Zeles and Harry J. Checkos, employees of Stone & Webster Management Consultants, Inc., in support of its proposed depreciation rates. The testimony of both witnesses was admitted without objection and cross-examination of both witnesses was waived by all parties. Witness Zeles prepared and sponsored the depreciation study forming the basis for **[*13]** Petitioner's proposed rates, and Witness Checkos presented an estimate of the current costs associated with the dismantling of the Petitioner's coal-fired generation facilities. We find the methodology employed by Witnesses Zeles and Checkos to be reasonable and to form a sufficient factual basis for our acceptance of the Petitioner's proposed depreciation rates not specifically addressed in the S & A.

Based upon the evidence presented, all of Petitioner's depreciation rates, including those resulting from the S & A are as follows:

Account Number	Percent
310	3.43
340	4.03
352	1.98
353	2.51
354	1.81
355	3.48
356	2.38
357	1.89
358	2.63
361	3.14
362	3.06
364	3.22
365	2.43
366	2.66
367	3.30
368	2.63
369	6.04
370	3.15
371	7.59
373	4.05
390	2.75

391.1	4.75
391.2	9.46
392.1	5.42
392.4	1.11
393	3.57
394	5.52
395	5.53
396	4.96
397	5.48
398	5.51

The Public presented the testimony of its Principal Engineer Harold Rees in support of the S & A. That testimony was admitted into the record without objection and all parties waived cross-examination of him. Mr. Rees's testimony described the method by which he had calculated depreciation rates as well as **[*14]** the process by which the Public and Petitioner arrived at the agreed upon rates reflected on the S & A. Witness Rees also provided lengthy Schedules which provided additional detail concerning both the agreed upon rates for the specified accounts as well as the makeup of those individual accounts. We find that Witness Rees's testimony established that the method employed to arrive at the depreciation rates enumerated in the S & A are reasonable and provides sufficient factual basis for our acceptance of those rates. We also find that Mr. Rees's testimony provides additional support for our acceptance of the depreciation rates proposed by the Petitioner for the remaining accounts not specified in the S & A. The S & A results in a reduction from Petitioner's originally proposed depreciation accruals of $ 893,195. The impact of the S & A is to set depreciation expense at $ 32,839,120 for the test period. Based upon the substantial factual record supporting them and upon the agreement of all of the Parties to this Cause, we accordingly accept the depreciation rates for the accounts specified in the S & A and further accept the depreciation rates for the remaining accounts as proposed **[*15]** by the Petitioner. In accordance with the S & A we therefore find the composite depreciation rate for Petitioner's electric department to be 3.39%.

4. Fair Value. Petitioner, pursuant to I.C. 8-1-2-6, seeks a fair return on the fair value of its used and useful electric utility property dedicated to serving the public. In support of its position, Petitioner provided evidence based upon property valuation at original cost, reproduction cost and fair value. Petitioner has also submitted evidence regarding the earnings necessary to achieve a 6% and a 6.35% fair rate of return on fair value.

In contrast, Public contends that the Commission should treat the fair value as equal to original cost. In effect, Public urges the Commission to ignore the fact that utility property prudently obtained and utilized may appreciate in value. This we cannot do based upon prior decisions of this Commission in such rate proceedings as Indiana Michigan Power Company, IURC Cause No. 39317, (Final Order issued November 12, 1993), and Indianapolis Water Co., IURC Cause No. 39713, (Final Order) issued August 10, 1994), and Court decisions such as Indianapolis Water Co. v. PSC (1985), Ind. **[*16]** App., 484 N.E.2d 635, 640; Columbus Gaslight Co. v. Public Service Commission (1923), 193 Ind. 399, 140 N.E. 538, 539; Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia (1923), 262 U.S. 679; and Duquesne Light Co. v. Barasch (1989), 488 U.S. 299.

Nevertheless, Public abides by its continuing effort to convince this Commission to find that the net original cost of Petitioner's property is equivalent to the fair value of its property. Based upon the clear language in I.C. 8-1-2-6, the cited court decisions, and the evidence now before us, we again reject the Public's position. We must instead find the current fair value of Petitioner's used and useful property dedicated to serving the public and use that fair value finding in determining Petitioner's allowed return.

(1) Evidence on Original Cost. The OUCC and Petitioner proposed that the total net original cost of Petitioner's electric property used and useful in providing service to the public is $ 640,075,664 (Petitioner's Exhibit RJD, Schedule 2 (rebuttal) and Public's Exhibit 2B), calculated as follows:

Net Utility Plant Allocated to Electric:	$ 495,299,462
Culley Clean Air Compliance Project:	101,383,553
Ancillary Culley Projects:	9,811,899
Demand Side Management ("DSM")	
Expenditures:	6,395,053
Materials and Supplies:	12,750,951
Coal Inventory:	14,434,746
Total Electric Original Cost Rate Base:	$ 640,075,664
Less: Non-Jurisdictional Rate Base:	$ 65,560,183
Total Jurisdictional Original Cost Rate Base:	$ 574,515,481

[*17]
There was no significant disagreement between the parties as to the original cost of the properties included in Petitioner's electric utility rate base for purposes of this proceeding. We find the total jurisdictional original cost rate base to be $ 574,515,481.

(2) Evidence on Reproduction Cost. The statute requires that in determining fair value, the Commission must give such consideration as it deems appropriate to all bases of valuation which may be presented or which the Commission is authorized to consider. One method of valuation which has been presented in this case is the cost to reproduce Petitioner's property new, less depreciation. Public Serv. Comm'n v. City of Indianapolis (1956), 235 Ind. 70, 131 N.E.2d 308, 315.

Petitioner's witness David C. Moody, a Vice President in the Appraisal Division of Stone & Webster Management Consultants, Inc., performed an appraisal of Petitioner's electric property on the basis of the cost to construct the property new, less depreciation. Mr. Moody determined the reproduction cost new by trending the original costs of the various components of Petitioner's electric utility plant from their installation dates to December 31, **[*18]** 1993, using trend factors reflecting changes in construction costs over time. Mr. Moody also determined the depreciation associated with the property giving consideration to the results of a detailed field inspection, its operating condition, and obsolescence. The determination of depreciation for the generating plants involved assessment of their operating condition compared to the operating condition of a new, modern coal-fired generating facility of similar design. From his study Mr. Moody concluded that the reproduction cost new of Petitioner's property in service at December 31, 1993 was $ 1,639,611,437 and the reproduction cost new less depreciation ("RCNLD") was $ 1,176,917,270. (Petitioner's Exh. DCM-1.)

The Public objected to Mr. Moody's testimony and exhibits on the basis that determining reproduction costs new less depreciation is a hypothetical exercise and the Commission may not base rates upon a hypothesis or situation never in existence. The Public cites, PSC v. City of Indianapolis, 131 N.E.2d 308, which states, "The statute does not permit the fixing of rates on a hypothesis or a situation never in existence." Similarly, PSC v. Indiana Bell Tel., 130 N.E.2d **[*19]** 480, states "Appellants could not arbitrarily disallow federal income tax which Appellee had paid, or was obligated to pay, by assuming a tax savings under a capital structure which did not exist." The Public argued the determination of reproduction costs new is a hypothetical exercise at estimating what it would cost to rebuild a massive amount of utility plant today in its current condition.

Under cross-examination Mr. Moody agreed that subjectivity is involved in valuing utility plant and determining its percent condition and that competent appraisers could reasonably disagree as to the value of utility plant and the percent depreciation.

Mr. Moody used the Handy-Whitman index to trend original cost. He then determined the depreciation allowance to be applied to current cost. His current cost new less depreciation for electric plant in service is depicted on Exhibit CM-1, page 1. His current cost new less depreciation for production plant is on Exhibit DCM-2. Mr. Moody testified that "determination of the depreciation associated with Petitioner's electric generating plants involved an assessment of the operating condition of the plant compared to the operating condition of a **[*20]** new, modern coal-fired generating facility of similar design. Losses in value attributable to physical and functional causes can be quantified by the extent to which such losses affect the annual cost and level of production." (Petitioner's Exhibit K, p. 11).

Mr. Moody used the Trimble County, Kentucky plant, which is part of the Louisville Gas & Electric system as a surrogate for comparison of costs as a recently constructed plant. Mr. Moody, in reviewing the capital costs of Petitioner's production plant, took the original cost to construct Petitioner's plants, trended it forward using Handy-Whitman and then compared that cost on a dollar per kilowatt basis to the construction cost for the Trimble plant, with some adjustment made to reflect variations in functional characteristics. Because the Trimble plant costs were higher than Petitioner's trended costs, he stated that there was no functional obsolescence as it affects the capital costs of Petitioner's plant.

Mr. Moody then made an effort to review any obsolescence as it affects operation. He stated that such obsolescence is measurable through the difference in the annual cost to produce a unit of output. To accomplish this **[*21]** review, Mr. Moody took the annual cost of the Trimble plant and made adjustments for differences in the quality and cost of fuel compared to Petitioner's plants. Any variation between this resulting cost and Petitioner's actual product cost, Mr. Moody believed was caused by a combination of functional causes and physical deterioration.

Mr. Moody's use of the Trimble plant as a surrogate to determine the physical deterioration and functional obsolescence of Petitioner's generating plant for purposes of fair value was challenged by the Public in cross-examination. Mr. Moody agreed that neither he nor SIGECO management had any involvement in siting the Trimble plant, choosing the contractors to build the plant, or overseeing the construction of the plant. Similarly, neither Mr. Moody nor SIGECO management oversees or controls the manner in which the Trimble plant is operated and the costs associated with the Trimble plant.

Also, under cross-examination, Mr. Moody agreed that the Handy-Whitman Index he used to determine replacement costs does not take into account how stringent or how lax plant owners may be in planning, siting, contracting for, constructing, and overseeing utility plant **[*22]** projects. Mr. Moody, however, attempted to distance himself from the use of the Handy-Whitman Index by saying that his use of it was very limited because the Trimble County plant in Kentucky was a very recent plant.

Under cross-examination, Mr. Moody also agreed that if SIGECO's generating plants were rebuilt today, many of their characteristics would be different. Yet, Mr. Moody, for purposes of showing reproduction costs new, did not specifically take into account, other than the Trimble comparison, how reproduction costs new would be affected by the changed characteristics of SIGECO's generating plants if newly constructed today.

During cross-examination by the Public, Mr. Moody was asked how close to accuracy his percent condition calculations for SIGECO's plant were. He responded that he really had no way to determine whether they were within five, ten or any other percent of complete accuracy. Mr. Moody admitted that there was subjectivity in his determination of percent condition when he was asked why all of his calculated condition percentages were round numbers which end in zero. For example, we note the following examples that the Public's cross-examination identified: **[*23]** 35 percent for poles and fixtures, 40 percent for overhead conductors and devices, 20 percent for underground conduit. The Public also criticizes Mr. Moody's inspection of only 400 poles out of 100,000 owned by SIGECO.

Mr. Moody testified that to replace portions of SIGECO's underground system as well as SIGECO's transmission system, one would have to contend with infrastructure which has been constructed subsequent to when the utility plant was originally installed. Thus, Mr. Moody attempted to make the point that if SIGECO had to replicate those portions of its underground system and transmission system today, it could not do so because the Company would have to contend with infrastructure that did not exist at the time the utility plant was originally installed. In Mr. Moody's opinion to build the original system today would cost much more than can be attributed to inflation or increases in price levels. For this reason, Mr. Moody found that no further reduction in the current cost new less depreciation of Petitioner's distribution and transmission plant should be made. Public argued that this ignores the actual condition of these items of plant.

The basis of the cross-examination **[*24]** was to concentrate on the subjectivity involved in making a RCNLD recommendation. The Public contends that Mr. Moody's comparison of SIGECO's generating plant to the Trimble County plant was unsupported.

Mr. Moody stated that an inspection of a sampling of the poles is capable of providing a very accurate assessment of the conditions. Mr. Moody also stated that he relied on his experience in having conducted such inspections in 26 other states and in foreign countries, as well as his previous inspections of the SIGECO system.

As noted by Petitioner, Mr. Moody's evidence was the only evidence as to Petitioner's reproduction cost new of its property. We have reviewed Mr. Moody's testimony on this point as well as Public's challenges to his testimony. Mr. Moody agreed that subjectivity is involved in valuing utility plant and determining its percent condition and that competent appraisers could reasonably disagree as to the value of that utility plant. Calculating the reproduction costs new of property is indeed a complex task, a task which involves examining property ranging in age from near new to many years old and attempting to analyze myriad technological advances that have occurred **[*25]** over time in making an assessment as to what would be that property's reproduction cost new today. Certainly a reproduction cost new study must involve the making of many assumptions and the application of considerable judgment. It is clear from the evidence that Petitioner's properties were not created and placed by one massive construction program, but rather, developed over time under differing states of technology and with influences and constraints that could scarcely be imagined with a retrospective look at an endless array of property accounts. We are faced with a concern that plagues all reproduction cost new studies which is the very real probability that Petitioner's system would not in fact be reproduced in the same fashion today. Innumerable external factors including the constraints of law, the advances of technology, electricity demand, efficient planning and countless others must be accurately reflected, otherwise, a reproduction cost new study cannot be said to reflect current or fair value. It appears that Mr. Moody's reproduction cost new study was performed in a reasonable fashion and provides a plausible estimation of the current cost to reproduce Petitioner's **[*26]** plant new exactly as it was less depreciation. This Commission has often said that a reasonable measure of the fair value of utility's property is what a willing buyer might pay a willing seller in an arm's length transaction. The concerns pointed out in the reproduction cost new study are but exemplary of the myriad potential problems with accepting a book valuation and trending calculation of reproduction cost new as current value. It can be said with certainty that if one were to replicate Petitioner's entire system today in a single massive effort, it would not look as it did when built. We may only speculate as to how a prospective purchaser would value a generating plant. It is these types of considerations that make reproduction cost new analyses less than entirely persuasive as a best determinant of the fair value of utility property.

No witness other than Mr. Moody submitted evidence on RCNLD.

(3) Determination of Fair Value. Petitioner's witness Moody testified that in determining the fair value of Petitioner's electric utility plant, consideration should be given to both the depreciated original cost and the RCNLD. Mr. Moody stated that in his opinion the fair value **[*27]** is $ 756,478,679 which was determined by giving 61.7% weight to depreciated original cost and 38.3% weight to RCNLD. The weight given to depreciated original cost was representative of the percentage of Petitioner's capital structure made up of fixed obligations (debt, preferred stock and no-cost capital) that are unaffected by inflation or the physical characteristics of the assets. Mr. Moody weighted the RCNLD component of the fair value amount by the common equity component of the capital structure (including a pro rata share of the job development investment tax credits). Petitioner's witness Paul R. Moul, who testified for Petitioner on cost of capital and rate of return, agreed that Mr. Moody's approach is proper and reasonable. (Petitioner's Exh. D, p. 71.)

The OUCC and Intervenors did not present testimony from an appraiser regarding the reproduction costs new or the final fair value figure of Petitioner's plant. The OUCC, however, presented testimony from its economist, Mr. Gillingham, which is germane to this topic. Mr. Gillingham testified that from a financial prospective what is important is that the return granted to utilities should be a return which is sufficient **[*28]** to allow them to attract capital from the marketplace under reasonable terms. He testified that the primary difference between a return on fair value and a return on original cost is the manner in which investors are compensated for inflation. Both methods compensate for inflation, but in different ways. In fair value, the principal upon which the return is earned is increased for inflation, whereas under original cost, the return is increased for inflation. Both methods compensate investors for inflation, but in different ways. He said that it is entirely possible that the result from both methodologies could be identical or very similar. Mr. Gillingham testified that what is important to meet the Hope criteria is essentially that the return be sufficient to allow the utility to pay both reasonable interest expense and dividends, and attract debt and equity from the marketplace under reasonable terms. He testified that it is entirely possible to set fair value at "or only slightly above original cost and allow the utility to earn a dollar return which is entirely reasonable. From the perspective of earning a reasonable return, it is wholly irrelevant if the authorized net operating **[*29]** income is based upon a larger percentage applied to a smaller original cost rate base, or a smaller percentage applied to a larger fair value rate base. What is relevant is whether the return is fair to the utility's shareholders and also fair to the utility's ratepayers." (Public's Exhibit 7, p. 30.)

Mr. Gillingham testified that setting fair value at or near original cost is much more reliable and efficient than setting fair value at a subjective, hypothetical point deep between original cost and replacement costs new. In his opinion, setting fair value at original cost allows investors to be compensated for inflation through the weighted cost of capital and avoids the more complicated and time consuming task of having to estimate a hypothetical value for rate base and then back inflation out of the weighted cost of capital. Setting fair value at original cost should and does result in a reasonable return if properly done. In his opinion, there is no reason why a reasonable return should be inflated and rendered excessive in an effort to pay tribute to a wholly subjective, hypothetical, fair value depiction of rate base.

Mr. Gillingham testified that the vast majority of regulatory **[*30]** jurisdictions use original cost rate base for ratemaking purposes. He also stated that there are only four or five jurisdictions in the United States that actually increase net operating income out of tribute to the notion of return on fair value. More importantly, he said investors have endorsed original cost rate base for ratemaking purposes by providing huge amounts of capital to utilities operating in original cost jurisdictions. In his opinion, investors would not provide these funds if original cost ratemaking denied them a reasonable return on their investment.

Finally, Mr. Gillingham testified that if this Commission does find that fair value should be set at a level higher than original cost thus compensating for inflation in the fair value rate base, the Commission should, as it has regularly done in the past, remove inflation from the percent return applied to the fair value rate base so as to prevent the ratepayers from paying for the effects of inflation twice, once in the rate of return and a second time in the fair value rate base.

In his rebuttal testimony, Mr. Moody supported his fair value rate base on what he described as a philosophical as well as a practical **[*31]** basis. Philosophically, Mr. Moody stated that if Petitioner has conducted its business in a way that the results exceed the minimum requirements of its charter to serve the public, it is only fair that the Commission recognize this benefit by encouraging utilities to conduct business in such a manner (Exhibit S, p. 5). He opined that as a practical matter, without an incentive for exceeding minimum requirements, it may not even be physically prudent to allocate resources to do so. Other things being equal, in his opinion, a company in a fair value jurisdiction is more likely to allocate resources that are a benefit to the public if there is a reasonable chance that the resulting increased value will be compensated for (Exhibit S, p. 5).

Under cross-examination by the Public with reference to Mr. Moody's rebuttal testimony, Mr. Moody indicated that the only place for fair value is in utility ratemaking and fair value has no place to fit in a real world valuation of public utilities market value. He also indicated that one thing he had not done in his fair value evaluation was to consider the cost of bringing the company to its then state of efficiency, a matter which he believed the **[*32]** Commission is also allowed to consider in reaching a fair value figure. He also stated, "To the extent inflation has impacted my fair value determination, it has been past inflation, not anticipated future inflation." (Exhibit S, p. 6).

The Public, through cross-examination, explored Mr. Moody's opinion as to how different types of investors might assess a different fair value to SIGECO. Mr. Moody agreed that some potential buyers, in valuing SIGECO, would consider how profitable the entity will be in the future. Another potential buyer, less interested in jurisdictional operation but more interested in interstate transmission of power to more lucrative markets on the East Coast, might value SIGECO differently. Similarly, a not-for-profit entity, such as a co-operative G&T, less interested in profit and more interested in reasonably priced generation, might assign a different value to SIGECO. Lastly, regarding a corporate raider, that is a purchaser whose interest is in buying an entire company, dividing it into its subcomponents, and selling off those subcomponents at the highest price, Mr. Moody had no opinion as to whether such a corporate raider would value SIGECO differently **[*33]** than the previously described purchasers.

The Public cross-examined Mr. Moody regarding his "philosophical and practical reasons for the use of fair value as rate base" (Exhibit S, p. 5, 8-21). Mr. Moody's assertion seems to be that a utility "in a fair value jurisdiction is more likely to allocate resources that are a benefit to the public if there is a reasonable chance that the resulting increased value will be compensated for" (Id.). Mr. Moody explained that that statement is made in the context of adding plant or systems as a benefit above and beyond the minimal high standards that exist for the provision of safe, adequate and reliable service at a reasonable price. He indicated it is "things beyond that minimum is what that addresses." When asked what things that would have rendered this type of extraordinary benefit to SIGECO's ratepayers, Mr. Moody responded by indicating that he is not sure that SIGECO makes decisions not to build things on that basis and that it might make a decision to go beyond building a minimal system if it thought there was an economic reason to do so.

When asked if SIGECO needs the incentive of additional fair value return dollars in order to **[*34]** provide more than safe, adequate and reliable service at the lowest cost reasonably possible, Mr. Moody responded that SIGECO is more likely to make decisions like that if SIGECO believes there is an economic reward for doing so, and if SIGECO has an idea that whatever it does will be rewarded appropriately, it is more likely to be generous in installing these extra systems to serve the public.

The OUCC asked Mr. Moody if SIGECO were to get every dollar of increased annual operating revenue requested in this Cause, but achieved that increase through a higher cost of equity embedded in a higher weighted cost of capital applied to original cost rate base, rather than through a deflated return percentage applied to an inflated fair value rate base, what additional things is it that SIGECO is not going to do in the future because it did not get the increase based on "fair value return?" Mr. Moody responded that he does not think the Company addresses its expectations or its capital investments on that basis. He said specifically, as a general theory and in a general case, it is more likely to install plant that serves the public more than minimally if it does not need to worry about **[*35]** whether it will be an economic investment.

Finally, when asked whether it is true that SIGECO is going to do the very best job it can to provide safe, adequate and reliable service to its ratepayers at the lowest cost reasonably possible so long as it gets a reasonable stream of revenue from this Commission and is compensated for reasonable operating expenses, Mr. Moody agreed. However, Mr. Moody said the point he would like to make is that by giving SIGECO some increment for extraordinary performance, SIGECO will be capable of doing more. We are unpersuaded by Mr. Moody's point. Mr. Goebel testified during cross-examination that in his opinion. SIGECO has always strived to be an extremely efficient company since he began his employment in 1969. He stated that the utility and its management have incentives to be as efficient as possible.

Given the other evidence of record in this Cause as to the nature, status and condition of very substantial items of Petitioner's utility property, we must conclude that Mr. Moody's proposed reproduction cost new of $ 1,176,917,270 for the reproduction cost less depreciation of Petitioner's property represents an amount substantially in excess of **[*36]** the current market or fair value of Petitioner's property. Having made this determination, we look to the record for a more reasonable quantification of the fair value of Petitioner's property. Petitioner has proposed that we find the current fair value of its plant and equipment used and useful in rendering electric service is $ 901,061,049. This is based on fair value of $ 756,284,845, together with the other elements which are includible in rate base. This amount also reflects the adjustment of $ 193,834 for land cost previously referred to herein. On an Indiana jurisdictional basis, Petitioner's proposal is that the fair value of Indiana jurisdictional plant and equipment is $ 810,452,614. Petitioner based this finding on Mr. Moody's calculation by giving 61.7% weight to depreciated original cost and 38.3% weight to RCNLD.

Mr. Moody proposes to calculate the fair value of Petitioner's property by an allocation of net original cost and RCNLD based upon the proportion of debt and equity in the capital structure. Mr. Moody's proposal is an interesting one but appears problematic. Petitioner's proposal uses RCNLD as an input. We have found previously that Petitioner's RCNLD amount **[*37]** is excessive and thus would not be a proper input to this calculation. Further, we question the underlying assumptions of the calculation. The fair value can be represented by what a willing buyer would pay the seller, but to use the simplistic approach, applying the book value ratios equity and debt to a non-market value such as RCNLD is not a consistent allocation. A better argument might be made for using the market value of the equity to represent the increase in value over original cost. However, because the market value fluctuates, sometimes widely, from time to time, its use seems questionable. Further, it seems inappropriate to use only the market value of the equity and not that of debt. Given these concerns, with both the data base and methodology, we find that Petitioner's proposed fair value should be given limited weight.

We are once again faced with the quandary to find a reasonable fair value for Petitioner's used and useful property. The OUCC, although successful in pointing out flaws in Petitioner's testimony, again argues that the fair value is equal to original cost. In fact, a substantial portion of the OUCC's proposed order contains arguments of why this Commission **[*38]** should find fair value to be original cost. The OUCC's historical and legal narrative is very interesting; however, it does little to aid in the resolution of this case. Even though some of the points made by the OUCC are valid, the OUCC still fails to present an alternative valuation for fair value other than original cost, minus the cost for some land. Poking holes in Petitioner's presentation and making a case for equating fair value with original cost does not change the statutory requirement that fair value be used for setting rates, nor does it change the Courts' interpretation of that requirement, that being that original cost is not a mere substitute for fair value.

As we, again, consider Public's arguments in support of its contention that fair value should be net original cost, we are compelled to make some observations. As noted, several of OUCC's arguments make practical sense. OUCC's contention that original cost is much easier to calculate is undisputed. OUCC's position that so long as an appropriate net operating income is authorized, whether it is calculated on original cost or fair value makes little difference, is not without merit. Further, OUCC's contention that **[*39]** the difficulty in deriving fair value leads to rather farcical fair valuation proposals is certainly of merit. OUCC's persistent contentions begin to conjure images of the cartoon devil lightly resting on our shoulder cajoling us to accept its proposal -- just once. Despite OUCC's persistence and the practical merits of some of its arguments, it apparently fails to recognize the true genesis of this Commission's position on fair value ratemaking. Regardless of the protestations or pleas of OUCC or its imaginary minion, this Commission is bound by statute and the Indiana Courts' construction of these statutes. Simply because the task is difficult or that a party suggests there is a better way, we cannot disregard the duty imposed upon us by the statute and the Courts.

While evidence of replacement cost may be helpful in the task of determining fair value, it is clear that, absent unusual circumstances, a third party would be unwilling to pay full replacement cost for any utility. Petitioner's contention that facilities are worth more than their original cost seems well-founded both by the evidence and logic. If the potential buyer of the utility is able to generate an income roughly **[*40]** equivalent to that which would be earned by new facilities, such buyer would be willing to pay something more than original cost. Inflation would increase the cost of comparable new facilities to more than the original cost of older facilities. On the other hand, as noted before, a utility built piece by piece as demand has grown or declined and technology has changed will not be as efficient an arrangement as one designed and installed with current knowledge. Therefore, a potential buyer would not be willing to pay the full replacement cost. The price parties in the secondary market are willing to pay for the utility's equity does reflect one group's valuation of the utility. The fair value must of necessity reflect some past inflation to the extent that this has not been offset by obsolescence. Fair return on fair value rate base should reflect expectations of future inflation so these should not be included in the fair value.

Based on the evidence of record and these factors, we find the fair value of Petitioner's rate base to be $ 794,473,230.

5. Fair Rate of Return. Having determined the fair value of Petitioner's property, the Commission must determine what level of net **[*41]** operating income represents a reasonable rate of return on that fair value. This determination requires a balancing of the interests of the investors and the consumers. In Bethlehem Steel Corp. v. Northern Ind.

Public Serv. Co. (1979), Ind. App., 397 N.E.2d 623, 630, the court explained that "[w]hat 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." One consideration in evaluating the reasonableness of a utility's return is the utility's overall weighted cost of capital.

(a) Cost of Capital. Petitioner and the Public each submitted evidence on Petitioner's overall weighted cost of capital. For that purpose, both parties utilized Petitioner's capital structure as of December 31, 1993. (Petitioner's Exh. PRM-18; Public's Exh. 2, Sch. 5, p.1.) There was no material difference between Petitioner and the Public with respect to the capital structure or the cost rates for any of the components of the capital structure other than common equity.

i) Petitioner's Evidence. Petitioner's evidence on cost of capital and rate of return was submitted **[*42]** by Paul R. Moul, Managing Consultant of the firm P. Moul & Associates, an independent utility consulting firm. Mr. Moul has over twenty years of experience in performing financial studies of utilities. He has testified before this and other commissions on numerous occasions and lectured widely on the subject of cost of capital.

Mr. Moul recommended originally that the Commission find that the cost of Petitioner's common equity capital was 12.75% resulting in an overall cost of capital of 8.14% when combined with the debt, preferred stock and other components of Petitioner's capital structure. In determining the common equity cost rate, Mr. Moul utilized four methods of measurement: the discounted cash flow ("DCF") model, the risk premium analysis, the capital asset pricing model ("CAPM"), and the comparable earnings approach. The results of these studies were as follows:

Method	**Common Equity Cost Rate**
DCF	11.10%
Risk Premium	12.93%
CAPM - Traditional	12.52%
CAPM - Zero Beta	13.85%
Comparable Earnings	13.55%
Recommendation	12.75%

Mr. Moul emphasized the importance of using more than one method, particularly given what is described as the tendency of the DCF method **[*43]** to understate the cost of common equity under current market conditions.

At the rebuttal hearing, Mr. Moul revised his recommendations regarding Petitioner's cost of common equity increasing it from 12.75% to 13.50%. Mr. Moul explained that this increase was attributable to a significant rise in capital costs since his direct testimony was presented, including short-term and long-term interest rates, and a 75 basis point increase in dividend yields. This rise was also recognized by the other two cost of capital witnesses.

In supporting his position, Mr. Moul testified that it was important to provide the Company with an opportunity to experience an adequate level of pre-tax interest coverage so as to allow the Company to maintain its AA bond rating. Additional factors discussed by Mr. Moul in support of his position were the increased business risk for electric utilities resulting from increased competition in the electric generation market, the trend toward open access of the transmission network, new environmental regulations, and the large requirement for future capital expenditures facing Petitioner, amounting to $ 270 million during the 1994 to 1998 period. Mr. Moul also cited **[*44]** the unique risks associated with the earnings test component of the Indiana fuel cost adjustment ("FAC") process which effectively caps Petitioner's net operating income ("NOI") at the amount used to establish rates in Petitioner's most recent rate order. Mr. Moul said he was unaware of any other regulatory jurisdiction which imposes such an NOI cap.

During cross-examination by the Public, Mr. Moul agreed that if a utility, through return on original cost rate base, would have the ability to go to the capital markets and acquire both debt and equity under reasonable terms and receive a return which was commensurate with the return given on investments on similar risk, that the utility would then be receiving a reasonable return. He indicated there are plenty of other regulatory jurisdictions that do exactly that. Moreover, Mr. Moul indicated that while SIGECO seeks a 12.75% return on equity, its requested level of return on "fair value" rate base actually increases SIGECO's requested return on equity to 13.58%.

The interest coverage issue was also discussed by Petitioner's witness Goebel. Mr. Goebel testified that the credit rating agencies were maintaining a "stable" outlook for **[*45]** Petitioner's AA bond rating in anticipation of "supportive" regulatory action in this proceeding, especially with respect to fixed charge coverages. Mr. Goebel showed the benefits of the AA rating by pointing out that Petitioner's embedded cost of debt was among the lowest in the country, ranking third lowest on a recent Duff & Phelps review of 116 utilities.

Petitioner also submitted the testimony of William D. Patterson, Managing Director of Smith Barney Shearson and head of its Utilities Group in the Investment Banking Division. Mr. Patterson testified regarding the business risks facing combination electric and gas utilities like Petitioner. Mr. Patterson said that as competition increases, lower rated utility securities will suffer higher financing costs and reduced access to capital. He claimed that downgrades create unfavorable perceptions in the market which linger long after interest coverage and cash flow ratios begin to improve. He also stated that after being downgraded, it is difficult for a utility to improve its credit rating.

Mr. Patterson concluded that it was essential for Petitioner to maintain its AA rating and that without adequate and timely rate relief, a **[*46]** reduction in Petitioner's debt rating will become a distinct possibility.

ii) Commission Determinations on Cost of Common Equity. In finding an appropriate cost of capital for Petitioner, it is not necessary for us to resolve all differences among the witnesses in the inputs they used in the econometric models. We know from our experience that the determination of the cost of common equity is not the precise exercise these models sometimes imply and that small changes in data, assumptions and methodology can have a significant effect. This is particularly true in markets which are trending significantly higher or lower, such as is being experienced today. Such general and specific market conditions cast additional doubt on forecast validity. This conclusion is supported by the differing results offered by the three cost of capital witnesses in this Cause. No one method has been universally accepted by this Commission as the exclusive and proper method. This opinion seems to be shared by our witnesses as well because none of them has relied solely on one methodology to the exclusion of all others. We are also aware that significant judgment was utilized by each of the witnesses **[*47]** in reaching their ultimate recommendations. Estimation of an adequate cost of capital is not a precise science but rather application of models to specific facts and using reasoned judgment. However, even experts in the field can differ as is the case here.

We recognize that some of the differences may be the result of the inherent problems with one method or another such as the DCF method. However, the differences demonstrate the need to use more than one method and use reasoned judgment to determine a fair return on equity.

Countrymark presented the testimony of Kenneth Eisdorfer concerning return on equity. Mr. Eisdorfer's pre-filed testimony indicated that his recommended cost of equity was 10.3%. At the time of intervenor's case-in-chief, Mr. Eisdorfer revised his recommendation upward to 10.50% to reflect increases in interest rates which had occurred since his pre-filed testimony was filed with this Commission.

There are certain basic facts regarding cost of capital and rate of return which stand out from the evidence. The first such fact is that capital costs have increased dramatically since the fall of 1993. For example, one of the attachments to Mr. Gillingham's testimony **[*48]** shows that AA-rated utility bond yields in October, 1993 were 6.89%. (Public's Exh. 7, Attachment 3, p.1.) By the final hearing in November, 1994, AA-rated utility bond yields were 8.99% (Petitioner's Exh. R, p. 4), an increase of over 200 basis points. Interest rates continued upward even after the pre-filing of the evidence of the Public and Countrymark, leading to the need for Mr. Gillingham and Mr. Eisdorfer to revise their recommendations upward at the final hearing. However, while Mr. Gillingham and Mr. Eisdorfer increased their recommendations by 35 and 20 basis points respectively, cross-examination of Mr. Gillingham and Mr. Moul's rebuttal testimony indicated that current and forecasted yields on many treasury instruments, and Petitioner's dividend yield (a component of the DCF model) had increased even more greatly. Moreover, Value Line increased the beta coefficient assigned to Petitioner (a component of the CAPM) from .60 to .65, reflecting the higher market risk of the Company's stock.

We find that these increases in capital costs must be considered in our cost of common equity finding in this case. We must also temper this information with the well known fact that interest **[*49]** rates fluctuate and are influenced by several factors unrelated to this case. We have witnessed interest rates climb and fall, both of which occurred during the course of a single regulatory proceeding. We must remember that we are setting prospective rates which may be in effect for some time. Because of this, the Commission must be careful to not embrace a trend which could reverse itself within a short time, having the opposite effect.

The second issue raised by Petitioner is its belief that it needs to reasonably support its AA credit rating. Mr. Moul testified that Petitioner's original requested rate increase would produce a pre-tax interest coverage of 3.65 times which is within the 3.5 to 4.0 times criteria for an AA rated electric utility with an above average to average business position. (Petitioner's Exh. R, pp. 10, 12.) Mr. Moul testified that it is critical that this rate case provide the support necessary to begin the restoration process necessary to regain the financial ratio benchmarks required to sustain Petitioner's AA bond rating which it has held for many years. (Id., p. 12.) Petitioner's evidence shows this historical AA rating has substantially benefitted **[*50]** it and its ratepayers by keeping capital costs low and contributing to Petitioner's long standing reputation of being an efficiently managed and financially sound and conservative utility.

Mr. Gillingham and Mr. Eisdorfer each state that they have applied the standards of Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n (1923), 262 U.S. 679, and Federal Power Commission v. Hope Natural Gas Co. (1994), 320 U.S. 591. They each recognize that one of the standards set forth in these cases is that a fair return should be sufficient to allow the utility "to maintain its credit." We must conclude, contrary to the position taken by the Public and Countrymark, that this standard supports Petitioner's requested rate increase in that it allows Petitioner to maintain its AA credit rating. The positions of the Public and Countrymark, on the other hand, would most probably result in the downgrading of Petitioner's debt rating to the detriment of both Petitioner and its ratepaying public.

Through cross-examination, the Public suggested that a AA credit rating may not be cost justified. From this evidence we conclude that the maintenance of Petitioner's long-standing

AA bond [*51] rating is beneficial to both Petitioner and its customers. Petitioner testified that it has one of the lowest embedded debt costs in the country which Mr. Goebel attributed, among other things, to its AA credit rating. Mr. Goebel also testified that Petitioner has the need to refinance at least $ 111.25 million of maturing or puttable debt over the next five years. Obviously, Petitioner's credit quality will have an impact on the interest rates associated with these refinancings.

Petitioner also offered the testimony of Mr. Patterson of Smith Barney Shearson on this point. Mr. Patterson and his firm are directly involved in the raising of equity and debt capital for utilities in the public and private capital markets. Mr. Patterson testified that credit ratings not only influence long-term debt costs but also the costs of preferred and common stock and short-term debt.

Mr. Patterson explained that credit ratings are a slippery slope. It is much more difficult to improve than to drop. Rating agencies typically demand consistently improved results over extended periods coupled with realistic positive forecasts before granting upgrades. Downgrades, according to Mr. Patterson, create [*52] unfavorable perceptions in the market which linger long after interest coverage and cash flow ratios begin to improve. Mr. Patterson also pointed out that higher ratings result in easier access and lower costs for all types of capital. Firms with less than BBB ratings, for example, are excluded from using certain financing mechanisms.

Public does not directly dispute that Petitioner's AA credit rating has been beneficial to customers. Petitioner has shown that it operates its electric utility business efficiently. Petitioner also faces substantial refinancing requirements in the next few years for which its credit rating will play an important part. The Commission concludes that Petitioner's credit rating is always of concern to the Commission.

The third important factor is that the DCF model, heavily relied upon by the Public, understates the cost of common equity. The Commission has recognized this fact before. In Indiana Mich. Power Co. (IURC 8/24/90), Cause No. 38728, 116 PUR4th 1, 17-18, we found:

[T]he **unadjusted DCF result is almost** always well below what any informed financial analyst would regard as defensible, and therefore requires an upward adjustment based largely [*53] on the expert witness's judgment.

Accord, Indiana-American Water Co. (IURC 2/2/94), Cause No. 39595, p. 34, 150 PUR4th 141, 167.

The essential problem is that the DCF model purports to determine the rate of return investors require on the market price of their stock. Yet, the Public proposes that after this rate of return is calculated, it be applied to book value, i.e. an original cost rate base. Since the market price of the stock of Petitioner as well as all of the other electric utilities included in the barometer groups used by each of the parties exceeds book value, the DCF result applied to a book value rate base will not produce what Petitioner believes are reliable results.

We have heard testimony in this, as well as other utility rate cases criticizing the DCF model based on the market verses book price issues. While we recognize the problems inherent with the DCF model, we still believe the model does provide useful information on a very crucial but imprecise area of the ratemaking process. It is for this very reason the Commission has had concerns in our past orders with a witness relying solely on one methodology in reaching an opinion on a proper return [*54] on equity figure.

All three witnesses recognized that a key standard set forth in the Bluefield and Hope cases is the determination of a rate of return which is comparable to that available on other investments of corresponding risk. Mr. Gillingham and Mr. Eisdorfer gave no consideration to the determination of what a comparable return would be. Mr. Moul, on the other hand, utilized a Comparable Earnings approach as one of his methods. Mr. Moul analyzed both historical returns and forecasted returns for non-regulated companies having the same risk parameters as Petitioner. Mr. Moul's analysis related to return on book equity. Mr. Moul explained that return on book equity can be applied to an original cost rate base and avoids the mis-specification which results under the DCF model when market prices and book value diverge. From an available data base of 1,600 companies, Mr. Moul selected twelve which fit Petitioner's risk profile. Mr. Moul developed a rate of return of 13.55% from this approach, averaging historical and forecasted rates of return for the companies in the sample.

Mr. Gillingham criticized Mr. Moul's Comparable Earnings approach "[b]ecause accounting methods **[*55]** vary among companies, comparison of book returns tend to lose their meaning. . . ." (Public's Exh.7, p. 25.) Mr. Gillingham also states that although the companies in the sample matched the risk parameters of Petitioner at the time the analysis was performed, "there is no guarantee that they match Petitioner's risk profile over time" and it would take only a "slight change" in one of the parameters to exclude or include a company from the group. (Public's Exh. 7, p. 26.) Just as there are shortcomings with the CAPM and the DCF models, there too are problems inherent with the Comparable Earnings approach. However, we believe this model may offer worthwhile information to this Commission in understanding how Mr. Moul derived his recommended ROE.

In summary, Mr. Moul argues that the returns on equity available from investments of comparable risk, as determined by the unregulated marketplace, indicate that the 12.75% common equity cost rate initially proposed by Petitioner is conservative. Mr. Moul's Comparable Earnings approach resulted in a recommended level of 13.55%.

Mr. Moul also used the Risk Premium method in which he estimated the premium over Petitioner's cost of debt necessary **[*56]** to compensate the common stockholders for the additional risk associated with their investment. Under this approach, Mr. Moul determined a common equity cost rate of 12.93%, based on an 7.75% debt rate and the premium by which returns for the S&P Public Utilities group exceed bond yields.

All three witnesses employed the CAPM approach. Under this method, a risk spread or "market premium" is determined over a hypothetical riskless investment and then adjusted by a beta coefficient intended to reflect the difference in risk between the company in question and the market as a whole. Mr. Gillingham's CAPM results were reduced by his inclusion of short-term and intermediate-term treasury instruments as proxies for the riskless rate. The Commission has previously found that long-term treasury bonds should be used in the CAPM:

We find that the use of long term T-bonds is the more appropriate input to the CAPM analysis.

Indiana Michigan Power Co. (IURC 11/12/93), Cause No. 39314, p. 78. Moreover, Mr. Gillingham used forecasted treasury rates in his analysis. By the time of the final hearing, these forecasts were considerably higher than those in Mr. Gillingham's testimony.

We reject **[*57]** Mr. Eisdorfer's use of the 1966 to 1993 period to determine the market premium in the CAPM. This appears to be purely an arbitrary period which may have been results driven. Mr. Moul stated that the market premiums under other potential periods are much higher. (Petitioner's Exhibit R.) The period of 1926 to 1993 used by Mr. Moul and Mr. Gillingham is the most appropriate in light of the limitations discussed by the author of the data.

Mr. Moul and Mr. Eisdorfer both used arithmetic averages in determining the market premium in the CAPM. Mr. Gillingham used both arithmetic and geometric averages. Each of the witnesses relied on the Ibbotson Associates publication Stocks, Bonds, Bills and Inflation to determine the market premium. Mr. Moul points out that this publication states that the arithmetic average must be used in the CAPM. (See Indiana Cities, (IURC 7/8/9d) Cause No. 39166.)

Mr. Moul made an adjustment for flotation costs in some but not all of his analyses. Mr. Gillingham opposed such an adjustment on the ground that Petitioner did not have current plans to make a public offering of common stock. We find that there is no basis upon which to consider flotation costs. **[*58]** Although there may be some merit in Petitioner's contention that a company must be in a competitive capital attraction posture at all times, there are no current plans to issue common stock.

Based on all the evidence, we find that a reasonable cost of common equity for Petitioner is 12.25%. We recognize that there were disputed differences in methodology between the witnesses. However, when weighing the evidence presented and considering our discussions above, this level appears reasonable. Our determination does not end here though. We are required to make a determination as to a fair return on Petitioner's investment. The above finding on a proper level of ROE, while important, must be considered in light of our fair return determination.

(b) Cost of Capital Determination. Based on all the record evidence, we find Petitioner's overall weighted cost of capital to be 7.94%. Our determination is as follows:

Description	**Amount**	**Percent**	**Cost**	**Weighted Cost**
Long-Term Debt	$ 297,315,000	42.6%	6.91%	2.94%
Preferred Stock	19,604,500	2.8%	5.87%	0.16%
Common Equity	254,834,047	36.6%	12.25%	4.48%
Customer Deposits	1,329,258	0.2%	6.00%	0.01%
Deferred Taxes & Pre-1971 ITC	97,624,974	14.0%	0.00%	0.00%
JDITC	26,324,548	3.8%	9.25%	0.35%
Total	$ 697,032,327	100.0%		7.94%

[*59]
The cost rate used for the job development investment tax credits of 9.25% is equal to the weighted cost of investor-supplied capital, as follows:

Description	**Amount**	**Percent**	**Cost**	**Weighted Cost**
Long-Term Debt	$ 297,315,000	52.0%	6.91%	3.59%
Preferred Stock	19,604,500	3.4%	5.87%	0.20%
Common Equity	254,834,047	44.6%	12.25%	5.46%
Total	$ 571,753,547	100.0%		9.25%

(c) Determination of Fair Rate of Return. As we indicated above, while we may consider cost of capital evidence in determining a fair return, cost of capital is not our sole consideration. Office of Utility Consumer Counselor v. Public Service Commission (1983), Ind. App., 449 N.E.2d 604, 607. Setting a fair rate of return is the prerogative of the Commission after giving weight to all material evidence, so as to determine that return which properly balances the interests of the Company and the customers, allows Petitioner to earn a return comparable to that available on other investments with corresponding risks, is reasonably sufficient to assure financial soundness of the utility under scrutiny, and adequate for sound utility management to attract investors, maintain and **[*60]** support the utility's credit, and enable the utility to raise monies necessary for it to meet its public service obligations economically. Re Indiana-American Water Co., Inc., IURC Case No. 30880 (Final Order issued October 26, 1990, at p. 17).

The above decision is particularly relevant to this proceeding because Petitioner makes a compelling argument that it requires a return that will provide coverages and support for its AA bond rating. Petitioner further contends that substantial new debt financing will be necessary for its Culley Plant Clean Air Compliance Project and Petitioner's refinancing efforts.

Petitioner has requested a fair rate of return of 6% on the fair value of its property. Petitioner's witness Moul supported this rate of return. Mr. Moul's recommendation was related to the fair value proposal sponsored by Petitioner's witness Moody.

Mr. Moul first developed an historical inflation rate of 5.60% relating to the 1977 through 1993 time period. The year 1977 was chosen because it reflects the average date of installation for the property included in Mr. Moody's appraisal. Mr. Moul then deducted from Petitioner's weighted cost of capital of 8.14% the amount **[*61]** of 2.14% which is 38.3% of the inflation rate. He used 38.3% of the inflation rate for this adjustment because that is the proportion of Petitioner's fair value rate base which reflects RCNLD. The remaining portion of the fair value rate base reflects original cost. While we understand the mechanical process Mr. Moul went through to determine his fair return figure, we are not persuaded that the methodology is a sound one for determining a fair return. Once again the Commission believes the method may be helpful, but the ultimate determination must be derived through a review of the entire record and through use of reasoned judgment. This determination by the Commission is not one that can be done through very specific mathematical formulas because there are too many variables which could effect the results which are not considered. Mr. Moul's recommendation is just another piece to be considered in this fair return puzzle.

There was no dispute by any party other than that Petitioner must be afforded sufficient dollars of NOI to meet its debt and preferred stock costs. Thus, in Federal Power Comm'n v. Hope Natural Gas Co. (1944), 320 U.S. 591, 603, the Court said:

From the investor **[*62]** 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.

(Emphasis added.) This means the Petitioner's authorized net operating income must include $ 19,778,338 for payment of interest (original cost rate base of $ 640,075,667 times the long term debt component of the capital structure of 3.09%), and enough dollars to pay the dividend requirement on its preferred stock. We will, therefore, not make any reduction for inflation from the non-common equity components of the capital structure in determining a fair rate of return on the fair value rate base.

We find that a 5.79% rate of return on the fair value rate base is fair and reasonable. This will produce an authorized return somewhat in excess of the product of cost of capital and the original cost of Petitioner's property. However, as we mentioned earlier, the courts have made it clear that cost of capital is but an "initial point of reference in establishing a 'fair rate of return'." L.S. Ayres v. Indianapolis Power & Light Co. (1976), 169 Ind. App. 652, 659-660, **[*63]** 351 N.E.2d 814, 820-821. In determining what is fair, the Commission "may consider a myriad of factors" and "many circumstances." Gary-Hobart Water Corp. v. Indiana Util. Reg. Comm'n (1992), Ind. App., 591 N.E.2d 649, 653; Office of Util. Consumer Counselor v. Public Serv. Co. (1983), Ind. App., 449 N.E.2d 604, 607.

Among the circumstances we have considered is the importance of Petitioner maintaining its AA credit rating. We find that a 5.79% rate of return on the fair value rate base should produce a pre-tax interest coverage ratio sufficient to allow Petitioner to maintain its AA credit rating. Further, the fair value of Petitioner's utility property is obviously well in excess of its original cost. Use of a fair rate of return of 5.79% should allow Petitioner to benefit from this appreciation in value.

6. Petitioner's Operating Results Under Present Rates. For the 1993 calendar test year, Petitioner's jurisdictional operating results, adjusted for fixed known and measurable changes subject to reasonably accurate qualification within one year of December 31, 1993, were shown by Petitioner to be:

Operating Revenues	$ 221,376,020'
Operating Expenses and Taxes	
Other Than Income Taxes	$ 166,402,987
Income Taxes	$ 12,715,886
Total Operating Expense and Taxes	$ 179,118,873
Net Operating Income (present rates)	$ 42,257,147

[*64]

Petitioner and Public made several proposed pro forma adjustments. Many of the disputes as to various adjustments have been amicably resolved as of conclusion of the hearing process on November 28, 1994. We note there is no remaining dispute over revenue adjustments. These undisputed adjustments on a total electric basis were as follows:

OPERATING REVENUES:	**TOTAL ELECTRIC**
Alcoa Generating Company	
and Other Utilities	($ 7,016,023)
Fuel Cost Revenue	(4,612,792)
Eliminate Difference in Estimate & Actual	(655,461)
Municipal Wholesale Customer	(388,779)
Annualization of Oct. 1, 1993 Rate Increase	1,547,341
Annualization of Feb. 28, 1994 Rate Increase	5,037,455
LP-1 Rider Revenue	419,658
Pole Rental Revenue	72,796
	($ 5,545,805)
OPERATING EXPENSES:	
Fuel Costs	(3,501,422)
Purchased Power Expense	(8,076,918)
Chemical Expense	2,153,836
Payroll - Operations	835,126
Payroll - Maintenance	425,061
Payroll Taxes	184,975
Culley Scrubber Expense	4,248,592
Advertising Expense	(253,585)
Insurance Expense	339,783
Rate Case Expense	250,267
Depreciation Expense	(642,080)
DSM Expenses	1,078,734

Pension Expense	385,987
Gross Income Taxes	(66,550)
Property Tax Expense	1,355,742
Electric Power Research and Institute	(20,800)
Edison Electric Institute	(25,099)
Supplemental Retirement Income	(163,515)
IURC Expense	18,134
Miscellaneous Expenses	(45,507)
	($ 1,519,239)

[*65]

OPERATING REVENUES:	**JURISDICTIONAL**
Alcoa Generating Company and Other Utilities	$ 0
Fuel Cost Revenue	(4,612,792)
Eliminate Difference in Estimate & Actual	(655,461)
Municipal Wholesale Customer	0
Annualization of Oct. 1, 1993 Rate Increase	1,547,341
Annualization of Feb. 28, 1994 Rate Increase	5,037,455
LP-1 Rider Revenue	419,658
Pole Rental Revenue	72,796
	$ 1,808,997
OPERATING EXPENSES:	
Fuel Costs	(3,142,327)
Purchased Power Expense	(7,248,574)
Chemical Expense	1,932,945
Payroll - Operations	770,524
Payroll - Maintenance	392,180
Payroll Taxes	170,680
Culley Scrubber Expense	3,752,828
Advertising Expense	(253,585)
Insurance Expense	313,489
Rate Case Expense	228,542
Depreciation Expense	(558,891)
DSM Expenses	948,300
Pension Expense	356,112
Gross Income Taxes	(60,107)
Property Tax Expense	1,218,306
Electric Power Research and Institute	(18,994)
Edison Electric Institute	(22,920)
Supplemental Retirement Income	(150,859)
IURC Expense	18,134
Miscellaneous Expenses	(41,556)
	($ 1,395,773)

The remaining disputes over expense adjustments, shown on a total electric basis are as follows:

	Item	Adjustment Per Petitioner on Rebuttal	Adjustment Per OUCC on Modified	Difference
a.	Injuries and Damages Expense	($ 631,019)	($ 798,645)	($ 167,626)
b.	Uncollectible Expense	82,765	-	(82,765)
c.	State Environmental Permit Fee Expense	331,869	237,076	(94,793)
d.	Maintenance Expense	1,725,000	-	(1,725,000)
e.	SFAS 106 (OPEB's) Expense	3,362,704	-	(3,362,704)
f.	Management Recruitment Expense	-	(72,079)	(72,079)
g.	Gainsharing Program Expense	-	(84,904)	(84,904)
h.	Coal Litigation Expense	-	(435,114)	(435,114)
i.	Out-of-Period Maintenance	-	(21,500)	(21,500)
	Sub-total			6,046,485
	Income Taxes Related to Above Differences			2,285,297
	Total			$ 3,761,188

[*66]

Except for tax consequences flowing from determination of the above expense adjustments in dispute, all other expense issues have been resolved by the parties and that is reflected in Petitioner's rebuttal exhibits RDG-2 and WRH-1 (rebuttal).

We now review each disputed expense adjustment and make our findings thereon.

a. Injuries and Damages. Both Petitioner and Public adjusted actual test year expenses of $ 1,574,281 incurred for Injuries and Damages ("I & D") downward to reflect a representative going level. Although I & D expense is made up of four individual elements, only one of these items - I & D Accruals, remains in dispute. The parties have agreed on adjustments, affecting the other three individual components (insurance premiums, amortization of two workers' compensation death claims, and miscellaneous expenses) which when combined represent a decrease of $ 326,752.

To calculate Petitioner's original adjustment to the I & D Accrual component, Petitioner's witness Richard DeCleene took the actual amounts accrued for expected uninsured claims for the test year and for the previous four years, indexed each for inflation, and then averaged those indexed amounts to arrive **[*67]** at an estimated representative I & D Accrual level of $ 395,974 resulting in a proposed downward adjustment of $ 242,022. The Public disagreed with witness DeCleene's methodology. Public's Assistant Chief Accountant John Cook eliminated two claims which he testified were non-recurring, then computed an I & D level based upon an average of actual claims paid during the same five-year period without adjusting that average for inflation. Witness Cook's methodology resulted in a proposed I & D Accrual expense level of $ 166,107 resulting in a downward adjustment of $ 471,893.

In rebuttal, Petitioner's witness DeCleene accepted the Public's position that the amount of actual claims paid should be used in calculating the adjustment to I & D Accrual Expense, and increased its downward adjustment to $ 304,267, resulting in a revised I & D Accrual level of $ 333,733. Mr. DeCleene did not accept the Public's elimination of the two claims from the average, nor did he accept the elimination of inflation indexing. Accordingly, the two issues remaining to be decided by this Commission are whether the two claims in dispute should be excluded from the five-year average, and whether that average **[*68]** should be indexed for inflation.

Due to the confidential nature of the settlement of the two largest claims paid by Petitioner during the averaging period, Petitioner and Public filed an "In Camera Stipulation" requesting the Commission to determine whether those claims and their settlements should remain confidential. That stipulation was filed on November 2, 1994, and the Commission determined that those matters should remain confidential due to specific non-disclosure agreements contained in the settlement documents in each claim. Public's witness Cook then submitted Pre-filed Supplemental Testimony under seal which has been admitted, and we have considered that pre-filed supplemental testimony in arriving at our decision on this issue. The Public excluded both of these settlements because it viewed the claims as non-recurring and hence not reflective of an ongoing expense level. Public also contended that the settlement costs associated with one of the actions should be excluded on the ground that Petitioner had acted imprudently by disregarding safety rules resulting in the unsafe environment in which the accident occurred.

If Mr. Cook's position were accepted, then Petitioner's **[*69]** I & D would be set at $ 775,636, a reduction of $ 798,645 from Petitioner's actual test year I & D expenditures of $ 1,574,281. On rebuttal, Petitioner, through its witness DeCleene, agreed that an I & D level of $ 943,262 would not be unreasonable. I & D includes accruals to injuries and damages reserve, certain insurance premium expenses, and amortization for two workers' compensation death claims. The only dispute remaining upon Petitioner's rebuttal position is that of the proper ongoing level for accruals for uninsured claims to injuries and damages reserve. As stated, the difference of $ 167,626 between Petitioner's proposed accrual of $ 333,733 and the $ 166,107 accrual proposed by Public concerns the inclusion or exclusion of the two largest claims paid by Petitioner during the averaging period and the inflation indexing related to claims.

The two claims are referenced for confidentiality purposes as "Action A" which was settled during litigation for a total payment by Petitioner of $ 350,000 in 1991, and "Action B" which was settled for a total of $ 625,000, $ 500,000 of which was paid by Petitioner as its total retained interest and the remaining $ 125,000 of which was **[*70]** paid by Petitioner's insurer in 1990. Both involved parties on this issue recognize that Action A and Action B were both unique occurrences that arose from extraordinary factual situations that will never happen again. In fact, Petitioner stated that it has taken remedial actions since the occurrence of Action A and Action B to assure the same or similar fact situations reoccurring is virtually impossible. Public agreed that the remedial actions taken by Petitioner are good but then argues that the Petitioner's remedial actions taken to guarantee Actions A and B will never occur again, constitute evidence for Public's position that those claims are non-recurring and therefore should be excluded for I & D calculations. Public also contends that Action A, though odd in nature, should have been foreseen by Petitioner and since it was not, Petitioner was imprudent in not avoiding the occurrence, and the $ 350,000 accrual on that claim should also be excluded on the basis of Petitioner's alleged imprudence.

Petitioner's witnesses Goebel and DeCleene disagree with Public. Mr. Goebel, who supervises Petitioner's claims' policies, handling and settlements, testified that Commission acceptance **[*71]** of Public's position would effectively force Petitioner to move from its present highly cost effective policy of being self-insured for worker's compensation, and having a $ 500,000 liability self-insured retention, to one of obtaining very expensive first dollar insurance coverage for all claims. Petitioner argues that the rationale is that since Public did not challenge the insurance premiums paid, or claims paid by insurance, that Public's message is clear - i.e. - it will review by hindsight those claims settled by Petitioner on a self-insured basis while Public will not challenge claims where there is an insurance intermediary involved.

Petitioner's evidence also contradicts Public's contentions that Actions A and B should be excluded due to "non-recurrence" or "imprudence". First, Mr. Goebel testified that the ratemaking goal is not to determine whether specific claims paid will recur, but to set a reasonable ongoing level for I & D expense. In a sense, all claims are non-recurring because the myriad of facts that coalesce to result in one claim will not repeat. All claims have a degree of uniqueness. Therefore, merely because the facts of one claim will never specifically **[*72]** recur does not indicate that other perhaps equally unique claims will not occur during the years when Petitioner's rates are in effect. Therefore, the target is to set a reasonable level of expense for all claims that Petitioner will incur on a reasonable going level accrual basis during the life of the electric rates we are setting today. It is true that Actions A and B will not recur but other significant claims will probably occur requiring Petitioner's I & D expenditures to resolve them.

Petitioner also contends that its proposed accrual level (on rebuttal) position for uninsured I & D claims of $ 333,733 is prudent for a utility the size of Petitioner which has more than 800 employees in its electric department and where Petitioner's facilities are ubiquitous within the eight counties it serves. Petitioner also owns and operates three powerplants and has thousands of miles of transmission and distribution lines. Working with electricity is also recognized in law to be a hazardous activity. Petitioner's evidence, on direct and cross-examination, established that the statutory liability for a worker's compensation death claim now exceeds $ 200,000, medical expenses related to claims **[*73]** are increasing drastically, as is the value of lost wages, and the cost of litigation. Petitioner states that it has been very successful in its claims litigation defense efforts, and that is an obvious reason for its low actual pay-out on claims when compared with its historic accrual. However, Petitioner's trial loss or eventual settlement of major claims - some of which are presently pending - would greatly impact its I & D accrual, particularly if set at only $ 166,107 per year as suggested by Public. Petitioner states that due to the vagaries of litigation and jury verdicts, it is reasonable to conclude that Petitioner's actual pay out of I & D will increase rather than decrease.

Public's witness Cook agreed on cross-examination that a business enterprise the size of Petitioner's can expect to experience claims for personal injury and property damage from time to time. One way of protecting against losses from such claims is to obtain liability insurance. Public seems to acknowledge the appropriateness of the recovery through rates of the premiums for such insurance. However, as shown by Petitioner's rebuttal evidence and as confirmed by Mr. Cook, it is often cost effective **[*74]** for utilities to self-insure such claims up to some maximum amount and reserve outside insurance for especially large claims.

The issue here is essentially whether the Petitioner should recover in rates the cost of self-insuring against claims up to $ 500,000 in amount. Petitioner argues that if the Public prevails in its position, the purpose of self-insurance would be defeated for Indiana utilities, even if it is the less expensive option. We agree with Petitioner that this would not be good regulatory policy.

This is not to say that every claim is recoverable, no matter how egregious the conduct of the utility. If Petitioner were proven to have acted with malice or to have willfully injured someone, the case may be different. But that is not the case with respect to Claims A and B. Instead, they appear to be ordinary negligence claims of the type that electric utilities will come up against from time to time as a normal part of their business. These claims were settled before trial without an adjudication of fault. Since we conclude that Petitioner's self-insurance practices are prudent, we will not delve into the facts of each of these claims to resolve whether Petitioner's employees **[*75]** were prudent with respect to the acts which gave rise to those claims. It is not the role of the Commission to litigate negligence claims.

Based upon the evidence presented, we find the amount of Claims A & B should be included in the five-year averaging to arrive at a representative I & D Accrual level. However, we agree with the Public's witness that there is no basis that the average should be indexed for inflation. Therefore, we find that $ 925,636 is an appropriate and reasonable ongoing level for I & D. Of that amount, the annual accurual for claims is $ 316,107, which we also find to be reasonable. This amount represents a downward adjustment to the test year of $ 648,645. The jurisdiction portion of this adjustment is $ 598,448.

b. Bad Debt Expense. In calculating its adjustment to bad debt expense, the Petitioner totalled the net write-offs and revenues for the test year with the four previous years and computed an average bad debt expense ratio based on total write-offs to total revenues. Total net write-offs and revenues for the five years were $ 2,378,325 and $ 1,030,758,385 respectively, which produced an average bad debt to revenue ratio of .0023. Application of **[*76]** this ratio to Petitioner's adjusted jurisdictional revenues related to bad debt expense (includes residential, commercial and industrial revenues only) of $ 216,314,568 resulted in a proposed pro forma bad debt expense of $ 497,524. Deducting test year bad debt expense of $ 414,759 from the pro forma bad debt expense resulted in Petitioner's proposed upward adjustment of $ 82,765.

The Public's witness Cook accepted Petitioner's methodology, but excluded $ 370,111 of industrial write-offs that were made in 1991, resulting in a net write-off total of $ 2,008,214. Mr. Cook's use of the reduced net write-off figure and the same total period revenue of $ 1,030,758,385 produced a bad debt to revenue ratio of .0019. Applying this ratio to Petitioner's adjusted jurisdictional revenues related to bad debt expense of $ 216,314,568 provided a pro forma bad debt expense of $ 411,049 compared to actual test year bad debt expense of $ 414,759. Due to the small variance between its computed pro forma and actual test year bad debt expense, Public proposed that the test year level of bad debt expense be utilized in this proceeding for setting rates.

Public contends the 1991 indicated write offs **[*77]** are not repetitive since there were no industrial write offs in 1989, 1990 and 1993 - with there being only $ 35,934 in 1992. Petitioner counters with witness DeCleene's testimony that industrial write offs will obviously occur from time to time, and that Petitioner's methodology of five-year averaging has already mitigated the 1991 industrial bad debt amount of $ 370,111 by 80%. Petitioner states that Public's approach has the effect of excluding large industrial write-offs from being included as a legitimate expense for cost recovery in the rate setting process.

After reviewing the evidence presented, we believe the Public's position is more reasonable. We are cognizant that by averaging its write-offs, Petitioner has to some extent mitigated the effect of including the high 1991 industrial write-offs in computing its bad debt expense ratio. However, we are not convinced that simply smoothing out the effects of what appears to us to be an aberration is the appropriate method for treating the 1991 write-offs. The evidence in the record shows that of the remaining four years in the period used to compute the average, there were no industrial write-offs in three of the years and only **[*78]** $ 35,934 in the fourth year. The rationale behind using an average to project expenses or revenues is to smooth out the highs and lows of normal fluctuations in arriving at a representative level. We do not agree that the 1991 industrial write-off which is almost ten times the amount of the combined total of the other four years totals considered in the average is a normal fluctuation. Inclusion of that write-off would significantly distort the average and result in a non-representative figure. Petitioner's allegation that this exclusion effectively results in a policy of non-recovery of large industrial write-offs is not convincing. The intent is to provide a representative ongoing level for this expense, not to provide rate recovery for every write-off. Petitioner has urged this Commission to allow recovery of a non-representative expense on a going forward basis. This we will not do. Accordingly, we find that Petitioner's pro forma bad debt expense is $ 414,759, which results in no adjustment to test year.

c. State Environmental Permit Fee Expense. The difference between Public and Petitioner over Environmental Permit Fee Expense amounts to $ 94,793 and concerns whether it **[*79]** is proper for Petitioner to utilize the statutory amount of fees that it must pay to the State of Indiana on January 1, 1995. Public contends that since January 1, 1995, is twelve months and one day beyond the close of the 1993 calendar test year, that the use of 1995 fees is prohibited by the Prehearing Order in this Cause.

The permit fees Petitioner had to pay on January 1, 1995 to the State of Indiana pursuant to a specific statutory schedule is not only subject to reasonably accurate quantification within one year from the close of the test year, but those fees are precise. In addition, their higher fees will be in place prior to any rate adjustment becoming effective from this proceeding.

The rates being set today are forward looking, and we would be remiss in ignoring the statutory mandated amount of these permit fees to be paid by Petitioner one day beyond the adjustment period. Therefore, we find Petitioner's state environmental permit fees are $ 331,869 and the jurisdictional amount is $ 291,679.

d. Maintenance Expense. The Petitioner proposed a $ 1,725,000 upward adjustment to the actual test year non-payroll maintenance expense level of $ 18,088,297. The proposed **[*80]** adjustment consists of the amount by which an inflation adjusted five-year average amount for non-payroll maintenance expense exceeds the Petitioner's actual test year expenditures. Petitioner's witness J. Gordon Hurst testified that the use of a five-year average amount was justified based upon the fact that non-payroll maintenance expenses have been subject to wide fluctuation, and that the test year amount was not representative of actual expense levels. Witness Hurst also testified that because the cost of some maintenance materials had increased over time, he believed that the five-year average amount should be adjusted to 1993 dollars to account for the effects of inflation. The Petitioner made the adjustment for inflation using the Consumer Price Index (CPI).

The Public opposed the use of both a five-year average and an inflation adjustment in determining the appropriate ongoing level for non-payroll maintenance expenses. Public's Chief Engineer Daniel J. Kuester testified that the test year non-payroll maintenance expense level was representative of the Petitioner's ongoing level of expenditures and should not be adjusted. Witness Kuester pointed out that of Petitioner's **[*81]** proposed $ 1.7 million annual upward adjustment, over $ 1.4 million was accounted for by Petitioner's inflation adjustment alone. Mr. Kuester testified that the five-year average of Petitioner's actual dollar expenditures was $ 307,371, only 1.7% higher than that of the test year. Mr. Kuester concluded that the unadjusted five-year average was so close to that of the test year that the use of such an averaging technique was not warranted.

Witness Kuester also opposed the adjustment of non-payroll maintenance expense for inflation in general, and the use of the CPI-U as proposed by the Petitioner in particular. Witness Kuester testified that because the test year expense level is a representative one, it would be unnecessary to adjust it with any index. In addition, Mr. Kuester testified that the particular CPI-U index proposed by the Petitioner reflects price changes for a varied basket of retail goods, and as such would be an inaccurate and inappropriate measure of price changes for industrial maintenance materials and costs.

In Rebuttal, Petitioner's witness Hurst testified that the use of a five-year average for non-payroll maintenance expenses was essential because of the significant **[*82]** fluctuations in those expenses over time. Witness Hurst pointed to the fact that SIGECO estimates that such expenses for the twelve-month period ending September 30, 1994, exceeded $ 20 million, substantially in excess of the test year amount. Witness Hurst also reiterated his contention that the use of an inflation adjustment was warranted. Mr. Hurst cited the 2.3% average annual increase in wages for contracted maintenance and the 17.88% annual increase in certain turbine maintenance materials over a five-year period as examples of the need for such an adjustment. Mr. Hurst acknowledged the difficulty in choosing an accurate index which measures the effect of inflation on maintenance expenses, and contended that the date through September of 1994 was supportive of an overall upward trend in prices.

In the Prehearing Conference Order approved in this Cause on May 11, 1994, we specified the methodology to be employed by the parties in adjusting test year accounting figures:

9. Accounting Methodology. The accounting methodology to be used in this Cause should adjust for changes that are fixed as to time, known to occur and measurable, subject to reasonably accurate quantification, **[*83]** within one year from the close of the test year except for the three items specified in paragraph 10 below.

Non-payroll maintenance costs were not specified in paragraph 10 of that Order, so any adjustment of the test year figures for those expenses should conform to the requirements of the language cited above. The Petitioner's proposed inflation adjusted five-year average for those expenses does not meet those requirements and must therefore be rejected. We therefore find that the test year non-payroll maintenance expense of $ 18,088,297 to be appropriate for use in Petitioner's revenue requirements in the Cause.

It is unrefuted in the record of this Cause that the CPI-U inflation index proposed by the Petitioner is a measure of inflation based upon changes in the price for a "fixed market basket" of retail goods. Public's witness Kuester testified that the basket includes such items as "food, shelter, fuels, transportation fares, charges for doctors' and dentists' services, medicine, and other goods that people buy for day to day living."(Public's Exhibit No. 6, at 7 citing U.S. Department of Labor - Bureau of Labor Statistics). We find that such a measure cannot be a reasonably **[*84]** accurate measure of the cost of industrial maintenance supplies and related costs because the "market basket" upon which the CPI-U index is based does not reasonably reflect changes in those types of expenses. Petitioner's witness Hurst pointed to two specific examples of escalating costs in his Rebuttal testimony, but did not offer any evidence to suggest how those changes were reflected by the CPI-U to a reasonable degree of accuracy. If we were to assume cost escalation over time by the factor proposed by Petitioner, we would expect to see an increase over time in the amount expended for non-payroll maintenance in real terms. The data presented by the Petitioner in Exhibit JGH-4 is not consistent with that assumption.

We note that the degree to which inflation has caused individual components of Petitioner's maintenance expense to increase from the time of Petitioner's last general rate case must by definition be reflected in Petitioner's test year expense levels so long as the test year data is not stale. We find that the data from that test year ending December 31, 1993 agreed to by the Parties and approved by the Commission in the Prehearing Conference Order on May 11, 1994, **[*85]** is sufficiently recent to be representative of non-payroll maintenance expenses from the perspective of inflation.

We also agree with Petitioner's witness Kuester that the test year level of non-payroll maintenance expense is representative and appropriate for inclusion in Petitioner's rates. The fact that certain expenses are highly volatile or subject to wide variation does not in and of itself mean that the level of expenses actually experienced in the test year are not representative. In this Cause, the Petitioner's witness Hurst sponsored Exhibit JGH-4 which detailed Petitioner's annual non-payroll maintenance expenses for the calendar years ending December 31, 1989, 1990, 1991, 1992, and the test year. The Total Maintenance - Net of Payroll for those years shows a variation from a high of over $ 21.5 million in 1990 to a low of around $ 14 million in 1992. It is therefore clear from the record that Petitioner's expenses in this area fluctuate annually. It is equally clear that the level of maintenance expenses vary for the Petitioner depending upon the twelve-month periods chosen for comparison. Although Mr. Hurst testified in rebuttal that non-payroll maintenance expenses **[*86]** for the twelve months ending September 30, 1994 had exceeded $ 20 million, he admitted during cross-examination that those same expenses for the twelve-month period ending March 31, 1994, were approximately $ 17.5 million, an amount over $ 500,000 less than that for the test-year period. Mr. Hurst explained that calendar year figures were the best measure of these volatile expenses because they best reflect the full maintenance cycles which are run by the Petitioner on a calendar year basis. We agree.

As Mr. Kuester pointed out and as Mr. Hurst acknowledged, the five-year average of the actual expenses incurred by the Petitioner is only 1.7% greater than the test year amount. Given the substantial variation in Petitioner's maintenance expenses and given Mr. Hurst's testimony that calendar year expense figures best reflect Petitioner's maintenance cycle, we conclude that the expense level from the agreed-upon test year from the calendar year 1993 is as representative of non-payroll maintenance expenses as can be reasonably determined in this proceeding. We find that the record in this Cause does not support the use of the five-year average expense proposed by the Petitioner. This Commission **[*87]** has consistently found the most recent complete expense data to be the best measure of ongoing expense levels, and we are not persuaded to adopt either an averaging formula or an inflation index in this proceeding. We accordingly filed Petitioner's non-payroll maintenance expense amount to be $ 18,088,297. Therefore, we find no adjustment to the test year should be made.

e. SFAS 106 Expense. On January 1, 1993, Petitioner was required to implement SFAS 106, Employers' Accounting for Postretirement Benefits Other Than Pensions, issued by the Financial Accounting Standards Board ("FASB"), the rulemaking body of the accounting profession which establishes standards for financial accounting and reporting. SFAS 106 requires that the cost of post-retirement benefits other than pensions ("OPEBs"), primarily health care and life insurance benefits, be accrued over the course of the employees' active service. Formerly, OPEB costs were recognized by Petitioner and most other employers on a pay-as- you-go ("PAYGO") or cash basis under which such costs were recognized as an expense when the benefits were paid to or on behalf of retired employees. SFAS 106 also permits the accumulated **[*88]** post-retirement benefit obligation as of the date of implementation (the "transition obligation") to be amortized over a period of up to twenty years. The implementation of SFAS 106 has increased the level of OPEB costs which must be recognized by Petitioner for financial reporting purposes. Petitioner has requested that the SFAS 106 accrual methodology be adopted for ratemaking purposes.

The accounting and regulatory issues relating to SFAS 106 are described in detail in the Commission's Order dated December 30, 1992 in Cause No. 39348 (the "Generic Order") issued in the generic investigation of SFAS 106. In the Generic Order the Commission provided that Indiana utilities can request recovery of SFAS 106 expenses in their general rate proceedings but they must demonstrate that the expense is prudent and reasonable. (Generic Order, at 35). The Generic Order requires the utility to show, at a minimum, the following:

The period over which the transition obligation is to be amortized with compelling justification for a shorter time than 20 years;

The methodology and assumptions, both actuarial and otherwise, used in the calculation of the SFAS 106 accruals;

A specific request setting **[*89]** forth the amount of the recovery sought through rates in excess of the current cash portion of the expense with calculations demonstrating the amortization of the regulatory asset at the level of collections proposed to be funded through rates; and

Evidence as to the most current positions taken or pronouncements made by the FASB or the SEC pertinent to SFAS 106 and the implementation thereof.

Petitioner's benefits program was discussed by Mr. Goebel and Petitioner's witness Debra S. McChane, a professional health and welfare benefit actuary with William M. Mercer, Inc., an employee benefits and actuarial consulting firm. They testified that Petitioner's total benefits package is at or below the average package provided by other regional utilities, and its post-retirement medical and life insurance benefits are below average. (Petitioner's Exh. A, p. 27; Petitioner's Exh. E, p. 26.) The Public's evidence on SFAS 106 was presented by Mr. Cook. He testified on cross-examination that Petitioner's benefits package was not unreasonable.

Petitioner's witness DeCleene testified regarding Petitioner's SFAS 106 ratemaking request. Mr. DeCleene stated that Petitioner requested recovery in **[*90]** rates of the annual SFAS 106 accrual, as quantified by Ms. McChane, which amount reflects the amortization of the transition obligation over 20 years. Mr. DeCleene also stated that Petitioner proposed to amortize over five years SFAS 106 costs which were deferred as a regulatory asset pursuant to the Generic Order from the effective date of SFAS 106 through the expected date of a rate order in this proceeding, with the annual amortization being reflected in the revenue requirement herein. (Petitioner's Exh. C, pp. 24-25.) The total amount of SFAS 106 costs in excess of the PAYGO amount sought to be recovered in this proceeding is $ 3,362,704. (Petitioner's Exh. RJD-1, p. 24.)

Mr. DeCleene also testified regarding the most current positions of FASB and the SEC regarding the implementation of SFAS 106. Mr. DeCleene stated that Petitioner was required to implement SFAS 106 and, although it could temporarily defer the difference between the SFAS 106 accrual and the PAYGO amount through the creation of a regulatory asset, Petitioner could not continue the deferral if the Commission decided to stay on the PAYGO method for ratemaking and instead would have to expense the SFAS 106 costs **[*91]** which would negatively impact Petitioner's net income. Mr. DeCleene said that of the 50 commissions which have considered the issue, 46 have adopted SFAS 106 or a form of accrual accounting for OPEB costs.

Ms. McChane testified regarding the quantification of Petitioner's SFAS 106 costs. She sponsored an actuarial valuation of the SFAS 106 costs which was the basis for the ratemaking request discussed by Mr. DeCleene. Ms. McChane testified regarding the actuarial assumptions used in the valuation, including the assumptions regarding medical trend rates, discount rate, population, turnover, retirement rates, disability and mortality. Ms. McChane stated that the assumptions were, in her opinion, within the reasonable range of assumptions used in the valuation of post-retirement benefits.

Mr. Goebel testified that Petitioner proposed to create a Voluntary Employee Beneficiary Association ("VEBA") trust for the external funding of the SFAS 106 costs. Ms. McChane stated that VEBA funding was the best alternative for Petitioner. She explained why other alternatives were not as favorable given Petitioner's circumstances.

Petitioner has submitted extensive evidence on the reasonableness **[*92]** of its benefit plans. The evidence establishes that the OPEBs provided by Petitioner are reasonably necessary and not excessive. No party contended otherwise. Accordingly, we find that Petitioner's OPEB costs are prudently incurred and reasonable.

Having so found, we must decide whether the cost of OPEBs should be recovered through rates on an accrual basis. After giving thorough consideration to the evidence, the Commission finds that the full SFAS 106 accrual, including the amortization of the transition obligation and the amortization of amounts deferred pursuant to the Generic Order should be used for ratemaking purposes. SFAS 106 required Petitioner to reflect these costs during the period they are deemed to be earned, i.e., during the period the employees actively provide service to the company and its customers. We find that use of the SFAS 106 accrual for ratemaking purposes better matches cost recovery with the cost of providing service. This finding is consistent with our conclusion in Indiana Michigan Power Co. (IURC 11/12/93), Cause No. 39314, at 143-147, wherein we stated:

This Commission has previously recognized that accrual accounting is a proper and preferred **[*93]** method of recording significant items of expense. The accrual accounting required by SFAS 106 is similar to the accrual accounting for most other accrual expenses such as pensions, depreciation and income taxes, which are routinely included in the determination of revenue requirement.

There is no dispute that I & M's post-retirement benefits are a form of compensation that are reasonable and necessary to attract and retain employees. This Commission believes that, to the extent possible, the costs of providing utility service should be matched with the period in which the service is rendered. I&M's current rates should reflect the current cost of these benefits, as determined in accordance with GAAP. Current recovery through rates of the SFAS 106 accruals will provide a proper matching of revenues and expenses by including in current rates the full cost of current service, including the cost of post-retirement benefits earned during the current period. Continuing to use the pay-as-you-go, or cash basis, method for ratemaking is no longer appropriate because it would fail to include in current rates a significant current cost of service.

These reasons for adopting SFAS 106 for ratemaking **[*94]** apply equally to Petitioner. We have also approved the use of SFAS 106 for ratemaking purposes in every other case where we considered the issue. See Indianapolis Water Co. (IURC 8/10/94), Cause Nos. 39713 and 39843, p. 45 ("we believe that Petitioner has sufficiently demonstrated the necessity and desirability of including the SFAS 106 accrual OPRB requirements in its expenses" but external funding required); Indiana-American Water Co. (IURC 2/2/94), Cause No. 39595, pp. 13-16, 150 PUR4th 141, 153-155 (SFAS 106 recovery with external VEBA funding approved); Gary-Hobart Water Corp. (IURC 12/1/93), Cause No. 39585, pp. 4-5; Indiana Gas Company (IURC 5/8/95), Cause No. 39353, Phase II.

We disagree with the Public's position that the Commission should continue with the PAYGO method for ratemaking because Petitioner has not shown the benefits to the ratepayers of a switch to SFAS 106. The quote from the Indiana Michigan order, cited above, identified the benefit to both the Company and the customers from the use of SFAS 106 for ratemaking -- the proper matching of cost recovery and the cost of providing service. The customers also benefit by the avoidance of the negative **[*95]** impact on Petitioner's net income that would result from continuation of the PAYGO method. Allowing Petitioner the recovery of its SFAS 106 costs is consistent with the treatment which has been accorded other utilities throughout the country with which Petitioner must compete in attracting capital. To treat Petitioner differently would negatively impact its earnings and impair its ability to attract capital needed to provide utility services to the public.

Nor do we agree with Mr. Cook that the SFAS 106 valuation is too "speculative" to be used for ratemaking and is not "fixed, known and measurable." The Commission finds that when properly quantified (as they have been here), SFAS 106 costs are sufficiently fixed, known and measurable to be used for ratemaking purposes. Ms. McChane testified in detail regarding the procedures used to quantify Petitioners' SFAS 106 costs, including the assumptions used, and confirmed that the assumptions were reasonable. Mr. Cook did not challenge Ms. McChane's valuation, the assumptions used therein, or the compliance of the valuation with the standards of SFAS 106.

Mr. DeCleene confirmed that the SFAS 106 accrual amount will be used as the OPEB **[*96]** expense amount on Petitioner's financial statements. While future adjustments may become necessary if the assumptions are later changed, adjustments to SFAS 106 valuations are prospective only and will not change the amount previously recorded as the OPEB expense. Therefore, they are fixed, known and measurable.

The SFAS 106 valuation was based on Petitioner's existing benefits package. Mr. Goebel testified Petitioner's management does not intend to curtail or cancel the OPEB benefits provided to its employees and retirees. (Petitioner's Exh. O, p. 8.) As we stated in the Indiana Michigan order previously cited:

Ratemaking in general is based on projections about the cost of providing service. There are numerous costs, such as depreciation or return on equity, that require the consideration of numerous assumptions. Actuarial valuations have been the basis of pension expense for years.

(Order, at 144.) We concluded in the Indiana Michigan order that "the actuarial valuation of post retirement benefit expense is reasonably quantifiable and sufficiently reliable for ratemaking purposes." (Id.) We reach the same conclusion here.

We further note that Mr. Cook stated on **[*97]** cross-examination that he did not contend that Petitioner's financial statements would be misleading if they reflected OPEB expenses in accordance with SFAS 106. The Public's position that SFAS 106 costs are unduly speculative appears to be inconsistent with the position of the accounting and auditing profession and the SEC that the use of accrual costs, rather than PAYGO costs, is necessary to properly reflect the financial condition of the company. Indeed, the very purpose of GAAP, including SFAS 106, is to make financial statements reliable and accurate for third parties, such as investors.

Mr. Cook states that SFAS 106 costs are not fixed, known and measurable because "[u]ntil monies are actually disbursed for providing the benefits, the event or transaction is only a possibility or expectation of such occurrence." (Public's Ex. 1, p. 24.) We find that this position is rendered somewhat moot by Petitioner's VEBA funding proposal. The evidence establishes that the SFAS 106 costs will be irrevocably deposited by Petitioner in an external fund and that the money in the fund can be used only for employee benefits. Thus, the transfer of monies to the funding vehicle will be made currently. **[*98]** This is very similar to the situation involving pensions which are recovered in rates based on an actuarial valuation and deposited by Petitioner in its pension plans.

The Public also argues that use of SFAS 106 would increase costs to ratepayers more than the PAYGO amount. This is true initially but over time the amount recovered in rates should be the same. Therefore, there will be no over recovery of these costs by the utility. The real issue is whether the OPEB costs relating to current service should be paid by current customers or shifted to future generations of customers. The Commission must consider the interests of all customers, both current and future. As previously discussed, the SFAS 106 approach allows better matching of revenues and costs.

The final argument of the Public is that the SFAS 106 approach results in intergenerational inequity, retroactive ratemaking, and piecemeal ratemaking. In support of this position, Mr. Cook states:

Retroactive ratemaking relates to situations where past costs that were not specifically provided for in rates are attempted to be recovered through current rates.

(Public's Exh. 1, p. 26.)

We find this position to be inconsistent **[*99]** with the Public's PAYGO proposal. The PAYGO method reflects in rates only the cash payments made to current retirees for benefits attributable to the retirees' past service. Thus, under the PAYGO method 100% of the OPEB costs reflected in rates relate to past service. Indeed, the Public itself has challenged the recovery of the PAYGO amount on this very basis. See Indianapolis Power & Light Co. (IURC 8/6/86), Cause No. 37837, p. 26 (Public's witness "Krevda reasoned that 'present day ratepayers are not receiving any benefit of services rendered in the past by the retired employees. . . .'"). Accordingly, the retroactive ratemaking argument does not support the Public's position.

It is true that the SFAS 106 accrual includes the amortization of the transition obligation. But as the name implies, this is a means to an end -- the transition from cash basis accounting to accrual accounting. After the amortization period is completed, there will be a complete and proper matching of cost recovery and cost incurrence. The PAYGO method advocated by the Public never resolves intergenerational inequities, but continues in perpetuity to require customers to bear the cost of providing service **[*100]** in the past.

We also approve Petitioner's proposed amortization periods and its external funding proposal. We have approved and even required external funding in other cases. See Indiana Michigan Power Co., Indiana-American Water Co. and Indianapolis Water Co., supra. Public's witness Cook stated that if the Commission did allow recovery of the SFAS 106 accrual, he supported external funding. Therefore, this part of Petitioner's proposal is uncontroverted.

The Commission finds, based upon the evidence herein, that Petitioner should be allowed to recover its SFAS 106 costs in excess of the PAYGO amount through its revenue requirements, in the amount of $ 3,362,704 or a jurisdictional amount of $ 3,102,464.

f. Management Recruitment Expense. During the 1993 test year, Petitioner recruited a new manager of power production through the use of a professional employee recruiting service at a cost of $ 72,079. Public's evidence through its witness Eckert excluded that sum as non-recurring.

Petitioner contends that the recruitment of a key employee, such as a power production manager (the employee recruited has since been promoted to Vice President) is an essential element **[*101]** of Petitioner's business, particularly when an experienced and highly skilled technical and professional employee is needed on relatively short notice. Petitioner argues this is particularly true in the electric industry today which is becoming more competitive causing such employees to be in high demand. Petitioner further posits that since this expenditure was actually made during the test year that it should be allowed because it is a representative expenditure of managing its human resources needs. As its business becomes more competitive, Petitioner is likely to encounter higher costs in this area.

We agree with Petitioner that recruitment of qualified personnel to fill key positions is very important. However, we must set rates based on the test year expenses that are adjusted for changes that are fixed, known, and measurable within 12 months end of the test year. Petitioner has provided no evidence to support that the recruitment of a key employee is an annual expenditure. In fact, Petitioner's witness DeCleene suggested in rebuttal that these items are "infrequently occurring" and that "a compromise position would be to amortize this amount over the three year period." (Petitioner's **[*102]** Exhibit O, at 23/6-12).

Witness DeCleene also suggested that this type of cost is not unusual and that it will "incur new and different costs," however, Petitioner did not present any evidence supporting the existence of such recurring unusual costs or quantifying their magnitude. We accordingly agree with the Public's adjustment and find that O & M expenses should be decreased by $ 72,079. The jurisdictional adjustment is $ 65,666.

g. Gainsharing Program Expense. During the test year, Petitioner expended $ 84,904 to develop, design and start up a "Gainsharing Program" intended to improve the productivity and creativity of Petitioner's employees by allowing them to share in productivity improvements. Public proposes to exclude this expenditure because it is a developmental cost which will not recur. Petitioner contends such costs are necessary for any new program inasmuch as such programs are dynamic and not static in nature.

Petitioner contended that quality initiative programs are important to its business, but has provided no supportive evidence as to what the ongoing costs of the Gainsharing Program will be or what quality initiative programs it will initiate in the future. **[*103]** In fact, Petitioner's witness DeCleene testified that the development costs are not recurring:

[w]hile a "Gainsharing" Program will not be developed each year, other costs will be incurred as the Company strives to lower its costs and improve its overall efficiency.

(Petitioner's Exhibit O, at 22/20-22). Although we agree with Petitioner that quality initiative programs are important, the Petitioner failed to establish that the expense for the Gainsharing Program was fixed, known, and measurable within 12 months end of the test year. Since the only evidence of record supports the non-recurring nature of this expenditure, we agree with the Public's adjustment and find O & M expenses should be decreased by $ 84,904. The jurisdictional amount of this adjustment is $ 77,350.

h. Coal Litigation Expense. Coal costs are the single largest expense to most electric utilities, including Petitioner. The electric utility industry entered into long-term coal contracts with major coal companies during the fuel shortage of the 1970s so as to assure a continuous and reliable supply of coal for electric power generation. Those coal contracts have become uneconomic and non-market responsive **[*104]** during the 1990s for numerous reasons we will not discuss here. Suffice it to say that Petitioner, and many other similarly situated utilities, have engaged in efforts to adjust or resolve those presently above-market coal contracts through negotiated settlement or litigation, when necessary. In Indiana, such activity by electric utilities is laudable inasmuch as the costs involved flow through the statutory fuel adjustment clause procedure and are borne by ratepayers. Petitioner stated it is therefore engaging in its coal contract efforts in the interest to directly save its ratepayers fuel costs, in addition to other desirable competitive factors. Petitioner, through the testimony of Kent H. Stump, stated that during litigation, it successfully resolved a contract with Amax Coal Company, one of its major suppliers, which resulted in significant fuel cost savings to the public. It is engaged in similar efforts with its remaining major long term contract supplier, Old Ben Coal Company (since acquired by Ziegler), "Old Ben".

During the test year, Petitioner expended $ 435,114 for legal fees and consulting services devoted to efforts to adjust or resolve the pending litigation with **[*105]** Old Ben. Public has excluded that amount by its evidence based on its supposition that the litigation will be finally resolved in the near future and that the cost is therefore non-representative on a going-level basis.

Petitioner argues in its evidence that the Old Ben negotiations and litigation have been in progress for more than three years with no final result as yet. The U.S. District Court issued one summary judgment that is adverse to Petitioner and one summary judgment that is adverse to Petitioner and one summary judgment that favors it. Both are presently on appeal to the 7th Circuit Court of Appeals in Chicago. Petitioner filed its initial brief on appeal on November 30, 1994.

Petitioner's evidence on cross-examination and by its witness Stump establishes that the litigation is at an important juncture and that tens of millions of dollars are involved. Whether the litigation will end with a final judgment of the 7th Circuit Court of Appeals, expected sometime next year, or whether the Court of Appeals' decision will only lead to further proceedings and additional time-consuming and costly litigation, is speculative and problematic. The Commission does not believe that **[*106]** Petitioner should be discouraged from expending required sums of money for legal and consulting specialists in highly complicated litigation of this type when large sums of money are at stake and both Petitioner and ratepayers have a vital interest in the final outcome. Public does not question the amounts expended by Petitioner during the test year or the prudence of such expenditures. Public's only objection is that the sum will not be recurring and that no one knows when or how this crucial litigation will be resolved. Given the Commission's experience with its cases that have been reviewed by the Courts, the likelihood is that complex litigation of this type will last longer than anyone anticipates. Petitioner's evidence is that it expects these rates will be in effect for only approximately three years, and we can not say that the Old Ben litigation, or expenditures therefor, will not amount to at least $ 435,114 on average over the years 1994-1996. We find that level of litigation expense for a case of this type and importance to be reasonable and find that the sum should be included in Petitioner's expenses. Therefore, we find no adjustment to test year should be made.

i. **[*107]** Out-of-Period Maintenance Expense. During the 1993 test year, Petitioner paid an invoice for and recorded as expense $ 21,500 for services rendered in a prior year (1992). Public proposes that since the services provided were for an out-of-test year period, they should not be included in the test year expenses.

Petitioner counters that the postponement of expensing and paying the invoice related to a dispute over the contracted services, therefore the expense was not fixed until the dispute was resolved in 1993. Furthermore, Petitioner stated that there are likely to be some items of this nature every year as a matter of course and the inclusion of the $ 21,500 in test year expense merely reflects the going level of such items.

During cross-examination, Public's witness Cook pointed out that the services were performed in 1992, and thus the costs of those services reflect a cost of maintenance for 1992, not for 1993. Although we find this issue difficult to decide, we believe the Public's adjustment to be appropriate. Petitioner did not submit any evidence to support its position that claims such as the one disallowed by Public will occur every year. The record shows that the **[*108]** services were performed outside of the adjustment period detailed in the prehearing conference order, and accordingly should not be included as part of Petitioner's pro forma O & M expense. Therefore, the jurisdictional downward adjustment to test year should be $ 19,506.

It should be noted that neither intervenor took an active position on any of the foregoing expense issues.

Based on the above determinations, we find Petitioner's pro forma jurisdictional net operating income at present rates to be summarized as follows:

Operating Revenues	$ 221,376,020
Operating Expenses	124,053,026
Depreciation	29,576,303
Taxes other than Income	11,039,540
Federal and State Income Taxes	13,452,939
Total Operating Expenses and Taxes	178,121,808
Net Operating Income (present rates)	$ 43,254,212

Taking the above net operating income realized by Petitioner at its present rates when applied to the fair value rate base of $ 794,473,230 as determined in Paragraph No. 4, above, this present net operating income produces a return of 5.44%. That return is less than the fair rate of return we determined in Paragraph 5 to be not less than 5.79%. Therefore, based on a consideration of all **[*109]** the evidence and the foregoing findings, we further find that the Indiana jurisdictional electric operating income available to Petitioner for earning a fair return under present rates is insufficient to provide Petitioner the opportunity to earn a fair return on the fair value of its Indiana jurisdictional electric properties used and useful for the convenience of the public. Therefore, Petitioner's net operating income under present rates is inadequate, unjust and unreasonable and

Petitioner's net operating income allowed by this Commission should be increased.

7. Petitioner's New Revenue Requirement. When our determination of Petitioner's fair rate of return of 5.79% is applied to our determination of Petitioner's fair value rate base $ 794,473,230, our finding, and the mathematical result, is that Petitioner should be allowed a net operating income of $ 46,042,726 (which includes an increment of $ 42,726 for the DSM equity adder which was accepted by all parties in the proceeding), and Petitioner is entitled to an opportunity to earn that amount, which amount we expressly find to be a fair return upon the fair value of Petitioner's Indiana jurisdictional electric property **[*110]** used and useful, and reasonably necessary, for the convenience of the public in Petitioner's provision of electric utility service. For Petitioner to earn the jurisdictional net operating income of $ 46,042,726, an increase in Petitioner's gross annual retail electric operating revenues of $ 4,546,730 is required. We find that Petitioner should be, and is hereby authorized to increase its retail electric rates and charges to produce the aforesaid additional operating revenue. This authorized revenue increase indicates an overall electric retail rate increase by Petitioner of 2.05%.

Based on the evidence, we find that Petitioner should be, and is hereby authorized, to increase its rates and charges to allow it an opportunity to produce additional annual operating revenue of $ 4,546,730. This increase is reasonably calculated to allow Petitioner to earn net operating retail electric income of $ 46,042,726. Petitioner is ordered to file tariffs with the Engineering Staff of this Commission designed to produce the amount of additional annual revenue hereby authorized.

8. Revenue Allocation

a) Cost Allocation Methods Study. In Cause No. 37803, this Commission required the Petitioner **[*111]** to present a study to determine the appropriate cost of service methodology for use in its next rate proceeding. The Petitioner provided such a study in this cause as Exhibit M-1, SIGECO Cost Allocation Methods Study, sponsored by William R. Hopkins, a vice president with Stone and Webster Management Consultants, Inc. Exhibit M-1 shows and Mr. Hopkins testified that SIGECO's system exhibited strong summer peaking in the months of June, July, August and September. The study concludes that a 4 coincident peak (CP) allocation methodology, based upon the average of the peak demands for the summer months, is most appropriate for allocating the fixed costs of production plant.

According to Exhibit M-1, Petitioner's selection of the 4 CP cost allocation methodology was based upon the following: 1) it is well supported by experts in the field and the IURC had previously commented that system planning is the critical component of allocation choice; 2) the method was consistent with prior studies approved both by this Commission and by the Federal Energy Regulatory Commission; and 3) it is supported by SIGECO's summer peaking load pattern.

b) Cost of Service - Classification. Robert D. **[*112]** Greneman of Stone and Webster Management Consultants, Inc. prepared and sponsored the cost of service studies (Exhibit L-1) presented by the Petitioner and described the process which produced those studies. Mr. Greneman testified that three steps were used in the costing procedure: functional assignment, classification, and allocation of costs. Functional assignment was defined as the process by which plant and its associated expenses are assigned to the proper account. The functionalized cost groups were then classified based upon the group's predominant cost causation factor into demand, energy, DSM, revenue and various customer components. Then each class of service was allocated a proportionate share of cost responsibility by either applying allocation factors or through direct assignment.

Mr. Greneman applied the production plant classification and allocation methodology determined by Mr. Hopkins to be the most appropriate. In his cost of service study, production plant is classified as demand related and allocated based upon the 4 CP methodology. Mr. Greneman also presented a fully allocated cost of service study which uses a 12 CP allocation methodology as required by the **[*113]** order in Cause No. 37803, and the summary sheets from a cost of service study which uses a 1 CP methodology.

The Public presented testimony from Staff Engineer Garrett Hart. Mr. Hart disagreed with Petitioner's classification of all production plant costs as demand-related. Mr. Hart contended that such a classification was illogical, not reflective of cost causation, in conflict with the Petitioner's history of generation expansion and inconsistent with its system planning process. He testified that because the Petitioner had historically constructed baseload plant with a high level of installed cost per kilowatt rather than peaker generation facilities which have the lowest installed cost, SIGECO must have constructed those plants with the energy load of its system in mind. Mr. Hart pointed out that in SIGECO's most recent Integrated Resource Planning (IRP) filing, it had specifically identified "Electric Energy Consumption Growth" as the first component listed for consideration of the "Amount of Generating Capacity Needed", and that reference was made throughout the filing to the role that energy consumption plays in the Petitioner's planning process. (Public's Exh. No. 5). Mr. **[*114]** Hart testified that SIGECO's planning process, as defined in its IRP, establishes energy consumption as an integral part of the planning process. Mr. Hart concluded that because the Petitioner classified all production plant costs as demand-related, its methodology was inconsistent with both cost causation and with SIGECO's own planning process and inappropriate for application in this Cause.

Mr. Hart applied the Equivalent Peaker Method (EPM) to Mr. Greneman's cost of service study. Using the EPM, baseload production plant costs which exceed the installed cost of an equivalent amount of peaker (combustion turbine) capacity are classified as energy related rather than demand related. Where possible, Mr. Hart selected peakers from SIGECO's system of similar vintage to each of the company's baseload plants to determine the appropriate equivalent peaker cost per kilowatt. For example, to calculate the A.B. Brown equivalent peaker cost per kilowatt, an estimate of the installed cost per kilowatt for an 80 megawatt combustion turbine was taken from the 1993 EPRI Technical Assistance Guide. The equivalent peaker cost per kilowatt for each baseload plant was then multiplied by its installed **[*115]** capacity to arrive at an equivalent peaker cost for each plant. Existing peaker units were assigned equivalent peaker costs equal to their installed cost. The sum of all equivalent peaker costs was then divided by the total installed cost of all generation facilities on the Petitioner's system to arrive at the equivalent peaker percentage. That percentage is the proportion of production plant which is classified as demand-related and the remainder is classified as energy-related.

Mr. Hart testified that based upon his application of the EPM, 38.972% of the Petitioner's production plant should be classified as energy-related and 61.028% of production plant should be classified as demand-related. He stated that his application of the EPM was conservative because he intentionally selected peaker facilities which were generally newer than their baseload counterparts and had relatively higher installed costs, resulting in a lower percentage of plant classified as energy-related. During cross-examination, Mr. Hart acknowledged that his application of the EPM would result in a higher allocation of production costs, approximately $ 670,000, to Petitioner's retail jurisdictional customers. **[*116]**

Intervenor PPG Industries, Inc. presented the testimony of Nicholas Phillips, Jr. of Drazen-Brubaker Consultants, Inc. Mr. Phillips pointed out in his direct testimony that Petitioner's cost-of-service study understates the rate of return and amount of subsidy paid by Rate LP customers. Mr. Phillips explained that because Petitioner did not use a customer component (minimum-size) in its classification of distribution plant, Petitioner's study actually overstates the residential rate-of-return and understates the amount of subsidy received by the residential class, further compounding the subsidy/excess situation. (PPG Exhibit 1, pp. 16-17).

In his direct testimony Mr. Phillips also commented on the EPM. Mr. Phillips stated that the EPM is flawed because it fails to allocate the lower fuel costs associated with baseload generation to those customers which consume the most energy. He stated that in order for the EPM to reflect cost causation, the higher energy costs associated with peaker generation employed solely to accommodate the system peak should be allocated to those customers contributing most to that peak: the low load factor residential rate classes. He further contended **[*117]** that the EPM incorrectly focuses only on the capital costs associated with the construction of generation facilities and ignores the fuel costs. He testified that utilities plan their systems to minimize the total of capital and fuel costs, not just to minimize the capital costs. Mr. Phillips testified that if a generation plant is expected to run beyond the break-even point (the break even point is defined by Mr. Phillips as the point at which the lower fuel costs associated with baseload plants outweigh their higher capital costs) the choice between the construction of baseload plants or peakers is irrelevant. The EPM does not account for the break-even point phenomenon.

Mr. Phillips was also critical of the EPM because it does not reflect the comparative reliability between baseload and peaker units. He contended that because baseload units are more reliable than peakers, the EPM does not accurately reflect that portion of the planning process. During cross-examination, Mr. Phillips agreed that the forced outrage rate statistic, which he cited in support of this contention, would necessarily show higher outrage rates for peakers because peakers run for significantly fewer hours **[*118]** annually than baseload units.

Petitioner presented rebuttal testimony from both Mr. Hopkins and Mr. Greneman on this issue, both of whom were critical of the EPM. Mr. Greneman testified that he had investigated other jurisdictions' use of the EPM and found no case where this method has been regularly accepted. Mr. Hopkins states that the EPM was temporarily used once in one jurisdiction.

Witness Hopkins voiced many of the same criticisms of the EPM as those presented by PPG witness Phillips regarding fuel symmetry, reliability and system planning. He also criticized the EPM by stating that it contains "an inherent.inaccuracy" contending that it double-counts class demands in the cost allocation process, which penalizes high-load factor customers. Mr. Hopkins explained on page 5 of his rebuttal testimony that Mr. Hart's EPM approach divides the production plant capital costs into peaker related and energy related segments. The EPM uses the 4 CP demand allocator of each class to allocate the peaker segment and the energy allocator (or the average demand) to allocate the energy segment. Mr. Hopkins believes this double counts demand because any class with a load factor above the system **[*119]** average will be assigned excess costs. To avoid this Mr. Hopkins believes it is necessary to subtract the class average demands from the 4 CP demands to derive a more proper allocator.

Mr. Hopkins also testified that Mr. Hart's use of the EPM is incomplete because only the capital cost portion of production plant are addressed and operating costs, principally fuel, are ignored. He believes that higher load factor customers should receive some benefit from the additional investment costs allocated to them in the form of lower energy costs. Practical or regulatory considerations, including the Federal Power plant and Industrial Fuel Use Act of 1978, may have made the construction of peakers impractical or impossible at the time the Petitioner's baseload plants were constructed. Mr. Hopkins makes this point in reference to the EPM's substitution of representative peakers for each of SIGECO's base load units.

SIGECO's rebuttal witness Mr. Greneman testified that the substitution of peaking units for baseload units in the EPM was arbitrary and incorrect because peaking units do not always offer the lowest cost generation solution. He was critical of Mr. Hart's application of the EPM **[*120]** because it was not a completely allocated cost of service study and failed to flow through other cost of service elements such as administrative and general expenses, labor expenses, and intangible and general plant. In response to cross-examination by the OUCC, Mr. Greneman acknowledged that the inclusion of those cost of service elements could result in a higher classification of costs as being energy related.

Also in response to cross-examination, Mr. Greneman stated that he does not recognize a correlation between the various choices of classification and allocation in a cost of service study and integrated resource planning. The Commission finds this surprising because if the purpose of a cost of service study is to reflect cost causation, as all witnesses testifying on this topic have asserted, how can resource planning not be a major consideration when the number one cost causer is the construction of new generation capacity? This Commission agrees that properly designed utility rates should reflect, to the extent possible, cost causation and one of the first steps in designing those rates is the classification and allocation methodology. Therefore, the classification and allocation **[*121]** methodologies selected should also, to the extent possible, reflect cost causation. This point is made in the first finding of Petitioner's Cost Allocation Methods Study (Exhibit M-1) presented by Mr. Hopkins, which states the "planning" basis is the preferred method for deciding the appropriate allocation approach.

While this Commission has not previously endorsed or accepted the Equivalent Peaker Methodology for demand cost allocation, we were presented similar arguments and issues in the 1990 PSI Rate Case, Cause No. 37414-S2. In that case, the OUCC witness proposed a methodology which is similar to the EPM. The Commission did not accept the EPM, regardless of any merit the theory might otherwise have had, because of the failure of the OUCC witness to study PSI's system load characteristics or the reasons why PSI built its base load generating stations. (In Re PSI, Cause No. 37414-S2, Order, April 4, 1990, page no. 77.) We are confronted with a similar situation in this proceeding. OUCC witness Mr. Hart stated on cross-examination that he had not studied Petitioner's system load characteristics.

The Commission agrees with the arguments of Petitioner and the Intervenors in **[*122]** this case that the EPM appears to encourage low load factor use of a utility's system. We are persuaded by Mr. Phillips' break-even point phenomenon and Mr. Hopkins' fuel symmetry argument. We are also unable to support the EPM because of the additional uncertainty inherent within the estimates necessary to perform such a study. The assumptions required by the EPM are not widely accepted and have not been routinely implemented in any other jurisdiction. This Commission simply cannot adopt a methodology based on the present record which is lacking in evidentiary support for the EPM. We therefore reject Public's proposed EPM and agree with Petitioner that production plant costs should be classified as demand-related and a coincident peak methodology should be used for allocation in this proceeding.

c) Cost of Service - Allocation. As discussed previously, Petitioner's witness Mr. Hopkins has proposed a 4 CP production plant demand allocation methodology in this case. Mr. Hopkins has provided support for this methodology through Petitioner's Exhibit M-1, the Cost Allocation Methods Study. Mr. Hopkins testified that neither the 1 CP nor the 12 CP method are appropriate because SIGECO **[*123]** is a summer peaking electric utility. In his study of system load characteristics, Mr. Hopkins found that SIGECO exhibited a strong tendency toward summer peaking; more so than that of other large Indiana electric utilities. He observed that Petitioner's load characteristics are moving toward a single pronounced summer peak (1 CP) rather than toward more evenly spread monthly peak demands (12 CP). Nevertheless, Mr. Hopkins' position is that its monthly peak demand patterns recur generally as they have throughout its history and the 4 CP approach remains the correct demand allocation method for Petitioner at this time and for the foreseeable future.

During cross-examination, Mr. Hopkins explained that other CP allocation methodologies were rejected based upon the application of the FERC tests (see Exhibit M-1, the Cost Allocation Methods Study) and other factors including loss of load hours over time. He also stated that other non-coincident peak methodologies were rejected because of perceived problems in the way in which fuel costs were allocated and because SIGECO employs predominately one type of generation facility.

Public's witness Mr. Hart proposes the use of a 12 CP method **[*124]** if the EPM discussed above is not approved. As pointed out by Intervenor PPG during cross-examination of Petitioner's rebuttal witness Mr. Hopkins, the OUCC's 12 CP proposal, while allowing for a smaller increase for Rate A (residential) customers, will cause a larger increase to Rate EH (residential electric heating) customers as compared to Petitioner's proposal. Mr. Hopkins testified that Rate EH customers are beneficial to SIGECO because these customers consume additional electricity during the winter months.

PPG's witness Mr. Phillips supported Petitioner's choice of the 4 CP demand allocation methodology. Mr. Phillips stated that the 4 CP method is 1) an appropriate cost of service methodology for SIGECO's system; 2) consistent with past practice; and 3) used by the Petitioner for planning and calculating its system reserve margin. Moreover, the 4 CP method is consistent with actual load analysis of the Petitioner's electric system. (PPG Exhibit 1, p.16). Mr. Phillips noted that over the last ten years, Petitioner's summer peaks were significantly higher than the winter peak, demonstrating that either the 4 CP or the 1 CP is the appropriate cost of service methodology. Mr. **[*125]** Phillips analyzed Petitioner's electric load characteristics (Exhibit NP-1, Schedules 1 through 5) and reviewed Petitioner's capacity and fuel mix (Exhibit NP-1, Schedule 6), with the resulting conclusion that 4 CP remains appropriate for Petitioner in this Cause.

Intervenor Countrymark Cooperative presented the testimony of Kenneth Eisdorfer. In his testimony Mr. Eisdorfer agreed with and provided additional support for Petitioner's use of the 4 CP demand allocation methodology. Exhibit KE-1 details the relative monthly system peaks on the SIGECO system for the ten most recent calendar years. The annual system peak has a value of 100% and this exhibit shows SIGECO's annual system peak occurred during either July, August or September for the past 10 years. In his testimony, Mr. Eisdorfer averaged the system peaks for the 4 summer months (95.3) and for the remaining eight months of the year (70.1) and stated these figures support the 4 CP methodology.

There is insufficient evidence to support the 12 CP method in this case. It is clear from the evidence presented by Mr. Hopkins, Mr. Phillips and Mr. Eisdorfer that the summer peak is the determining factor in SIGECO's planning requirements. **[*126]** Therefore, we agree with Petitioner's witness Mr. Hopkins, PPG's witness Mr. Phillips and Countrymark's witness Mr. Eisdorfer that the 4 CP methodology is appropriate. The Commission finds that the 4 CP method used by Petitioner to allocate production plant in its cost of service study (RDG-2 rebuttal) is proper and direct that it be used for rate-making in this proceeding.

d) Classification of Scrubber Costs. The Commission's order in Cause No. 39347, approved October 14, 1992, granted approval of the construction of certain qualified emission control systems at SIGECO's Culley 2 and 3 generation facilities pursuant to I.C. 8-1-2-27. In the "Compromise and Agreement for Settlement" in that Cause, Petitioner agreed to propose and support classification of the capital costs associated with the Culley 2 and 3 scrubber on a 75% demand/25% energy basis in its next general rate proceeding. Petitioner has proposed the cost allocation agreed to by the parties in Cause No. 39347 in this proceeding.

Neither of the Intervenors in this proceeding was a party of the record in Cause No. 39347. PPG's witness Phillips was critical of the proposed scrubber cost classification. He testified **[*127]** that because the scrubber was an inseparable part of the generating plant, it should be classified the same as the plant itself, which is 100% demand-related. Mr. Phillips testified that he was unaware of any other scrubber classification proposed by or approved for any other Indiana utility.

Like Mr. Phillips, Countrymark's witness Eisdorfer also testified that any energy allocation of scrubber cost was unfair to energy-intensive industrial customers because the size of the scrubbers is dictated solely by the size of the generating unit. During cross-examination, Mr. Eisdorfer would not agree with the Public's contention that scrubbers are a substitute for higher cost fuel and should be allocated on an energy basis. He maintained that scrubbers were the Petitioner's lowest cost emission control system and were not a capital substitute for possibly higher-cost, lower sulfur coal. Mr. Eisdorfer did agree that if low-sulfur coal was determined to be Petitioner's lowest cost pollution control strategy, those fuel costs would be allocated based upon energy consumption.

The Public generally supported the Petitioner's proposal. Witness Hart testified that any deviation from the scrubber **[*128]** cost allocation agreed to in Cause No. 39347 should be toward a greater classification of the scrubber cost as energy related. The Public's proposed EPM classifies 38.972% of production plant as energy related whereas the stipulation in Cause No. 39347 classifies 25% as energy related. Mr. Hart suggested that if any deviation were to occur, the Commission should apply the higher EPM percentage.

The Commission is mindful of the complexity, controversy and expense (more than $ 90 million) associated with SIGECO's compliance with the Clean Air Act. In the order in Cause No. 39347, the Commission commended the parties for resolution of the issues and encouraged negotiated resolutions to future cases involving Clean Air Act compliance. We are not inclined to replace an allocation methodology, which the parties in that cause have negotiated and agreed upon, in the absence of strong evidence to suggest that such an allocation is unreasonable. Such an act might have an adverse affect on the resolution of future cases.

The record in this Cause supports the approval of Petitioner's proposed scrubber classification of 75% demand/25% energy. We find that Petitioner's proposed classification **[*129]** of capital costs associated with the Clean Air Act compliance to be reasonable and should be approved.

e) Reduction of Interclass Subsidies. In Petitioner's last general rate order, Cause No. 37803, the Commission found that Petitioner ". . . should be required to reduce any subsidy between classes to the extent of at least 25% until such time as the Commission finds that any such subsidy has been sufficiently reduced or eliminated." (Final Order, IURC Cause No. 37803, approved 2/11/86). All parties to this proceeding agree that interclass subsidies exist under Petitioner's current rates, and all parties offered proposals for their reduction.

Petitioner's witness Mr. Hopkins has recommended a movement of each rate class' rate of return toward equalization with the overall rate of return (ROR) thereby reducing interclass subsidies. Mr. Hopkins' proposal is based upon two criteria articulated in his direct testimony: (1) Limit the amount of any single class rate increase to approximately two times the overall proposed rate increase. (2) Bring the ROR for each rate class to within approximately 25% of the overall ROR. A third criteria Mr. Hopkins mentioned in his oral testimony **[*130]** is to not lower the general residential class (Rate A) rate of return from the level established in the last rate case.

The RORs proposed by Mr. Hopkins reduce the subsidy/excess revenue for each rate class by a different amount and bring the ROR for each class to within 25% of Petitioner's overall proposed ROR. The proposed increase for each rate class is limited to two times the overall 4.77% requested rate of increase except for the Rate A (residential) and Rate B (residential w/electric water heating) rate classes which would receive increases of 13.38% and 13.27%, respectively. (Petitioner's WRH-2, Rebuttal)

During cross-examination, Mr. Hopkins acknowledged that he had not calculated the fixed percentage by which his proposed rate design would eliminate interclass subsidization, but rather had concentrated his efforts on aligning the ratio of class ROR to overall ROR in devising his proposal. He testified that by using those ratios as a basis for comparison, his proposed increase for Rate A was necessary in order to satisfy his third criteria mentioned above. On cross-examination, Mr. Hopkins pointed out that the Petitioner's proposal for reducing subsidy/excess was designed **[*131]** not to lose ground, admitting that the proposal would set the Rate A subsidization level at the same point (0.76) as was set after the previous rate order almost ten years ago.

PPG witness Mr. Phillips addressed the reduction of subsidy/excess on Petitioner's system and recommended a uniform 50% reduction. In his direct testimony, Mr. Phillips explained that according to Petitioner's proposed cost-of-service study, Rate A customers are paying rates almost $ 11 million below the cost required to serve them. (PPG Exhibit 1, page 24). In contrast, the large power class (Rate LP) are paying rates $ 4.3 million greater than the cost required to serve them. Mr. Phillips stated that a reduction of existing revenue subsidies by 50% would make a fair and meaningful movement toward cost-based rates. The per class rate impacts of his proposal are shown on Exhibit NP-2, Schedule 3. Mr. Phillips specifically recommended a minimum reduction of 50% in this proceeding and that a procedure be established to move rates closer to costs by a specified future date. (PPG Exhibit 1, pp. 25-26).

Countrymark's witness Mr. Eisdorfer proposed a 2/3 reduction of subsidy/excess. He noted "some anomalies" in **[*132]** Mr. Hopkins' proposal, specifically the minimal movement of the General Service class toward cost. During cross-examination, Mr. Eisdorfer was asked about the anomaly between the General Service rate class and the Large Power rate class, and he testified that a uniform reduction of subsidization across rate classes should be recommended rather than an uneven reduction. Mr. Eisdorfer stated that the length of time between general rate cases is a factor in determining the amount of reduction in interclass subsidization. He stated that his proposed 2/3 reduction is partially premised upon the fact that, based upon the nine years that have elapsed since Petitioner's last rate order, there may not be an opportunity for further movement toward cost-based rates in the near future.

The Public's Chief Engineer Daniel J. Kuester voiced concern that the Petitioner's proposed methodology would be inequitable because while it will reduce much of the existing subsidy/excess for some rate classes, it will only slightly reduce the subsidy/excess for other classes. Mr. Kuester states on page 9 of his testimony that this exacerbates the subsidy/excess problem. In Schedule 1, Mr. Kuester presented **[*133]** a table detailing the percent by which the Petitioner's proposed rate design would reduce existing subsidy/excess. That schedule shows that the Petitioner's proposal would reduce subsidy/excess from between 7.37% for the General Service class to 92.81% for the Electric Heating Class.

Mr. Kuester also expressed concern about the potential rate shock to residential customers which Petitioner's proposed 13.38% (Rebuttal Ex. WRH-2) rate increase might cause. Mr. Kuester was also critical of Petitioner's proposal because Mr. Hopkins had failed to adhere to his own criteria by proposing rate increases for two classes (Rate A and B) which were more than two and one half times the overall proposed increase.

Mr. Kuester proposed that Petitioner uniformly reduce subsidy/excess by 25% for all rate classes. He testified that such an across-the-board adjustment would be in keeping with the Commission's order in Cause No. 37803 and would also satisfy the criteria established by Mr. Hopkins. Schedule 2 attached to Mr. Kuester's testimony applies the 25% subsidy/excess reduction to the 4 CP cost of service study filed by the Petitioner.

In rebuttal, Mr. Hopkins contended that Mr. Kuester's proposed **[*134]** 25% subsidy/excess reduction would make the return ratio for the residential class worse than the level set by Petitioner's last rate order. He also states that it is Mr. Kuester's proposal that exacerbates the subsidy/excess problem by reducing the residential subsidy 25% rather than his proposal which reduces the subsidy by 37%.

We note at the outset that all parties agree that cost-based rates are a desirable goal for Petitioner and the testimony of each proposes a movement toward such rates through the reduction of interclass subsidization. While cost-based rates are a laudable goal, the achievement of those rates must be tempered with the recognition that large increases in utility rates can have a detrimental impact on the customers who must pay them. The solution is a reasonable balance between the long term benefits of cost-based rates and the short term detriments of rate shock. The lengthy period between the filing of this Cause and the order in Petitioner's previous rate proceeding makes it difficult to approve a large shift toward cost-based rates in this proceeding. In light of this, the Commission questions whether a comparison of the rate of return ratios of the two **[*135]** rate cases is accurate. We note that there may have been significant differences in the weather of the two test years which may partially account for such differences, but no party has presented data in this regard.

While we do not agree with Mr. Kuester's assertion that Mr. Hopkins' methodology, which adjusts the subsidy/excess in each rate class a different amount, invariably leads to inequality in the treatment of the individual classes or further exacerbates the subsidy/excess problem, we do find that a uniform reduction of subsidy/excess revenues is more appropriate. We find Mr. Kuester's 25% reduction to be more reasonable for five reasons in addition to those detailed in the preceding paragraph. First, a 25% minimum level of subsidy/excess reduction was ordered in SIGECO's previous rate order, Cause No. 38703. Second, there will be no significant rate decreases to any rate classes. Third, the customer classes providing the largest subsidy, Rates LP and HLF, will receive no increase or a slight decrease. Additionally, for certain customers of Rate LP there may be a decrease resulting from the addition of a demand credit of $ 1.75 per kVA for transmission voltage service proposed **[*136]** by Petitioner. (See Finding No. 9 hereinbelow) Fourth, the increase to the three residential classes is more "in-line" with the total rate increase and more closely complies with Mr. Hopkins criteria of limiting the per class increase to twice the overall increase. Fifth, the 25% reduction may also help mitigate possible rate shock to these classes.

As stated previously, PPG's witness Phillips also recommended that a procedure be established in this proceeding to continue to reduce subsidy/excess revenues by a specified future date. Specifically, Mr. Phillips recommended a 25% reduction within two years of the date of this order and another 25% reduction within four years of the date of this order. None of the other parties commented on this recommendation. SIGECO witnesses have indicated in evidence that Petitioner will be before the Commission with another electric rate case in approximately three (3) years, thus giving us an opportunity to revisit the subsidy/excess situation. If the rates authorized herein last for a period of four or more years, the Commission may consider instituting an investigation into further reducing the subsidy/excess.

9. Petitioner's Structural Changes **[*137]** in Rates. Petitioner proposes two structural changes in its rates. First, it proposes to recognize a transmission voltage level service cost discount ($ 1.75 per kVA) to customers presently on Rate LP where the customer is served at 69 kV or higher voltages by Petitioner. Second, Petitioner's proposed rates more specifically define demand charges for customers on Rates GS (General Service) and LP (Large Power). Both present rates measure load factors based on energy usage steps, however the new rates more explicitly set out a demand charge. As to Rate GS, Petitioner's witness Hopkins corrected the initial proposed rate change by his Additional Supplemental Testimony (Corrected Exhibit WRH-4), which changes the GS rate less dramatically than originally proposed by Petitioner to moderate the billing impacts. The corrected proposal is a separately stated demand charge of $ 1.30 per kW for billing demands above 10 kW, while retaining the present hours use energy block.

Neither Public nor Intervenors objected to the above structural changes in Petitioner's rates, and we hereby find that these changes should be approved.

10. Petitioner's Rates and Regulations. The following four **[*138]** changes are proposed by Petitioner to the General Terms and Conditions of its tariff:

1. The Fuel Adjustment Clause Base Price (Section 17) which is presently 1.7407 per kWh, should be changed to 1.5267 per kWh, to effectively zero out the adjustment for the pro forma test year. The new base price is computed by Mr. DeCleene in calculating his Entry B adjustment to test year revenue (Exhibit RJD-1, Page 3).

2. The wording of the minimum monthly bill provision regarding Auxiliary or Standby Service (Section 15) should be changed to read: "(f) The minimum monthly bill for Auxiliary or Standby service shall be as specified in the applicable rate schedule". Since Rate GS is proposed to have a separately stated demand charge this rewording is more suitable than the existing $ 3.00 per kW or kVA amount.

3. The charge for investigating fraudulent, unauthorized use or tampering (Section 3) should be increased from $ 35.00 to $ 40.00. A similar change was recently approved for the Petitioner's gas tariff.

4. The requirement for a Residential Conservation Service Program Audit under the Utility Residential Weatherization Program Loan (Section 21) should be eliminated. A similar change **[*139]** was recently approved in the Petitioner's gas tariff.

No party objected to the four changes, and the Commission finds them to be acceptable. Petitioner's new tariff to be filed in compliance with this order should include the above four changes to Petitioner's General Terms and Conditions.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. Petitioner shall be and is hereby authorized to increase its rates and charges for retail electric service, in accordance with the findings herein, to produce additional retail electric operating revenues of $ 4,546,730, which amount is designed and intended to allow Petitioner the opportunity to earn annual jurisdictional net operating income of $ 46,042,726. This results in a total overall rate increase of approximately 2.05%. The increase is to be placed in effect in accordance with this Order and upon approval of Petitioner's filed tariffs, by the Commission's Engineering Staff.

2. Petitioner's structural changes to its Large Power (LP) tariff and its General Service (GS) tariff are hereby approved, as are the four changes to the General Terms and Conditions of its tariff.

3. Petitioner's increased rates are subject **[*140]** to confirmation by the Commission's Engineering Staff that Petitioner's Clean Air Act Project, including all ancillary projects, at its Culley Power Plant are operational. If there is a disagreement as to the operational status of the Project subsequent to the date that Petitioner's approved tariff has been filed and implemented, then such disagreement shall be brought to the attention of this Commission by an appropriate subdocketed filing in this Cause for Commission resolution.

4. As found in this Order, Petitioner's new rates shall include both the impact and cost of Petitioner's compliance with SFAS 106 for its electric department and the DSM accounting and earned equity incentive requested by Petitioner.

5. The consolidated complaint proceeding in Cause No. 40078 shall be and is hereby denied.

6. Petitioner has fully complied with the requirements of our Order in Cause No. 37803 and it is discharged from any further obligation thereunder except the continuing effort to appropriately reduce any interclass subsidy/excess revenues in future rate cases.

7. Petitioner continue to reduce subsidy/excess revenues as described in finding paragraph 8 (e).

8. This Order shall be effective **[*141]** on and after the date of its approval.

Source: Legal > / . . . / > **IN Utility Regulatory Commission Decisions**
Terms: **unadjusted pre/2 dcf pre/3 result pre/5 almost** (Edit Search)
View: Full
Date/Time: Saturday, August 6, 2005 - 1:39 PM EDT

AG-DR-03-003

REQUEST:

3. With reference to page 14, lines 1-5, please provide a copy of the relevant material from the book.

RESPONSE:

See Attachment AG-DR-03-003.

WITNESS RESPONSIBLE: Roger A. Morin

Chapter 7
Alternative DCF Models

7.1 The Quarterly DCF Model

The standard annual form of the DCF model:

$$K = D_1/P_0 + g$$

assumes an annual dividend payment, a yearly increase in dividends starting exactly one year from the present, a constant rate of dividend growth, and a stock price P_0 that is determined on a dividend payment date. But because dividends are normally paid quarterly, the investor's required return should be assessed with a DCF model that recognizes quarterly payments.

It is a rudimentary tenet of security valuation theory discussed in Chapter 4 that when determining investor return requirements, the cost of equity is the discount rate that equates the present value of future cash receipts to the observed market price. Clearly, given that dividends are paid quarterly and given that the observed stock price reflects the quarterly nature of dividend payments, the market required return must recognize quarterly compounding, for the investor receives dividend checks and reinvests the proceeds on a quarterly schedule. Perforce, a stock that pays 4 quarterly dividends of one dollar commands a higher price than a stock that pays a 4-dollar dividend a year hence. Since investors are aware of the quarterly timing of dividend payments and since the stock price already fully reflects the quarterly payment of dividends, it is essential that the DCF model used to estimate equity costs also reflect the actual timing of quarterly dividends.

The traditional annual DCF model is based on the limiting assumptions that dividends are paid annually, and that dividends increase once a year starting exactly one year from the present. These assumptions are unnecessarily restrictive. Most companies, including utilities, in fact pay dividends on a quarterly basis. The quarterly DCF model discussed in subsequent sections of this chapter rests on the exact same assumptions as the annual DCF model except that the DCF model is refined to reflect the actual corporate practice of paying dividends quarterly rather than once a year. The quarterly version of the DCF model also assumes that the dividend rate is raised once a year instead of every quarter.

As both a practical and theoretical matter, stock yield calculations must be adjusted for the receipt of cash flows on a quarterly basis. The annual DCF model inherently produces incorrect results because it assumes that all cash flows received by investors are paid annually. By analogy, a bank rate on deposits that does not take into consideration the timing of the interest payments understates the true yield if the customer receives the interest payments more than once a year. The actual yield will exceed the stated nominal rate. Bond yield calculations are also routinely adjusted for the receipts of semi-annual interest payments. What is true for bank deposits and for bonds is equally germane for common stocks.

Most, if not all, finance textbooks discuss frequency of compounding in computing the yield on a financial security. The handbooks that accompany popular financial calculators used almost universally by the financial community contain abundant directions with respect to frequency of compounding.

Appendix 7-A formally derives the quarterly DCF model, which has the following form:

$$K = \frac{[D_1 (1+K)^{3/4} + D_2 (1+K)^{1/2} + D_3 (1+K)^{1/4} + D_4]}{P_0} + g \qquad (7\text{-}1)$$

line

where D_1, D_2, D_3, D_4 = quarterly dividends expected over the coming year

g = expected growth in dividends

P_0 = current stock price

K = required return on equity

Equation 7-1 must be solved by iteration because K appears on both sides of the equation. Note that an even more general form of the quarterly DCF model can be derived for the case where the stock price is not determined on a dividend payment date. If we let f_1, f_2, f_3, and f_4 denote the fraction of the year before the quarterly dividends are received, Equation 7-1 becomes:

$$K = \frac{[D_1 (1+K)^{1-f_1} + D_2 (1+K)^{1-f_2} + D_3 (1+K)^{1-f_3} + D_4{}^{1-f_4}]}{P_0} + g \qquad (7\text{-}2)$$

line

In the special case where the stock price happens to be determined on a dividend payment date, f_1, f_2, f_3, and f_4 are equal to 0.25, 0.50, 0.75 and 1.00 and Equation 7-2 reduces back to Equation 7-1.

The two-stage non-constant growth DCF model described in Chapter 4 has a quarterly counterpart:

$$P_0 = \frac{D_1(1+g)}{(1+K)^{0.25}} + \frac{D_2(1+g)}{(1+K)^{0.50}}$$

$$+ \frac{D_3(1+g)}{(1+K)^{0.75}} + \frac{D_3(1+g)}{(1+K)^{1.00}}$$

$$+ \frac{D_1(1+g)^2}{(1+K)^{1.25}} + \frac{D_2(1+g)^2}{(1+K)^{1.50}}$$

$$+ \frac{D_3(1+g)^2}{(1+K)^{1.75}} + \frac{D_3(1+g)^2}{(1+K)^{2.00}}$$

$$+ \frac{P_2}{(1+K)^{2.00}} \qquad (7\text{-}3)$$

The symbol g represents the first ~~and second~~ stage growth rate~~s~~ while P_2 represents the stock price in period 2 that is obtained by applying the quarterly DCF model using the second-stage growth rate.

X

1 for D

Intuitively, the quarterly form of the DCF model described by Equation 7-1 resembles the standard annual form, but with a slightly modified dividend yield component. Letting $D_1' = D_1(1+K)^{3/4} + D_2(1+K)^{1/2} + D_3(1+K)^{1/4} + D_4$ in Equation 7-1, the quarterly DCF equation becomes:

$$K = D_1'/P_0 + g \qquad (7\text{-}4)$$

which is very similar to the annual version. One can think of the D_1' term as an augmented D_1 term that simply captures the added time value of money associated with investors receiving successive quarterly dividends and reinvesting them over the remainder of the year at K%. That is to say, during the course of one year, the investor has the value of the first quarter's dividend for 3/4 of the year; the second quarter dividend for 1/2 of the year; the third quarter dividend for 1/4 of the year, and the fourth quarter dividend is received at the end of the year. The following illustration shows how to implement the quarterly DCF model and estimate the investor's required market return.

EXAMPLE 7-1

The common stock of Consolidated Natural Gas (CNG) is trading at \$52.13. The dividend is expected to increase annually at a constant rate of 8.8%. The current quarterly dividend rate is \$0.48 and has been in effect for two quarters. Thus, an investor buying CNG stock expects to receive, in the next year, two more dividends at the existing rate of \$0.48 and two dividends at the new rate of \$0.48(1 + g). The cost of equity capital is obtained by solving iteratively the quarterly version of the DCF model in Equation 7-1 by means of a computer spreadsheet. To solve that equation, the following input data for CNG:

D_1 $\quad D_{1q} = \$0.48$

D_2 $\quad D_{2q} = \$0.48$

D_3 $\quad D_{3q} = \$0.48\ (1 + .0880) = \$0.52$

D_4 $\quad D_{4q} = \$0.48\ (1 + .0880) = \$0.52$

$P_0 \ = \$52.13$

$g \ = 8.80\%$

are substituted into Equation 7-1 as follows:

$$K = \frac{[0.48\,(1+K)^{3/4} + 0.48\,(1+K)^{1/2} + 0.52\,(1+K)^{1/4} + 0.52]}{\$52.13} + .0880$$

Sans Serif

The equation is solved iteratively by successive approximations for K_e, the cost of equity. Here, $K_e = 12.82\%$.

Note that the annual DCF model produces an estimate of 12.64%, which is less than the 12.82% estimate derived from the quarterly DCF model.

$$K = D_1/P_0 + g = \$2.00/\$52.13 + .088 = 12.64\%$$

The difference is attributable to the time value of money associated with receiving quarterly dividends. The annual version of the DCF model typically understates the cost of equity by approximately 30-40 basis points, depending on the magnitude of the dividend yield component.

AG-DR-03-004

REQUEST:

4. With reference to page 22, Table 4, please provide all workpapers and calculations used in constructing Table 4. Please include both a hard copy and an electronic copy in Microsoft Excel format with all data and formulas intact.

RESPONSE:

The information on Table 4 was drawn directly from Dr. Woolridge's Schedules 15 and 16. No calculations or formulas are involved except for calculation of the averages.

WITNESS RESPONSIBLE: Roger A. Morin

AG-DR-03-005

REQUEST:

5. With reference to page 29, lines 18-22, please provide copies of all studies in the empirical finance literature that demonstrate internal growth is a poor explanatory variable in explaining market value and P/E ratios.

RESPONSE:

See Attachment AG-DR-03-005.

WITNESS RESPONSIBLE: Roger A. Morin

Investor growth expectations: Analysts vs. history

Analysts' growth forecasts dominate past trends in predicting stock prices.

James H. Vander Weide and Willard T. Carleton

For the purposes of implementing the Discounted Cash Flow (DCF) cost of equity model, the analyst must know which growth estimate is embodied in the firm's stock price. A study by Cragg and Malkiel (1982) suggests that the stock valuation process embodies analysts' forecasts rather than historically based growth figures such as the ten-year historical growth in dividends per share or the five-year growth in book value per share. The Cragg and Malkiel study is based on data for the 1960s, however, a decade that was considerably more stable than the recent past.

As the issue of which growth rate to use in implementing the DCF model is so important to applications of the model, we decided to investigate whether the Cragg and Malkiel conclusions continue to hold in more recent periods. This paper describes the results of our study.

STATISTICAL MODEL

The DCF model suggests that the firm's stock price is equal to the present value of the stream of dividends that investors expect to receive from owning the firm's shares. Under the assumption that investors expect dividends to grow at a constant rate, g, in perpetuity, the stock price is given by the following simple expression:

$$P_s = \frac{D(1+g)}{k-g} \qquad (1)$$

where:

P_s = current price per share of the firm's stock;

D = current annual dividend per share;

g = expected constant dividend growth rate; and

k = required return on the firm's stock.

Dividing both sides of Equation (1) by the firm's current earnings, E, we obtain:

$$\frac{P_s}{E} = \frac{D}{E} \cdot \frac{(1+g)}{k-g} \qquad (2)$$

Thus, the firm's price/earnings (P/E) ratio is a non-linear function of the firm's dividend payout ratio (D/E), the expected growth in dividends (g), and the required rate of return.

To investigate what growth expectation is embodied in the firm's current stock price, it is more convenient to work with a linear approximation to Equation (2). Thus, we will assume that:

$$P/E = a_0(D/E) + a_1 g + a_2 k. \qquad (3)$$

(Cragg and Malkiel found this assumption to be reasonable throughout their investigation.)

Furthermore, we will assume that the required

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rate of return, k, in Equation (3) depends on the values of the risk variables B, Cov, Rsq, and Sa, where B is the firm's Value Line beta; Cov is the firm's pretax interest coverage ratio; Rsq is a measure of the stability the firm's five-year historical EPS; and Sa is the ındard deviation of the consensus analysts' five-year EPS growth forecast for the firm. Finally, as the linear form of the P/E equation is only an approximation to the true P/E equation, and B, Cov, Rsq, and Sa are only proxies for k, we will add an error term, e, that represents the degree of approximation to the true relationship.

With these assumptions, the final form of our P/E equation is as follows:

$$P/E = a_0(D/E) + a_1g + a_2B + a_3Cov + a_4Rsq + a_5Sa + e. \quad (4)$$

The purpose of our study is to use more recent data to determine which of the popular approaches for estimating future growth in the Discounted Cash Flow model is embodied in the market price of the firm's shares.

We estimated Equation (4) to determine which estimate of future growth, g, when combined with the payout ratio, D/E, and risk variables B, Cov, Rsq, and Sa, provides the best predictor of the firm's P/E ratio. To paraphrase Cragg and Malkiel, we would expect that growth estimates found in the best-fitting ıuation more closely approximate the expectation used by investors than those found in poorer-fitting equations.

DESCRIPTION OF DATA

Our data sets include both historically based measures of future growth and the consensus analysts' forecasts of five-year earnings growth supplied by the Institutional Brokers Estimate System of Lynch, Jones & Ryan (IBES). The data also include the firm's dividend payout ratio and various measures of the firm's risk. We include the latter items in the regression, along with earnings growth, to account for other variables that may affect the firm's stock price.

The data include:

Earnings Per Share. Because our goal is to determine which earnings variable is embodied in the firm's market price, we need to define this variable with care. Financial analysts who study a firm's financial results in detail generally prefer to "normalize" the firm's reported earnings for the effect of extraordinary items, such as write-offs of discontinued operations, or mergers and acquisitions. They also attempt, to the xtent possible, to state earnings for different firms using a common set of accounting conventions.

We have defined "earnings" as the consensus analyst estimate (as reported by IBES) of the firm's earnings for the forthcoming year.[1] This definition approximates the normalized earnings that investors most likely have in mind when they make stock purchase and sell decisions. It implicitly incorporates the analysts' adjustments for differences in accounting treatment among firms and the effects of the business cycle on each firm's results of operations. Although we thought at first that this earnings estimate might be highly correlated with the analysts' five-year earnings growth forecasts, that was not the case. Thus, we avoided a potential spurious correlation problem.

Price/Earnings Ratio. Corresponding to our definition of "earnings," the price/earnings ratio (P/E) is calculated as the closing stock price for the year divided by the consensus analyst earnings forecast for the forthcoming fiscal year.

Dividends. Dividends per share represent the common dividends declared per share during the calendar year, after adjustment for all stock splits and stock dividends). The firm's dividend payout ratio is then defined as common dividends per share divided by the consensus analyst estimate of the earnings per share for the forthcoming calendar year (D/E). Although this definition has the deficiency that it is obviously biased downward — it divides this year's dividend by next year's earnings — it has the advantage that it implicitly uses a "normalized" figure for earnings. We believe that this advantage outweighs the deficiency, especially when one considers the flaws of the apparent alternatives. Furthermore, we have verified that the results are insensitive to reasonable alternative definitions (see footnote 1).

Growth. In comparing historically based and consensus analysts' forecasts, we calculated forty-one different historical growth measures. These included the following: 1) the past growth rate in EPS as determined by a log-linear least squares regression for the latest year,[2] two years, three years, . . ., and ten years; 2) the past growth rate in DPS for the latest year, two years, three years, . . ., and ten years; 3) the past growth rate in book value per share (computed as the ratio of common equity to the outstanding common equity shares) for the latest year, two years, three years, . . ., and ten years; 4) the past growth rate in cash flow per share (computed as the ratio of pretax income, depreciation, and deferred taxes to the outstanding common equity shares) for the latest year, two years, three years, . . ., and ten years; and 5) plowback growth (computed as the firm's retention ratio for the current year times the firm's latest annual return on common equity).

We also used the five-year forecast of earnings

PAGE 4

per share growth compiled by IBES and reported in mid-January of each year. This number represents the consensus (i.e., mean) forecast produced by analysts from the research departments of leading Wall Street and regional brokerage firms over the preceding three months. IBES selects the contributing brokers "because of the superior quality of their research, professional reputation, and client demand" (IBES *Monthly Summary Book*).

Risk Variables. Although many risk factors could potentially affect the firm's stock price, most of these factors are highly correlated with one another. As shown above in Equation (4), we decided to restrict our attention to four risk measures that have intuitive appeal and are followed by many financial analysts: 1) B, the firm's beta as published by Value Line; 2) Cov, the firm's pretax interest coverage ratio (obtained from Standard & Poor's Compustat); 3) Rsq, the stability of the firm's five-year historical EPS (measured by the R^2 from a log-linear least squares regression); and 4) Sa, the standard deviation of the consensus analysts' five-year EPS growth forecast (mean forecast) as computed by IBES.

After careful analysis of the data used in our study, we felt that we could obtain more meaningful results by imposing six restrictions on the companies included in our study:

1. Because of the need to calculate ten-year historical growth rates, and because we studied three different time periods, 1981, 1982, and 1983, our study requires data for the thirteen-year period 1971-1983. We included only companies with at least a thirteen-year operating history in our study.
2. As our historical growth rate calculations were based on log-linear regressions, and the logarithm of a negative number is not defined, we excluded all companies that experienced negative EPS during any of the years 1971-1983.
3. For similar reasons, we also eliminated companies that did not pay a dividend during any one of the years 1971-1983.
4. To insure comparability of time periods covered by each consensus earnings figure in the P/E ratios, we eliminated all companies that did not have a December 31 fiscal year-end.
5. To eliminate distortions caused by highly unusual events that distort current earnings but not expected future earnings, and thus the firm's price/earnings ratio, we eliminated any firm with a price/earnings ratio greater than 50.
6. As the evaluation of analysts' forecasts is a major part of this study, we eliminated all firms that IBES did not follow.

Our final sample consisted of approximately sixty-five utility firms.[1]

PAGE 5

RESULTS

To keep the number of calculations in our study to a reasonable level, we performed the study in two stages. In Stage 1, all forty-one historically oriented approaches for estimating future growth were correlated with each firm's P/E ratio. In Stage 2, the historical growth rate with the highest correlation to the P/E ratio was compared to the consensus analyst growth rate in the multiple regression model described by Equation (4) above. We performed our regressions for each of three recent time periods, because we felt the results of our study might vary over time.

First-Stage Correlation Study

Table 1 gives the results of our first-stage correlation study for each group of companies in each of the years 1981, 1982, and 1983. The values in this table measure the correlation between the historically oriented growth rates for the various time periods and the firm's end-of-year P/E ratio.

The four variables for which historical growth rates were calculated are shown in the left-hand column: EPS indicates historical earnings per share growth, DPS indicates historical dividend per share growth, BVPS indicates historical book value per share growth, and CFPS indicates historical cash flow per share growth. The term "plowback" refers to the product of the firm's retention ratio in the currennt year and its return on book equity for that year. In all, we calculated forty-one historically oriented growth rates for each group of firms in each study period.

The goal of the first-stage correlation analysis was to determine which historically oriented growth rate is most highly correlated with each group's year-end P/E ratio. Eight-year growth in CFPS has the highest correlation with P/E in 1981 and 1982, and ten-year growth in CFPS has the highest correlation with year-end P/E in 1983. In all cases, the plowback estimate of future growth performed poorly, indicating that — contrary to generally held views — plowback is not a factor in investor expectations of future growth.

Second-Stage Regression Study

In the second stage of our regression study, we ran the regression in Equation (4) using two different measures of future growth, g: 1) the best historically oriented growth rate (g_h) from the first-stage correlation study, and 2) the consensus analysts' forecast (g_a) of five-year EPS growth. The regression results, which are shown in Table 2, support at least

TABLE 1

Correlation Coefficients of All Historically Based Growth Estimates by Group and by Year with P/E

Historical Growth Rate Period in Years

it	1	2	3	4	5	6	7	8	9	10
1981										
EPS	−0.02	0.07	0.03	0.01	0.03	0.12	0.08	0.09	0.09	0.09
DPS	0.05	0.18	0.14	0.15	0.14	0.15	0.19	0.23	0.23	0.23
BVPS	0.01	0.11	0.13	0.13	0.16	0.18	0.15	0.15	0.15	0.15
CFPS	−0.05	0.04	0.13	0.22	0.28	0.31	0.30	0.31	−0.57	−0.54
Plowback	0.19									
1982										
EPS	−0.10	−0.13	−0.06	−0.02	−0.02	−0.01	−0.03	−0.03	0.00	0.00
DPS	−0.19	−0.10	0.03	0.05	0.07	0.08	0.09	0.11	0.13	0.13
BVPS	0.07	0.08	0.11	0.11	0.09	0.10	0.11	0.11	0.09	0.09
CFPS	−0.02	−0.08	0.00	0.10	0.16	0.19	0.23	0.25	0.24	0.07
Plowback	0.04									
1983										
EPS	−0.06	−0.25	−0.25	−0.24	−0.16	−0.11	−0.05	0.00	0.02	0.02
DPS	0.03	−0.10	−0.03	0.08	0.15	0.21	0.21	0.21	0.22	0.24
BVPS	0.03	0.10	0.04	0.09	0.15	0.16	0.19	0.21	0.22	0.21
CFPS	−0.08	0.01	0.02	0.08	0.20	0.29	0.35	0.38	0.40	0.42
Plowback	−0.08									

two general conclusions regarding the pricing of equity securities.

First, we found overwhelming evidence that the consensus analysts' forecast of future growth is superior to historically oriented growth measures in predicting the firm's stock price. In every case, the R^2 ıe regression containing the consensus analysts' .ecast is higher than the R^2 in the regression containing the historical growth measure. The regression coefficients in the equation containing the consensus analysts' forecast also are considerably more significant than they are in the alternative regression. These results are consistent with those found by Cragg and Malkiel for data covering the period 1961-1968. Our results also are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy–and–sell decisions.

TABLE 2

Regression Results
Model I

Part A: *Historical*

$P/E = a_0 + a_1 D/E + a_2 g_h + a_3 B + a_4 Cov + a_5 Rsq - a_6 Sa$

Year	$\hat{a}_0$	$\hat{a}_1$	$\hat{a}_2$	$\hat{a}_3$	$\hat{a}_4$	$\hat{a}_5$	$\hat{a}_6$	R^2	F Ratio
1981	−6.42*	10.31*	7.67*	3.24	0.54*	1.42*	57.43	0.83	46.49
	(5.50)	(14.79)	(2.20)	(2.86)	(2.50)	(2.85)	(4.07)		
1982	−2.90*	9.32*	8.49*	2.85	0.45*	−0.42	3.63	0.86	65.53
	(2.75)	(18.52)	(4.18)	(2.83)	(2.60)	(0.05)	(0.26)		
1983	−5.96*	10.20*	19.78*	4.85	0.44*	0.33	32.49	0.82	45.26
	(3.70)	(12.20)	(4.83)	(2.95)	(1.89)	(0.50)	(1.29)		

Part B: *Analysis*

$P/E = a_0 + a_1 D/E + a_2 g_a + a_3 B + a_4 Cov + a_5 Rsq - a_6 Sa$

Year	$\hat{a}_0$	$\hat{a}_1$	$\hat{a}_2$	$\hat{a}_3$	$\hat{a}_4$	$\hat{a}_5$	$\hat{a}_6$	R^2	F Ratio
1981	−4.97*	10.62*	54.85*	−0.61	0.33*	0.63*	4.34	0.91	103.10
	(6.23)	(21.57)	(8.56)	(0.68)	(2.28)	(1.74)	(0.37)		
1982	−2.16*	9.47*	50.71*	−1.07	0.36*	−0.31	119.05*	0.90	97.62
	(2.59)	(22.46)	(9.31)	(1.14)	(2.53)	(1.09)	(1.60)		
1983	−8.47*	11.96*	79.05*	2.16	0.56*	0.20	−34.43	0.87	69.81
	(7.07)	(16.48)	(7.84)	(1.55)	(3.08)	(0.38)	(1.44)		

s:
..oefficient is significant at the 5% level (using a one-tailed test) and has the correct sign. T-statistic in parentheses.

Second, there is some evidence that investors tend to view risk in traditional terms. The interest coverage variable is statistically significant in all but one of our samples, and the stability of the operating income variable is statistically significant in six of the twelve samples we studied. On the other hand, the beta is never statistically significant, and the standard deviation of the analysts' five-year growth forecasts is statistically significant in only two of our twelve samples. This evidence is far from conclusive, however, because, as we demonstrate later, a significant degree of cross-correlation among our four risk variables makes any general inference about risk extremely hazardous.

Possible Misspecification of Risk

The stock valuation theory says nothing about which risk variables are most important to investors. Therefore, we need to consider the possibility that the risk variables of our study are only proxies for the "true" risk variables used by investors. The inclusion of proxy variables may increase the variance of the parameters of most concern, which in this case are the coefficients of the growth variables.[4]

To allow for the possibility that the use of risk proxies has caused us to draw incorrect conclusions concerning the relative importance of analysts' growth forecasts and historical growth extrapolations, we have also estimated Equation (4) with the risk variables excluded. The results of these regressions are shown in Table 3.

Again, there is overwhelming evidence that the consensus analysts' growth forecast is superior to the historically oriented growth measures in predicting the firm's stock price. The R^2 and t-statistics are higher in every case.

CONCLUSION

The relationship between growth expectations and share prices is important in several major areas of finance. The data base of analysts' growth forecasts collected by Lynch, Jones & Ryan provides a unique opportunity to test the hypothesis that investors rely more heavily on analysts' growth forecasts than on historical growth extrapolations in making security buy-and-sell decisions. With the help of this data base, our studies affirm the superiority of analysts' forecasts over simple historical growth extrapolations in the stock price formation process. Indirectly, this finding lends support to the use of valuation models whose input includes expected growth rates.

[1] We also tried several other definitions of "earnings," including the firm's most recent primary earnings per share prior to any extraordinary items or discontinued operations. As our results were insensitive to reasonable alternative definitions of "earnings" we report only the results for the IBES consensus.

[2] For the latest year, we actually employed a point-to-point growth calculation because there were only two available observations.

[3] We use the word "approximately," because the set of available firms varied each year. In any case, the number varied only from zero to three firms on either side of the figures cited here.

[4] See Maddala (1977).

TABLE 3

Regression Results
Model II

Part A: *Historical*

$P/E = a_0 + a_1 D/E + a_2 g_h$

Year	$\hat{a}_0$	$\hat{a}_1$	$\hat{a}_2$	R^2	F Ratio
1981	−1.05	9.59	21.20	0.73	82.95
	(1.61)	(12.13)	(7.05)		
1982	0.54	8.92	12.18	0.83	167.97
	(1.38)	(17.73)	(6.95)		
1983	−0.75	8.92	12.18	0.77	107.82
	(1.13)	(12.38)	(7.94)		

Part B: *Analysis*

$P/E + a_0 + a_1 D/E + a_2 g_a$

Year	$\hat{a}_0$	$\hat{a}_1$	$\hat{a}_2$	R^2	F Ratio
1981	3.96	10.07	60.53	0.90	274.16
	(8.31)	(8.31)	(20.91)	(15.79)	
1982	−1.75	9.19	44.92	0.88	246.36
	(4.00)	(4.00)	(21.35)	(11.06)	
1983	−4.97	10.95	82.02	0.83	168.28
	(6.93)	(6.93)	(15.93)	(11.02)	

Notes:

* Coefficient is significant at the 5% level (using a one-tailed test) and has the correct sign. T-statistic in parentheses.

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On the Use of Consensus Forecasts of Growth in the Constant Growth Model: The Case of Electric Utilities

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■ The constant growth model is often used for estimating the cost of equity capital in utility rate setting proceedings. A major source of controversy over the cost of equity is the method used to estimate the model's projected growth variable. (See, for example, [23, 24, 36] for a discussion of several technical aspects related to the estimation of the dividend yield component in the constant growth model.) The best estimate of projected growth is assumed to be one that incorporates all information regarding future growth contained in alternative growth proxies. In recent years, utility commissions and researchers have been more receptive to consensus financial analyst's forecasts (FAF's) of growth as opposed to historical growth rates as the basis for the growth variable estimate (e.g., [5], [10], [12], and [21]).[1] A consensus forecast should incorporate the information contained in alternative forecasts and therefore provide the most appropriate estimate for rate of return regulation and research. (Motivation for the use of a consensus growth estimate is provided by the forecasting literature that examines the benefits of combined forecasts, e.g., [18, 19, 26].)

Here the informational content of the increasingly popular consensus forecast provided by Lynch, Jones, and Ryan's *Institutional Brokers Estimate System* (I/B/E/S)

Our thanks to Louis Ederington and two anonymous referees for their valuable comments. All remaining errors are the responsibility of the authors. We wish to also thank the Center for the Study of Regulated Industry at Georgia State University for financial support; to Lynch, Jones, and Ryan for providing the I/B/E/S data through an academic research grant; and to Salomon Brothers, Inc. for also providing data.

[1]There is a growing body of literature demonstrating the superiority of FAF's relative to naive forecasts (e.g. [6, 7, 14]) and that the revision of FAF's conveys information to investors (e.g. [1, 11, 15, 16]). See [17] for an in-depth review of this literature.

is examined relative to the frequently used alternative forecasts by Salomon Brothers, Inc. and Value Line. In comparing the relative informational content of FAF's, this adds to previous research (e.g., [8, 30, 37, 38]) that has to date only examined the use of FAF's versus historical growth rates as estimates of the growth rate in the constant growth model. For completeness, historical growth estimates are also examined. The analysis is performed for a group of electric utilities over 1982–1986. Electric utilities are commonly the focus of applied academic research (e.g., [4, 5, 21, 28, 29, 30, 37, 38]), and the constant growth model is frequently used in electric utilities' rate setting proceedings.

The results of the analyses for the sample utilities show the following:

(i) There generally are large size differences between both the various FAF's and between the FAF's and historical growth rates;

(ii) Neither the consensus I/B/E/S forecast nor the FAF forecasts by Salomon Brothers and Value Line contain by itself all the information included in the other FAF forecasts; and

(iii) FAF-based growth rates contain all the information found in historical growth rates.

The study's primary conclusion is that although a consensus FAF can be formed to contain all the information incorporated in alternative analysts', forecasts, and historical growth rates, the construction of the consensus forecast requires the judicious choice of the weight to be assigned to each forecast. More generally, the results suggest that the informational content of forecasts used as proxies for investor expectations should be compared using a methodology similar to this study's before being accepted in research and regulatory proceedings.

I. Hypothesis, Model, and Methodology

A. The Hypothesis

The standard constant growth model states,

$$k = \frac{D_0(1 + g)}{P_0} + g. \qquad (1)$$

where,

P_0 = current stock price,
D_0 = current dividend per share,
g = expected constant growth rate of dividends, and
k = required rate of return on equity.

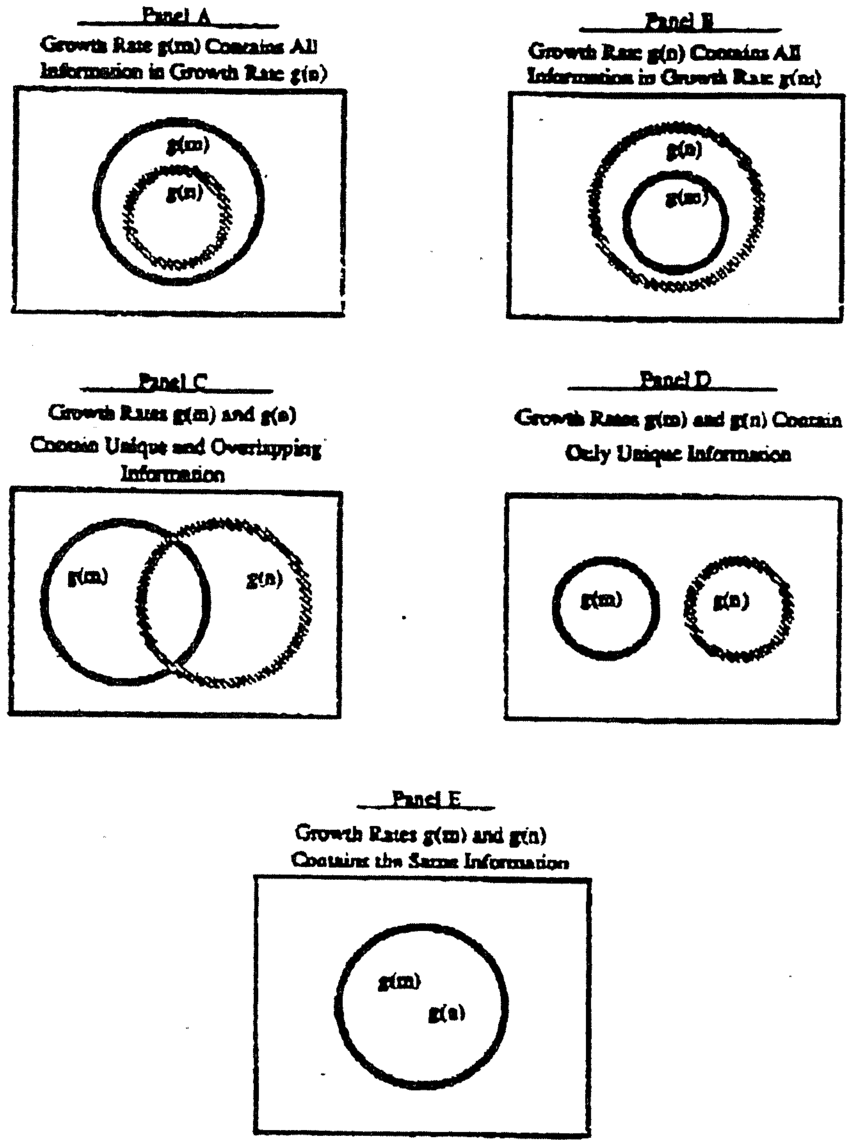
The estimate of the constant growth rate chosen for Equation (1) ideally contains all the information regarding the valuation of equity capital included in all other alternative growth estimates. This concept is depicted graphically in Exhibit 1, which compares the relative informational content of two growth estimates, $g(m)$ and $g(n)$. For exposition purposes, it is assumed that $g(m)$ and $g(n)$ are the only two growth estimates available to investors. However, the analysis can be easily extended to the joint comparison of more than two growth estimates.

In Exhibit 1, the solid-lined circle encompasses all the information included in $g(m)$ and the broken-lined circle all the information in $g(n)$, which investors incorporate into stock prices. Panel A depicts a scenario in which $g(m)$ contains all the information incorporated in $g(n)$, and $g(n)$ does not contain all the information in $g(m)$. As a result, $g(m)$ should be wholly used to estimate the growth component in Equation (1). Panel B depicts an opposite scenario in which $g(n)$ should be used instead of $g(m)$ as a proxy. In Panel C neither growth estimate contains all the information found in the other, although there is some overlap of information as shown by the shaded area of intersection. In Panel D, both estimates contain unique information; there is no common information. Because neither forecast in Panels C and D contains all the information included in the other, some type of average of $g(m)$ and $g(n)$ should be used as the growth estimate. Finally, in Panel E both $g(m)$ and $g(n)$ contain exactly the same information found in the other. In this case, $g(m)$ and $g(n)$ should be equal and either could be used as an estimate of growth.

B. The Model

The growth estimate's relative informational content is tested using the model developed in the works by Malkiel [27] and Cragg and Malkiel [8]. In their research on expectations and valuation, Cragg and Malkiel constructed a linear price-earnings model that approximates a dividend growth model, such as Equation (1) (see their equations 3.3-13 and 3.3-14, 3.3-18, and 4.4-1). The linear price-earnings model is stated as follows:

Exhibit 1. Graphical Depiction of Growth Estimates' Relative Informational Content



$$\frac{P_0}{E_0} = \alpha + \beta_1 \frac{D_0}{E_0} + \beta_2 g + \Sigma \alpha_i RISK_i + \epsilon . \qquad (2)$$

That is, the price-earnings is a linear function of a constant, plus the dividend payout ratio factor, expected future growth factor, and a series of risk factors. In Equation (2), $RISK_i$ is the ith measure of risk associated with the cost of equity k, and ϵ is an error term. Malkiel [27] and more recently Vander Weide and Carleton [37, 38] found that the linear specification in Equation (2) is a fairly robust approximation of the true nonlinear price-earning ratio model which can be derived from Equation (1) and, therefore, is useful for examining alternative proxies for growth. The specific measures of risk used in Equation (2) are discussed in Section II. However, to facilitate the presentation of the paper's methodology, the sources of the growth estimates are discussed first.

C. The Growth Estimates

Five end-of-the-year growth estimates were collected for a group of 62 electric utilities for December 1982 through December 1986. The selection criteria are discussed in Section II. The growth rates are:

GIBES = mean 5-year financial analysts' consensus earnings growth forecast available through Lynch, Jones, and Ryan's *Institutional Brokers Estimate System* (I/B/E/S);[2]

GSB = The projected 5-year normalized growth rate forecasted by Salomon Brothers, Inc. in their publication *Electric Utility Monthly*;

GVLD = The 3 to 5-year forecasted growth in dividends per share as reported in the *Value Line Investment Survey*;

GVLE = The 3 to 5-year forecasted growth in earnings per share as reported in the *Value Line Investment Survey*; and

GHD5 = The 5-year log-linear historical growth in dividends paid per share.[3]

The financial analysts' forecasts GIBES, GSB, GVLD, and GVLE are included in the study for several reasons. First, these growth estimates have been used in previous research to examine electric utilities' cost of equity (e.g., [5, 21]) and are frequently used in rate setting proceedings. Second, for the five years examined in this study, this set of growth estimates permits an appreciably larger sample of utilities than do sets of these estimates combined with other growth estimates (e.g., Merrill Lynch) also available to the authors. Third, although the model in Equation (2) specifies dividend growth, this study uses both dividend and earnings estimates. Theoretically, dividends and earnings per share growth are identical in the constant growth model, and from a practical viewpoint, financial analysts focus on earnings and, therefore, earnings per share data are more readily available. Finally, the historical growth rate GHD5 is included to provide additional insights into the use of analysts' versus historical growth rates. See also [8, 29, 30, 37, 38] for an examination of the use of historical growth rates to estimate the cost of equity.

D. Methodology

The model in Equation (2) is initially estimated using each growth forecast to test hypotheses that each forecast contains all the information contained in all other forecasts. Later, the model in Equation (2) is used to examine the relative informational content of various combinations of forecasts. Similar to all empirical valuation models, a caveat of these tests is that they are really joint tests of each growth rate's informational content and that investors price equity securities in a manner consistent with Equation (2). Maintaining that investors follow Equation (2) in setting security prices, the hypotheses regarding the alternative growth forecasts' informational content are tested using the following variation of Equation (2):

$$\frac{P_0}{E_0} = \varphi + \beta_1 \frac{D_0}{E_0} + \beta_2^{*} g(m) + \beta_2^{**} g(n) + \Sigma\, \alpha_i RISK_i + \epsilon, \qquad (3)$$

for

m and n = GIBES, GSB, GVLD, GVLE, and GHD5, but $m \neq n$.

The informational content of each growth estimate, as depicted in Exhibit 1, is tested by performing pairwise likelihood ratio tests using Equations (2) and (3). See Maddala [25] for details on tests using likelihood ratios. In performing the tests, the basic approach is to compare $g(m)$ and $g(n)$ via two tests. In the first test, Equation (2) is estimated using $g(m)$ and Equation (3) is estimated using $g(m)$ and $g(n)$. The overall fit of Equation (2), as measured by the log of the likelihood function, is then tested against the overall fit of Equation (3). As an example, suppose the test statistic is significant. This indicates that $g(n)$ contains some information not found in $g(m)$. The second test involves estimating Equation (2) using $g(n)$ and comparing its overall fit to Equation (3), again estimated using $g(m)$ and $g(n)$. If the test statistic from the second test is insignificant, then $g(m)$ does not contain any information not already incorporated in $g(n)$. In this case, these results would suggest that $g(n)$ is a better proxy for investor expectations than $g(m)$, again maintaining that

[2] Use of the I/B/E/S median as opposed to the mean growth forecasts does not alter the study's findings. These results are available from the authors.

[3] Five-year historical growth in earnings per share was also examined. The results for the 5-year historical earnings growth rate show it never contains information not already incorporated in the FAF growth estimates, and that the FAF growth estimates always contain significantly more information than the 5-year historical earnings growth rates. In the interest of space these results are not presented but are available from the authors.

Exhibit 2. Possible Outcomes of Pairwise Likelihood Ratio Tests of the Informational Content of Two Alternative Constant Growth Estimates, $g(m)$ and $g(n)$.

Test No.[1]	Significant	Relative Importance
1	Yes	Growth rate $g(m)$ contains all the information in $g(n)$ plus some additional information. See Panel A, Exhibit 1. Growth rate $g(m)$ should be used as an estimate of the constant growth rate.
2	No	
1	No	Growth rate $g(n)$ contains all the information in $g(m)$ plus some additional information. See Panel B, Exhibit 1. Growth rate $g(n)$ should be used as an estimate of the constant growth rate.
2	Yes	
1	Yes	The growth rates $g(m)$ and $g(n)$ contain both unique and overlapping information, or only unique information. See Panels C and D, Exhibit 1. A combination of $g(m)$ and $g(n)$ should be used as an estimate of the constant growth rate.
2	Yes	
1	No	The growth rates $g(m)$ and $g(n)$ contain the same information. See Panel E, Exhibit 1. Either growth rate can be used as an estimate of the constant growth rate.
2	No	

[1]Using Equations (2) and (3). Test No. 1 tests the informational content of $g(m)$ relative to $g(n)$. Test No. 2 tests the informational content of $g(n)$ relative to $g(m)$.

investors follow Equation (2) in setting stock prices. Four outcomes are possible when performing the pairwise likelihood ratio tests using Equations (2) and (3). These outcomes and their interpretation as they relate to the growth estimates' relative informational content are summarized in Exhibit 2.

Exhibit 3. Listing of Electric Utility Companies in Sample

Allegheny Power	Louisville Gas & Elec.
American Elec. Pwr.	MDU Resource Group
Atlantic City Elec.	Minnesota Pwr. & Lt.
Baltimore Gas & Elec.	Nevada Power Co.
Boston Edison	New England Electric
Carolina Pwr. & Lt.	Northeast Utilities
Central & South West	Northern States Power
Central Ill. Pub. Svc.	Ohio Edison
Cilcorp	Oklahoma Gas & Electric
Commonwealth Edison	Orange & Rockland Util.
Commonwealth Energy	Otter Tail Power
Consolidated Edison	PacifiCorp
Dayton Pwr. & Lt.	Pacific Gas & Elec.
Delmarva Pwr. & Lt.	Penn. Pwr. & Lt.
Detroit Edison	Portland General Corp.
Duke Power Co.	Potomac Electric Pwr.
Eastern Utilities	Public Service Ent. Group
El Paso Electric	Public Service New Mexico
Empire District Electric	Puget Sound Pwr. & Lt.
FPL Group	San Diego Gas & Elec..
Hawaiian Electric	Savannah Electric
Houston Industries	Southern Calf. Edison
Idaho Power Co.	Southern Ind. Gas & Elec.
Illinois Power Co.	Southern Company
Interstate Power	TECO Energy
Iowa Electric Lt. & Pwr.	Texas Utilities
Iowa Resources Inc.	Tucson Electric Pwr.
Iowa Southern Utilities	Union Electric
Ipalco Enterprises	Utah Pwr & Lt.
Kansas Pwr. & Lt.	Wisconsin Pwr. & Lt.
Kentucky Utilities	Wisconsin Public Service

II. The Data

A. The Companies

End-of-the year data were collected for 1982–1986 for a sample of investor-owned electric utilities operating in the United States. Several different criteria are imposed in the selection of the sample companies. First, the sample comprises companies for which data are available through I/B/E/S, Salomon Brothers, Inc.'s *Electric Utility Monthly*, and the *Value Line Investment Survey* for each of the five years in the study, and each year's forecasted growth rates are positive for each source. Second, companies were excluded which experienced negative historical dividend growth over 1982–1986 except through stock splits and stock dividends. These criteria exclude companies for which it is believed the constant growth model is not appropriate, since in practice the model is not used to estimate the cost of equity for companies with negative growth rates. Excluded companies are primarily those which have exhibited considerable financial burdens due to nuclear construction programs (e.g., Long Island Lighting, Public Service Indiana, and Public Service New Hampshire). Third, to avoid possible distortions, sample companies are required to have a fiscal year ending December 31. Imposing these criteria results in the sample of 62 utilities listed in Exhibit 3.

B. The Risk Variables

A large number of variables have been used in research and regulatory proceedings to characterize electric utilities' equity risk. (Cragg and Malkiel [8] used risk measures such as equity beta and the variance of the long-term growth forecast [chapter 4], and Vander Weide and Carleton [37, 38] used the firm's pre-tax interest coverage ratio and the stability of the firm's five-year historical earnings per share among others.) The risk measures, $RISK_i$ in Equations (2) and (3), used in this study are defined below.

BETA = The company's equity beta.

BOND1, *BOND2*, and *BOND3* = A dummy variable for the Moody's bond rating. If a company has either an "Aaa" or "Aa" rating, *BOND1* is assigned a value of 1 and *BOND2* and *BOND3* values of 0. For an "A" rating, *BOND2* is assigned a value of 1 and *BOND1* and *BOND3* values of 0. Finally, for a company with a "Baa" rating, *BOND3* is assigned a value of 1 and *BOND1* and *BOND2* values of 0.

NUKE = A dummy variable for the company's nuclear status. *NUKE* is assigned a value of 0 if the company did not exhibit significant nuclear construction/regulatory risk during the 1982–1986 sample period. *NUKE* is assigned a value of 1 if the company did exhibit significant nuclear related construction/regulatory risk during the sample period. The source of data for *NUKE* is discussed below.

A primary consideration in the choice of these risk variables is that they have all been used in academic studies to characterize equity risk.[4] Beta is widely used as a measure of systematic risk, and its theoretical underpinnings are well-known.[5] Studies have shown that bond ratings incorporate numerous measures of risk (e.g., [9, 31, 32]) and that bond ratings are significantly correlated with equity returns (e.g. [20, 33, 39]). The importance of nuclear risk for capital costs became apparent with the Three Mile Island accident on March 28, 1979. Studies have shown that as a result of the accident, both bond risk premiums [2] and stock prices ([3, 22]) for the entire electric utility industry reflected an increased perception of risk, with the risk effect being the greatest for firms with significant nuclear exposure.

C. Data Sources

The sources of data for the growth estimates were described in Section I. The dependent variable P_0/E_0 in Equations (2) and (3) is the end-of-year price-earnings ratio. It equals the closing price on the last trading day of each year divided by earnings per share normalized for the effects of extraordinary items and discontinued operations.[6] Three proxies were used for normalized earnings. They are the estimates for the forthcoming year of primary earning per share before extraordinary items and discontinued operations provided by I/B/E/S, Salomon Brothers, and Value Line.[7] The dividend payout ratio D_0/E_0 equals the end-of-year indicated dividend per share, divided by the proxy for normalized earnings per share. Dividends also exclude the payment of special dividends. The source of data for dividends is *Electric Utility Monthly*. The source of data for BETA is the *Value Line Investment Survey* and bond rating data are obtained from *Moody's Bond Record*. Finally the data for the risk variable NUKE are from various Salomon Brothers publications (e.g., [34]). In these

[4] In an earlier version of this paper, various accounting measures (e.g., debt-to-equity and times-interest-earned) were used, as well as the dispersion of the analysts' forecasts, as measures of equity risk. The results using these measures are consistent with the conclusions associated with the results reported in this paper, that the consensus I/B/E/S consensus forecast does not contain all relevant information and the construction of a consensus forecast requires the judicious choice of the weight to be assigned each analyst's forecast. The authors prefer usage of BETA, BOND, and NUKE because of their intuitive appeal and their apparent ability to parsimoniously represent the information contained in the other risk measures.

[5] The authors acknowledge that the use of beta to estimate utilities' cost of equity capital continues to be debated in the literature (e.g., [4] and the comments and replies in earlier issues of this journal).

[6] As pointed out by a referee, a caveat to this paper's analyses relates to the comparability of utilities' earnings per share both across companies and through time. The level and quality of earnings may vary across companies due to, for example, differing treatment of allowances for funds used during construction (AFUDC) and the tax effects of normalization versus flow-through accounting (e.g., the treatment of depreciation, tax deferrals, and investment tax credits). Earnings per share may not be directly comparable across time due to changes in accounting conventions. In SFAS 90, for example, it was decided during this study's sample period that plant abandonment and disallowances were no longer extraordinary items for regulated utilities.

Exhibit 4. Mean Values and Standard Deviations (in parentheses) for Sample Utilities[1]

	1982		1983		1984		1985		1986	
	Non-Nuclear Group	Nuclear Group	Non-Nuclear Group	Nuclear Group	Non-Nuclear Group	Nuclear Group	Non-Nuclear Group	Nuclear Group	Non-Nuclear Group	Nuclear Group
P/E[2]	6.98 (0.82)	6.78 (1.45)	7.09 (1.06)	6.02 (0.93)	7.41 (1.07)	6.42 (0.70)	9.19 (1.03)	7.42 (0.90)	11.45 (1.10)	9.11 (1.31)
GIBES	5.23% (1.15%)	5.17% (1.33%)	5.14% (1.29%)	4.99% (0.95%)	4.90% (1.22%)	4.40% (1.23%)	4.67% (1.15%)	4.38% (1.11%)	4.64% (1.05%)	3.94% (1.18%)
GVLD	5.89 (2.62)	6.16 (2.33)	5.69 (2.50)	5.09 (1.78)	5.66 (2.62)	4.91 (1.49)	5.53 (2.23)	4.96 (1.58)	4.99 (2.05)	4.30 (1.72)
GVLE	6.30 (2.19)	6.50 (1.44)	5.65 (2.12)	5.64 (1.91)	5.54 (2.72)	4.75 (1.67)	4.93 (1.95)	4.43 (1.90)	4.44 (1.55)	3.45 (1.90)
GSB	6.35 (1.34)	6.05 (1.25)	6.31 (1.25)	5.81 (1.25)	6.33 (1.44)	5.30 (1.23)	5.93 (1.28)	5.05 (1.13)	5.61 (1.23)	4.71 (1.17)
GH5D	6.18 (3.79)	5.70 (3.38)	6.07 (2.86)	5.69 (3.05)	6.03 (2.77)	5.51 (2.56)	5.94 (2.91)	5.22 (2.27)	5.68 (3.03)	4.68 (2.38)

[1]The growth rates are defined as follows: GIBES, the mean I/B/E/S consensus five-year earnings forecast; GSB, the Salomon Brothers' projected 5-year normalized growth; GVLD, the Value Line 3 to 5-year forecasted growth in dividends; GVLE, the Value Line 3 to 5-year forecasted growth in earnings; and GHD5, 5-year historical growth in dividends.

[2]The price-earnings ratio is calculated for each company using the year-ending closing price divided by the I/B/E/S consensus estimate of primary earnings per share before extraordinary items and discontinued operations for the forthcoming year.

publications, Salomon Brothers categorizes electric utilities into two groups—those with (NUKE = 1) and those without (NUKE = 0) significant nuclear risk based upon the utilities' investment in nuclear construction relative to the value of equity and other factors.

[7]Fortunately, the various sources of projected earnings per share and forecasted growth rates exhibited only slight correlation. Regressing the projected earnings per share on forecasted growth resulted in an average adjusted R-square of approximately 0.15. Thus, the effects of spurious correlation in the regression analysis presented in this paper should be minimal.

The tests were also conducted using several other definitions of earnings per share, including the most recent reported twelve-month earnings per share, which, as of the end of December was for the period from October of the previous year through September of the current year. Assuming perfect foresight, normalized earnings were also defined in an earlier version of this paper as the annual primary earning per share actually reported for the current year. These earnings are generally not available until February or March of the following year. The conclusions drawn from the use of all of these alternative definitions of earnings per share are the same as those reported in this paper. The empirical results using these alternative definitions are available from the authors upon request.

III. Empirical Results

A. Summary Statistics

Exhibit 4 reports the means and standard deviations of the price-earnings ratios and all growth estimates for each year in the study. For comparative purposes the data are reported by nuclear risk classification, i.e., for the Nonnuclear Group the risk variable NUKE = 0 and for the Nuclear Group NUKE = 1. Of particular interest is the appreciable difference between the various FAF's for each group. For example, GSB generally exceeds GIBES for both groups. The difference, approximately 100 basis points, is statistically and potentially economically significant in all years.[8] For example,

[8]For each year statistical tests were conducted to test whether each pair of forecasts was significantly different. These results are available upon request.

Exhibit 5. Estimates of Regression Coefficients for the Price-Earnings Model Using Equation (4)[a]

Variable	Regression Coefficient	Growth Estimate Used in Regression: GIBES	GSB	GVLD	GVLE	GHDS
Constant	φ_1	3.09*	-0.99	1.47	3.29*	3.49*
		(0.92)	(0.99)	(0.87)	(0.85)	(0.80)
YR83	φ_2	-0.17	-0.13	-0.09	-0.10	-0.19
		(0.16)	(0.14)	(0.15)	(0.16)	(0.15)
YR84	φ_3	0.38#	0.47*	0.43*	0.41*	0.28
		(0.16)	(0.15)	(0.17)	(0.16)	(0.15)
YR85	φ_4	1.74*	1.97*	1.72*	1.80*	1.62*
		(0.17)	(0.15)	(0.15)	(0.16)	(0.16)
YR86	φ_5	3.68*	3.96*	3.70*	3.80*	3.56*
		(0.17)	(0.16)	(0.15)	(0.17)	(0.16)
D_1/E_0	β_1	6.99*	9.51*	8.84*	6.99*	6.95*
		(0.63)	(0.66)	(0.66)	(0.59)	(0.57)
g	β_2	24.01*	51.37*	22.80*	15.11*	11.70*
		(5.46)	(5.71)	(2.93)	(2.84)	(1.92)
BETA	α_1	-2.40#	-2.23#	-2.06#	-2.14#	-2.19#
		(1.03)	(0.94)	(0.97)	(1.02)	(1.00)
NUKE	α_2	-0.84*	-0.63*	-0.79*	-0.83*	-0.87*
		(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
BOND2	α_3	-0.49*	-0.28*	-0.50*	-0.61*	-0.41*
		(0.11)	(0.10)	(0.10)	(0.11)	(0.11)
BOND3	α_4	-1.12*	-0.62*	-1.19*	-1.32*	-1.04*
		(0.17)	(0.17)	(0.16)	(0.17)	(0.17)
Logged Likelihood Function		-388.79	-361.35	-369.86	-384.57	-380.45
Adjusted R^2		0.80	0.83	0.82	0.80	0.80

[a]Standard errors in parentheses.

*Significant at the 0.01 level.

#Significant at the 0.05 level.

a 100 basis point difference in the recommended cost of equity translates into a change in revenue requirements in excess of $2.0 billion per year for the electric utility industry.[9]

B. Estimation

The models in Equations (2) and (3) are estimated by pooling the data across companies and time periods. As is common when pooling cross-section and time-series data, dummy variables are also added to allow the intercept term to vary for each year (e.g., see Maddala [25, Chapter 14]). The dummy variables are included to allow for yearly changes in variables, such as general capital market conditions and investor behavior, which are not explicitly included in Equations (2) and (3), and are maintained to result in an additive shift in the overall level of all firms' price-earnings ratios. With the inclusion of the time dummy variables and the risk variables discussed in Section II, the final formulation of Equation (2) is

$$\frac{P_0}{E_0} = \varphi_1 + \varphi_2\, YR83 + \varphi_3\, YR84 + \varphi_4\, YR85 + \varphi_5\, YR86 + \beta_1 \frac{D_0}{E_0} + \beta_2 g + \alpha_1\, BETA + \alpha_2\, NUKE + \alpha_3\, BOND2 + \alpha_4\, BOND3 + \epsilon . \tag{4}$$

where,

$YR83$ = 1 if 1983, 0 otherwise;
$YR84$ = 1 if 1984, 0 otherwise;
$YR85$ = 1 if 1985, 0 otherwise;
$YR86$ = 1 if 1986, 0 otherwise; and

all other variables are as previously defined.

A reformulation similar to Equation (4) is also applied to Equation (3).

The regression model in Equation (4) is structured such that the intercept term, φ_1, captures the combined effects of a utility with either a "Aaa" or "Aa" bond rating, BOND1 = 1, and a company with no nuclear risk, NUKE = 0. Therefore, the bond rating regression parameters α_3 and α_4 measure, respectively, the mean differences between the price-earnings ratio P_0/E_0 of utilities with "A" and "Baa" rated bonds relative to those with "Aaa" or "Aa" rated bonds holding all else constant. Likewise, the regression parameter α_2 measures the differences between the mean price-earnings ratios of utilities with nuclear risk relative to companies without such risk, again holding all other factors constant.

C. The Results

Exhibit 5 reports selected statistics from estimation of Equation (4) using each of the growth estimates and the I/B/E/S proxy for normalized earnings per share.[10] Only the results using the I/B/E/S proxy for normalized earnings are reported since the conclusions drawn from the empirical findings are the same regardless of the proxy for normalized earnings.[11] The results in Exhibit 5 indicate that Equation (4) is a reasonable model of the electric utilities' price-earning ratios with the signs of all the estimated regression coefficients as expected. For example, β_2 shows that utilities with higher expected growth rates, holding all else constant, have higher price-earnings ratios. Also, the negative coefficient for α_2 indicates that utilities with significant nuclear risk have, on average, price-earnings ratios approximately 0.90 lower than utilities without such risk. The negative coefficients for α_3 and α_4, for "A" and "Baa" rated bonds, respectively, indicate that utilities with lower bond ratings exhibit lower price-earnings ratios (approximately 0.5 lower for "A" and 1.0 lower for "Baa" rated bonds). The results also show that the regression coefficient α_1 for BETA is, as expected, negatively related to the price-earnings ratio. Finally, the coefficients for the yearly dummy variables are consistent with the significantly upward trend in the sample companies' price-earnings ratios over the sample period (see summary statistics for P/E ratio in Exhibit 4).

Exhibit 6 reports the calculated pairwise likelihood ratio tests and is arranged such that the calculated likelihood ratios correspond to tests of the informational content of the growth estimates in Column 1 relative to the growth estimates in Columns 2 through 6. The results in Exhibit 6 show that when the informational content of GIBES is tested relative to all other growth estimates, all calculated likelihood ratios are significant at the 0.01 level (see Row 1). (Because of the serious economic consequences which could result from the incorrect rejection of the null hypotheses and the large number of pairwise tests, the probability of Type I error is set at 0.01.) For example, when the

[9]Salomon Brothers [35] reports $133 billion of common equity outstanding as of June 30, 1986 for their 100 Electric Utilities. Using a marginal tax rate of 40% (federal and state), a 100 basis point difference in the recommended cost of equity would translate into a $2.22 billion [($133 billion × 1%)/(1 - 40%)] difference in annual revenue requirements.

[10]The regression estimates for the reformulated version of Equation (4) are available upon request.

[11]The results using the Salomon Brothers and Value Line proxy for normalized earnings are available upon request.

Exhibit 6. Pairwise Likelihood Ratio Tests of the Informational Content of Alternative Proxies for Growth Rate in the Constant Growth Model[1]

		Calculated Likelihood Ratio Tests[2]				
		GIBES	GSB	GVLD	GVLE	GHD5
	(1)	(2)	(3)	(4)	(5)	(6)
(1)	GIBES	N/A	56.32*	40.20*	11.72*	17.80*
(2)	GSB	1.44	N/A	8.12*	10.48*	1.42
(3)	GVLD	2.34	25.14*	N/A	3.78	2.18
(4)	GVLE	3.28	56.92*	33.20*	N/A	25.44*
(5)	GHD5	7.12*	39.62*	23.36*	17.20*	N/A

*Significant at the 0.01 level.

[1]The growth rates are defined as follows: GIBES, the mean I/B/E/S consensus 5-year earnings forecast; GSB, the Salomon Brothers' projected 5-year normalized growth; GVLD, the Value Line 3 to 5-year forecasted growth in dividends; GVLE, the Value Line 3 to 5-year forecasted growth in earnings; and GHD5, 5-year historical growth in dividends.

[2]Significant likelihood ratio tests indicate that the growth rate in Columns (2)–(6) contains information not incorporated in the growth rate in Column (1). The ratio tests are chi-squared distributed with 1 degree of freedom. The critical test values are 3.84 at the 0.05 level of significance, and 6.63 at the 0.01 level.

informational content of GIBES is compared to the Salomon Brothers growth rate, GSB, the calculated likelihood ratio equals 56.32 (see Row 1, Column 3) which is highly significant, indicating that GSB contains information not incorporated in GIBES. Conversely, when the informational content of all the other growth estimates is tested relative to GIBES (see Column 2), only GHD5 is significant. For example, when testing the hypothesis that GIBES contains information not found in GSB, the calculated likelihood ratio equals 1.44 (see Row 2, Column 2), which is insignificant. This suggests that the I/B/E/S growth estimate does not contain any information not already found in GSB. The overall results indicate that all alternative growth estimates contained information not incorporated in GIBES (Row 1), whereas GIBES only contained some information not in GHD5 (Column 2). Consequently, maintaining that Equation (2) represents investors' pricing behavior for the sample utilities, the results suggest that GIBES was not the best proxy.

If the set of all possible growth estimates is restricted to only those analyzed in this study, the results suggest that for the sample utilities, investor expectations are best proxied from some combination of GSB and GVLD. The hypothesis that GSB contained all information included in other growth rates is rejected when tested relative to GVLE and GVLD, whereas the hypotheses for all growth rates are rejected when tested relative to GSB. In addition, the hypothesis that GVLE includes all information is rejected when tested against all other growth estimates including GVLD, whereas the hypothesis the GVLD contains all information is not rejected when tested against GVLE. This finding provides supports, therefore, for the use of some type of combined financial analyst forecast for estimating the constant growth term.[12]

Additional analyses were performed comparing the combined informational content of GSB and GVLD relative to the information contained in various combinations of GIBES, GVLE, and GHD5. When testing the hypothesis that the combination of GSB and GVLD contains more information than the combinations of *(i)* GIBES and GVLE, *(ii)* GIBES and GHD5, and *(iii)* GVLE and GHD5, the calculated likelihood ratios are 56.66, 39.56, and 34.28, respectively, which are all highly significant. In testing the hypotheses that these three combined forecasts contain information not already incorporated in GSB and GVLD, all likelihood ratio tests were insignificant. As an additional test, the hypothesis that the combination of GSB and GVLD contains more information than the combination of GIBES, GVLE, and GHD5 was also tested resulting in a likelihood ratio of 34.10, which is again highly significant. Finally, the combination of GIBES, GVLE, and GHD5 was found not to contain any information in addition to that incorporated in GSB and GVLD.

D. Performance of the I/B/E/S Consensus Forecast

The performance of the consensus forecast, GIBES, is possibly explained by several factors. First, GIBES

[12]Insights into the weights to assign to GSB and GVLD to derive the optimal growth estimate, g^*, are provided from the estimated regression coefficients, β_2^* for GSB and β_2^{**} for GVLD, from the reformulated version of Equation (4) by letting $g^* = wGSB + (1 - w)GVLD$ and maintaining the hypothesis that $\beta_2^* = w\beta_2$ and $\beta_2^{**} = (1 - w)\beta_2$. The estimate for w is $(\beta_2^*/\beta_2^{**})/(1 + \beta_2^*/\beta_2^{**})$. The estimated coefficients for β_2^* and β_2^{**} equal 37.54 and 10.50, respectively, resulting in an estimate of w of approximately 80% for GSB and 20% $(1 - w)$ for GVLD.

equally weights each individual analyst's forecast to obtain the consensus forecast. However, studies (e.g., [13, 19]) of other economic variables indicate that in an optimal forecast the weights assigned to individual forecasts are usually unequal. Since GSB and GVLE are often included in the derivation of GIBES, the results suggest that it may be that the equal weighting scheme is suboptimal. Furthermore, the finding that an individual forecast such as GSB comes close to including all information found in the other forecasts is consistent with the findings in the other studies (e.g., [16, 26]) that have examined forecasts of macroeconomic variables. These studies show that in cases where the combined forecast is derived using incorrect weights, it is possible for a good individual forecast to actually outperform the combined forecast.

Another possible limitation of the I/B/E/S consensus data which has been noted in the literature (e.g., [17, 21]) is that the forecasts contained in the I/B/E/S consensus forecast may not represent each source's most recent forecast. To the extent that there is a lag in collecting the most recent forecasts, GIBES may not incorporate all relevant current information.

The I/B/E/S data used in this study were usually made publicly available the Thursday of the third week of December. The Salomon Brothers forecast, GSB, was prepared at the end of each November and was published in the *Electric Utility Monthly* usually within the first week of December. Since this study uses end-of-month December price and earnings data, the published GSB was approximately one month old and may not have represented Salomon Brothers most recent unpublished forecast. (See [1] for an examination of the impact on stock prices from releasing revisions of analysts' forecasts to select clients before making them available to the general public.) Also, for some of the utilities in the sample the Value Line forecasts were approximately two months old. Hence, considering the timing of the release of the Salomon Brothers and Value Line data, the performance of GIBES relative to GSB and GVLE cannot be fully explained by the possibility that the I/B/E/S consensus data did not contain all the most recent forecasts.[13]

E. Financial Analysts' Forecast vs. Historical Growth

The results in Exhibit 6 also provide additional evidence of the superiority of FAF's over historical growth based forecasts. The results show that all financial analysts' forecasts contain a significant amount of information used by investors in the determination of share prices not found in the historical growth rate GHD5. However, the historical growth rate, GHD5, also contains information not incorporated in GIBES and GVLE.

It seems somewhat paradoxical that the financial analysts' forecasts GIBES and GVLE would not contain all the information found in the readily available historical growth rate GHD5. However both GIBES and GVLE are forecasts of growth in earnings, not dividends. The information incorporated in a rational earnings forecast need not include information found in historical dividend growth, even if such information is incorporated in stock prices, unless historical dividend growth also contains information pertaining to future growth in earnings. However, it would be expected that a rational forecast of future growth in dividends would at least incorporate any information found in historical dividend growth rates. Exhibit 6 shows that the Value Line's forecasted dividend growth rate, GVLD, contains all the information in the historical growth rate, GHD5, and more.

Finally, GSB always contains information not found in GHD5 and GHD5 does not contain information not already incorporated in GSB. Since GSB is, for the sample companies, a part of the appropriate proxy for *g*, the results indicate that an estimate comprised wholly of FAF's is preferable to one based solely on historical growth rates, or a combination of historical growth rates and FAF's. These findings are consistent with those in [8, 37]. However Newbold, Zumwalt, and Kannan [30] compared ARIMA model forecasts to Value Line's, and found that combining forecasts increased forecasting ability.

IV. Summary and Conclusion

Consensus analysts' forecasts are being increasingly used as proxies for investor expectations. Exclusive use of a consensus forecast assumes that it incorporates all information relating to equity valuation contained in alternative proxies. This assumption is of critical im-

[13]As pointed out by a referee, the I/B/E/S consensus growth forecasts are a mixture of both arithmetic and geometric growth rates and, therefore, it may be argued that their comparison to individual analyst's forecasts is unfair. However, as also noted by the referee, such criticism is moot since I/B/E/S forecasts are purchased by analysts, regulators, and companies who use I/B/E/S as an alternative to other forecasts.

portance both in investor research and in regulatory rate setting proceedings where consensus forecasts are often used to establish cost of equity recommendations. Using an approximation to a constant growth valuation model, this study examined the informational content of the commonly used I/B/E/S consensus growth forecast relative to selected individual analyst's forecasts provided by Salomon Brothers and Value Line. Historical growth rates were also examined. The analyses were performed for a group of electric utilities.

Within the limitations of the empirical pricing model used in the study the results indicate, for the sample of utilities examined, that the I/B/E/S consensus forecast did not contain all relevant information. Instead, the selected individual analysts' forecasts consistently contained significant amounts of information not reflected in the consensus data. The results demonstrate that in research and regulatory proceedings, analyses similar to that performed in this study should be conducted to establish the adequacy of forecasts used as proxies for growth. Finally, the results provide additional evidence that historical growth rates are poor proxies for investor expectations: hence, they should not be used to estimate utilities' cost of equity capital.

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FURTHER EVIDENCE ON THE VALUE OF PROFESSIONAL INVESTMENT RESEARCH

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The securities purchase-and-sale recommendations of the professional research staffs of retail brokerage houses represent a potentially important source of information and advice to the individual investor in corporate common stocks. For many investors such recommendations may be the paramount influence on their portfolio decisions, and, therefore, a major determinant of the effectiveness with which they can participate in an equities market that has increasingly come to be dominated by institutional traders. Similarly, competition among brokerage houses for commission revenue business often centers on the proclaimed quality of the various firms' respective research outputs.

The question as to whether there is truly a payoff from devoting resources to producing those outputs, however, has been addressed on a number of occasions in the literature of finance—typically, from the standpoint of the consumer of the product. In that regard, the issue has been the ability of professional securities research to uncover and communicate opportunities for investors to earn above-average portfolio rates of return. The reviews to date are decidedly mixed. Certain investigators have found such research frequently to be of potential value in formulating investment strategies [2, 4, 11, 15, 19], while others have concluded that it is almost entirely without merit [1, 5, 6, 10, 16, 17, 24, 26].

Clearly, individual investors *are* paying for large quantities of this research, either directly through subscriptions to investment advisory services or indirectly in the commissions charged by brokerage firms that supply securities recommendations to their customers. Thus, it appears as though the product is in demand—which, in a private-enterprise economy, is not generally a characteristic thought to be possessed by an item having no value. For that reason, it seems to be appropriate here to take another look at the matter, using some new evidence that provides a rather different perspective than has been available in previous studies. Specifically, this paper shall consider not only the *potential* for individual investors to exploit one of the major categories of professional investment advice to earn superior portfolio returns, but also will examine the *actual* return experiences of a representative sample of investors who were, in fact, observed to trade on such advice.

I. Scope of the Data

The raw materials for the investigation are comprised of several elements of a data base which was compiled for purposes of a broad-scale study of the individual investor in the corporate equity market. One component consists of a file of all the common stock transactions executed between January, 1964, and December, 1970, in a random sample of some 2500 accounts of a large nationwide brokerage house. The account holders were

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all individual, rather than corporate or institutional, customers of the firm. A questionnaire survey of the group revealed it to have a demographic profile which was not only diverse but quite representative of the general population of U.S. common stockholders at the time [12]. Approximately 175,000 separate trades in just under 4,000 different common stocks are included in the file. Full descriptions of both the investor sample and the transaction information can be found in [12, 13, 20, 21].

The second data set contains a complete record of the securities purchase and sale recommendations released to its customers by the cooperating brokerage firm's research department during the same seven-year time period. The release date, the security discussed, and the nature of the investment advice offered were identified for each of the some 6000 recommendations encompassed by that record–directly from the firm's files, rather than from the secondary sources utilized by most previous studies. Details on the composition and character of these recommendations are available in [11].

The last information element is a chronology of the per-share prices and cash dividends of the recommended securities. In addition to the master file developed for the broader study containing monthly price data and dividend amounts and distribution dates, the particular closing market prices of each recommended security were compiled: for the date of its recommendation; for the first, fifth, and tenth *preceding* trading days; and for the fifth, tenth, fifteenth, and twentieth *subsequent* trading days.[1]

The indicated interval, which represents effectively a six calendar-week period surrounding every recommendation release date, was selected for attention on the basis of the results of two prior analyses of the recommendations. One [25] documented a significant increase in trading activity in the recommended securities by the investor sample over approximately the same period of time. The other [11] suggested the existence of abnormal positive rates of return on those securities during the (calendar) months they were recommended. Accordingly, there is good reason to believe that the interval to be focused on here–which is more finely tuned than that in [11]–*is* the relevant one for observing investor reactions to, and return experiences with, the professional investment advice being conveyed.

II. Analytical Approach

The analysis proceeds in several stages. First, the rates of return on the recommended securities in the vicinities of their respective recommendation dates are contrasted with those that could have been realized concurrently from trading in the general run of common stocks of comparable risk. For this purpose, the recommendation date of each security was designated as trading day $t = 0$. Returns on the security were then calculated, using the data described above, for a succession of intervals around that date, beginning with $t = -10$ and ending with $t = +20$, in the form:

$$R^i_{j,k} = (P^i_k - P^i_j + D^i_{j,k})/P^i_j \tag{1}$$

where P^i_j and P^i_k are the closing prices of security i on trading days $t = j$ and $t = k$ (adjusted for stock splits and stock dividends), and $D^i_{j,k}$ is the cash dividend, if any, paid by the security during the interval in question.[2]

[1] These data had to be hand-collected since a daily price tape was unavailable to the researchers for the years in question.

[2] More accurately, $D^i_{j,k}$ represents the dividend payment associated with any *ex-dividend* date occuring in the interval.

The standard by which these returns were judged, to determine whether they were unusually high or low, is that prescribed by the Capital Asset Pricing Model [7, 8, 14, 18, 22, 23]. Specifically, the benchmark rate of return applicable to security i for the trading-day period $t = j$ to $t = k$ was taken to be:

$$\hat{R}^i_{j,k} = R^f_{j,k} + \hat{\beta}^i(R^m_{j,k} - R^f_{i,k}) \tag{2}$$

where $R^f_{j,k}$ denotes the yield available from the risk-free investment held over the period, $\hat{\beta}^i$ is an (estimated) index of security i's degree of systematic risk, and $R^m_{j,k}$ represents the concurrent rate of return on a well-diversified market portfolio of risky assets. The difference $R^i_{j,k} - \hat{R}^i_{j,k}$ was then adopted as a measure of the "excess" or "residual" return on security i in the vicinity of its recommendation by the brokerage firm.

The particular inputs employed in defining the $\hat{R}^i_{j,k}$ were effectively mandated by conditions of data availability. Thus, the strict form of the Capital Asset Pricing Model, as in (2), has been found to be less appropriate for investment performance evaluation than a "two-factor" version wherein $R^f_{j,k}$ is interpreted to be the yield on a constructed zero-beta portfolio rather than on a designated risk-free security [2, 3, 9]. Lacking a file of *daily* prices and dividends for a comprehensive array of securities, however, it was impossible to estimate zero-beta portfolio yields and rates of return on a market portfolio of equities for each of the 1738 stock trading days in the study period. Consequently, it was necessary to rely on public data sources for surrogates. In that regard, the *S&P* 500-stock index was chosen as a representation of the market portfolio, and its daily movements were used to compute the relevant $R^m_{j,k}$. Similarly, Treasury-Bill yields were inserted for the $R^f_{j,k}$; in the case of a specific five-trading-day (seven-calendar-day) measurement interval, for example, $R^f_{j,k}$ would be set at 7/30, the then-prevailing 30-day Treasury-Bill yield. While this definition of the risk-free rate is not the preferred one in the current literature, it has been found in previous work with this data base that the results of investment performance appraisals over the years at issue are *not* sensitive to the substitution of T-Bill rates for zero-beta yields [21]. The $\hat{\beta}^i$ for the various recommended securities were obtained by regressing their monthly returns on those of a value-weighted market portfolio over the 84 months of the study period. That process is also detailed in [21].

The outcome of the foregoing analysis, as shall be seen, suggests that there was, in fact, a clear potential for investors to achieve positive excess returns if they had acted on the advice of the brokerage firm's research staff on and around the dates of securities recommendations *and* if they were able to acquire (or dispose of) the stocks in question at prices like the recorded daily closing prices compiled to calculate the $R^i_{j,k}$. Thus, the findings are consistent with, and reinforce, those in [11] and [15].

It is possible here, however, to go beyond the usual treatment of hypothetical returns and examine the actual trading activities of the individual investor sample in order to determine whether the group *was* able in practice to exploit the potential advantage that the firm's research appears to have held out to them. This shall be done in two ways: (1) by comparing the indicated closing prices with those at which observed transactions by the sample in the recommended securities took place on the same dates; and (2) by contrasting the rates of return realized by the sample on identifiable investment "round trips" (i.e., complete cycles from purchase to resale) in recommended securities with the returns that were realized on non-recommended round trips [20]. Both analyses support the notion that not only in principle could differential profits have been made by following the recommendations; they actually were attainable *and* were attained by the firm's customer group.

III. Recommendations and Returns

For purposes of developing the record of returns displayed by securities that were the subjects of research recommendations, the list of such recommendations was pared to only those advisories wherein a specific and direct investment suggestion was made. These include the "buy", "weak buy", "sell", and "weak sell" categories. Eliminated from consideration were research reports that were offered "for information only", those which indicated stock as "suitable to establish tax-loss positions" and those in which the conclusion about a security was either "hold" or "do not purchase" [11]. The rationale was that none of the latter categories would be likely to lead to the kind of active and predictable trading responses by investors for which the measurement of potential returns from those actions would be particularly meaningful. Approximately 4500 recommendations remain on the revised list—a sample size which should still permit useful conclusions to be drawn.

Table 1 portrays the results of a comparison between the observed rates of return on the securities included on that list and the concurrent returns on comparable-risk securities, i.e., a tabulation of the $R^i_{j,k} - \hat{R}^i_{j,k}$ "residuals" described above. The figures shown are the mean values of those residuals, and only the time intervals for which they were found to be statistically significant are recorded.

The first column in the table denotes the actual computed excess-return percentages for each of the various periods. The second column translates these percentages into a set of corresponding continuously-compounded annual rates.[3] For *BUY* recommendations, the figures effectively represent the differential rates of return that an investor could have realized from engaging in purchase-and-resale cycles of varying durations in the recommended securities, on and around their recommendation dates. In the case of *SELL* recommendations, the counterpart investment cycles would have required opening short positions (while concurrently being long in the market portfolio) and subsequently covering those exposures. The positive net returns shown for sell recommendations were computed on that basis: i.e., on average, the securities in question *underperformed* the market, and thereby, would have yielded short-sale profits during the indicated intervals.

The data convey the message that there were, in fact, some opportunities for investors to obtain superior investment returns by concentrating on the sample of recommend securities rather than dealing in the general run of similar-risk common stocks in the market, over the seven-year time period studied. Indeed, certain of the annualized differential-return figures are quite impressive. The securities research reports at issue must, therefore, have contained at least some new information and/or analytical insights of value.[4]

[3]Where the translation takes into account the distinction between trading-day and calendar-day intervals.

[4]See [11] for a discussion of the character of such possibilities. It is worth noting that neither in that analysis, nor in the present one, is there any evidence of transitory distortions in the prices of the recommended securities. Thus, the positive return residuals in the vicinity of the recommendation dates were not subsequently reversed by price corrections.

TABLE 1.–Risk-Adjusted Excess Rates of Return on Recommended Common Stocks, 1964-70

Trading-Day Interval Around Recommendation Date (t = 0)	Mean Excess Return on Recommended Securities: Actual	Annualized
A. For BUY Recommendations (N = 3903):		
t = - 5 to t = - 1	0.68%	44%
t = - 1 to t = 0	0.39%	120%
t = 0 to t = 5	0.70%	34%
t = 5 to t = 10	0.16%	8%
t = 10 to t = 15	0.21%	12%
t = 15 to t = 20	0.22%	11%
t = - 5 to t = 20	2.39%	25%
t = - 1 to t = 20	1.69%	21%
t = 0 to t = 20	1.30%	16%
B. For SELL Recommendations (N = 558):		
t = - 1 to t = 0	0.67%	203%
t = 0 to t = 5	0.68%	35%
t = - 1 to t = 5	1.36%	63%

Note: All tabulated returns significantly different from zero at 95-percent confidence level. Annualized returns are in continuously-compounded form. BUY category includes "weak buy" recommendations; SELL includes "weak sells."

Evidence that positive excess returns show up, in connection with buy recommendations, several days in advance of the recommendations themselves, is consistent with prior findings [11, 25]. In part, this anticipation is attributable to information "leakage" in the research process within the brokerage firm. Account executives frequently will learn of the tone of a research report while it is still in preparation and begin to pass along trading suggestions to their customers before the report is formally released. Such preliminary indications to account executives of the character of imminent recommendations will, in fact, be conveyed quite deliberately on occasion. In effect, then, the recorded release date for many recommendations is only an approximation of the time much of the information therein actually began to be transmitted. The pre-release-date rise in trading activity in the recommended securities, detected in [25] for the firm's customer group, is an additional manifestation of this phenomenon.

Another factor, also cited in [11] and [25], has to do with the nature of the securities involved in the recommendations. It is not unlikely that often these would be the stocks of companies that had experienced some favorable developments in the recent past, news of which may well have been what prompted the brokerage firm's research staff to undertake its own analysis. Accordingly, one might expect to see positive excess returns on many securities prior to the recorded times of their recommendations simply because these would be stocks that had already been attracting some attention on the part of investors.[5] However, as long as the recommendations, in fact, uncovered and communicated *new* information–as appears to have been the case–further excess returns should be

[5]For that matter, they may have attracted the prior attention of the brokerage firm itself. Instances of repeat recommendations of particular stocks were not at all uncommon [25].

observed. Table 1 suggests that investors who were able to exploit those recommendations would have enjoyed on the order of a one-to-two percentage- point absolute investment return advantage over the market within a relatively short interval.

IV. Transaction Prices

The opportunity for investors actually to capitalize on this potential advantage in practice, of course, will depend both on their receiving the investment advice imbedded in the recommendations on a timely basis and on their ability to engage in transactions in the recommended securities at prices like those used here to calculate the $R_{j,k}^{i}$. The availability of transactions data for a large sample of the customers of the cooperating brokerage house, covering the same seven-year period as does the recommendation file, makes it possible to examine both issues.

The first, as indicated above, is confirmed in [25] by the fact of a substantial increase in recommended-security trading volume by the customer sample in the vicinity of recommendation dates. Such volume is observed to rise sharply and remain higher than normal during an interval beginning roughly ten trading days before and continuing until fifteen trading days after the recorded recommendation dates. Thus, the firm's customers do seem to be made aware of, and respond to, its research quite promptly—since the same "anticipation" phenomenon found in the return data appears in the trading-volume figures as well. Presumably, this is not entirely coincidental.

The question then becomes whether those customers, all of whom were *individual* investors [12], were able to implement their trades at prices that would have allowed them to achieve above-average returns. A comparison of the execution prices documented in the investor-sample transactions file, with the closing daily trading prices employed to determine the $R_{j,k}^{i}$, suggests an affirmative answer. For that purpose, the ratio of execution price to same-day closing price was computed for each observed transaction by the sample which occured on the various benchmark dates surrounding the recommendations for which closing-price information was collected.

The means of those ratios are recorded in Table 2. The figure of 1.001 listed for trading day $t = 5$ in the *BUY* column, for example, indicates that the purchase transactions engaged in by the sampled customer group in securities that had been recommended for acquisition by the brokerage firm five trading days earlier took place, on average, at prices that were just one-tenth of one percent higher than the closing prices of those securities.[6] A value of this ratio substantially greater than one for *BUY*s, or substantially below one for *SELL*s, would be evidence of what could be described as poor "access"—i.e., of an inability of individuals in practice to trade in recommended stocks on terms that would have allowed the potential differential- return opportunities therein to be realized.

It is apparent from the tabulation that there is little cause for concern on this score. The mean price ratios were, in fact, very close to 1.000 across the board. Only for the *BUY* side of one of the trading-day reference dates examined did the figure differ from 1.000 in a statistically significant unfavorable direction, and even there the discrepancy was merely 0.003 on the high side. Computations for day $t = 20$ were not made in the

[6] Again, only "buy", "weak buy", "sell", and "weak sell" recommendations were included in the analysis.