Kentucky-American Water Company
Case No. 2004-00103
Information Request Response to Commission Staff
Respondent: OAG Witness Dr. J. Randall Woolridge
Set I

PSC-I-21. Refer to the Direct Testimony of Dr. J. Randall Woolridge at 24 and Exhibit JRW-7 at 3.
a. Describe how Dr. Woolridge developed an annual historic growth rate of 3.5 percent for the Small Water Companies Group and of 4.75 percent for the Large Water Companies Group.
b. Describe the predictive value of Dr. Woolridge's "annual historical growth rate."
c. Describe the following categories that are found in Exhibit JRW-7:
(1) Sales.
(2) Earnings per share (EPS).
(3) Dividends per share (DPS).
(4) Book Value per share (BVPS).
d. For each category listed in Item 21(c), explain how the category is
is derived and describe how the category relates to the other listed categories computationally and behaviorally.
e. For each company listed in the Exhibit, explain why the company is
a suitable proxy for Kentucky-American.
f. Dr. Woolridge states: "For the SWC Group, EPS growth is the lowest and also the most volatile. The other growth rates are more consistent over time, with sales growth in the 5.0% range, and DPS and BVPS growth in 4.0% range."
Describe how Dr. Woolridge derived these ranges.

Response:

a. See discussion in testimony at 24 for the SWC Group and at 25 for the LWC Group.

b. Historic growth rates are readily available in virtually all investment reports. As such, they clearly have value to investors in forming expectations concerning future growth. This is especially true when no forecasts of future growth are available. However, the predictive value of historic growth rates is questionable due to a number of issues. These include: (1) past growth may not reflect future growth potential; (2) a single growth rate number (for example, for five or ten years), may not measure investors' expectations due to the sensitivity of a single growth rate figure to fluctuations in individual firm performance; and (3) short-term historic growth rates may not reflect long-term growth potential Nonetheless, despite the fact that historic growth rates may not have great predictive value does not mean that they do not affect investors' expectations.

c. (1) Sales refers to total sales or revenues.
c. (2) EPS is the net income or profit per share.
c. (3) Dividends per share is total annual dividends paid on a per share basis.
c. (4) Book value per share is the shareholder's equity divided by the number of shares.

d. (1) Sales refers to the total annual revenues of the company. It is the top line of the income statement. It is not directly related to the other items other than you must have sales to have earnings.

d. (2) EPS is the net income or profit per share. It is the bottom line of the income statement. The relationship to sales is discussed above. Dividends are paid out of earnings, and the earnings that are not paid out in the form of dividends are retained and go to increase shareholders' equity.

d. (3) Dividends per share is total annual dividends paid on a per share basis. Dividends to shareholders are paid out of earnings.

d. (4) Book value per share is the net worth or shareholder's equity of the company divided by the number of shares outstanding. Its relationship to other variables is discussed above.

e. The companies in the Exhibit are suitable proxies for KAWC in that they are primarily in the water service industry. As shown in Exhibit_(JRW-3), the companies SWC Group are more comparable to KAWC because they are closer in size.

f. Through an evaluation of the data found in the Exhibit and the exercise of informed judgment.

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PSC-I-22. Refer to the Direct Testimony of Dr. J. Randall Woolridge at 25 and Exhibit JRW-7.
a. Describe how Dr. Woolridge derived an average of 3.4 percent growth for the Large Water Companies Group.
b. Describe how Dr. Woolridge derived an average growth rate for 3 of the 4 companies in the Large Water Companies Group in Value Line as 7.2 percent.
c. List all reports, articles, studies, and analyses upon which Dr. Wooldridge (sic) has based his methodology for developing an average historical growth rate.
d. List all reports, articles, studies, and analyses that support Dr. Woolridge's methodology for developing an average historical growth rate.

Response:

a. It is the average of the five and ten year growth rates for EPS, DPS, and BVPS.

b. An average of 7.1% is shown on page 5 of the Exhibit.

c. Dr. Woolridge employed compounded annual growth rates to compute an average historic growth rate.

d. The is the same question as c. above.

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PSC-I-23. At page 26 of his direct testimony, Dr. J. Randall Woolridge states: "Given a historic and projected growth rate range of 3.5% to 7.1% for the SWC Group, and giving slighter greater weight to the projected growth rate figures, an expected growth rate of 5.5% is reasonable for these smaller water companies." State why greater weight is given to the projected growth rate.

Response:

The 3.5% and 7.1% are nearly equally weighted. A slightly greater weight is given to the forecasts because analysts are aware of historic growth when they prepare their forecasts. As such, they account for historic growth when they make their forecast.

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PSC-I-24. Refer to the Direct Testimony of Dr. J. Randall Woolridge at 26. Describe how Dr. Woolridge derived an expected growth range of 5.0 – 5.5%.

Response:

This is the most reasonable range given the historic growth rate of 4.75%, internal growth of 5.1%, and average projected EPS growth of 5.9%.

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PSC-I-25 Refer to the Direct Testimony of Dr. J. Randall Woolridge at 26. Describe how Dr. Woolridge derived the dividend yield used in the DCF analysis.

Response:

The derivation of the dividend yield is discussed at pages 20 and 21 of the testimony.

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PSC-I-26. Refer to the Direct Testimony of Dr. J. Randall Woolridge at 31. Explain why betas for only 3 of the 5 Small Water Companies Group members are listed.

Response:

Only 3 of the 5 companies are covered by the *Value Line Investment Survey*, the source of betas.

PSC-I-27. Refer to the Direct Testimony of Dr. J. Randall Woolridge at 39. Explain why use of an average inflation rate is more appropriate than using the current inflation rate.

Response:

Because the current inflation rate may not reflect what forecasters and consumers expect. The average that is used here reflects the expectations of professional forecasters and consumers.

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PSC-I-28. Refer to the Direct Testimony of Dr. J. Randall Woolridge at 40. Explain why use of the Standard and Poor's 500 ("S&P 500") is appropriate to develop an expected real growth in earnings.

Response:

The S&P 500 consists of 500 companies from ten different economic sectors (health care, energy, technology, etc.). The composition of the S&P 500 is intended to reflect the U.S. economy.

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PSC-I-29. Provide a copy of Marc H. Goedhart, Timothy M. Koller, and Zane D. Williams, "The Real Cost of Equity," *McKinsey on Finance* (Autumn 2002).

Response:

The requested article is included as attachment PSC-I-29A

The real cost of equity

The inflation-adjusted cost of equity has been remarkably stable for 40 years, implying a current equity risk premium of 3.5 to 4 percent

Marc H. Goedhart, Timothy M. Koller, and Zane D. Williams

As central as it is to every decision at the heart of corporate finance, there has never been a consensus on how to estimate the cost of equity and the equity risk premium.[1]

Conflicting approaches to calculating risk have led to varying estimates of the equity risk premium from 0 percent to 8 percent—although most practitioners use a narrower range of 3.5 percent to 6 percent. With expected returns from long-term government bonds currently about 5 percent in the US and UK capital markets, the narrower range implies a cost of equity for the typical company of between 8.5 and 11.0 percent. This can change the estimated value of a company by more than 40 percent and have profound implications for financial decision making.

Discussions about the cost of equity are often intertwined with debates about where the stock market is heading and whether it is over- or undervalued. For example, the run-up in stock prices in the late 1990s prompted two contradictory points of view. On the one hand, as prices soared ever higher, some investors expected a new era of higher equity returns driven by increased future productivity and economic growth. On the other hand, some analysts and academics suggested that the rising stock prices meant that the risk premium was declining. Pushed to the extreme, a few analysts even argued that the premium would fall to zero, that the Dow Jones industrial average would reach 36,000 and that stocks would earn the same returns as government bonds. While these views were at the extreme end of the spectrum, it is still easy to get seduced by complex logic and data.

We examined many published analyses and developed a relatively simple methodology that is both stable over time and overcomes the shortcomings of other models. We estimate that the real, inflation-adjusted cost of equity has been remarkably stable at about 7 percent in the US and 6 percent in the UK since the 1960s. Given current, real long-term bond yields of 3 percent in the US and 2.5 percent in the UK, the implied equity risk premium is around 3.5 percent to 4 percent for both markets.

The debate

There are two broad approaches to estimating the cost of equity and market risk premium. The first is historical, based on what equity investors have earned in the past. The second is forward-looking, based on projections implied by current stock prices relative to earnings, cash flows, and expected future growth.

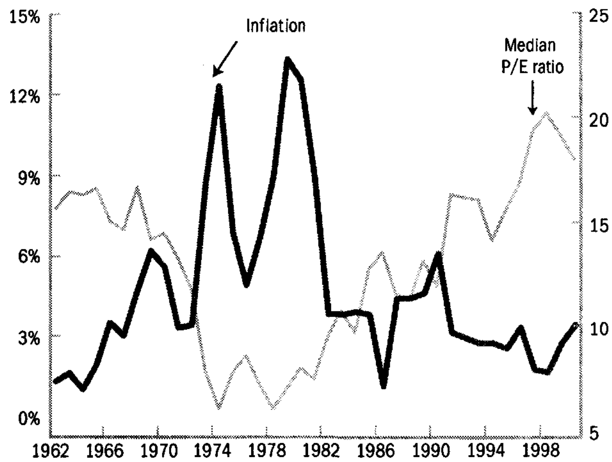
The latter is conceptually preferable. After all, the cost of equity should reflect the return expected (required) by investors. But forward-looking estimates are fraught with problems, the most intractable of which is the difficulty of estimating future dividends or earnings growth. Some theorists have attempted to meet that challenge by surveying equity analysts, but since we know that analyst projections almost always overstate the long-term growth of earnings or dividends,[2] analyst objectivity is hardly beyond question. Others have built elaborate models of forward-looking returns, but such models are typically so complex that it is hard to draw conclusions or generate anything but highly unstable results. Depending on the modeling assumptions, recently published research suggests market risk premiums between 0 and 4 percent.[3]

Unfortunately, the historical approach is just as tricky because of the subjectivity of its assumptions. For example, over what time period should returns be measured—the previous 5, 10, 20, or 80 years or more? Should average returns be reported as arithmetic or geometric means? How frequently should average returns be sampled? Depending on the answers, the market risk premium based on historical returns can be estimated to be as high as 8 percent.[4] It is clear that both historical and forward-looking approaches, as practiced, have been inconclusive.

Overcoming the typical failings of economic models

In modeling the behavior of the stock market over the last 40 years,[5] we observed that many real economic variables were surprisingly stable over time (including long-term growth in corporate profits and returns on capital) and that much of the variability in stock prices related to interest rates and inflation (Exhibit 1). Building on these findings, we developed a simple, objective, forward-looking model that, when applied retrospectively to the cost of equity over the past 40 years, yielded surprisingly stable estimates.

Exhibit 1. US median P/E vs. inflation

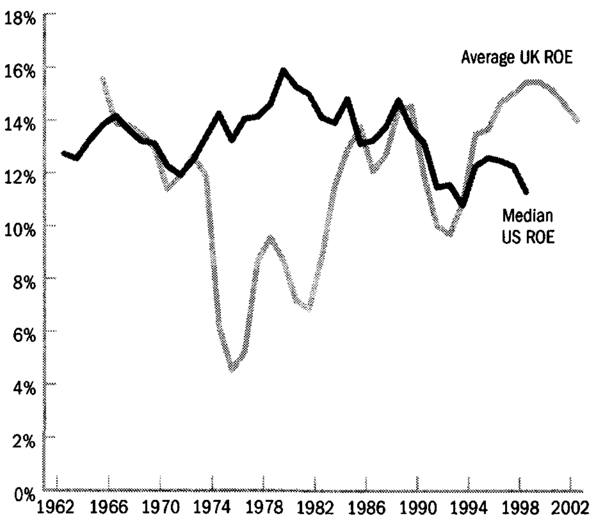


Source: McKinsey analysis

Forward-looking models typically link current stock prices to expected cash flows by discounting the cash flows at the cost of equity. The implied cost of equity thus becomes a function of known current share values and estimated future cash flows (see sidebar, "Estimating the cost of equity"). Using this standard model as the starting point, we then added three unique characteristics that we believe overcome the shortcomings of many other approaches:

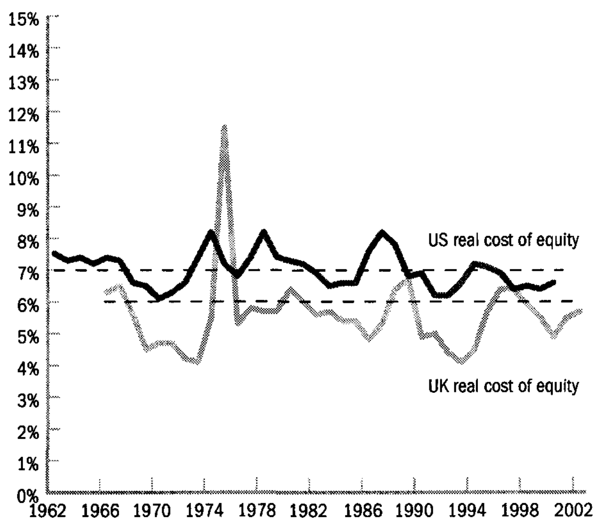
1. *Median stock price valuation.* For the US, we used the value of the median company in the S&P 500 measured by P/E ratio as an estimate of the market's overall valuation at any point in time. Most researchers have used the S&P 500 itself, but we argue that the S&P 500 is a value-weighted index that has been distorted at times by a few highly valued companies, and therefore does not properly

Exhibit 2. Return on book equity (ROE)



Source: McKinsey analysis

Exhibit 3. Annual estimates of the real cost of equity



Source: McKinsey analysis

reflect the market value of typical companies in the US economy. During the 1990s, the median and aggregate P/E levels diverged sharply. Indeed by the end of 1999, nearly 70 percent of the companies in the S&P 500 had P/E ratios below that of the index as a whole. By using the median P/E ratio, we believe we generate estimates that are more representative for the economy as a whole. Since UK indices have not been similarly distorted, our estimates for the UK market are based instead on aggregate UK market P/E levels.

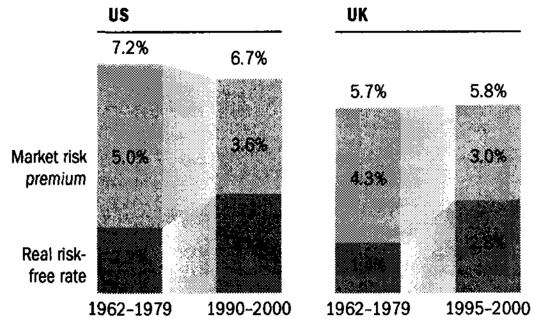
2. *Dividendable cash flows.* Most models use the current level of dividends as a starting point for projecting cash flows to equity. However, many corporations have moved from paying cash dividends to buying back shares and finding other ways to return cash to shareholders, so estimates based on ordinary dividends will miss a substantial portion of what is paid out. We avoid this by discounting not the dividends paid but the cash flows available to shareholders after new investments have been funded. These are what we term "dividendable" cash flows to investors that might be paid out through share repurchases as ordinary dividends, or temporarily held as cash at the corporate level.

We estimate dividendable cash flows by subtracting the investment required to sustain the long-term growth rate from current year profits. This investment can be shown to equal the projected long-term profit growth (See sidebar, "Estimating the cost of equity") divided by the expected return on book equity. To estimate the return on equity (ROE), we were able to take advantage of the fact that US and UK companies have had fairly stable returns over time. As Exhibit 2 shows, the ROE for both US and UK companies has been consistently about 13 percent per year,[6] the only significant exception being found in UK returns of the late 1970s.

3. *Real earnings growth based on long-term trends.* The expected growth rate in cash flow

The stability of the implied inflation-adjusted cost of equity is striking. Despite a handful of recessions and financial crises over the past 40 years . . . equity investors have continued to demand about the same cost of equity in inflation-adjusted terms.

Exhibit 4. Decomposition of the inflation-adjusted cost of equity



Source: McKinsey analysis

and earnings was estimated as the sum of long-term real GDP growth plus expected inflation. Corporate profits have remained a relatively consistent 5.5 percent of US GDP over the past 50 years. Thus, GDP growth rates are a good proxy for long-term corporate profit growth. Real GDP growth has averaged about 3.5 percent per year over the last 80 years for the US and about 2.5 percent over the past 35 years for the UK. Using GDP growth as a proxy for expected earnings growth allows us to avoid using analysts' expected growth rates.

We estimated the expected inflation rate in each year as the average inflation rate experienced over the previous five years.[7] The nominal growth rates used in the model for each year were the real GDP growth combined with the contemporary level of expected inflation for that year.

Results

We used the above model to estimate the inflation-adjusted cost of equity implied by stock market valuations each year from 1963 to 2001 in the US and from 1965 to 2001 for the UK (Exhibit 3). In the US, it consistently remains between 6 and 8 percent with an average of 7 percent. For the UK market, the inflation-adjusted cost of equity has been, with two exceptions, between 4 percent and 7 percent and on average 6 percent.

The stability of the implied inflation-adjusted cost of equity is striking. Despite a handful of recessions and financial crises over the past 40 years including most recently the dot.com bubble, equity investors have continued to demand about the same cost of equity in inflation-adjusted terms. Of course, there are deviations from the long-term averages but they aren't very large and they don't last very long. We interpret this to mean that stock markets ultimately understand that despite ups and downs in the broad economy, corporate earnings and economic growth eventually revert to their long-term trend.

We also dissected the inflation-adjusted cost of equity over time into two components: the inflation-adjusted return on government bonds and the market risk premium. As Exhibit 4 demonstrates, from 1962 to 1979 the expected

Estimating the cost of equity

To estimate the cost of equity, we began with a standard perpetuity model:

$$P_t = \frac{CF_{t+1}}{k_e - g} \tag{1}$$

where P_t is the price of a share at time t, CF_{t+1} is the expected cash flow per share at time $t + 1$, k_e is the cost of equity, and g is the expected growth rate of the cash flows. The cash flows, in turn, can be expressed as earnings, E, multiplied by the payout ratio:

$$CF = E(\textit{payout ratio})$$

Since the payout ratio is the share of earnings left after reinvestment, replacing the payout ratio with the reinvestment rate gives:

$$CF = E(1 - \textit{reinvestment rate})$$

The reinvestment rate, in turn, can be expressed as the ratio of the growth rate, g, to the expected return on equity:

$$\textit{reinvestment rate} = \frac{g}{ROE}$$

And thus the cash flows can be expressed as:

$$CF = E\left(1 - \frac{g}{ROE}\right) \tag{2}$$

We then combined formulas (1) and (2) to get the following:

$$\frac{P_t}{E_{t+1}} = \frac{1 - \frac{g}{ROE}}{k_e - g} \Rightarrow k_e = \frac{E_{t+1}}{P_t}\left(1 - \frac{g}{ROE}\right) + g \tag{3}$$

If the inflation embedded in k_e and g is the same, we can then express equation 3 as:

$$k_{er} = \frac{E_{t+1}}{P_t}\left(1 - \frac{g}{ROE}\right) + g_r \tag{4}$$

Where k_{er} and g_r are the inflation-adjusted cost of equity and real growth rate, respectively. We then solved for k_{er} for each year from 1963 through 2001, using the assumptions described in the text of the article.

inflation-adjusted return on government bonds appears to have fluctuated around 2 percent in the US and around 1.5 percent in the UK. The implied equity risk premium was about 5 percent in both markets.[8] But in the 1990s, it appears that the inflation-adjusted return on both US and UK government bonds may have risen to 3 percent, with the implied equity risk premium falling to 3 percent and 3.6 percent in the UK and US respectively.

We attribute this decline not to equities becoming less risky (the inflation-adjusted cost of equity has not changed) but to investors demanding higher returns in real terms on government bonds after the inflation shocks of the late 1970s and early 1980s. We believe that using an equity risk premium of 3.5 to 4 percent in the current environment better reflects the true long-term opportunity cost for equity capital and hence will yield more accurate valuations for companies. MoF

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[1] Defined as the difference between the cost of equity and the returns investors can expect from supposedly risk-free government bonds.

[2] *See* Marc H. Goedhart, Brendan Russel, and Zane D. Williams, "Prophets and profits?" *McKinsey on Finance,* Number 2, Autumn 2001.

[3] *See,* for example, Eugene Fama and Kenneth French, "The Equity Premium," *Journal of Finance,* Volume LVII, Number 2, 2002; and Robert Arnott and Peter Bernstein, "What Risk Premium is 'Normal'," *Financial Analysts Journal,* March/April, 2002; James Claus and Jacob Thomas, "Equity premia as low as three percent?" *Journal of Finance,* Volume LVI, Number 5, 2001.

[4] *See,* for example, *Ibbotson and Associates,* Stock, Bonds, Bills and Inflation: 1997 Yearbook.

[5] *See* Timothy Koller and Zane Williams, "What happened to the bull market?" *McKinsey on Finance,* Number 1, Summer 2001.

[6] One consequence of combining a volatile nominal growth rate (due to changing inflationary expectations) with a stable ROE is that the estimated reinvestment rate varies tremendously over time. In the late 1970s, in fact, our estimates are near 100 percent. This is unlikely to be a true representation of actual investor expectations at the time. Instead, we believe it likely that investors viewed the high inflation of those years as temporary. As a result, in all of our estimates, we capped the reinvestment rate at 70 percent.

[7] This assumption is the one that we are least comfortable with, but our analysis seems to suggest that markets build in an expectation that inflation from the recent past will continue (witness the high long-term government bond yields of the late 1970s).

[8] There is some evidence that the market risk premium is higher in periods of high inflation and high interest rates, as was experienced in the late 1970s and early 1980s.

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Set I

PSC-I-30. Provide a copy of Richard Bower, "The N-Stage Discount Model and Required Return: A Comment," *Financial Review* (February 1992).

Response:

The requested article is included as attachment PSC-I-30A.

The Financial Review Vol. 27 No. 1 February 1992 Pp. 141–149

The N-Stage Discount Model and Required Return: A Comment

*Richard S. Bower**

Abstract

A number of financial economists have observed that estimates of the market discount rate have a downward bias when dividend timing is ignored. They have done so in academic and utility industry journals as well as in testimony. Most conclude or imply that such a downward bias carries over to the calculation of a regulated utility's required rate of return. This paper demonstrates that in fact the conventional cost of equity calculation, ignoring quarterly compounding and even without adjustment for fractional periods, serves very well as a measure of required return.

Introduction

In a recent issue of *The Financial Review*, Brooks and Helms presented an N-stage dividend discount model [1]. The model is a welcome addition to the analytic tool kit available for estimation of market discount rates.

Nevertheless, I think they make an unwarranted leap from the model to the conclusion that failure to consider quarterly compounding and fractional periods introduces a downward bias in rate of return calculation, and that theirs is "an efficient procedure ... for estimating the required rate of return" ([1], p. 656). That this presumption may mislead analysts involved in public utility rate proceedings is likely because their illustration involves a regulated electric utility, Commonwealth Edison Company, and their point seems to have relevance for regulatory proceedings.

Brooks and Helms are not alone in their observation. A number of financial economists note that market discount rate estimates are biased downward when div-

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idend timing is ignored. These findings have appeared in academic and utility industry journals as well as in testimony. Academic articles include [1, 2, 7, 8, 12], and examples in the utility literature are [3, 14]. For recent testimony that makes the point, see [9]. The same point is made in Morin's *Utilities' Cost of Capital* [10, pp. 141–142]. Most authors have concluded or implied that such a downward bias carries over to the calculation of the required rate of return.

Linke and Zumwalt [2, 7, 8] are the exceptions. They made it clear that there is a distinction between a utility's market discount rate (k in my notation) and the rate year required return (r) that regulators should allow, and that reconciling the two necessitates a calculation.

I do not dispute the observation that an estimate of the market discount rate has a downward bias when dividend timing is ignored, nor do I find fault with the Linke and Zumwalt market rate to rate year required return adjustment calculations. My intention here is to point out that the conventional cost of equity calculation used in utility rate cases (k^* in my notation), which ignores timing, is (or is easily transformed into) an unbiased estimate of rate year required return (k^{**} in my notation), while the correct market discount rate, if unadjusted, has an upward bias when used to represent required utility return.

Base Case

The market discount rate annually compounded for the year ahead is the rate k that satisfies the equation

$$P_0 = \frac{d1}{(1 + k)^{t1}} + \frac{d2}{(1 + k)^{t2}} + \frac{d3}{(1 + k)^{t3}} + \frac{d4}{(1 + k)^{t4}} + \frac{P_0(1 + \hat{g})}{(1 + k)}, \quad (1)$$

where P_0 is the market price of a stock at time 0; dn is the first, second, third, or fourth dividend expected in the year ahead (quarterly dividends are assumed but the assumption is unimportant); $\hat{g}$ is the expected annual growth rate in stock price; and tn is the fraction of a 365-day year before dividend n is to be received. I consider the ex-dividend date to be the date the dividend is received because it is the date on which the dividend becomes the investor's property, a property that remains the investor's even if the stock is sold prior to the payment date. Brooks and Helms used the actual dividend payment date, which I follow when I use their illustration in this note.

The total dividend expected in the year is $D = d1 + d2 + d3 + d4$, and the conventional cost of equity calculation used in utility rate cases is

$$k^* = (D/P_0) + \hat{g}. \tag{2}$$

If market price (P_0) and book value (B_0) are equal at time 0, and the rate year begins at time 0, then, using k^* as allowed return (r), regulators would approve prices for utility services that provide expected earnings (E):

$$E = k^*P_0. \tag{3}$$

Combining equations (2) and (3),

$$\hat{g} = E - D/P_0. \tag{4}$$

Regulators using this approach will provide an expected cash flow that just satisfies equation (1):

$$P_0 = \frac{d1}{(1 + k)^{t1}} + \frac{d2}{(1 + k)^{t2}} + \frac{d3}{(1 + k)^{t3}} + \frac{d4}{(1 + k)^{t4}} + \frac{P_0 + E - D}{(1 + k)}. \tag{1a}$$

If regulators set allowed return equal to k (the market discount rate) rather than the smaller k^*, expected cash flow would discount to a current price greater than P_0. The market discount rate (k), when used directly in this way, would produce a required return (r) with an upward bias.

The conventional estimate of cost of equity (k^*) is also the correct estimate of required return (r) when price and book values are not equal. To see that it is, consider a payout rate PAY_m. Set it equal to d_m/k^*P_0 at each dividend date n. Then use this payout with the earnings indicated by applying the same required return rate to book value, k^*B_0.

The result is that each term in equation (1) or (1a) is multiplied by the ratio B_0/P_0 so that the dividends and final book value that could be provided and are expected discount to initial book value at the market discount rate, k.

If the rate year does not begin at the same time that the market price is observed, an adjustment in the calculation of k^* (to k^{**}) is required. Because P rises as the time ($t1$) to the first dividend ($d1$) falls, the calculation of k^{**} will vary from k^* with $t1$. The market discount rate (k) will not change.

To get a correct conventional measure of required return, prices must be adjusted to reflect any time difference from $d1$ in market price and rate year book value. For example, if the market price used is the price 30 days before a dividend date, and initial book value for the rate year is 90 days before a dividend date, then the proper price to use in the conventional but adjusted cost of equity calculation, k^{**}, is $P_0/(1 + k)^{60/365}$, and

$$k^{**} = (D/[P_0/(1 + k)^{(60/365)}]) + \hat{g} \tag{5}$$

is the right measure of required return (r). This adjustment is one that staff witnesses for the New York Public Service Commission appear to make in calculating k^* (see [13]). If the market price is 90 days before and the rate year book value 30 days before the dividend date, then $(1 + k)^{-60/365}$ would be used to adjust P_0.

Because the timing difference from dividend dates for market price and rate year book value may result in either an upward or downward adjustment of the same magnitude in the conventional estimate of cost of equity (k^*), omitting the adjustment—failing to use k^{**}—introduces error but not bias. The conventional measure of cost of equity (k^*), a measure that does not consider quarterly compounding and usually fails to consider fractional periods, has no downward bias as an estimate of required return (r). It is, as the Federal Energy Regulatory Commission (FERC) and other regulatory bodies have concluded, a fair measure to use in calculating the allowed return for a utility. The FERC, in its *Generic Determination of Rate of Return on Common Equity for Public Utilities*, embraces the Linke and Zumwalt analysis in Order No. 442 [4], reconsiders it in Order No. 442-A [5], and settles on the required return I develop here in Order No. 461 [6].

First Illustration

For illustration, consider the Brooks and Helms no-growth case for Commonwealth Edison. That this is an illustration simplifying most of the very difficult problems of estimation facing a cost of equity analyst is particularly clear in the case of Commonwealth Edison. Its very complicated situation is described in a November 1990 Salomon Brothers report [11]. On June 9, 1989, Commonwealth Edison stock closed at 37 5/8; the next dividend date is 52 days away on August 1, 1989; the expected dividend on that date is \$0.75, and assumed and expected growth is zero. With this information, k = 8.287 percent, and equation (1) yields

$$37.625 = \frac{0.75}{1.08287^{(54/365)}} + \frac{0.75}{1.08287^{(146/365)}} + \frac{0.75}{1.08287^{(238/365)}} + \frac{0.75}{1.08287^{(327/365)}} + \frac{37.625(1 + 0)}{1.08287},$$

and $k^* = 7.973$ percent or \$37.625.

If market and book values were equal and the rate year began on June 9, 1989, then setting allowed and required return (r) equal to k^* would provide earnings of $k^*P(0.07973 \times 37.625)$, or \$3.00. Because rate case earnings reflect cash flow timing, including dividend payments, as well as short-term interest expense and revenue, the \$3.00 covers the \$0.75 dividends received by investors on May, August, November, and February 1st and maintains book and market value at \$37.625.

Suppose, however, that the rate year begins on January 1, 1990. The book value estimated for that date is \$32.68, according to Value Line, and the next dividend is 31 rather than 52 days away. Adjusting price for the difference in dividend timing and calculating a conventional but adjusted required return

$$\begin{aligned} k^{**} &= (D/[P_0/(1 + k)^{(-21/365)}]) + \hat{g} \\ &= (3/[37.625/1.08287^{(-21/365)}]) + 0 \\ &= 7.9370\%. \end{aligned}$$

Earnings based on an allowed and required return (k^{**}) of 7.9370 percent and a book value ($32.68) would be set at $2.594 and, with payout at 25 percent of earnings each quarter ($d_1/k^{**}P_0$), would be associated with a $0.6485 dividend on February 1, 1990 and on subsequent dividend dates.

The present value of the expected dividend flow and the unchanged or zero growth end-of-year 1990 book value is the January 1, 1990 book value:

$$B_0 = \frac{0.6485}{(1.08287)^{(31/365)}} + \frac{0.6485}{(1.08287)^{(120/365)}} + \frac{0.6485}{(1.08287)^{(212/365)}} + \frac{0.6485}{(1.08287)^{(304/365)}} + \frac{32.68(1+0)}{(1.08287)}.$$

$$B_0 = 32.68.$$

In other words, the allowed return set equal to the conventional but adjusted cost of equity estimate (k^{**}) provides earnings and dividends sufficient to support book value at the market discount rate. In this illustration, the conventional but adjusted cost of equity calculation (k^{**}) provides the correct estimate of the required rate of return.

Second Illustration

My first illustration has assumed no growth and full payout of dividends. A second illustration with dividend growth and fractional payout may be more useful. Linke and Zumwalt [7, pp. 16–17] provided the material for that illustration. A stock with dividend due one quarter away is now selling at $8.2294, which is also its book value. The dividend expected is $0.25 at the end of the current and the following quarter and $0.265 in each of the four following quarters. Price, like dividends, is expected to increase 6 percent from one year to the next, so that one year from now price is expected to be 8.2294 × 1.06, or $8.7232. The rate year begins with the first dividend one quarter away, so k^* and k^{**} are equal.

The market discount rate (k) is 19.375:

$$8.2294 = \frac{0.25}{1.19375^{0.25}} + \frac{0.25}{1.19375^{0.50}} + \frac{0.265}{1.19375^{0.75}} + \frac{0.265}{1.19375} + \frac{8.7232}{1.19375}.$$

The conventional cost of equity (k^*) is

$$\begin{aligned} k^* &= D/P_0 + \hat{g} \\ &= 1.03/8.2294 + 0.06 \\ &= 18.516\%. \end{aligned}$$

The conventional cost of equity (k^*) is less than the market discount rate (k), but as a measure of required return (r), it is still correct. The earnings it provides, $k^*P_0 = 0.18516 \times 8.2294 = 1.524$, are just sufficient to cover dividends and support book and market value growth of 6 percent:

	Q1	Q2	Q3	Q4	Year
Book, Start of Q	8.2294	8.3604	8.4914	8.6074	
Earnings	0.381	0.381	0.381	0.381	1.524
Dividend	0.25	0.25	0.265	0.265	1.03
Book, End of Q	8.3604	8.4914	8.6074	8.7234	

This illustration is obvious. The point may be less clear, but more interesting, if book value varies from market price, and rate year timing differs from market timing. The results remain the same, however: While the conventional cost of equity may have a downward bias as an estimate of the market discount rate, it is a correct and unbiased estimate of a utility's required return.

Conclusion

Although many analysts have concluded that required return has a downward bias if it is calculated ignoring quarterly compounding and fractional periods, it would be surprising if they were correct. Too many rate cases have come and gone, and too many utilities have survived and sustained market prices above book, to make downward bias in the conventional calculation of required return a likely reality.

Brooks and Helms and the other authors are correct when they say that the conventional cost of equity calculation is a downward-biased estimate of the market discount rate. They are not correct, however, in concluding that it has a bias as a measure of required return. As a measure of required return, the conventional cost of equity calculation (k^*), ignoring quarterly compounding and even without adjustment for fractional periods, serves very well.

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Kentucky-American Water Company
Case No. 2004-00103
Information Request Response to Commission Staff
Respondent: OAG Witness Dr. J. Randall Woolridge
Set I

PSC-I-31. Refer to the Direct Testimony of Dr. J. Randall Woolridge at 55. State whether, in Dr. Woolridge's opinion, historical growth rates are biased. Explained.

Response:

Given that historic growth rates are the result of simple computations, they are unbiased measures of historic compounded growth.

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PSC-I-32. At page 67 of his direct testimony, Dr. Woolridge states: "Using the arithmetic mean overstates the return experienced by investors." Provide an estimate of how much its use overstates the return.

Response:

The overstatement depends on the overall horizon over which a return is compounded. A recent study by Eric Jacquier, Alex Kane; Alan J Marcus entitled "Geometric or Arithmetic Mean: A Reconsideration" in the November/December issue of the *Financial Analysts Journal* shows that over a forty year horizon the overstatement is 100 percent.

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Set I

PSC-I-33. Refer to the Direct Testimony of Dr. J. Randall Woolridge at 69 – 70. List all reports, articles, studies, and analyses that discuss the "Peso Problem" and its effect on the use of historic stock returns as a measure of expected returns.

Response:

The 'peso problem' issue was first highlighted by the Nobel laureate, Milton Friedman, and it gets its name from conditions related to the Mexican peso market in the early 1970s. It refers to the idea that a highly improbable event, which may or may not occur in the future, is currently factored into stock prices, leading to seemingly low valuations. These are many studies that evaluate the 'peso problem' in alternative markets. A recent study by Pietro Veronesi highlights many of the studies that relate the 'peso problem' to stock market returns. The study is included as attachment PSC-I-33A.

The Peso Problem Hypothesis and Stock Market Returns*

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Abstract

The Peso Problem Hypothesis has often been advocated in the financial literature to explain the historically puzzlingly high risk premium of stock returns. Using a dynamic model of learning, this paper shows that the implications of the Peso Problem Hypothesis are much more far reaching than the ones commonly advocated, implying most of the stylized facts about stock returns. These include high risk premia, time-varying volatility, asymmetric volatility reaction to good and bad news, excess sensitivity of price reaction to dividend changes and thus excess return volatility,

Introduction

Stock market returns have a number of features that have been puzzling financial economists for long. Among others, these include a high realized risk premium, excess volatility, changing volatility, asymmetric reaction of volatility to good and bad news.[1] The financial literature has put forward various models to explain one or more of these stylized facts. As an example, a number of papers have argued that the puzzlingly high risk premium of stock returns may be due to a "Peso problem situation" (see e.g. Rietz (1988), Brown, Goetzmann and Ross (1995), Danthine and Donaldson (1998), Goetzman and Jorion (1999a,b)): that is, since no catastrophic event ever realized during the sampling period to the US economy *ex post* realized returns are high even if *ex ante* expected returns are low.

However, the possibility that a bad event *could* happen may affect investors expectations in many other ways aside from generating higher returns *ex-post.* For example, referring to a comment by Robert C. Merton about the high volatility during the 30's, Schwert (1989) writes:

> '... the Depression was an example of the so called "Peso problem," in the sense that there was legitimate uncertainty about whether the economic system would survive.... Uncertainty about whether the "regime" had changed adds to the fundamental uncertainty reflected in past and future volatility of macroeconomic data.'

This paper builds on this intuition to explore the implications for the *ex-post* behavior of stock returns under the assumption that a bad state could happen but it did not during the sample period. Using an intertemporal, rational expectations model of learning, this paper

[1]The literature on each of these findings is immense, and I refer the reader to classic textbooks, such as Campbell, Lo and MacKinlay (1997) or Cochrane (2000) for references and discussion. Classic early references are Mehra and Prescott (1985) for the equity premium; Shiller (1981) and LeRoy and Porter (1981) for excess volatility; Engle (1982), Bollerslev (1986) and Nelson (1991) for the modeling of time-varying volatility; French et al. (1987), Schwert (1989, 1990), Hamilton and Lin (1997) for a characterization of time-varying return volatility and macro-economic factors.

shows that the Peso Problem Hypothesis has much more far reaching implications than just a high *realized* equity premium. Indeed, I show that all the stylized facts described above are implied by a model where there is a very small probability that the economy may enter into a very long recession.

Specifically, suppose that economic fundamentals – call them "dividends" – are generated by a diffusion process whose drift is not observable. For simplicity, the drift is assumed constant for most of the time. Suppose now that at every instant, there is an *ex-ante* very small probability that the economy enters into a long recession. That is to say, there is a very small probability that the drift changes to a lower value and there is also a small probability to revert back to normal. Since investors do not observe the true drift but can only learn about it by observing the past realizations of fundamentals, this model implies that investors' uncertainty about the true drift fluctuates over time. For example, suppose that at some time t investors' conditional probability of the normal state $\pi(t)$ is close to 1. A sequence of negative dividend innovations will tend to decrease $\pi(t)$ driving it closer to $\frac{1}{2}$, that is the point of maximum uncertainty. It is intuitive that when there is more uncertainty, investors' beliefs tend to react more to news. Hence, since in a rational expectations model the stock price depends on investors' conditional expectations, during period of high uncertainty investors' expect to react heavily to news and hence they also expect that returns are more volatile. As a consequence, they require a higher discount for holding the stock. This feedback effects from the sensitivity of investors' beliefs to news onto the stock price itself determines most of the results. Indeed, Veronesi (1999) shows that this model implies that the equilibrium price of the asset is an increasing and convex function of $\pi(t)$ and studies the general properties of the model. In particular, the stock price is very steep for $\pi(t)$ close to one and rather flat for $\pi(t)$ close to zero which yields to a stock-market overreaction to bad news in good times and an underreaction to good news in bad times.

Building on the results from Veronesi (1999), this paper formally studies the *ex-post* features of stock returns under the assumption that during the sampling period it never occurred that the drift of the dividend process shifted to the lower one: that is, the economy never entered a long recession. This assumption formalizes the "Peso problem hypothesis" and captures the spirit of Merton's comment reported above. Conditioning on this assumption, I show the following: first and most obviously, there is a positive bias on the mean realized returns. This bias is positively albeit not-linearly related to stock return volatility and to the degree of risk aversion. Second, returns display "excess volatility", in the sense that they are more volatile than the underlying fundamentals (dividends). This is due to an implied excess sensitivity of prices to dividend changes. Third, the volatility of returns changes over time, it is mean reverting and it is negatively correlated with realized returns, increasing after bad news and decreasing after good news. I finally perform Monte Carlo simulations to gauge the size of the effects reported in the theoretical section.

The paper is organized as follows: in section 1, I review the model and the results in Veronesi (1999). Section 2 investigates the properties of stock returns under the "Peso Problem Hypothesis." Section 3 relates the model to U.S. data and describes the results of Monte Carlo simulations. Section 4 concludes. All results are given in the appendices.

1. The Model

The model is similar to Campbell and Kyle (1993), Wang (1993) and Veronesi (1999), and thus I describe it only briefly. I consider an economy with a single physical consumption good, which can be allocated to investment or consumption. Two investment assets are available to investors/consumers: a risky asset and a riskless asset. The risky asset yields a stochastic dividend rate $D(t)$, described by the linear process:

$$dD = \theta dt + \sigma d\xi \tag{1.1}$$

where the assumptions about $\theta(t)$ are described below, σ is a constant, and $\xi(t)$ denotes a Wiener process. The supply of the risky asset is normalized to unity. Instead, the riskless asset is infinitely elastically supplied and yields a constant rate of return r.

Finally, I assume that investors/consumers are endowed with a CARA utility function over consumption $U(c,t) = -e^{-\rho t - \gamma c}$, where ρ is the parameter of time preference and γ is the coefficient of absolute risk aversion.

1.1. Modeling a Peso Problem Situation

I now capture the spirit of Merton's quote in the Introduction by assuming the following: (1) during the sample period $[0,T]$ the drift rate of dividends has been a constant $\theta(t) = \overline{\theta}$; (2) there is a small *ex-ante* chance that the drift rate of dividends shifts to a low state $\theta(t) = \underline{\theta} < \overline{\theta}$; and (3) investors do not actually observe $\theta(t)$ and hence are unaware of whether a shift ever occurred or not. This last assumption is the key ingredient to generate the additional implications of the Peso-Problem situation uncovered in this paper, as it is responsible for the additional "uncertainty about whether the "regime" had changed" that "adds to the fundamental uncertainty," to use the words of Merton.

More specifically, I assume that during an infinitesimal time interval Δ, there is probability $\lambda\Delta$ that $\theta(t)$ shifts to the low state $\underline{\theta}$ from the normal state $\overline{\theta}$. Moreover, I also assume that in this event there is yet probability $\mu\Delta$ that the state would shift back to the normal state $\overline{\theta}$, with $\mu >> \lambda$. Thus, in this model a bad state is characterized by two parameters: How low the drift rate $\underline{\theta}$ is, and for how long it will last. To be consistent with the assumption of a Peso Problem situation, the probability of shifting to the bad state λ must be chosen very small, such as $\lambda = .005$, which implies a shift once every 200 years. However, in order to ensure that unconditionally the economy is growing, I will also be assuming $\mu >> \lambda$. Sections 2 and 3 will further discuss these issues and the parameter choices.

1.2. Investors' Posterior Probability

Investors only observe the realized series of dividends. Let $\{\mathcal{F}(t)\}$ be the filtration generated by the dividend stream $(D(\tau))_{\tau=0}^{t}$ and define the posterior probability of the good state $\overline{\theta}$ by

$$\pi(t) = Pr(\theta(t) = \overline{\theta}|\mathcal{F}(t)).$$

We then have:

Lemma 1.1: The posterior probability $\pi(t)$ satisfies the stochastic differential equation:

$$d\pi = (\lambda + \mu)(\pi^s - \pi)dt + h(\pi)dv \tag{1.2}$$

where $\pi^s = \mu / (\mu + \lambda)$, $h(\pi) = \left(\frac{\overline{\theta}-\underline{\theta}}{\sigma}\right)\pi(1-\pi)$ and $dv = \frac{1}{\sigma}\left[dD - E\left(dD|\mathcal{F}(t)\right)\right]$. Moreover, dv is a Wiener Process with respect to $\mathcal{F}(t)$.

Proof: See Liptser and Shiryayev (1977, pg. 348). See also David (1997). □

Notice that $(\pi^s, 1-\pi^s)$ is simply the stationary distribution of the two states. Also, notice that even if the drift $\theta(t)$ shifts between two discrete states, the process for the posterior distribution $\pi(t)$ is continuous.

1.3. The Equilibrium

A rational expectations equilibrium is defined as follows:

Definition 1.1: A *Rational Expectations Equilibrium* (REE) is given by $(P(D,\pi), X(W,P,D,\pi), c(W,P,D,\pi))$, where $P(D,\pi)$ is the price level for given dividend level D and belief π, $X(W,P,D,\pi)$ and $c(W,P,D,\pi)$ are the demand for the risky asset and the consumption level for given level of wealth W, price P, dividend and belief, respectively, such that

1. **Utility Maximization:** $(c(\cdot), X(\cdot))$ maximizes investors' expected intertemporal utility, i.e.
$$\max_{c,X} E\left[\int_0^\infty U(c,s)ds|\mathcal{F}(0)\right]$$
subject to an intertemporal budget constraint and a transversality condition;
2. **Market Clearing:** $P(\cdot,\cdot)$ adjusts so that $X(W, P(D,\pi), \pi) = 1$ for every W and every pair (D,π)

The assumption of CARA utility function has the convenient property that the demand of risky asset $X(W, P, D, \pi)$ is independent of wealth level W. Therefore, I will denote it as $X(P, D, \pi)$ only. Similarly, consumption won't depend on P and D.

1.3.1. Equilibrium Prices

The following proposition is proven in Veronesi (1999).

Proposition 1.1: (a) Let the conditional expectation of future dividends be denoted by

$$P^*(D,\pi) \equiv E\left[\int_0^\infty e^{-rs} D(t+s)ds \mid D(t) = D, \pi(t) = \pi\right].$$

Then, there exists a REE where the price function $P(D, \pi)$ is given by:

$$\begin{aligned} P(D,\pi) &= p_0 + S(\pi) + P^*(D,\pi) && (1.3)\\ &= p_0 + S(\pi) + p_D D + p_1 + p_\pi \pi && (1.4) \end{aligned}$$

where $p_0 = -\frac{\gamma\sigma^2}{r^2}$, $p_D = \frac{1}{r}$, $p_1 = \frac{\underline{\theta}}{r^2} + \left(\frac{\overline{\theta}-\underline{\theta}}{r^2(\lambda+\mu+r)}\right)\mu$, $p_\pi = \frac{(\overline{\theta}-\underline{\theta})}{r(\lambda+\mu+r)}$ and $S(\cdot)$ is a negative, convex and U-shaped function of $\pi \in [0,1]$ which satisfies the differential equation (4.3) in the Appendix. A.

(b) Let $\lambda = \mu = 0$ and let $\theta = \overline{\theta}$. Then the solution reduces to

$$P(D,\overline{\theta}) = p_0 + p_D D + p_\theta \overline{\theta} \qquad (1.5)$$

where p_0 and p_D are in part (a) and $p_\theta = 1/r^2$.

The fact that $S(\pi)$ is negative implies that the equilibrium price function $P(D, \pi)$ in (1.3) is given by a discount $p_0 + S(\pi) < 0$ over discounted expected dividends $P^*(D, \pi)$. Since $P^*(D, \pi)$ is the price that would occur if investors were risk neutral, I will refer to it as the *risk-neutral price.* Since $S(\pi)$ is U-shaped, this discount is smaller for extreme values of π (i.e. for π close to 0 and 1) than for π close to $\frac{1}{2}$. Figure 1 plots $P^*(D, \pi)$ and $P(D, \pi)$ for the calibrated parameter in Section 3.[2] Finally, notice that part (b) contains the price function of the asset in the case where investors know that the drift rate is $\overline{\theta}$ and that it is a constant. This will allow us also to address the point of model misspecification.

Veronesi (1999) contains additional results in terms of conditional expected returns and conditional volatility. I refer the reader to my earlier work, and rather proceed to the implications of a peso-problem situation for returns.

2. Stock Returns under the "Peso Problem Hypothesis"

This section investigates the theoretical properties of returns under the "Peso Problem Hypothesis," as modeled in the previous section. Specifically, following Bossaerts (1996), I take the perspective of the econometrician and investigate how investors' conditional expectation is affected by the fact that *ex post* no change in regime actually occurred (but they didn't know). That is to say, if during the sample period $[0,T]$ the state has been $\overline{\theta}$, investors will only observe realizations of the process $dD = \overline{\theta}dt + \sigma d\xi$. This sequence of observations has a specific effect on investors posterior probability $\pi(t)$, through the updating rule (1.2), that on average will tend to be concentrated in an area close to one. These sequences of dividends and probabilities in turn have implications on the time series of *equilibrium* stock prices and therefore on the time series of returns, which is the ultimate object of the investigation. The next two sections investigate these effects.

2.1. The "Peso Problem" and the Small-Sample Bias in Expected Returns

For notational convenience, I will let $E^{\overline{\theta}}[\cdot\ |\mathcal{F}(t)]$ denote the expectation operator under the assumption that investors' information is described by $\mathcal{F}(t)$ – that is, the probability $\pi(t)$ – but dividend realizations are generated by the process (1.1) with $\theta(t) = \overline{\theta}$. As in Campbell

[2] All plots use the parameters assumed in Table 1. The reader is referred to Veronesi (1999) for other similar plots with different parameter values.

and Kyle (1993), Wang (1993) and Veronesi (1999), it is convenient to state the results about returns in terms of dollar excess returns. That is, I will let $dQ = (D - rP)\,dt + dP$ denote the return on a zero investment portfolio long one share of the asset and financed by borrowing at the risk-free rate r. As in proposition 1.1, a star "*" will denote quantities under risk-neutrality. I now obtain the implication for conditional expected returns under risk-neutrality and under risk-aversion.

Proposition 2.1: Let $\theta(t) = \overline{\theta}$ during the sample period $[0, T]$. Then:

(a) If investors are risk neutral, the conditional expected return is positive and given by:

$$E^{\overline{\theta}}[dQ^* \mid \mathcal{F}(t)] = \frac{\overline{\theta} - \underline{\theta}}{r}(1-\pi)\left(1 + \frac{\overline{\theta} - \underline{\theta}}{(\lambda + \mu + r)\sigma} h(\pi)\right) dt \tag{2.1}$$

$$= \frac{\overline{\theta} - \underline{\theta}}{\sigma}(1-\pi)\sigma_{P^*}(\pi) dt \tag{2.2}$$

where $\sigma_{P^*}(\pi) = \frac{1}{r}\left(1 + \frac{\overline{\theta}-\underline{\theta}}{(\lambda+\mu+r)\sigma} h(\pi)\right)$ is the volatility of dQ^* under risk-neutrality.

(b) If investors are risk averse, then the expected return are given by:

$$E^{\overline{\theta}}[dQ \mid \mathcal{F}_t] = \left(\gamma\sigma + (\gamma r p_\pi + f'(\pi))h(\pi) + \left(\frac{\overline{\theta} - \underline{\theta}}{\sigma}\right)(1-\pi)\right)\sigma_P(\pi) dt \tag{2.3}$$

where $\sigma_P(\pi) = \sigma_{P^*}(\pi) + S'(\pi)h(\pi)$ is the volatility of dQ, and $f(\pi)$ is a U-shaped, convex function of π that satisfies the ODE (4.1) in Appendix A.

Part (a) shows that if we suppose the state has been $\theta(t) = \overline{\theta}$ over the sample period, the time series of excess returns should display a positive drift even under risk neutrality. This is of course not surprising and it has been discussed already in the literature on the Peso Problem (see e.g. Rietz (1988), Danthine and Donaldson (1998)). However, equation (2.2) also shows that we should observe a positive relationship between excess returns and volatility, although the coefficient to the stock return volatility $\sigma_{P^*}(\pi)$ is not constant.

Part (b) shows a similar positive relationship between returns and volatility, but this time with a positive risk aversion coefficient. A more intuitive formula can be obtained through the decomposition:

$$E^{\overline{\theta}}[dQ\ |\mathcal{F}_t] = E[dQ\ |\mathcal{F}_t] + E^{\overline{\theta}}[dQ^*|\mathcal{F}_t] + S'(\pi)h(\pi)E^{\overline{\theta}}[dv\ |\mathcal{F}_t].$$

Thus, the presence of risk aversion affects the small sample bias in stock returns. In fact, we see that the expected return conditional on $\theta(t) = \overline{\theta}$ is given by the *ex-ante*, required expected return $E[dQ \mid \mathcal{F}_t]$ (which is the quantity the econometrician is interested in), plus two terms which depend on the actual state $\overline{\theta}$. The first, $E^{\overline{\theta}}[dQ^* \mid F_t]$, is the same positive bias that is realized even under risk-neutrality. The second, $S'(\pi)h(\pi)E^{\overline{\theta}}[dv\ |\mathcal{F}_t]$ is an extra term which is due to risk aversion. We find that if the state is $\theta = \overline{\theta}$ and $\pi > \hat{\pi}$ where $\hat{\pi}$ is such that $S'(\widehat{\pi}) = 0$, this is a positive term. Hence, if the state has been the normal one over the sample period, the positive bias is higher than in the case of risk neutrality. The simulation results will show the quantitative effects of this bias in returns.

2.2. The "Peso Problem" and Return Volatility

In this subsection I investigate in more detail the process for the volatility $\sigma_{P^*}(\pi) = \frac{1}{r}\left(1 + \frac{\overline{\theta}-\underline{\theta}}{(\lambda+\mu+r)\sigma}h(\pi)\right)$ introduced in (2.2), under the assumption that $\theta(t) = \overline{\theta}$.

Proposition 2.2: If $\theta(t) = \overline{\theta}$ and $\pi(t) > \frac{1}{2}$ over the sample period, then:

$$d\sigma_{P^*} = a\left(\sigma_{P^*}\right)dt - b\left(\sigma_{P^*}\right)d\xi \tag{2.4}$$

where $a\left(\sigma_{P^*}\right)$ and $b\left(\sigma_{P^*}\right)$ are two explicit functions of σ_{P^*}, given in Appendix B. In addition, $b\left(\sigma_{P^*}\right) > 0$.

In (2.4) $d\sigma_{P^*}$ depends only on the past values of σ_{P^*}, through the two functions $a\left(\sigma_{P^*}\right)$ and $b\left(\sigma_{P^*}\right)$, given in the Appendix B and plotted in Figure 2 for calibrated parameters (see next Section). Moreover, the stochastic element is given by the Wiener process $\xi(t)$. Notice that since $b\left(\sigma_{P^*}\right) > 0$, the coefficient of $d\xi$ is negative, as we would expect: under the assumption that $\pi > \frac{1}{2}$ over the sample period, positive shocks to fundamentals decrease volatility while negative shocks increase it. In addition, the drift rate $a(\sigma_{P^*})$ is positive for low σ_{P^*} and negative for high σ_{P^*}, implying a (non-linear) mean reverting process for volatility σ_{P^*}.

Finally, σ_{P^*} characterized in proposition 2.2 is the "risk-neutral" volatility. But risk aversion implies that $\sigma_P(\pi) = \sigma_{P^*}(\pi) + S'(\pi)h(\pi)$ (see proposition 2.1 (b)), and thus a higher volatility when $\pi > \hat{\pi}$ and lower when $\pi < \hat{\pi}$, where $\hat{\pi}$ is such that $S'(\hat{\pi}) = 0$. Since the "Peso problem" hypothesis requires $\theta(t) = \overline{\theta}$ over the sample period, the relevant case is for π very large. Hence, we should expect to observe larger volatility than what is implied by proposition 2.2, but with the same qualitative behavior; that is, it increases after negative shocks to fundamentals and decreases after positive shocks.

2.3. The "Peso Problem" and the Survival of Markets

The above discussion is also related to Brown *et al.* (1995) and the literature on survival of markets (see Goetzman and Jorion (1999a,b)). Brown *et al.* (1995) investigate the *ex post* statistical behavior of the time series of returns which have "survived" for a sample period $[0, T]$. They assume a simple diffusion process for (log) prices and postulate that the market does not survive if the price hits an absorbing lower bound. Under these assumptions, they show that if the price series did not hit the lower bound, the implied time series of returns should display many of the features actually observed in U.S. data series, including "puzzling" risk premia and mean reversion. They also show that the bias in expected returns should increase with return volatility, because the latter increases the probability of hitting the lower bound. As an example, they often suggest that since emerging markets have highly volatile stock returns, they should display abnormal excess returns if they survived *ex post.* Their model, however, does not address the issue of the possible sources of return volatility.

My model offers another explanation for the abnormal excess returns realized in emerging markets, which is also consistent with the substantial volatility of market returns. In periods of high uncertainty over the true state of the economy (which may include many factors, e.g. political ones), investors react heavily to news, and therefore stock returns should be highly volatile. If *ex post* the market survived, it means that the state of the world has been the favorable one over the sample period. Hence, proposition 2.1 applies and the expected returns should be positive and substantial.

3. Monte Carlo Simulations

In this section I use Monte Carlo simulations to study the characteristic features of the present model and compare them to the stylized facts of U.S. stock returns. The first step is to calibrate some of the parameters under the null hypothesis that $\theta(t) = \overline{\theta}$ over the sample period. These are $\overline{\theta}$, σ and the real interest rate r. We are subject to the difficulty that I have to assume a Gaussian dividend process for tractability reasons, whereas a log-normal process would probably be more appropriate. Even though this is just a rough approximation, I will use the mean and the standard deviation of dividend growth rates for $\overline{\theta}$ and σ, respectively.[3]

In addition, under the null hypothesis, no change in state ever occurred over the sample period, which implies I need to choose a very small value for λ. The choice $\lambda = .005$ implies an expected time for a shift of about 200 years. If a downward shift occurs, I assume that there is a $\underline{\theta} = 5\%$ average decrease in dividends for an expected time of 20 years ($\mu = .05$). These choices make a downward shift quite dramatic and are meant to capture the sense of the quotation in the introduction about the Peso problem that investors were facing during the 30's. However dramatic a shift would be, notice that the unconditional probability to be in the favorable state is around 0.91 and the unconditional expected θ is 0.009. Finally, the risk-free real interest rate r has been chosen to be 3% which is slightly above to the historical mean (less than 2%). This makes the estimates more conservative: low interest rates only amplify the price sensitivity to changes in dividends and to changes in beliefs, because dividends in the distant future have a greater weight in the determination of today's price, and all the effects will be more pronounced. Table 1 report the parameter values in the calibration.

[3]Annual data on real dividends from 1871 to 2000 were used. The source is Campbell and Shiller (1988) updated data series.

Finally, to have a sense of the order of magnitude of the coefficient of relative risk aversion implied by the assumptions made so far, Veronesi (1999, Proposition 3) shows that the value function for the representative agent can be written as $J(W,\pi) = -e^{\gamma r W} F(\pi)$ for some function $F(\pi)$. Thus, the relative risk aversion is simply given by $RRA = -WJ''(W,\pi)/J'(W) = \gamma r W = 0.03W$. In this economy with one unit of the risky asset, we can think of investor's financial wealth being in the order of magnitude of the price of the asset. In all simulations the price of the asset rarely exceeded the 100 level. Thus, we find that the coefficient of relative risk aversion implied by this model is generally below 3.

Given the parameters in Table 1, I generate 500 independent samples for dividends $D(t)$ using the Euler discrete approximation of the process in equation (1.1). Each sample has 900 "monthly" observations (75 years) while each month contains 22 (daily) observations. From the dividend observations I compute the posterior probabilities by approximating the process in (1.2). Finally, I use the dividend and probability series to compute the prices $P(D,\pi)$ and $P^*(D,\pi)$ by using (1.3) and (1.4). All the other variables are computed from these latter time series. Figures 3 shows the results of a particular sequence of dividends and probabilities, together with the implied price values and return volatility levels, generated by the above procedure.[4]

3.1. "GARCH" and Leverage Effects

In this subsection I fit the GARCH(1,1) model

$$\sigma_t^2 = \omega + \beta\sigma_{t-1}^2 + \alpha\eta_t^2 \tag{3.1}$$

[4]The volatility is estimate as

$$\sigma_t^2 = \sum_{i=1}^{20} (r_{i,t} - \bar{r}_t)^2$$

where $r_{i,t}$ is the return in day i in month t, and $\bar{r}_t$ is the average monthly return.

where $\eta_t \sim \mathcal{N}(0, \sigma_{t-1})$, on each of the 500 samples simulated.[5] Table 2 reports the distribution of the three parameters across the simulation. For comparison, I also include the estimates obtained using monthly data for excess returns from 1926:01-2001:12.[6] The results of the Monte Carlo simulation show that in average, the parameter estimates are almost identical to the ones observed in the data. The autoregressive parameter β equals a median .88 (mean = .87) across simulations, against a .86 in the data. Similarly, the impact of news to volatility is very similar, with $\alpha = .12$ in both cases. We can also notice that there is not much variation of the parameter estimates across samples, showing that the "Garch effect" is a genuine feature of the model, and mainly due to the Peso-Problem situation, as modeled in this paper.

The "Peso problem" hypothesis is also interesting because it entails an effect commonly referred to as the "leverage effect" (see Black (1976)), which is a negative relationship between returns and future volatility. In the above model, the distribution of π conditional on $\theta(t) = \overline{\theta}$ is concentrated in the area close to 1. As discussed, this implies that when π decreases, both volatility increases and the price decreases. Hence, we should observe a negative correlation between *ex post* returns and future volatility. This relationship between returns and future volatility is observed in U.S. data. Black (1976) explained this phenomenon as stemming from the increase in the debt-to-equity ratio of a leveraged firm following a drop in its stock price. The increase in the stock return volatility just reflects the increase in the riskiness of the leveraged firms. The model presented here provides an alternative explanation: both the price and the volatility of the stock react after bad news because the underlying uncertainty over the true state of the world increases.

In order to quantify this effect, Table 3 reports the results of the Monte Carlo simulation where an Exponential GARCH(1,1) model has been fitted on each of the 500 simulated samples.

[5]In this model it could happen that prices become negative, thereby making it impossible to compute percentage returns. For those simulated samples where this situation occured, I rescaled the dividend series to ensure positive prices. A previous version of the paper used "dollar returns" rather than percentage returns, which are free from this problem. The results were qualitatively similar, although harder to compare with the US data.

[6]Data are from the CRSP tapes at the University of Chicago.

The EGARCH(1,1) model is given by:

$$\log(\sigma_t) = \omega + \beta \log(\sigma_{t-1}) + \alpha[|\epsilon_t| - c\epsilon_t] \tag{3.2}$$

Under the leverage effect hypothesis, αc should be positive, implying that negative innovations have a greater impact on volatility than positive innovations. Moreover, $c > 1$ also implies that while negative innovations tend to increase the volatility, positive innovations tend to decrease it. As expected from equation (2.4), we see from Table 3 that the model implies an asymmetric reaction of volatility to bad and good news, as $c > 0$. Indeed, the model produces even "too much" of a leverage effect, as the parameter c has a median equal to 1.48 across simulations, while data yield the much smaller $c = .22$. Similarly, the autoregressive coefficient β results higher in the simulation (.997) than in the data (0.97). This implies that the volatility process implied by the model is more persistent than it is empirically observed. Still, one can conclude from the results in Table 2 and 3 that the model produces a good deal of time-variation in volatility, which is related with the directional movement in the stock market.

3.2. The small-sample bias in expected returns

This section discusses the quantitative implications of the Peso Problem for the estimated average returns, the standard finding in the Peso Problem literature (see e.g. Rietz (1988), Danthine and Donaldson (1998)). To quantify the effects, I will compare them to an alternative model, where agents know exactly the state $\theta(t) = \overline{\theta}$ and no shifts are possible. In this and the next section I will refer to this latter model as the Benchmark case, as it is the natural alternative to the Peso-Problem situation discussed here. In addition, it is a special case of the models by Wang (1993) and Campbell and Kyle (1993).

Table 4 shows the results of the Monte Carlo Simulations. From the first two columns, we see that indeed the small sample bias increases the mean average returns from 0.77% for the benchmark case, to above 3% for the Peso Problem, a four-fold increase. Although the latter number is still half of the equity premium, it shows that the small sample bias can induce large effects on the average return, as others have shown. The low value of the equity premium is due to the fact that as discussed in Section 3, the calibrated parameters imply a coefficient of relative risk aversion well below 3, thereby justifying also the very low equity premium in the benchmark case.

3.3. Stock price sensitivity to dividend changes and excess volatility

The model presented in this paper adds also to the debate on stock price fluctuations in response to dividend changes. In particular, starting with Shiller (1981) and LeRoy and Porter (1981), many papers challenged the efficient market, present-value model hypothesis on the basis that the stock price appeared to be too volatile, compared to *ex post* discounted dividends.[7] Indeed, by running a regression of monthly log-prices on log-dividends, we find the following:

$$\begin{array}{rccl} \log(P_t) = & 3.0687 & +1.1887 & \log(D_t) \\ & (0.0443) & (0.0386) & \end{array} \tag{3.3}$$

where standard errors are in parenthesis. This shows that a 1% change in dividend implies a change in price greater than 1%. This empirical regularity has been addressed by Barsky and De Long (1993), who only consider the long term case (around a 20 year time span). They propose a simple model where this "overreaction" of prices to dividend fluctuations stems from investors' revision of their own estimate of the long-term dividend growth rate, which they use to compute future dividends.

The model presented in this article gives a similar explanation to the excess sensitivity of prices to dividend changes. In fact, from the price function given in equation (1.3) and (1.4), we can see that a change in dividend has a direct and an indirect effect on the price of the asset: the direct effect is through the term $\frac{D}{r}$ and the indirect effect is through the revision in the probability π that the change in dividend would entail. Depending on the sensitivity of π

[7] See e.g. Mankiw, Romer and Shapiro (1985,1991), Campbell and Shiller (1988), Shiller (1989). Marsh and Merton (1986) offer an early reply to the concerns raised by Shiller (1981) and LeRoy and Porter (1981). See also West (1988) for a survey and references.

to news and the sensitivity of the price to changes in π the indirect effect may be substantial. To have a comparison, the last two columns in Table 4 report the results of the Monte Carlo simulation of the regression (3.3) both for the benchmark case, and the peso-problem case. In short, while the benchmark case yield a sensitivity parameter very close to 1, thereby justifying the concerns of the early literature started by Shiller (1981) and LeRoy and Porter (1981), the peso-problem effects are strong enough to generate a substantial excess sensitivity of price changes to dividend changes. The mean elasticity is about 2, which is quite higher than the one found empirically, but it confirms nonetheless that the "double kick" to prices stemming from learning and the Peso-Problem hypothesis can yield the effect.

To quantify the magnitude of the excess sensitivity of price reactions to dividend news, the second two columns of Table 4 show that the average volatility in the benchmark case is a small 6.5%, as the only volatility is stemming from changes in dividends, which are not very volatile (in sample, 6.5% was also the average volatility of dividend growth). In the Peso Problem Situation, instead, the average volatility in the simulations is around 21%. Thus, learning effects can have important effects on the level of the volatility of returns, as was first discussed by Timmerman (1993). The simulations in addition show that these learning effects have a rather strong impact on the volatility, even when the probability of entering into a (10-year) long recession is puny, about once every 200 years. Indeed, in this model even small movements in the updated probability of being in a recession are amplified by the fast increase in the discount when the probability π decreases, as shown in Figure 1.

4. Conclusion

This paper shows that the "Peso Problem Hypothesis" on economic fundamentals has several implications that have not previously documented. Specifically, I show that (*i*) returns should have GARCH behavior; (*ii*) there should be a negative predictive asymmetry between returns and future volatility; (*iii*) return volatility should increase during recessions; (*iv*) the time series of returns should have an upward bias due to small sample; and (*v*) price sensitivity to dividend changes should be greater than the one implied by standard present value models. In addition, Monte Carlo simulations show that the magnitude of the effects are comparable to those observed in the US data.

A concluding remark is in order: This paper shows theoretically that a "Peso Problem situation" generates a time-varying volatility with the same characteristics as the one in the data, and in particular with negative news that have a higher impact on the volatility than positive news. This is in line with the quote by Merton in the Introduction about the high volatility in the 30s. Yet, this of course does not imply that *all* "Garch effects" that we see in the data *must* be due to a Peso Problem situation. Other sources could be at play, possibly also related to uncertainty. Nonetheless, the contribution of this paper is to show that a Peso Problem situation would tend to generate *simultaneously* a number of features in returns, namely, effects (i) - (v) above, which are somewhat established feature of the data in "surviving" economies, as discussed in Section 2.3.

Appendix A

The two differential equations appearing in proposition 1.1 and 2.1 are the following:

$$-f''(\pi)Q_3(\pi) + f'(\pi)^2 Q_3(\pi) + f'(\pi)Q_2(\pi) + f(\pi)r + Q_0(\pi) = 0 \tag{4.1}$$

where $Q_3 = \frac{h(\pi)^2}{2}$, $Q_2 = h(\pi)\sigma\gamma - (\pi^s - \pi)(\lambda + \mu) + \gamma r p_\pi h(\pi)^2$ and $Q_0 = \frac{(r\gamma)^2}{2} p_\pi^2 h(\pi)^2 + r\gamma^2 \sigma p_\pi h(\pi)$.

$$S''(\pi)P_3(\pi) = S'(\pi)P_2(\pi) + rS(\pi) + P_0(\pi) \tag{4.2}$$

where $P_3(\pi) = h(\pi)^2/2$, $P_2(\pi) = \gamma\sigma h(\pi) - (\pi^s - \pi)(\lambda + \mu) + \gamma r p_\pi h(\pi)^2 + f'(\pi)h(\pi)^2$and $P_0(\pi) = \gamma r p_\pi^2 h(\pi)^2 + 2\gamma\sigma p_\pi h(\pi) + f'(\pi)\frac{\sigma}{r} h(\pi) + f'(\pi) p_\pi h(\pi)^2$.

Appendix B

Proof of Proposition 2.1: (a) By definition, for $\theta(t) = \overline{\theta}$ we have that:

$$E(dQ^*|\mathcal{F}_t, \overline{\theta})/dt = (D - rP^*) + E(dP^*|\mathcal{F}_t, \overline{\theta}, \pi)$$

We can substitute the definition of P^*, to obtain (after some tedious algebraic manipulations):

$$E(dQ^*|\mathcal{F}_t, \overline{\theta})/dt = \frac{\overline{\theta} - \underline{\theta}}{r} - \frac{\Delta\theta}{r}\pi + \frac{\Delta\theta}{r(\lambda + \mu + r)} h(\pi) E(dv|\mathcal{F}_t, \overline{\theta}, \pi)$$

Notice that dv is a Wiener process with respect to $\mathcal{F}_t$, but it is not with respect to $\mathcal{F}_t \cup \overline{\theta}$. In fact, we have $E(dv|\mathcal{F}_t, \overline{\theta}, \pi) = \frac{\Delta\theta}{\sigma}(1 - \pi)$. By substituting this in the above expression, we prove the claim.

(b) By definition, $E[dQ\ |\mathcal{F}_t, \overline{\theta}] = (D - rP)dt + E[dP\ |\mathcal{F}_t, \overline{\theta}]$. By substituting for $P(D, \pi)$, we obtain:

$$\begin{aligned}
E[dQ\ |\mathcal{F}_t, \overline{\theta}] &= (D - rP^*)dt + (-rp_0 - rS(\pi))dt + E[dP^*\ |\mathcal{F}_t, \overline{\theta}] + S'(\pi)E[d\pi\ |\mathcal{F}_t, \overline{\theta}] \\
&\quad + \frac{1}{2}S''(\pi)E[(d\pi)^2\mathcal{F}_t, \overline{\theta}] \\
&= E[dQ^*\ |\mathcal{F}_t, \overline{\theta}] + (-rp_0 - rS(\pi) + S'(\pi)(\pi^s - \pi)(\lambda + \mu) + \frac{1}{2}S''(\pi)h(\pi)^2)dt \\
&\quad + S'(\pi)h(\pi)E(dv\ |\mathcal{F}_t, \overline{\theta})
\end{aligned}$$

We now substitute $E(dv\ |\mathcal{F}_t, \overline{\theta}) = \frac{\Delta\theta}{\sigma}(1 - \pi)$ and from Veronesi (1999) (appendix A) we also have:

$$-rp_0 - rS(\pi) + S'(\pi)(\pi^s - \pi)(\lambda + \mu) + \frac{1}{2}S''(\pi)h(\pi)^2 = (f'(\pi) - \gamma r S'(\pi))h(\pi)\sigma_P(\pi) + \gamma r \sigma_P(\pi)^2 \tag{4.3}$$

We see that by using the definition of $\sigma_P(\pi)$, we can rewrite the RHS as $\sigma_P(\pi)(\gamma\sigma + (\gamma r p_\pi + f'(\pi))h(\pi)) = E[dQ\ |\mathcal{F}_t]$. Hence, by substituting all this back we obtain:

$$\begin{aligned}
E[dQ\ |\mathcal{F}_t, \overline{\theta}] &= E[dQ^*\ |\mathcal{F}_t, \overline{\theta}] + E[dQ\ |\mathcal{F}_t] + S'(\pi)h(\pi)E[dv\ |\mathcal{F}_t\overline{\theta}] \\
&= \frac{\Delta\theta}{r}(1 - \pi)(\sigma_P(\pi) - S'(\pi)h(\pi)) + (\gamma\sigma + (\gamma r p_\pi + f'(\pi))h(\pi))\sigma_P(\pi)dt \\
&\quad + S'(\pi)h(\pi)\frac{\Delta\theta}{\sigma}(1 - \pi)dt \\
&= \left(\gamma\sigma + (\gamma r p_\pi + f'(\pi))h(\pi) + \frac{\Delta\theta}{r}(1 - \pi)\right)\sigma_P(\pi)dt
\end{aligned}$$

concluding the proof. $\square$

Proof of Proposition 2.2: We show that if $\theta(t)=\overline{\theta}$ and $\pi>\frac{1}{2}$ during the sample period, we have:

$$\begin{aligned} d\sigma_{P^*} &= [-a_0+a_1\sqrt{1+s_0-s_1\sigma_{P^*}}+a_2\sigma_{P^*}-a_3\sigma_{P^*}^2-a_4\sigma_{P^*}\sqrt{1+s_0-s_1\sigma_{P^*}}]dt \\ & -\frac{\Delta\theta}{2\sigma}(\sigma_{P^*}-\frac{\sigma}{r})\sqrt{1+s_0-s_1\sigma_{P^*}}d\xi \end{aligned}$$

where, defining $\tilde{p}=\frac{(\overline{\theta}-\theta)^2}{\sigma r(\lambda+\mu+r)}$, $s_0=4\frac{\sigma}{r\tilde{p}_\pi}$, $s_1=\frac{4}{\tilde{p}_\pi}$, $a_0=\frac{(\Delta\theta)^2}{2\sigma(\lambda+\mu+r)}+3\sigma+\frac{\sigma(\lambda+\mu)}{r}$, $a_1=\frac{(2\lambda+r)(\Delta\theta)^2}{2\sigma r(\lambda+\mu+r)}$, $a_2=\frac{(\Delta\theta)^2}{2\sigma^2}+6r+4(\lambda+\mu)$, $a_3=\frac{3r(\lambda+\mu+r)}{\sigma}$ and $a_4=\frac{(\Delta\theta)^2}{2\sigma^2}$.

Use the definition of dv in Lemma 1.1 with $dD=\overline{\theta}dt+\sigma d\xi$ to obtain $dv=\frac{1}{\sigma}\Delta\theta(1-\pi)dt+d\xi$. This can be substituted into the process for $d\sigma_{P^*}$ obtained by Ito's Lemma to $\sigma_{P^*}(\pi)=\frac{1}{r}\left(1+\frac{\overline{\theta}-\theta}{(\lambda+\mu+r)\sigma}h(\pi)\right)$ to obtain:

$$\begin{aligned} d\sigma_{P^*}(\pi) &= \tilde{p}_\pi[(1-2\pi)(\pi^s-\pi)(\lambda+\mu)-h(\pi)^2]dt \\ & +\tilde{p}_\pi(1-2\pi)h(\pi)\frac{\Delta\theta}{\sigma}(1-\pi)dt+\tilde{p}_\pi(1-2\pi)h(\pi)d\xi \end{aligned} \tag{4.4}$$

Since $\sigma_{P^*}=\frac{\sigma}{r}+p_\pi h(\pi)$ implies the relation $\sigma_{P^*}-\frac{\sigma}{r}-\tilde{p}_\pi\pi+\tilde{p}_\pi\pi^2=0$. Under the assumption that $\pi>\frac{1}{2}$, we obtain a solution of π in terms of σ_P^*, given by $\pi=\frac{1}{2}+\frac{1}{2}\sqrt{1+s_0-s_1\sigma_{P^*}}$. By substituting for π, $h(\pi)$ and $h(\pi)^2$ in (4.4), tedious algebraic manipulations show the claim. $\square$

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Table 1

Calibration

$\overline{\theta}$	$\underline{\theta}$	σ	r	γ	λ	μ
.015	−.05	.12	.03	1	.005	.05

Table 2

GARCH Effects

U.S. Stock Market			
	ω ($\times 10^3$)	β	α
estimate	0.0685	0.8588	0.1205
asymptotic s.e.	(0.0153)	(0.0183)	(0.0212)
Monte Carlo Simulations			
	ω ($\times 10^3$)	β	α
mean	0.0322	0.8723	0.1239
sd	0.0474	0.0414	0.0471
min	0.0004	0.697	0.0486
5%	0.0028	0.789	0.0713
25%	0.0086	0.8526	0.0927
50%	0.018	0.883	0.1132
75%	0.0364	0.9007	0.1417
95%	0.1096	0.9225	0.215
max	0.6496	0.943	0.3511

GARCH Model:

$\sigma_t^2 = \omega + \beta\sigma_{t-1}^2 + \alpha\eta_t^2$

$\eta_t = (r_t - \bar{r}) \sim \mathcal{N}(0, \sigma_{t-1})$

Table 3

The Leverage Effect

	U.S. Stock Market			
	ω	β	α	c
estimate	-0.1646	0.9740	0.1109	0.2689
asymptotic s.e.	(0.0130)	(0.0048)	(0.0143)	(0.0947)
	Monte Carlo Simulations			
	ω	β	α	c
mean	-0.0485	0.997	0.0453	4.2742
sd	0.0296	0.0037	0.0277	10.6926
min	-0.2149	0.9726	0.0005	-0.0352
5%	-0.1003	0.9903	0.0041	0.4441
25%	-0.0661	0.9957	0.0229	0.9212
50%	-0.0448	0.998	0.0426	1.4888
75%	-0.0257	0.999	0.0637	2.8508
95%	-0.0079	1.000	0.0945	20.0874
max	-0.0029	1.000	0.1581	137.853

EGARCH(1,1) Model:

$\log(\sigma_t) = \omega + \beta \log(\sigma_{t-1}) + \alpha[|\epsilon_t| - c\epsilon_t]$

$\epsilon_t = \frac{\eta_t}{\sigma_{t-1}}$, $\eta_t = (r_t - \bar{r}) \sim \mathcal{N}(0, \sigma_{t-1})$

Table 4

Small Sample Bias and Excess Volatility

	US Stock Market	
Average Returns	Average Volatility	Price Sensitivity
6.45%	19.66%	1.1887

Monte Carlo Simulations

	Average Returns		Average Volatility		Price Sensitivity	
	Benchmark	Peso	Benchmark	Peso	Benchmark	Peso
mean	0.0076	0.0313	0.0658	0.2207	1.0255	2.0147
sd	0.0071	0.0126	0.0107	0.0951	0.0042	0.4280
min	-0.0109	-0.0055	0.0417	0.0872	1.0154	1.3612
5%	-0.0037	0.0101	0.0495	0.1251	1.0194	1.4834
25%	0.0023	0.0222	0.0582	0.1584	1.0226	1.6616
50%	0.0075	0.0307	0.0648	0.1893	1.0251	1.9056
75%	0.0127	0.0416	0.0724	0.2516	1.0282	2.2832
95%	0.0194	0.0516	0.0845	0.4138	1.0334	2.8765
max	0.0243	0.065	0.105	0.7182	1.0405	3.3375

Average return and average volatility are given by the time-series annualized mean and standard deviation of log-returns in the US sample 1926 - 2001, and in simulated data. The price-sensitivity refers to the slope coefficient of the regression $\log(P_t) = \alpha + \beta \log(D_t) + \epsilon_t$ in the data and in simulations. The benchmark model is the one where dividend growth is fixed and known to investors, while the Peso column refers to the effect of the Peso problem situation.

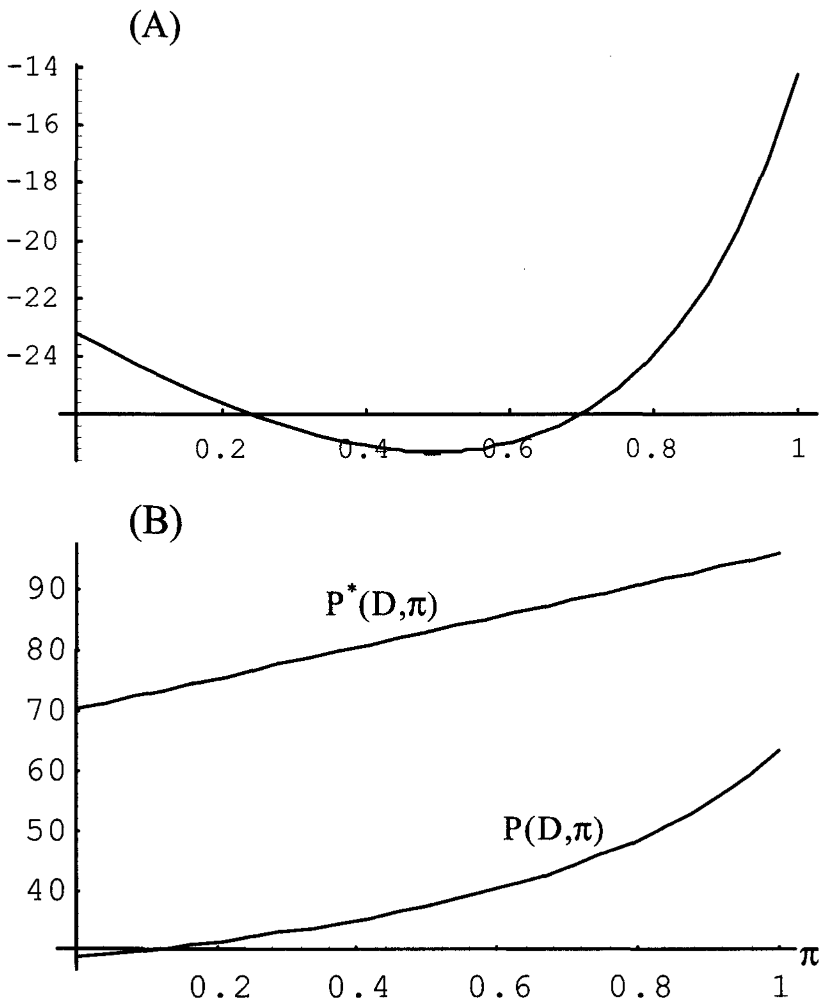

Figure 1: (A) The function $S(\pi)$. (B) The risk-neutral price $P^*(D,\pi)$ and the price function $P(D,\pi)$

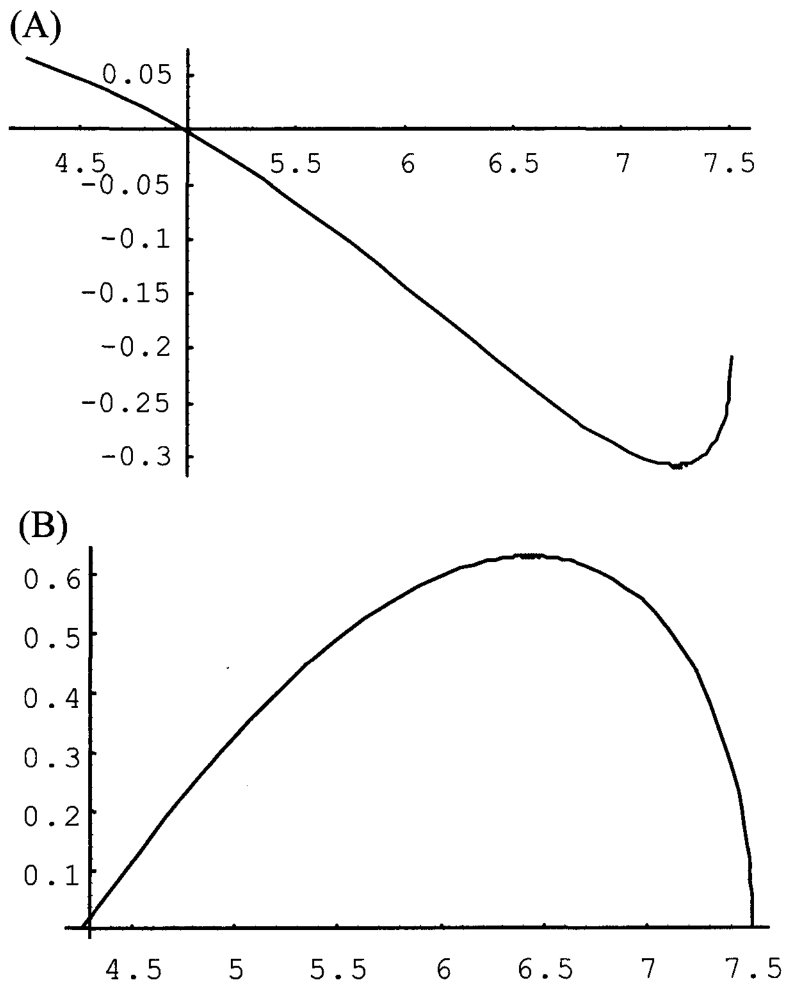

Figure 2: (A) The drift $a(\sigma_P*)$ of the volatility process. (B) The diffusion $b(\sigma_P*)$ of the volatility process.

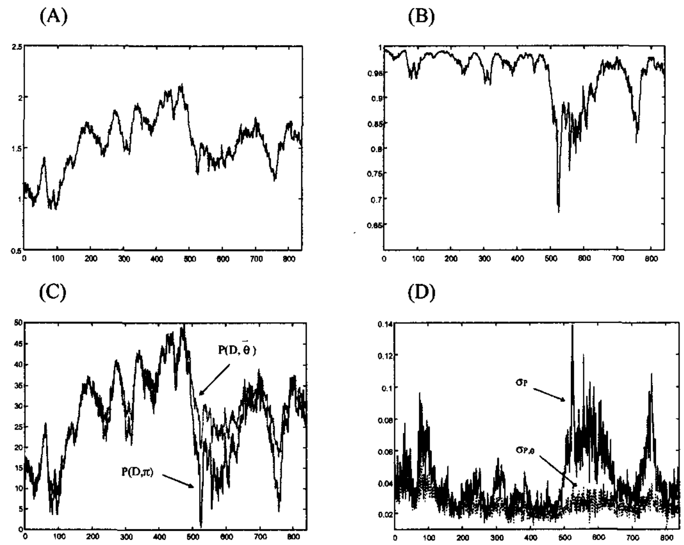

Figure 3: (A) A simulated dividend series; (B) The updated probability π; (C) The implies prices $P(D,\pi)$ and $P(D,\theta)$; (D) The estimated monthly volatility : σ_P and $\sigma_{P,\theta}$.

Kentucky-American Water Company
Case No. 2004-00103
Information Request Response to Commission Staff
Respondent: OAG Witness Dr. J. Randall Woolridge
Set I

PSC-I-34. List the last 5 state utility regulatory proceedings in which Dr. Woolridge appeared as a witness on the issue of return on equity and provide a copy of his testimony.

Response:

Ohio:

SBC Ohio (Case No. 02-1280-TP-UNC R-00-649). Attachment PSC-I-34A1.

Pennsylvania:

Pennsylvania-American Water Company (R-00038304), Attachment PSC-I-34A2.

National Fuel Gas Distribution Company (R-00038168), Attachment PSC-I-34A3.

Philadelphia Suburban Water Company (R-00016750), Attachment PSC-I-34A4.

Pennsylvania-American Water Company (R-00016339), Attachment PSC-I-34A5.

Kentucky-American Water Company
Case No. 2004-00103
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Respondent: OAG Witness Dr. J. Randall Woolridge
Set I

PSC-I-35. At pages 9 and 10 of his direct testimony, Dr. Woolridge states that he used the average of the quarterly capitalization ratios over the prior 3 years as the basis for his proposed capital structure.
a. State whether Dr. Woolridge is aware that Administrative Regulation 807 KAR 5:001, Section 10(c), requires the capitalization and net investment rate base to be based on a 13 month average for the forecasted period.
b. Explain how the use of a capital structure based upon a 3-year average of Kentucky-American's quarterly capital structures complies with Administrative Regulation 807 KAR 5:001, Section 10(c).

Response:

a. Yes. As I understand the administrative regulation, the capitalization and net investment rate base are to be presented on a 13 month average for the forecasted period.

b. As noted, the administrative regulation requires that the capitalization and net investment rate base be presented in a specific format for the application. However, for the evaluation of the historic capitalization of KAWC, it is apparent that the company's traditional financing strategy differs from that presented in the application. And the reason is that KAWC refinanced its short-term debt this spring. This refinancing distorts the company's capitalization over the next thirteen months. Using the average capitalization over a three-year period provides for a capital structure that more likely reflects how KAWC will be financed in the period over which the rates will be in effect.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	)	
	)	
ADJUSTMENT OF THE RATES OF KENTUCKY-AMERICAN WATER COMPANY	))	**CASE NO. 2004-00103**

COMMISSION STAFF'S FIRST SET OF INFORMATION REQUESTS TO THE ATTORNEY GENERAL

36. Refer to Direct Testimony of Andrea C. Crane at Schedule ACC-43.

a. Provide a revised schedule that lists each of Ms. Crane's recommended adjustments.

b. For each recommended adjustment, show the calculations used to derive the adjustment.

c. Multiplying the taxable income listed in the pro forma present rate column of $9,366,284 by 40.37 percent results in income taxes of $3,781,168, which is $272,982 greater than the reported income tax expense of $3,508,186. Explain this discrepancy.

d. Multiplying the taxable income listed in the per company column of $5,680,443 by 40.37 percent results in income taxes of $2,293,194, which is $79,913 greater than the reported income tax expense of $2,213,281. Explain this discrepancy.

Response:

a. The requested schedule is attached. Also attached is the excel file containing this schedule.

b. The calculations are contained on the excel files that have been provided to Staff.

c. The pro forma column is the sum of the "Per Company" income taxes and the "Recommended Adjustments" income taxes. The Per Company income taxes were taken from the Company's filing and Ms. Crane made to no adjustments to those amounts. The "Recommended Adjustments" income taxes are 40.36549 percent (rounded to 40.37% in Schedule ACC-43) times the taxable income of $3,685,841, less the consolidated income tax adjustment of $192,903.

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COMMISSION STAFF'S FIRST SET OF INFORMATION REQUESTS TO THE ATTORNEY GENERAL

36. (Continued)

d. Ms. Crane did not develop these amounts but simply used the amounts shown in the Company's filing. The discrepancy is most likely due to adjustments to taxable income made by the Company.

Respondent: Andrea C. Crane

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COMMISSION STAFF'S FIRST SET OF INFORMATION REQUESTS TO THE ATTORNEY GENERAL

ATTACHMENT TO QUESTION 36A

KENTUCKY AMERICAN WATER COMPANY

FUTURE TEST YEAR ENDING NOVEMBER 30, 2005

PRO FORMA INCOME STATEMENT

		Per Company	Recommended Adjustments	Pro Forma Present Rates	Recommended Rate Adjustment	Pro Forma Proposed Rates
1. Operating Revenues		$43,389,662	$1,878,598	$45,268,260	$111,933	$45,380,193
2. Residential Consumption			1,095,293			
3. Residential Customers			151,249			
4. Commercial Consumptions			753,187			
5. Commercial Customers			231,773			
6. Public Fire Revenue			89,013			
7. Private Fire Revenue			29,023			
8. AFUDC			(470,940)			
9. Total Revenue Adjustments			1,878,598			
10. Operating Expenses		21,910,724	(1,163,578)	20,747,146	754	20,747,900
11. Residential Consumption			192,843			
12. Residential Customers			22,648			
13. Commercial Consumptions			142,901			
14. Commercial Customers			42,571			
15. Salaries and Wages - Vacancies			(178,181)			
16. Salaries and Wages - Other			(193,796)			
17. Incentive Plans			(170,786)			
18. OPEBs			(51,381)			
19. Deferred Costs			(393,457)			
20. Waste Disposal			(58,667)			
21. Maintenance Costs			(211,477)			
22. Regulatory Commission Expense			(23,333)			
23. Rental Expenses			(58,295)			
24. Social Club Dues			(5,228)			
25. Institutional Advertising			(72,415)			
26. Business Development Costs			(117,525)			
27. Low Income Discount			(30,000)			
28. Total Expense Adjustments			(1,163,578)			
29. Depreciation & Amort.		7,760,915	(10,140)	7,750,775	0	7,750,775
30. Depreciation Expense			(1,770)			
31. Acquisition Amortization			(8,370)			
32. Total Dep. & Amort. Adjustments			(10,140)			
33. Taxes Other Than Income		2,712,460	(14,970)	2,697,490	0	2,697,490
34. Payroll Taxes			(13,065)			
35. Property Taxes			(1,905)			
36. Total Taxes Other Than Income			(14,970)			
37. Taxable Income Before Interest Expenses		$11,005,563	$3,067,286	$14,072,849	$111,179	$14,184,028
38. Interest Expense		5,325,120	(618,552)	4,706,568	0	4,706,568
39. Taxable Income		$5,680,443	$3,685,838	$9,366,281	$111,179	$9,477,460
40. Income Taxes @	40.37%	2,213,281	1,294,904	3,508,185	44,878	3,553,063
41. Operating Income		$8,792,282	$1,772,382	$10,564,664	$66,301	$10,630,965
42. Rate Base		$158,958,817		$149,515,650		$149,515,650
43. Rate of Return		5.53%		7.07%		7.11%

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IN THE MATTER OF:	)	
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COMMISSION STAFF'S FIRST SET OF INFORMATION REQUESTS TO THE ATTORNEY GENERAL

37. At pages 19 through 21 of her direct testimony, Andrea C. Crane proposes to eliminate Construction Work in Progress ("CWIP") from Kentucky-American's forecasted rate base. Historically, the Commission has allowed Kentucky-American to include CWIP in rate base but offset the return by including Allowance for Funds Used During Construction ("AFUDC") in operating revenues. Provide a comparison between the two methodologies and explain the differences between Ms. Crane's proposal for CWIP and the method that the Commission has previously used to determine Kentucky-American's rates.

Response: Ms. Crane's proposal is to eliminate all CWIP from rate base. AFUDC would also be eliminated from operating revenues. In the past, the Commission has permitted CWIP to be included in rate base but it has also included AFUDC in operating revenue.

As stated in her testimony, Ms. Crane's methodology has two significant advantages over the methodology previously approved by the Commission. First, Ms. Crane's methodology results in intergenerational equity by requiring the costs associated with various projects to be paid for by the customers that are actually being served by those projects and thus are benefiting from the projects. Alternatively, the Commission's methodology requires ratepayers to pay a return on plant that may never provided them with any benefit. Second, Ms. Crane's methodology shifts the risk during project construction from ratepayers to shareholders, where it properly belongs. Including CWIP in rate base is especially inconsistent with the use of a forward looking test period.

Respondent: Andrea C. Crane

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BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	**)**	
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COMMISSION STAFF'S FIRST SET OF INFORMATION REQUESTS TO THE ATTORNEY GENERAL

38. State the net revenue adjustment effect of Ms. Crane's proposal to exclude CWIP from rate base and move AFUDC "below-the-line".

Response: Based on the rate of return included in Ms. Crane's testimony, the net revenue adjustment effect is approximately $129,595, as shown below:

CWIP	($6,124,953)	
Return	7.11%	
Income Impact	($435,484)	
Interest Synchronization	$77,888	(3.15% debt costs X $6,124,953 X 40.37% tax rate)
Total Income Impact	($357,596)	
Revenue Multiplier	1.6885	
Total Revenue Impact	($603,801)	
Revenue Impact-AFUDC	$474,206	(Schedule ACC-42)
Net Impact	($129,595)	

Respondent: Andrea C. Crane

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COMMISSION STAFF'S FIRST SET OF INFORMATION REQUESTS TO THE ATTORNEY GENERAL

39. Explain why, as the Commission has permitted a cash return on CWIP for the jurisdictional electric and gas utilities, it should not afford the same ratemaking treatment to Kentucky-American.

Response: The Commission should adopt a policy of eliminating CWIP from rate base for the reasons stated in response to Question 37, above. In addition, Ms. Crane notes that the inclusion of CWIP in rate base is particularly inconsistent with the use of a forward looking test period.

Respondent: Andrea C. Crane

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COMMISSION STAFF'S FIRST SET OF INFORMATION REQUESTS TO THE ATTORNEY GENERAL

40. At page 26 of her direct testimony, Ms. Crane states: "Only items for which actual out-of-pocket cash expenditures must be made are included in a cash working capital calculation." State whether Ms. Crane agrees with the following statement and why or why not:

> While it is true that recording depreciation does not require the expenditure of cash at the time the expense is recorded and charged to the customer, cash was expended at the time the property was acquired, and the recorded depreciation is used to reduce the investment in that property even though approximately one-and-one half month's depreciation (equivalent to the revenue lag) has not been received from the consumer...[T]he question involved in the depreciation issue is the recognition of the time differential between the reduction of the rate base and the receipt of funds applicable to the provisions 45 days later. Clearly, it is not a question of whether cash has been expended in the test year.

Response: Ms. Crane agrees that depreciation expense is recorded monthly. However, it does not follow that depreciation expense should be included in a cash working capital calculation. Although depreciation is recorded monthly, ratepayers do not receive the benefit of the decline in rate base relating to this additional depreciation until the Company files its next base rate case. Therefore, customers receive no benefit from this depreciation being booked by the Company. Moreover, as acknowledged by the authors, "recording depreciation does not require the expenditure of cash at the time the expense is recorded..."

Respondent: Andrea C. Crane

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COMMISSION STAFF'S FIRST SET OF INFORMATION REQUESTS TO THE ATTORNEY GENERAL

41. List all state jurisdictions that permit a utility to include depreciation in its lead/lag study and provide copy of the statute(s), administrative regulation(s), or utility regulatory commission decision that authorizes such action.

Response: New Jersey is the only state that, to Ms. Crane's knowledge, includes depreciation in its lead/lag study. Attached are pages 33 and 34 from an Final Decision and Order in BPU Docket No. ER02080510 that discusses New Jersey regulatory policy on this issue.

Respondent: Andrea C. Crane

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COMMISSION STAFF'S FIRST SET OF INFORMATION REQUESTS TO THE ATTORNEY GENERAL

ATTACHMENT TO QUESTION 41

Agenda Date: 7/21/03
Agenda Item: 2A

STATE OF NEW JERSEY
Board of Public Utilities
Two Gateway Center
Newark, NJ 07102
www.bpu.state.nj.us

ENERGY

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY D/B/A CONECTIV POWER DELIVERY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES FOR ELECTRIC SERVICE	**FINAL DECISION AND ORDER** **BPU Dkt. No. ER02080510** **OAL Dkt. No. PUC 6917-02**

(SERVICE LIST ATTACHED)

BY THE BOARD:

This Final Decision and Order memorializes and provides the reasoning for the action taken by the Board of Public Utilities ("Board" or "BPU") in the above captioned matter by a vote of five Commissioners at the Board's July 21, 2003 public meeting, which action was summarized in the Board's Summary Order dated July 31, 2003. This Final Decision and Order supersedes the Board's July 31, 2003 Summary Order.

the likelihood that the 13.0% pre-tax return allowed by the Final Restructuring Order exceeded ACE's actual cost of capital, as well as the additional compensation it received from the interest earned on the deferred balance during the Transition Period, which presumably would continue throughout the recovery period. (RA-2 at 34-37). In quantifying the proposed disallowance, witness Crane calculated the monthly return on the CWC determined by the Company at the same rate of return it employed in determining the revenue requirement of the TBD units, and "grossed up" the result to provide for income taxes. (*Id.* at 37, Schedule ACC-9).[34]

<u>The Company's Rebuttal</u>

Witness Morgan defended the Company's CWC calculation, asserting that to avoid the cost and complexity of performing a CWC study between rate cases, the most reliable information available is traditionally used. He asserted that depreciation expense should be reflected in the CWC calculation with zero lag to properly compensate investors for the reduction in rate base attributable to the depreciation reserve, and that by not reflecting any return, including the equity component in its calculation, the Company had taken a conservative approach. Even if valid, the deficiencies asserted by witness Crane did not justify disallowing the CWC claim in its entirety, or the 13.0% pre-tax return. (P-5 at 12-15). Witness Chalk also disputed the RPA's calculation of the reduction in the revenue requirement associated with the recommended CWC disallowance, maintaining that it failed to take interest synchronization into account. With interest synchronization reflected, the recommended disallowance would be reduced from approximately $5.7 million to $4.8 million. (P-13 at 6-8).[35]

<u>NJLEUC's Position</u>

NJLEUC also found the Company's calculation of cash working capital to be excessive, contending that the revenue lag assumed by ACE was too long, that the calculation did not reflect the lag in the payment of debt interest, and that it improperly included such non-cash items as depreciation and amortization. (NJLEUCIB at 32-33).

<u>Staff's Position</u>

Staff disagreed with the RPA's proposed CWC disallowance, and in particular, the RPA's treatment of depreciation expense and interest on debt. As to the lead/lag days issue, ACE utilized the lead/lag days from its last base rate case, filed in 1990. Witness Crane opposed using these lead/lag days, since there had been no attempt by ACE to verify that they were still valid. (RA-2 at 34). Company witness Morgan asserted that due to the cost and complexity of performing lead/lag studies in between rate cases, it is a traditional regulatory approach to use

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34 While Schedule ACC-9 includes the last year of the Transition Period, it was properly excluded from Schedule ACC-8, given the RPA's proposed disallowance of the above-market cost of the TBD fossil units as of August 1, 2002.

35 At the February 21, 2003 hearing witness Crane agreed with Mr. Chalk on this issue. (Tr. 614). The RPA's revised (briefed) working capital disallowance was accordingly reduced to $3.793 million.

the most reliable information available. (P-5 at 12-13). Staff agreed with the Company that the lead/lag days from the last rate case could reasonably represent the lead/lag days during the Transition Period.

ACE included depreciation expense in its lead/lag study with a zero lag, arguing that this is appropriate because the total deprecation reserve is deducted from the plant in service balance in determining rate base, even though depreciation expense has not actually been collected from customers at the time the rate base is calculated. Including deprecation expense in the lead/lag study with a zero lag cures this mismatch. (*Id.* at 13). The RPA maintained that it was inappropriate to include deprecation expense because it does not result in cash outflows by the Company. The purpose of the lead/lag study is to determine the level of investor-supplied funds actually needed, not to compensate the Company for its expenses, as that compensation is included in other aspects of the deferral calculation. Therefore, only actual cash flows should be considered in determining ACE's need for a cash working capital allowance. (RA-2 at 35). Staff agreed with ACE, citing prior BPU decisions on this issue. In its Order dated April 6, 1987 in Docket No. ER85121163, *I/M/O Public Service Electric and Gas Company for an Increase in Rates*, the Board adopted the ALJ's recommended assignment of a zero lag to the Company's deprecation expense. This finding was reaffirmed by the Board in Docket No. WR00060362, *I/M/O Middlesex Water Company for Approval of an Increase in its Rates for Water Service and Other Tariff Changes,* by Order dated June 6, 2001.

RPA Witness Crane asserted that ACE should have included interest on debt in its cash working capital calculation, arguing that the Company has a contractual obligation to make these interest payments, which are generally made quarterly. Since ACE collects the funds needed to make such payments monthly, but generally pays interest expense quarterly, interest on debt provides a significant source of CWC. Ms. Crane maintained that this important source of cash working capital was ignored in ACE's calculation. (RA-2 at 36). In rebuttal, Mr. Morgan asserted that it is incorrect to single out for inclusion in a lead/lag study only the debt portion of the return on investment. The total return should be included with a zero lag since the return on investment is the property of investors when service is provided, as previously recognized by the BPU. In this case the Company assertedly took a conservative approach, in that it did not include any return on investment in the determination of the CWC associated with the TBD generation assets. (P-5 at 13-14). Staff agreed with ACE, noting that excluding interest on debt from the working capital calculation is consistent with prior BPU decisions. Staff also noted that the Company's determination of the revenue requirement of the TBD units included a consolidated tax savings adjustment that reduced the revenue requirement. Thus, the Company was consistent in its determination of the revenue requirement.

3. Restructuring/Consolidated TPS Billing Costs

RPA's Position

In recommending that ACE's claimed restructuring and consolidated TPS billing costs be disallowed, witness Crane contended that the Company had not met its burden of proof, and had improperly applied the 13.0% pre-tax return authorized by the Final Restructuring Order for

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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COMMISSION STAFF'S FIRST SET OF INFORMATION REQUESTS TO THE ATTORNEY GENERAL

42. List all accounting publications, journal articles, and studies that support the proposition that depreciation should be excluded from any lead/lag study.

Response: Ms. Crane did not rely upon any specific accounting publications, journal articles, or studies to support the proposition that depreciation should be excluded from any lead/lag study. As acknowledged in the Hahne and Aliff article referenced in question 40, depreciation is a non-cash expense. The Commission should eliminate depreciation expense from the Company's lead/lag study for this reason. If the Commission believes that it needs further support to adopt Ms. Crane's position, it can rely upon her representation that, to her knowledge, New Jersey is the only state in which Ms. Crane has testified that includes depreciation expense in a lead/lag study.

Respondent: Andrea C. Crane

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43. Refer to the Direct Testimony of Andrea C. Crane at 27. Provide a copy of the decisions of the Pennsylvania Public Utility Commission and West Virginia Public Service Commission in which depreciation expense was excluded from a utility's cash working capital study.

Response: Ms. Crane does not have copies of any decisions of the Pennsylvania Public Utility Commission or West Virginia Public Service Commission which discuss this issue. The positions of these commissions is well known to utilities in those states. Therefore, depreciation expense has not been claimed by any utility in any proceeding in Pennsylvania and West Virginia in which Ms. Crane filed testimony.

Respondent: Andrea C. Crane

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COMMISSION STAFF'S FIRST SET OF INFORMATION REQUESTS TO THE ATTORNEY GENERAL

44. List all state utility regulatory commissions, other than the Pennsylvania Public Utility Commission and West Virginia Public Service Commission, that exclude depreciation expense from a utility's cash working capital study. Provide a copy of each listed commission's decisions on this subject.

Response: See the responses to question 41 and 43, above.

Respondent: Andrea C. Crane

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45. State whether, in Ms. Crane's opinion, the use of the 1/8 formula approach to calculate Kentucky-American's cash working capital is a reasonable alternative to the use of a cash working capital study. Explain.

Response: In Ms. Crane's opinion, the use of a 1/8 formula approach to calculate a utility's cash working capital is not a reasonable alternative to the use of a cash working capital study, for two reasons. First, the formula method provides no information about the timing of cash flows, which is what should be measured in a cash working capital study. Second, the formula method always results in a positive cash working capital requirement although many utilities have negative cash working capital requirements, i.e., on average they receive revenues in advance of incurring expenses.

Respondent: Andrea C. Crane

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COMMISSION STAFF'S FIRST SET OF INFORMATION REQUESTS TO THE ATTORNEY GENERAL

46. State whether, in Ms. Crane's opinion, Kentucky-American complied with Financial Accounting Standards Board Statement No. 71 when it established regulatory assets accounts for:
    a. Shared Services Center costs
    b. Customer Call Center transition costs
    c. Security costs.

Response: FASB 71 addresses situations where the ratemaking treatment afforded to a particular cost differs from the financial accounting treatment that would otherwise be required. FASB 71 permits a utility to record a regulatory asset if future recovery is probable. Ms. Crane did not attempt to determine if future recovery of these costs was "probable" when the regulatory assets were created. The Company's auditors are ultimately responsible for determining if the Company complied with FASB 71, based on documentation provided by the Company regarding probable recovery. Whether or not the Company was in compliance with FASB 71 is irrelevant to the issue of whether the Commission should grant the ratemaking treatment now being requested by the Company.

Respondent: Andrea C. Crane

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	)	
	)	
ADJUSTMENT OF THE RATES OF KENTUCKY-AMERICAN WATER COMPANY	))	**CASE NO. 2004-00103**

COMMISSION STAFF'S FIRST SET OF INFORMATION REQUESTS TO THE ATTORNEY GENERAL

47. State whether, for each deferred debit that Ms. Crane in her direct testimony proposed to eliminate, Ms. Crane's position would be different if Kentucky-American's rates were established using a historical test period.

Response: Ms. Crane is generally not in favor of deferrals, which result in a reimbursement system rather than a ratemaking system that attempts to establish prospective rates based on prospective costs. Moreover, there is a long-standing prohibition against retroactive ratemaking, which is exactly what happens when utilities are permitted to defer costs for future recovery. Ms. Crane has never seen a situation where a utility has book a deferred credit, on the basis that it over-earned in any given year and needed to return these excess funds to ratepayers. Given the lack of symmetry in the ratemaking process with respect to the use of deferrals, Ms. Crane's recommendation to eliminate deferred debits would probably not be different even if the Company had used an historic test period.

Respondent: Andrea C. Crane

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	)	
	)	
ADJUSTMENT OF THE RATES OF	)	**CASE NO. 2004-00103**
KENTUCKY-AMERICAN WATER COMPANY	)	

COMMISSION STAFF'S FIRST SET OF INFORMATION REQUESTS TO THE ATTORNEY GENERAL

48. Refer to Kentucky-American's Response to Commission's Staff's First Set of Information Requests, Item 4. State Ms. Crane's opinion on the accuracy of Kentucky-American's performance over the past three years in budgeting for maintenance expense.

Response: Over the three years shown in this response, the Company's actual expenditures have been about 3.3% under budget, although the variance in some individual years has been significantly greater.

Respondent: Andrea C. Crane

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	)	
	)	
ADJUSTMENT OF THE RATES OF KENTUCKY-AMERICAN WATER COMPANY	))	**CASE NO. 2004-00103**

COMMISSION STAFF'S FIRST SET OF INFORMATION REQUESTS TO THE ATTORNEY GENERAL

49. Ms. Crane proposes to reduce Kentucky-American's Annual Incentive Plan ("AIP") by 60 percent or the portion of the AIP that is based upon financial performance goals of Kentucky-American. Explain why Ms. Crane did not propose the total removal of AIP.

Response: Ms. Crane did not propose total removal of the AIP because the remaining 40% is based on objectives that can directly benefit ratepayers. Moreover, the remaining 40% is not dependent upon the achievement of any of the financial goals. This distinguishes the Company's plan from many other incentive plans that make any award contingent upon the achievement of financial goals.

Respondent: Andrea C. Crane

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	)	
	)	
ADJUSTMENT OF THE RATES OF	)	**CASE NO. 2004-00103**
KENTUCKY-AMERICAN WATER COMPANY	)	

COMMISSION STAFF'S FIRST SET OF INFORMATION REQUESTS TO THE ATTORNEY GENERAL

50. State whether, in Ms. Crane's opinion, her rate case expense adjustment should be adjusted to reflect Kentucky-American's revised cost estimates provided in response to Item 19 of the Commission's Staff's Third Set of Information Requests.

Response: Ms. Crane believes that it is reasonable to limit the Company's recovery of rate case costs from ratepayers to the $552,049 recommended in her Direct Testimony.

Respondent: Andrea C. Crane

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	)	
	)	
ADJUSTMENT OF THE RATES OF KENTUCKY-AMERICAN WATER COMPANY	))	**CASE NO. 2004-00103**

COMMISSION STAFF'S FIRST SET OF INFORMATION REQUESTS TO THE ATTORNEY GENERAL

51. Explain how Ms. Crane determined that Kentucky-American's forecasted advertising costs include institutional advertising of $72,415.

Response: Please see the Company's Filing, Schedule F-4, page 1.

Respondent: Andrea C. Crane

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	)	
	)	
ADJUSTMENT OF THE RATES OF KENTUCKY-AMERICAN WATER COMPANY	))	**CASE NO. 2004-00103**

COMMISSION STAFF'S FIRST SET OF INFORMATION REQUESTS TO THE ATTORNEY GENERAL

52. State whether, in Ms. Crane's opinion, business development costs that are primarily used to expand regulated operations should be included in rates.

Response: Ms. Crane does not believe that regulated ratepayers should pay for a utility's business development costs, even if those business development opportunities relate to expansion of the utility's regulated operations.

Respondent: Andrea C. Crane

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	)	
	)	
ADJUSTMENT OF THE RATES OF	)	**CASE NO. 2004-00103**
KENTUCKY-AMERICAN WATER COMPANY	)	

COMMISSION STAFF'S FIRST SET OF INFORMATION REQUESTS TO THE ATTORNEY GENERAL

53. At pages 60 and 61 of her direct testimony, Ms. Crane proposes to eliminate the amortization expense associated with deferral of the security costs, Shared Service Company transition costs, and Customer Care Center transition costs. State whether, given Ms. Crane's proposed adjustments to eliminate CWIP from rate base and the AFUDC from operating revenues, Ms. Crane believes that the AFUDC equity gross-up amortization of $25,728 should be removed from Kentucky-American's forecasted operating expenses.

Response: Ms. Crane believes that the AFUDC equity gross-up amortization of $25,728 should be removed from Kentucky-American's forecasted operating expenses.

Respondent: Andrea C. Crane

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	)	
	)	
ADJUSTMENT OF THE RATES OF	)	**CASE NO. 2004-00103**
KENTUCKY-AMERICAN WATER COMPANY	)	

COMMISSION STAFF'S FIRST SET OF INFORMATION REQUESTS TO THE ATTORNEY GENERAL

54. At page 72 of her direct testimony, Ms. Crane proposes to eliminate the amortization expense of the acquisitions of the Tri-Village Water District and the Elk Lake Homeowners Association. Identify the account in which these amortization expenses are recorded.

Response: Ms. Crane is not certain into which account these costs are recorded. However, per Company Workpaper 4.1, page 7, it appears that they are booked to account 406.

Respondent: Andrea C. Crane

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	)	
	)	
ADJUSTMENT OF THE RATES OF	)	**CASE NO. 2004-00103**
KENTUCKY-AMERICAN WATER COMPANY	)	

COMMISSION STAFF'S FIRST SET OF INFORMATION REQUESTS TO THE ATTORNEY GENERAL

55. At page 74 of her direct testimony, Ms. Crane states that, Pennsylvania, New Jersey, and West Virginia have adopted consolidated income tax adjustments for ratemaking purposes.

    a. Provide a copy of all orders of the utility regulatory commissions of these states addressing the use of consolidated income tax adjustments for ratemaking purposes.

    b. State whether Ms. Crane's proposal to use the effective tax rate methodology to calculate the consolidated income tax adjustment rate is based upon these states' methodology.

Response:

a. Ms. Crane does not have copies of orders addressing the use of consolidated income tax adjustments for ratemaking purposes because these states adopted consolidated income tax adjustments many years ago and, in some cases, prior to Ms. Crane having testified in the state.

b. Pennsylvania and West Virginia use the effective tax rate methodology. New Jersey uses the rate base methodology. Ms. Crane believes that the effective tax rate methodology is more appropriate, since it is entirely prospective.

Respondent: Andrea C. Crane

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	)	
	)	
ADJUSTMENT OF THE RATES OF	)	**CASE NO. 2004-00103**
KENTUCKY-AMERICAN WATER COMPANY	)	

COMMISSION STAFF'S FIRST SET OF INFORMATION REQUESTS TO THE ATTORNEY GENERAL

56. List all other state regulatory commissions, other than the Pennsylvania Public Utilities Commission, New Jersey Board of Public Utilities, West Virginia Public Service Commission, that have adopted consolidated income tax adjustments for ratemaking purposes. Provide a copy of each listed commission's decisions on this subject.

Response: Ms. Crane has not undertaken a comprehensive study to determine which states have adopted consolidated income tax adjustments. However, she is aware that consolidated tax savings adjustments have been adopted in Texas and South Dakota. Supporting documentation from these states is attached. In addition, the Kansas Corporation Commission has adopted a "hybrid" approach in a case involving Westar Energy, using the Company's actual interest expense in the calculation of the Company's income tax liability, instead of the interest expense resulting from the weighted cost of debt used in the capital structure. In addition, the New Mexico Public Regulation Commission has stated that "PNM's payment to the holding company for income taxes shall be limited to PNM's share of the current tax liability of the consolidated corporation." (a copy of the terms and conditions approving PNM's holding company is attached). It remains to be seen how this will be interpreted in PNM's next base rate case.

Respondent: Andrea C. Crane

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	)	
	)	
ADJUSTMENT OF THE RATES OF KENTUCKY-AMERICAN WATER COMPANY	))	**CASE NO. 2004-00103**

COMMISSION STAFF'S FIRST SET OF INFORMATION REQUESTS TO THE ATTORNEY GENERAL

ATTACHMENT TO QUESTION 56

PUBLIC UTILITY COMMISSION OF TEXAS

EARNINGS REPORT

FOR

INVESTOR-OWNED TRANSMISSION & DISTRIBUTION SERVICE PROVIDERS (IOU TDSPs) IN THE ELECTRIC RELIABILITY COUNCIL OF TEXAS

General Instructions

Effective January 1, 2003

1701 N Congress Ave, PO Box 13326, Austin, Texas 78711-3326(512) 936-7000

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(IOU Transmission & Distribution Service Providers)

GENERAL INSTRUCTIONS

1. This report form is prescribed pursuant to Commission Substantive Rule 25.73(b) for the use of all IOU transmission & distribution service providers in the Electric Reliability Council of Texas (ERCOT). The objective of this report is to provide information needed to monitor the earnings and financial condition of all IOU TDSPs. Each TDSP subject hereto will submit its Earnings Report to the Commission in the form and manner herein prescribed.

   The reported information should be for the twelve-month period ending December 31. **The Earnings Report shall be filed not later than May 15 of the following year,** as specified in Substantive Rule §25.71(f)(4). Utilities who cannot meet this filing deadline should contact the PUC's Director of Financial Review with as much advance notice as possible. The law allows penalties to be imposed in the event that the rules supported by PURA are not followed.

2. Each IOU TDSP shall file with the Filing Clerk of Central Records at the Commission offices in Austin, Texas, three (3) copies of the printed Earnings Report (less instructions) and any attachments. *Of these three printed copies, two copies shall be bound, and one shall be unbound.* The unbound copy will be used for electronic scanning purposes. **Additionally, IOU TDSPs shall file an electronic version of the information contained in the required schedules and general questions. Please note**: To satisfy the requirement to file an electronic version of the Earnings Report, utilities may submit their report over the Internet using the Commission's FILER program *or* they may submit to the Commission a ***floppy diskette*** containing the Excel file containing the completed Earnings Report schedules. For utilities choosing to submit their report electronically through the Internet, please visit the PUC web site at http://www.puc.state.tx.us/interchange/filerindex.cfm for instructions. For utilities choosing to submit their report on a floppy diskette, note that before the Excel file is submitted to the Commission on diskette, **utilities should process the file with the Commission's FILER program to prepare the Earnings Report schedules for input into the PUC's Interchange filing system.**

3. An IOU TDSP with a rate proceeding pending before the Commission on the due date of the annual Earnings Report or who had a final order issued in such a proceeding within the last twelve months is exempt from filing the report.

4. Unless otherwise indicated, the information required in this report form will be taken from the accounts and other records prescribed in the Federal Energy Regulatory Commission chart of accounts. The definitions and instructions contained therein will also apply to this report wherever applicable. However, a query or response in this report regarding a practice or transaction is not to be construed as necessarily indicating conformity to accounting or other pertinent regulations.

5. If FERC Form 1 reports are available for the reporting period, they shall be relied upon for purposes of preparing this report.

6. In preparing the report, all instructions should be followed and each question should be answered fully and accurately. The expression "none" or "not applicable" will be given as the answer to any particular inquiry only where the expression truly and completely states the fact. Where a numeric response is required, insert the numeric value "0" as appropriate. All dollar amounts provided in response to questions or schedules should be rounded to the nearest dollar.

7. References to reports of previous periods or to other reports will not be accepted in lieu of information requested in this report. This report does not replace any other report required by the Commission unless substitution is specifically allowed by the Substantive Rules.

8. In accordance with Substantive Rule §25.71(d), all reports submitted to the Commission shall be attested to by an officer or manager of the TDSP under whose direction the report is prepared, or if under trust or receivership, by the receiver or a duly authorized person, or if not incorporated, by the proprietor, manager, superintendent, or other official in responsible charge of the TDSP's operation.

9. Any TDSP filing supplemental attachments to its Earnings Report shall place those items after the schedules and attestation page. The General Instructions to this Earnings Report are not to be submitted for filing. Each copy of the Earnings Report should be organized in the following order: (1) cover sheet; (2) general questions; (3) required schedules (including required supplemental schedules); (4) signature page; and (5) supplemental attachments (if any).

10. Schedules for the printed copies of the report and responses to the general questions should be printed using the Excel spreadsheet file. The Excel files containing the Earnings Report schedules contain print macros to simplify the printing process.

11. If it is necessary to revise any schedule after the initial filing of the report, a new diskette containing all schedules and three (3) printed copies of the report shall be provided. The diskette and all printed copies should be labeled "revised" and include the date of revision. General Question No. 10 shall be completed for all revised reports.

INSTRUCTIONS FOR GENERAL QUESTIONS AND SCHEDULES

General Questions

Please provide the requested information.

Schedule I: Summary of Revenues and Expenses

Note: In addition to completing this schedule in accordance with the instructions below, companies may, at their option, provide a second version of this schedule (and any other affected schedules) that shows the effects of direct assignment of costs for certain line-items. If the option to provide such alternative schedules is used, the company should change in such schedules only those line-items for which costs have been directly assigned. Alternative versions of any schedules should be clearly identified, and all line-items containing directly assigned costs (or the effects related thereto) should be clearly indicated on the schedules and, as necessary, also explained on Supplementary Schedule IV (or other additional workpapers).

Column 1 of this schedule should reflect information as reported on the IOU TDSP's financial statements and/or FERC Form 1, as applicable.

All interest expenses other than interest on customer deposits are to be excluded from Schedule I.

The revenue portion (lines 1 through 6) of this schedule should reflect all revenue received by the company, including revenue for any charges that are recovered "separately" (i.e., through a separate rider) by the company. Such revenues may include, but are not limited to, revenue received for nuclear decommissioning expenses, transmission cost recovery factors (TCRF), competition transition charges (CTC), municipal franchise fees, and the system benefit fund. Additionally, if applicable, the amount of reported revenues should reflect the negative impact of any excess mitigation credits. Additional explanatory information on any company-specific reporting treatments should be provided on Supplemental Schedule IV or additional workpapers.

For Schedules I through IV, the allocation percentage in column 4 (column 2 in Schedule IV) is calculated by dividing each Texas Jurisdictional item by the corresponding total electric item. This calculation is performed automatically by the spreadsheet.

Columns 1-8 for operations and maintenance expenses (line 11) are carried forward from Schedule II.

For **column 6**, in the "Total Revenues" section (the upper portion), no percentage inputs are required. Rather, companies should report revenue receipts for wholesale transmission in **column 7**, in the "Total Revenues" section (the upper portion), by directly inputting the appropriate dollar-amounts. For these inputs in the revenue portion of **column 7**, companies should include the payments received from others for wholesale transmission service per the commission's wholesale transmission matrix (include any incremental amounts approved by the commission after the matrix was finalized). The remaining expense (bottom) portion of **column 7** is automatically calculated by the spreadsheet (based on the percentage inputs to the bottom portion of column 6 as described below).

For **column 6**, in the "Expenses" section (the lower portion), companies should reflect the "wholesale transmission allocator" as calculated using information from the utility's most recent rate case. This allocator should be calculated using the total revenue requirement, by function, from the company's rate case information as follows: Using the generic business functions—Trans, Dist, Met, TBill, ABill, and TDCS (individual utilities should adjust the generic business functions if needed to match the functions used in the most recent rate case)—from Docket No. 22344, first determine the sum of the six generic business functions' revenue requirement (Total Revenue Requirement). The wholesale transmission allocator would then be derived by dividing the Transmission function revenue requirement by the Total

Revenue Requirement, with the resulting percentage being the percentage allocated to wholesale transmission. This percentage is the input to the "Expenses" portion of **Column 6** of Schedule I.

Column 8 is automatically calculated by the spreadsheet, and should reflect retail T&D revenues and expenses.

Column 8 of line 2 should correspond to Schedule XI.1a, line 13, column 7.

Amortization expense (line 12) is the sum of all items entered on Supplemental Schedule I-1 "Amortization Expense."

Nonbypassable (NBP) charges are carried automatically from Schedule Ia, line 18, and reflect only the amount of NBP charges included in the utility's "base" T&D revenue requirement (i.e., they are not recovered through a separate rider).

Columns 3-5 for federal income taxes (line 17) are carried forward from Schedule IV. Column 1, line 17 must be manually input on Schedule I. It should be the amount reported on the TDSP's Financial Statements.

Deferred expenses (line 18) are the total deferred expenses associated with a deferred accounting order and/or a rate moderation plan approved by a regulatory authority. <u>Deferred expenses recognized during the monitoring period, but associated with prior periods, should be excluded</u>. Please identify any excluded deferred expenses on a separate attachment.

Other expenses (line 20) is the sum of all items entered on Supplemental Schedule I-2 "Other Expenses."

<u>Schedule Ia: Summary of Other Nonbypassable Charges and Excess Mitigation Credits</u>

Provide the requested information regarding the utility's nonbypassable charges.

Lines 15 through 18 should include any amounts of nonbypassable charges recovered as part of the utility's "base" T&D revenue requirement (i.e., not recovered through a separate rider). The amount of line 18 will be carried automatically to Schedule I, line 19.

Lines 21 through 27 should contain information related to the company's excess mitigation credits during the monitoring period.

<u>Schedule II: Operations and Maintenance Expense</u>

This schedule further details operations and maintenance expense shown on Schedule I. Note that line 8 should reflect wholesale transmission matrix payments made to other transmission providers.

Column 1 of this schedule should reflect information as reported on the TDSP's financial statements.

Column 6 should use the same inputs calculated per the above instructions for Schedule I for the "Expenses" portion of that schedule's column 6.

Columns 7 and 8 are automatically calculated by the spreadsheet.

<u>Schedule III: Invested Capital at End of Reporting Period</u>

This schedule details the invested capital as of the end of the reporting period.

Column 1 of this schedule should reflect information as reported on the TDSP's financial statements.

Please enter reductions to invested capital as negative amounts on this schedule and the related supplemental schedules.

No items which have been specifically disallowed by the Commission should be included in columns 3 or 5 of this schedule.

Column 6 should use the same inputs calculated per the above instructions for Schedule I for the "Expenses" portion of that schedule's column 6.

Columns 7 and 8 are automatically calculated by the spreadsheet.

Working cash allowance (line 7) should be the amount of working cash allowance granted in the TDSP's last rate case as of the end of the reporting period. If the TDSP has not had a final order issued in a rate case within the last five years, please enter negative one-eighth (1/8) of total operations and maintenance expenses (line 11) from Schedule II in the appropriate columns of this line item.

Other invested capital additions (line 10) is the sum of all items entered on Supplemental Schedule IIIb-1 "Other Invested Capital Additions."

Other invested capital deductions (line 17) is the sum of all items entered on Supplemental Schedule IIIb-2 "Other Invested Capital Deductions."

The rate of return measure (line 28) expresses return from Schedule I as a percentage of total ending invested capital (excluding CWIP not allowed in rate base and accruing AFUDC). Ending balances for CWIP in rate base and accruing AFUDC are to be input manually on this schedule.

The Earned Return on Equity measure calculates automatically using data from Schedules I, II, III, and V.

Schedule IV: Federal Income Taxes

This schedule calculates federal income taxes (FIT) using Tax Method 2. The resulting FIT reflects current tax effects (at 35%) of book transactions adjusted for timing differences and permanent differences, and reflects deferred taxes (at 35%). Additionally the FIT reflects the effects of timing differences previously flowed through (at 35%), amortization of investment tax credits, and amortization of excess deferred taxes using the average rate assumption method (ARAM). The resulting FIT is not intended to tie to the FIT amount per the books of the TDSP.

Schedule IV should not reflect the effects of any disallowed or nonregulated plant, or any nonregulated operations. Schedule IV should not reflect the effects of any net operating loss carryforward or carryback.

Schedule IV should not reflect the operations of any affiliates or subsidiaries. It is to reflect only TDSP operations.

Please note that lines 1 - 11 are automatically taken from Schedule I on the spreadsheet.

Interest included in return (line 12) is calculated using the formula: weighted cost of debt * total electric invested capital on Schedule III (line 20).

The depreciation addback - permanent differences on Line 14 should be the same adjustment that is made to return in Tax Method 1 for permanent differences. This adjustment is not to reflect normalized or non-normalized timing differences.

The tax effect of non-normalized timing differences (at 35%) should be reflected on Line 32, and is the same adjustment that is made to return in Tax Method 1 for timing differences previously flowed through, but here the adjustment is multiplied by the tax rate of 35%.

The additional tax depreciation on Line 20 is timing differences related to depreciation, or the excess of tax depreciation over the book depreciation claimed on Schedule I for all plant reflected in Schedule III. This amount should be adjusted to remove the effects of the permanent differences on Line 14.

All normalized timing differences other than those related to depreciation should be reflected on Line 21. For purposes of this schedule, all non-normalized timing differences should be reported with permanent differences on Line 19.

The current provision for deferred taxes on Line 31 is calculated automatically using the formula: (additional tax depreciation [Line 19] + other timing differences [Line 20]) * 35%.

Reflect the amortization of excess deferred taxes using the amount booked during the monitoring period.

Schedule IVa: Consolidated Tax Savings

For item A, all regulated entities which are a part of the consolidated group should be listed by name. For purposes of this schedule, the term "regulated" applies to companies whose services or products provided to its customers are established by or are subject to approval by an independent, third-party regulator. All non-regulated affiliate companies with net taxable income shall be aggregated for reporting purposes, and all non-regulated affiliate companies with net taxable losses shall be aggregated as well.

Only numerical responses are to be included in the "Net Taxable Income or Loss" and "AMTI" column. Narrative answers such as "GAIN or "LOSS" are not acceptable.

For item B - E, provide the requested information on the bottom portion of the schedule. If additional space is required, please attach additional sheets detailing the appropriate responses.

The amounts reported on Schedule IVa should reflect the effect of intercompany eliminations, but should not reflect the effect of any allocations between affiliates of tax effects of consolidation.

Schedule IVb: Consolidated Tax Savings - Continued

This schedule should only be filled out by those utilities requiring additional space on Schedule IVa.

Schedule V: Weighted Average Cost of Capital

Please provide the capital structure and weighted average cost of capital of the TDSP as of the end of the monitoring period. It is not necessary to estimate the current cost of equity; for purposes of this filing you may use the TDSP's current allowed return on equity in Texas. The costs and balances of preferred stock, long-term debt, short-term debt (if included in the company's WACC), and preferred trust securities should correspond with those provided in response to Schedule Nos. VIa, VIIa, VIII and IXa.

Schedule VI: Weighted Average Cost of Preferred Stock

Please provide the weighted average cost of preferred stock capital based upon the following data for each class and series of preferred stock outstanding according to the balance sheet as of the end of the monitoring period. For each issue, please include:

a. Description.

b. Date of Issuance.

c. Redemption Status (indicate whether or not mandatory redemptions are required).

d. Annual Dividend Rate (in percent).

e. Par Value at Issuance.

f. Premium or (Discount) at Issuance.

g. Underwriting Fees and Issuance Expenses.

h. Gain or (Loss) on Redeemed Stock at Issuance.

i. Original Net Proceeds [column (e) + column (f) - column (g) + column (h)].

j. Net Proceeds as a Percent of Par Value [column (i) / column (e)].

k. Par Value Currently Outstanding.

l. Current Net Proceeds [column (k) x column (j)].

m. Issue as a Percent of Total Net Proceeds. Each issue should be weighted by the current net proceeds to derive the weighted cost of preferred stock.

n. Cost of Money (this will equal the stated dividend rate only if there were no issuance expenses or underwriting costs, discounts or premiums, or gains or losses on redeemed stock):

   Dividend rate divided by net proceeds as a percent of par value [column (d) / column (j)].

   For fixed-rate issues with mandatory redemption, the cost of money may be calculated using the yield-to-maturity method.

o. Weighted Cost of Preferred Stock [column (m) x column (n)]. The Weighted Average Cost of Preferred Stock is calculated by summing the data in column (o) for each issue.

Schedule VIa: Adjusted Cost of Preferred Stock

This schedule adjusts the weighted average cost of preferred stock (from Schedule VI) in order to reflect the amortization of gains or losses on redeemed stock which was not associated with a specific refunding issue of preferred stock. Data input is required on lines 3, 10, and 12 for any company reporting an unamortized balance of gains or losses on redeemed stock (reference line 1 of Schedule VIa). If such gains or losses are not amortized, or if all of the gains or losses on redeemed stock are already accounted for in column (h) of Schedule VI, then the value to be input on line 3 should equal the value appearing on line 1, and the value "zero" should be input on lines 10 and 12. The adjusted cost of preferred stock calculated on line 32 should then be carried forward to Schedule V for purposes of calculating the weighted average cost of capital.

Schedule VII: Weighted Average Cost of Long-Term Debt

Please provide the weighted average cost of long-term debt capital based on the following data for each class and series of long-term debt outstanding according to the balance sheet as of the end of the monitoring period. For capital lease obligations, the cost and balance of debt should be determined in accordance with generally accepted accounting principles. For each debt issue, please include:

a. Description

b. Date of Issuance

c. Maturity Date

d. Interest Rate (Effective interest rate should be used for issues supported by letters of credit.)

e. Principal Amount at Issuance

f. Premium or (Discount) at Issuance

g. Underwriting Fees and Issuance Expenses

h. Gain or (Loss) on Reacquired Debt at Issuance

i. Original Net Proceeds [column (e) + column (f) - column (g) + column (h)]

j. Net Proceeds as a Percent of Par Value [column (i) / column (e)]

k. Principal Currently Outstanding (including current maturities)

l. Current Net Proceeds [column (k) x column (j)]

m. Issue as a Percent of Total Net Proceeds. Each issue should be weighted by current net proceeds to derive the weighted cost of debt.

n. Cost of Debt (this will equal the stated interest rate only *if* there were no issuance expenses or underwriting costs, discounts or premiums, or gains or losses on reacquired debt):

   For variable rate issues, the cost of debt shall reflect the interest rate divided by net proceeds as a percent of par value [column (d)/column (j)].

   For fixed-rate issues, the cost of debt should reflect the yield-to-maturity based on the interest rate, net proceeds, issuance date and maturity schedule, determined by reference to any generally accepted table of bond yields, or a calculator with appropriate capability.

o. Weighted Cost of Long-Term Debt [column (m) x column (n)]. The Weighted Average Cost of Long-Term Debt is calculated by summing the data in column (o) for each issue.

Schedule VIIa: Adjusted Cost of Long-Term Debt

This schedule adjusts the weighted average cost of long-term debt (from Schedule VII) in order to reflect the amortization of gains or losses on reacquired debt which was not associated with a specific refunding issue of debt. Data input is required on lines 3, 10, and 12 for any company reporting an unamortized balance of gains or losses on reacquired debt (reference line 1 of Schedule VIIa). If such gains or losses are not amortized, or if all of the gains or losses on reacquired debt are already accounted for in column (h) of Schedule VII, then the value to be input on line 3 should equal the value appearing on line 1, and the value "zero" should be input on lines 10 and 12. The adjusted cost of long-term debt calculated on line 32 should then be carried forward to Schedule V for purposes of calculating the weighted average cost of capital.

Schedule VIII: Weighted Average Cost of Short-Term Debt

Please provide the historical balances, as available, of short-term debt and a calculation of the weighted average cost of short-term debt as of the end of the monitoring period. The balance and weighted average cost of short-term debt may be carried forward to Schedule V for purposes of calculating the weighted average cost of capital if the TDSP believes it is appropriate. This schedule should not include current maturities of long-term debt.

Schedule IX: Weighted Average Cost of Preferred Trust Securities; and Schedule IXa: Adjusted Cost of Preferred Trust Securities

Complete these schedules in accordance with the previous instructions for Schedule VI, Weighted Average Cost of Preferred Stock, and Schedule VIa, Adjusted Cost of Preferred Stock.

Schedule X: Historical Financial Statistics

Please provide a schedule with the following ratios for the monitoring period and the four preceding fiscal years calculated on a total company basis. The data used to calculate these ratios should be taken from the Company's audited financial statements, if available for the periods requested.

(1) Total Debt as a Percent of Total Capital

Numerator:		Notes Payable
	+	Long-Term Debt (Incl. Current Maturities & Capital Lease Oblig.)
Denominator:		Notes Payable
	+	Long-Term Debt (Incl. Current Maturities & Capital Lease Oblig.)
	+	Preferred Stock
	+	Preferred Trust Securities
	+	Common Equity

(2) Total CWIP as a Percent of Net Plant

Numerator:		Total Construction Work In Progress
Denominator:		Total TDSP Plant
	-	Accumulated Depreciation and Amortization

(3) Construction Expenditures as a Percent of Average Total Capital

Numerator:		Cash Construction Expenditures [See Note 5]
Denominator:		Average of Beginning and Ending Balance of Total Capital (See Definition of Total Capital Provided for Ratio No.1)

(4) Pre-Tax Interest Coverage

Numerator:		Income from Continuing Operations
	+/-	Nonrecurring Items (Before Tax)
	-	Equity AFUDC
	+	Income Taxes
	+	Interest Incurred (See Note 1 below)
Denominator:		Interest Incurred

(5) Funds From Operations / Total Debt

Numerator:		Cash Flow from Operations (Before Working Capital Changes) [See Note 4 below]
	-	AFUDC (both debt and equity portions)
	-	
Denominator:		Notes Payable
	+	Long-Term Debt (Incl. Current Maturities & Capital Lease Oblig.)

(6) Fixed Charge Coverage

Numerator:		Same as (4)
	+	1/3 of Rental Expenses

Denominator:		Interest Incurred
	+	1/3 of Rental Expenses

(7) Fixed Charge Coverage Ratio (Including Distributions on Preferred Trust Securities)

Numerator:		Same as (4)
	+	1/3 of Rental Expenses
	+	Distributions related to Preferred Trust Securities
Denominator:		Interest Incurred
	+	1/3 of Rental Expenses
	+	Distributions related to Preferred Trust Securities

(8) Funds From Operations Interest Coverage

Numerator:		Same as (5)
	+	Cash Interest Paid
Denominator:		Interest Incurred

(9) Net Cash Flow/Capital Outlays

Numerator:		Same as (5)
	-	Preferred Dividends
	-	Common Dividends
Denominator:		Cash Construction Expenditures [See Note 5 below]

(10) Cash Coverage of Common Dividends

Numerator:		Same as (5)
	-	Preferred Dividends
Denominator:		Common Dividends

(11) AFUDC as a Percentage of Net Income for Common Shareholders

Numerator:		Total AFUDC [See Note 2 below]
	+	Deferred Carrying Costs [See Note 3 below]
Denominator:		Net Income after Preferred Dividends

(12) Return on Average Common Equity

Numerator:		Net Income After Preferred Dividends
Denominator:		Average of Beginning and Ending Common Equity

NOTES

(1) "Interest Incurred" includes all Interest Charges, and excludes any recognition of ABFUDC, Deferred Borrowing Costs, Capitalized Interest, and Distributions related to Preferred Trust Securities.

(2) "Total AFUDC" includes both the Allowance For Borrowed Funds Used During Construction (ABFUDC) and the Allowance For Equity Funds Used During Construction (AEFUDC). Actual reported AFUDC should not be adjusted for related tax effects.

(3) "Deferred Carrying Costs" include any borrowing costs or equity return deferred under an accounting order or qualified phase-in plan.

(4) "Cash Flow from Operations" should reflect the amount reported in the Statement of Cash Flows, less ABFUDC and Capitalized Interest (if not already subtracted from Net Income in the Statement of Cash Flows), and should also reflect distributions related to Preferred Trust Securities.

(5) "Cash Construction Expenditures" should not include any AFUDC or Capitalized Interest.

Schedule XI: Revenue, Sales, and Customer Data

Complete the whole schedule even if you make no adjustment to revenue. Revenue and sales adjustments should be made on an as-needed basis to reflect significant changes in sales due to abnormal weather.

If you have no adjustment to revenue to account for weather abnormalities, carry over the unadjusted values in Schedules XI.1a and XI.2a to Schedules XI.1b and XI.2b (so that the adjustment figures in XI.1c and XI.2c result in zeroes). Then, in Schedule XI.5, explain *why* you have not made any weather-adjustment (i.e., why your adjustments are zeroes).

In Schedule XI.3, use a 65° base following the National Oceanic and Atmospheric Administration's definition of Cooling Degree Day (CDD) and Heating Degree Day (HDD). If your CDDs and HDDs are collected from more than one weather station, provide weighted average figures for the whole Texas service area. Then, if the weather measures that you have used for weather-adjustment are different from what you have provided in Schedule XI.3, incorporate those in Schedule XI.5 where you explain your weather adjustment method.

Schedule XII: Adjustments (Optional)

If the TDSP believes that material adjustments to any of the information provided in the report would be appropriate, please provide the details, including an explanation. Adjustments to Schedules I-IV should be presented on a total electric and a jurisdictional basis. Adjustments to Schedules V-X should be provided only on a total company basis. With the exception of Schedule XI relating to weather adjustments, the schedules included in the report should not include the proposed adjustments. Please do not include any adjusted schedules on the diskette submitted to the Commission. Printed schedules reflecting the proposed adjustments may be included as a supplemental attachment to the Earnings Report.

Schedule XIII: Extraordinary and Nonrecurring Items

This schedule details all extraordinary and nonrecurring items included in the numbers reported on other schedules of the earnings monitoring report that equal or exceed one percent (1%) of total expenses as reported on line 21 of Schedule I. For purposes of this schedule, extraordinary and nonrecurring items are those items that are not incurred in the regular course of the TDSP's business, or items that would have an abnormal effect on the revenues and/or expenses of the reporting period. Section A should detail all such items for the reporting period. Section B should detail all such items and/or events that the TDSP is aware of that will have an impact on the twelve months immediately following the reporting period.

Schedule XIV: Status of Nuclear Decommissioning Funds

Utilities or non-utilities owning or having a leasehold interest in a nuclear-fueled generating unit should provide this schedule for calendar year reporting periods. The following information should be provided for each generating unit on a Total Company and Texas Jurisdictional basis for multi-jurisdictional utilities.

1. The separate balances of the qualified and non-qualified portions of the fund at the beginning of the monitoring period.

2. The deposits made into the qualified and non-qualified portions of the trust during the monitoring period should be listed separately on the supporting schedule (Part D of Schedule XII) and the total should be brought forward to Part A of Schedule XII.

3. The total dollar amount of income earned separately by both the qualified and non-qualified portions of the trust during the monitoring period.

4. The ending balance of the qualified and non-qualified portions of the fund at the end of the monitoring period.

5. A list of the type of assets held in the qualified and non-qualified portions of the trust (for example, Municipal Bonds, Treasury Bonds, Equity Securities, etc.), and the percent of the trust invested in each type of asset as of the end of the monitoring period. Assets classes in which less than ten percent of the trust funds are invested in may be classified as "Other."

6. The date and amount of the last decommissioning cost estimate (in then current dollars).

7. The name of the trustee(s) holding the trust funds.

8. The currently allowed decommissioning expense in each jurisdiction responsible for funding decommissioning.

9. The annual rate of return for each fund as determined by the company, its trustee(s), company consultant, or investment advisors on a total return (pre-tax) basis and a net (after tax and management fees) basis. (Please indicate on the schedule which of the above entities is providing the reported rate of return.) Note: Preferred net return calculation is the Funds rate of return after (1) federal and state taxes, including tax on realized gains, and (2) management fees. If another formula is used to calculate net return, please provide an explanatory footnote.

Supplemental Schedule I-1: Amortization Expense

Enter the Total Company, the Total Electric, and the Texas Jurisdictional amount for all items being amortized on Schedule I, Line 12.

Please list each item individually.

Include pre-September 1999 long-term debt and preferred stock transaction costs if they are being amortized as a cost-of-service item per the final order in the company's unbundled cost-of-service docket. The reported amount should also include any allowed return granted in the company's unbundled cost-of-service docket and not included as an addition to rate base. Post-September 1999 long-term debt and preferred stock transaction costs should be included in Schedule VIa and VIIa.

Please do not include interest expense on long-term debt on this schedule.

Supplemental Schedule I-2: Other Expenses

Enter the Total Company, the Total Electric, and the Texas Jurisdictional amount for all other expense items not otherwise provided for on Schedule I.

Please list each item individually.

Please do not include interest expense on long-term debt on this schedule.

Supplemental Schedule II-1: Summary of Substantive Rules 25.77 Expenditures

Please provide a summary of the information required under Substantive Rules 25.77 for the monitoring period.

Supplemental Schedule III-1: Other Invested Capital Additions

Enter the Total Company, the Total Electric, and the Texas Jurisdictional amount for all other additions to invested capital not provided for elsewhere on Schedule III.

Please list each item individually.

Supplemental Schedule III-2: Other Invested Capital Deductions

Enter the Total Company, the Total Electric, and the Texas Jurisdictional amount for all other deductions to invested capital not provided for elsewhere on Schedule III.

Please list each item individually.

Supplemental Schedule IV: Comments/Footnotes

This schedule is to be used for providing comments or footnotes pertaining to other schedules in the report. Please provide the first page of this schedule even if there are no comments or footnotes. (Mark n/a if not completing this schedule).

Supplemental Schedule V: Discounted Rate Classes

This schedule provides detail on customers paying rates at discounted levels. Please see the instructions included on the schedule.

ARTICLE 20:10

PUBLIC UTILITIES

Chapter

CHAPTER 20:10:13

PUBLIC UTILITIES RATE FILING RULES

Section

20:10:13:88. Statement K -- Income taxes. Statement K shall show for the test period income taxes computed on the basis of the rate of return claimed applied to the overall utility rate base and separated between federal and state taxes. If the rate base claimed includes adjustments other that book figures for the test period 13-month average, the income taxes shall be computed separately for claimed rate base and for the 13-month average rate base per books for the test period. All tax adjustments shall be completely described and the amounts shown separately. Amounts of deferred taxes debited and credited shall be shown separately. The amounts and basis of assignment of income taxes attributed to other utility departments and nonutility operations shall be shown, together with all tax savings affecting the total tax liability. If the filing public utility joins in a consolidated tax return, the total estimated tax savings, expressed as a percentage, resulting from the filing of a consolidated return shall be given, as well as a full explanation of the method of computing the tax savings. Any abnormalities such as nonrecurring income, gains, losses, and deductions affecting the income tax for the test period shall be explained and the tax effect set forth. Items required by §§ 20:10:13:89 to 20:10:13:93, inclusive, shall be submitted as a part of statement K.

Applicants Exhibit ___(WJR-4)

<u>TERMS AND CONDITIONS REQUIRED BY THE COMMISSION'S JUNE 28, 2001 "ORDER APPROVING FORMATION OF A HOLDING COMPANY" AND AMENDATORY ORDER ENTERED DECEMBER 18, 2001</u>

In its "Order Approving Formation of a Holding Company" ("Order") entered on June 28, 2001, in Case 3137, the Commission required that, as a condition of Commission approval of Public Service Company of New Mexico's ("PNM") request to transfer of assets to the holding company, PNM must file "its agreement to (with a listing of) conditions and terms required by this Order ..." Order at 14, 28-29. In satisfaction of that requirement, PNM filed "Public Service Company of New Mexico's Notice of Compliance Filing on September 20, 2001. The Commission amended several of the terms and conditions imposed by the Order in a subsequent order entered December 18, 2001. This Exhibit sets forth each of the terms and conditions imposed by the Order, as set forth in Attachment 1 to Public Service Company of New Mexico's Notice of Compliance Filing, as amended by the December 18, 2001 Order, and identifies each term or condition that has been fulfilled, has been modified by subsequent Commission order or is not presently operative because of the determination of the Office of Public Utility Regulation of the Securities and Exchange Commission ("SEC") that PNM Resources does not meet the standard for intrastate exemption and its requirement that PNM Resources, Inc. register as a public utility holding company.

1. PNM shall not pay dividends which cause its debt rating to go below investment grade. Recommended Decision ("RD") at 59.

2. PNM shall provide at least fifteen days notice prior to a dividend being paid, such notice to include the size of the dividend, the proposed payout ratio and historic payout ratios for the preceding three years. Order at 15.

3. PNM shall not pay dividends in any year in excess of net earnings for that year without prior Commission approval. For purposes of this term and condition, a "year" is to be measured on a rolling, four-quarter basis. RD at 59; Order at 14; Errata Notice, 8/28/01.

4. PNM, PNMR and their affiliates shall not consummate the merger with Western Resources, Inc. ("Western") without prior Commission approval. RD at 59; Errata Notice 8/28/01 <u>[The Western transaction is no longer pending.]</u>

5. PNM, PNMR and their affiliates must agree that they will not challenge the Commission's authority to withhold approval of the Western merger. RD 59; Errata Notice issued 8/28/01. PNM, PNMR and their affiliates can only challenge a denial of approval based on the merits. Any future merger or approval must comply with applicable New Mexico law. Order at 15-16, 26. <u>[The Western transaction is no longer pending.]</u>

6. Valuation and ratemaking impacts of any asset transfer approved in conjunction with the formation of the holding company are reserved for future rate-related proceedings. RD at 59.

7. PNM must agree that the Commission retains jurisdiction over any reciprocal loan agreements between PNM and the holding company and over the other matters contained in the Order in this case where the Commission has reserved its authority to take further remedial action when it is in the public interest. RD at 59. [This condition will not be operative when PNM Resources becomes a registered holding company because such agreements will then be prohibited.]

8. PNM's payment to the holding company for income taxes shall be limited to PNM's share of the current tax liability of the consolidated corporation. RD at 60.

9. PNM is prohibited from owning or transferring the stock of PNMR or any of its affiliates (except a PNM subsidiary), and the subsidiaries of PNMR are prohibited from owning shares of PNM. RD at 60; Errata Notice 8/28/01.

10. PNM must continue to make FERC Form 1 filings with this Commission until further Commission order to the contrary. RD at 60.

11. PNM must agree to obtain prior Commission approval for purchases of capacity or energy from non-utility subsidiaries of any of the holding companies, except for emergency and economy energy purchases. December 18 Order, ¶ A(5).

12. PNM must waive any claims of SEC or FERC preemption challenges to orders of this Commission concerning cost allocations resulting from the creation of the holding company. RD at 60.

13. PNM must, within 6 months of the entry of this Order, develop a cost allocation manual with the cooperation of Staff and any interested parties. RD at 60. PNM filed its cost allocation manual as of June 28, 2002.

14. PNM shall include "royalty" related information in its next general rate proceeding as referenced in COA's testimony (pp. 74-75 of COA Ex. 1), except that PNM shall include business plans regarding affiliates and the holding company in its initial filing only to the extent such information relates to the interactions of those entities with PNM. This condition is not intended to limit the discovery rights of parties. December 18 Order, ¶ A(6).

15. PNM shall agree to, and implement the accounting and reporting recommendations of the COA (pp. 55-56 of COA Ex. 1). RD at 60.

16. PNM shall agree that to the extent the Commission has been preempted by PUHCA in its ratemaking authority, the Commission will assume all such authority if PUHCA is repealed. RD at 60; December 18, 2001 Order, ¶ A(7).

17. PNM must seek and obtain exemption from registration as a holding company under the Public Utility Holding Company Act of 1935. RD at 60. Notification to the Commission that the holding company has made the necessary filing with the Securities and Exchange Commission claiming exemption from the Public Utility Holding Company Act of 1935 shall constitute proof, in form acceptable to the

Commission, of a final, non-appealable exemption from registration under that Act. December 18, 2001 Order, ¶ C. [This condition was met by PNM Resources' filing its claim of exemption with the SEC at the time PNM Resources was formed.]

18. PNMR must agree to seek Commission approval of any transaction that could result in it becoming a registered holding company and that it will not proceed with such transaction if Commission approval is not given for the transaction. RD at 60. [This condition will not be operative when PNM Resources becomes a registered holding company.]

19. PNM's employees are prohibited from routinely providing services to other corporate entities. Incidental work shall be charged at the higher of cost or market. RD at 61.

20. PNM shall comply with the provisions of Rule 450.7(c) in their entirety, including instances involving generating plant not intended for the provision of retail service to New Mexico customers under the provisions of NMSA 1978, § 62-3A-8C (2001). RD at 23-25, 61. [This condition was modified by the Commission's Order of January 28, 2003 in Utility Case No. 3137 (Merchant Plant Filing).]

21. PNM shall comply with all representations made in its amended GDP and supporting testimony unless inconsistent with this Order. Order at 28; Errata Notice 8/28/01.

22. PNM will hold its customers harmless from any and all negative impacts of the holding company formation including any negative financial impacts, provided, however, that this condition will not be construed to prevent (in a future case) PNM from recovering legitimate transition costs which the Restructuring Act authorizes it to recover. Order at 16, 18. [The portion of this condition relating to transition costs was modified by the Commission's Order of January 28, 2003 in Utility Case No. 3137 (Merchant Plant Filing).]

23. Any adverse ratemaking consequences that arise by reason of federal preemption of a Commission decision resulting directly or indirectly from the formation of the holding company must not be assumed by PNM's retail customers. December 18 Order, ¶ A(1).

24. PNM and PNMR will include the following separateness covenants in any debt instruments:

a. Holding Company and PNM are being operated as separate corporate and legal entities. In agreeing to make loans to holding company, holding company lenders are relying solely on the creditworthiness of the holding company based on the assets owned by it, and the repayment of the loan will be made solely from the assets of the holding company and not from any assets of PNM; and

b. Holding company lenders will not take any steps for the purpose of procuring the appointment of an administrative receiver or the making of an administrative order for instituting any bankruptcy, reorganization, insolvency, wind up or liquidation or any like proceeding under applicable law in respect of PNM (Case 3103, pp. 19-20, condition 1). Order at 17.

25. Any future material indebtedness of PNM will comply with the foregoing restrictions (Case 3103, p. 20, condition 2). Order at 17.

26. PNM and PNMR will commit that the assets of PNM will not be pledged to pay or guarantee the debt of PNMR or any subsidiary of PNMR without prior approval of the Commission (Case 3103, p. 20, condition 3). Order at 17.

27. PNM's rates will not be materially and adversely affected by the Class II transaction that is the subject of this case, and PNM commits that it will not seek to recover any increased costs, including costs of capital, that may result from such transaction (Case 3103, p.20, condition 5), provided, however, that this condition will not be construed to prevent (in a future case) PNM from recovering legitimate transition costs which the Restructuring Act authorizes it to recover. Order at 17, 18. [The portion of this condition relating to transition costs was modified by the Commission's Order of January 28, 2003 in Utility Case No. 3137 (Merchant Plant Filing).]

28. PNM will agree to maintain service quality and reliability at acceptable levels and continue to comply with all Commission approved quality of service rules (Case 3103, p. 20, condition 10). Order at 17.

29. PNM will agree that it will maintain employee safety at an acceptable level. This commitment will apply to the integrated utility prior to open access and to the regulated transmission and distribution utility after open access (Case 3103, p. 20, condition 11). Order at 17.

30. PNM will commit to maintain its current local offices at least until the date of retail open access for industrial customers under the Restructuring Act of 1999 (Case 3103, p. 20, condition 12). Order at 17.

31. As a result of the holding company formation, PNM agrees that it will hold its customers harmless from any and all negative impacts of the holding company formation (Case 3103, p. 20, condition 15), provided however that this condition will not be construed to prevent (in a future case) PNM from recovering legitimate transition costs which the Restructuring Act authorizes it to recover. Order at 17-18. [The portion of this condition relating to transition costs was modified by the Commission's Order of January 28, 2003 in Utility Case No. 3137 (Merchant Plant Filing).]

32. PNM will retain its existing corporate identity along with all rights and obligations which relate to that legal status following formation of the holding company. (Case 2678, p. 82, No. 9). Order at 19.

33. In addition to any jurisdiction that the Commission otherwise has, the Commission will have jurisdiction to review the prudence and reasonableness of costs of goods, services or wholesale power purchased by PNM from any of its affiliated interests for inclusion in retail rates. December 18 Order, ¶ A(2).

34. The Commission's authority to apply "prudence" and "used and useful" tests to determine whether the costs of particular wholesale electric purchase agreements should be included in retail rates remains unaffected. (Case 2678, p. 91, No. 50). Order at 19.

35. Holding company formation will not affect the Commission's regulation of securities issued by PNM. (Case 2678, p. 91, No. 51). Order at 19.

36. The holding company will not diminish the Commission's authority over PNM's construction and siting of generation and transmission facilities. (Case 2678, p. 91, No. 52). Order at 19.

37. PNM must agree that, as a condition for Commission approval of the holding company, neither it nor any of its affiliated interests resulting from the formation of the holding company will assert federal preemption as the basis for challenging the Commission's treatment of costs, expenses or revenues related to transactions involving power or other goods and services between the utility and affiliated interests, or the Commission's determination of power supply resources which should be included or excluded from New Mexico rates, in any New Mexico rate case. December 18 Order, ¶ A(3).

38. PNM must agree that its waiver of any claim of federal preemption extends to Commission review of affiliate transactions for ratemaking purposes, and the waiver applies to preemption by both FERC and the SEC and would entitle the Commission to examine the reasonableness and the prudence of costs, cost allocations and cost assignments, for ratemaking purposes. December 18 Order, ¶ A(4).

39. PNM's requested transfer to PNMR of hardware and software associated with computer and communication systems is not approved. December 18 Order, ¶ E.

74702

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	)	
	)	
ADJUSTMENT OF THE RATES OF KENTUCKY-AMERICAN WATER COMPANY	))	**CASE NO. 2004-00103**

COMMISSION STAFF'S FIRST SET OF INFORMATION REQUESTS TO THE ATTORNEY GENERAL

57. List all state regulatory commissions that have rejected the use of consolidated income tax adjustments for ratemaking purposes. Provide a copy of each listed commission's decisions on this subject.

Response: Ms. Crane believes that the State of Delaware may have rejected the use of consolidated income tax adjustments for ratemaking purposes. The Hawaii Public Utilities Commission also rejected consolidated income tax adjustments in at least one case involving East Honolulu Community Services, Inc. on the basis that certain tax loss carryforwards had already been used by other members of the consolidated income tax group. She does not have copies of any Delaware Public Service Commission order or Hawaii Public Utilities Commission order addressing this issue.

Respondent: Andrea C. Crane

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	)	
	)	
ADJUSTMENT OF THE RATES OF KENTUCKY-AMERICAN WATER COMPANY	))	**CASE NO. 2004-00103**

COMMISSION STAFF'S FIRST SET OF INFORMATION REQUESTS TO THE ATTORNEY GENERAL

58. Refer to Direct Testimony of Andrea C. Crane at 74. State whether Ms. Crane's proposed consolidated income tax adjustment conforms to the federal income tax normalization requirements. Explain.

Response: Ms. Crane's proposed consolidated income tax adjustment does conform to the federal income tax normalization requirements. See the attached documentation from the Internal Revenue Service.

Respondent: Andrea C. Crane

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	)	
	)	
ADJUSTMENT OF THE RATES OF	)	**CASE NO. 2004-00103**
KENTUCKY-AMERICAN WATER COMPANY	)	

COMMISSION STAFF'S FIRST SET OF INFORMATION REQUESTS TO THE ATTORNEY GENERAL

ATTACHMENT TO QUESTION 58

For Release Upon Delivery
Expected at 10 a.m.
September 11, 1991

STATEMENT OF
MICHAEL J. GRAETZ
DEPUTY ASSISTANT SECRETARY (TAX POLICY)
DEPARTMENT OF THE TREASURY
BEFORE THE
SUBCOMMITTEE ON SELECT REVENUE MEASURES
COMMITTEE ON WAYS AND MEANS
UNITED STATES HOUSE OF REPRESENTATIVES

Mr. Chairman and Members of the Committee:

I am pleased to be here today to discuss the recent withdrawal of proposed regulations concerning the treatment under State ratemaking proceedings of consolidated tax savings under the normalization provisions of the Internal Revenue Code (the "Code"). These proposed regulations, which were published in November 1990 and withdrawn in April 1991, attempted to address the question whether the Internal Revenue Code should be interpreted to restrict the ability of State regulators to take into account certain tax savings realized by an affiliated group of corporations ("consolidated tax savings") in setting the rates that they permit public utilities to charge their customers.

Background

Public utility rates generally are set under State law to compensate the utility for the costs of providing utility services and to provide the utility's bondholders and shareholders with a fair return on the capital they invest in utility assets. The "cost of service" component of rates is based on the operating costs incurred by the utility during the year (such as fuel, salaries, postage, etc.), the depreciation of fixed assets during the year (generally allowed on a straight-line basis over a 25 to 40 year life), and Federal and State income tax expense for the year. The "return on capital" component of rates is based on the product of the "rate base" (generally the regulatory book value of assets employed to provide utility services) and a weighted average rate of return on debt and equity capital that bondholders and shareholders have invested in those assets.

Since 1969 the Internal Revenue Code has conditioned a public utility's ability to use accelerated depreciation for public utility property on specified ratemaking treatment of the tax savings due to the utility's use of accelerated methods of depreciation or shortened depreciation lives. In general, the Code provides that a public utility may not use accelerated depreciation for public utility property in computing its Federal income tax liability unless the regulators use a "normalization method of accounting" in calculating the utility's tax expense for ratemaking purposes.

There are two general ways a utility regulatory commission can account for the benefits of accelerated depreciation, shorter depreciation lives, and investment credits for public utility property in setting utility rates. One way, flowthrough accounting, treats these benefits as a current reduction in Federal income tax expense in computing the utility's cost of service. Under this method, current operating expenses are reduced, and the Federal tax benefit is immediately flowed through to current utility customers. A second way, normalization accounting, treats these benefits as a reduction in the utility's capital costs.

In general, normalization accounting requires a utility to compute its tax expense in determining its cost of service for ratemaking purposes as though it used the same method and period of depreciation that it uses in calculating its depreciation expense for purposes of setting its rates. This typically will be the straight-line method over a much longer life than is used for tax purposes. Thus, under this method, which the Code requires for a utility to be able to use accelerated depreciation on public utility property, regulators must calculate the utility's cost of service in a manner that permits the utility to collect from customers an amount for tax expense that exceeds the utility's actual current tax liability by the amount of the tax savings from accelerated depreciation.

Under normalization accounting, however, regulators may treat the tax savings as cost-free capital. It is not a violation of the normalization rules of the Code for regulators to reduce a utility's "rate base" -- generally the total amount of capital invested in the utility on which stockholders and bondholders are allowed to earn a return -- by the cumulative tax savings from using accelerated depreciation. A utility using normalization accounting may be thought of as treating the reduction in its current tax liability that results from using accelerated depreciation as an interest-free loan from the Treasury; this is accomplished by treating the utility as though it were required to pay to the Treasury the tax that would be due if accelerated depreciation were not allowed, and the Treasury loaned back to the utility -- without interest -- the excess of this amount over the utility's actual tax liability calculated using accelerated depreciation. In effect, normalization accounting operates to determine a utility's rate of return on a reduced rate base, thereby flowing through to customers over the service life of the asset the benefits of reduced capital expenses due to accelerated depreciation. The normalization rules are intended to ensure that the Federal tax savings provided through accelerated depreciation provide cost-free capital to utilities to promote investment and are not used to subsidize current consumption.

The History of the Normalization Requirement

A requirement that utilities use the normalization method of accounting was first added to the Internal Revenue Code in 1969. In 1964, Congress had foreshadowed the 1969 normalization rules by prohibiting Federal regulatory agencies from flowing through the 3 percent investment tax credit then available on public utility property more rapidly than ratably over the useful life of the asset and prohibiting Federal regulators from flowing through any part of the 7 percent investment credit on nonpublic utility property.[1] The Tax Reform Act of 1969 added section 167(l) to the Code to limit the use of flowthrough accounting, and, in general, to require utilities that claimed accelerated tax depreciation to use a normalization method of accounting.

Congress did not completely prohibit flowthrough accounting in 1969, however. At that time, about half of all State ratemaking authorities were requiring utilities to flow through to current customers the benefits of accelerated tax depreciation.[2] Congress was concerned about causing a widespread increase in rates paid by customers of those

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[1]Pub. L. No. 88-272, § 203(e) (1964). When Congress enacted a 7 percent investment tax credit (ITC) in 1962, regulated utilities were granted a credit of only 3 percent. The reduced rate was a compromise between those who argued that utilities should receive the same investment incentives as other businesses and those who argued that, because of their monopoly status, utilities did not need incentives to invest and that flowthrough accounting by ratemakers would defeat the purpose of making investment incentives available to utilities.

[2]Indeed, some ratemakers were insisting that utilities, such as the major telephone companies, which had been claiming straight-line depreciation, claim accelerated tax depreciation so that the Federal tax savings could be flowed through to ratepayers. Certain ratemakers were reducing rates by the available Federal tax savings even if a utility did not claim accelerated tax depreciation.

utilities, and the 1969 legislation was designed to stop the spread of flowthrough accounting to utilities not already using it; utilities using flowthrough were "grandfathered."

In structuring the 1969 prohibition, Congress did not attempt directly to prohibit State ratemaking authorities from using flowthrough accounting. Because of federalism concerns and suggestions that such a direct prohibition would raise constitutional issues, Congress instead conditioned a utility's ability to use accelerated depreciation on its use of normalization accounting.[3] The 1969 Act granted Treasury broad authority in section 167(l)(5) to issue regulations as needed to carry out the purposes of the normalization rules.

In 1971, Congress increased the investment tax credit on public utility property to 4 percent and required utilities to use a normalization method of accounting for the credit as a condition of claiming it with respect to public utility property.[4] In 1981, in connection with the adoption of the ACRS system of depreciation, Congress extended the normalization rules to all utilities by repealing the 1969 grandfather rules. In 1982, Congress expanded Treasury's regulatory authority to prevent the use of ratemaking techniques that are inconsistent

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[3]The 1969 normalization requirement grew out of H.R. 6659, which would have prohibited flowthrough accounting by State ratemakers. This direct prohibition was rejected in favor of imposing a loss of accelerated depreciation on utilities because the bill's opponents raised doubts about the constitutionality of prohibiting State regulators from using flowthrough accounting. See, e.g., Statement of Fred P. Morrissey, Commissioner, California Public Utilities Commission, before the Committee on Ways and Means on March 27, 1969, summarized in Summary of Testimony on Treatment of Tax Depreciation by Regulated Utilities, JCS 47-69 at 8 (July 11, 1969). The Treasury Department opined on May 5, 1969, that the direct prohibition was constitutional. See letter from Paul W. Eggers, General Counsel of the Treasury, submitted in response to a question from Congressman Utt to Assistant Secretary Cohen and reprinted in Hearings before the Committee on Ways and means, Ninety-first Congress, First Session on the Subject of Tax Reform, Part 15 of 15 at 5672 (April 24, 1969).

[4]Although the new ITC normalization rules in section 46(e) (which later became section 46(f)) allowed ratemakers to "share" part of the credit with current and future ratepayers, the rules were not identical to the section 167(l) normalization rules that were prescribed for accelerated depreciation in 1969. Under the 1971 rules, ratemakers were permitted to reduce the rate base by the amount of the investment tax credit or to flow through the credit over the life of the property.

with the statutory normalization requirement.[5] In 1986, Congress extended normalization accounting to cover the ratemaking treatment of the reduction in corporate income tax rates.[6] Notice 87-82, 1987-2 C.B. 389, 391, requires normalization of contributions in aid of construction (CIACs) received subsequent to the 1986 Act's changes in the method of tax accounting for most CIACs.[7]

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[5]The California regulatory commission had created a technique called the Average Annual Adjustment ("AAA") method, which creatively used certain "estimates and projections" to mimic the effects of a flowthrough method in a way that arguably did not violate the statutory normalization rules. In sections 168(e)(3)(C) (which later became section 168(i)(9)(B)) and 46(f)(10), Congress stated that the normalization requirements are not met if the taxpayer uses procedures and adjustments that are inconsistent with the normalization rules. Congress described the AAA method as one procedure or adjustment that violated the new statutory "consistency requirement," and authorized Treasury to prescribe by regulation other procedures and adjustments that would be treated as inconsistent with the normalization rules. <u>See</u> H.R. Rep. No. 97-827, 97th Cong. 2d Sess. at 7-10 (1982). The 1982 legislation also granted relief to eliminate the substantial tax liability of several California utilities that would have been assessed for prior years due to the disallowance of accelerated depreciation and investment credits on the grounds that the State regulatory commission's rules violated the Code's normalization requirements.

[6]By lowering the top marginal income tax rate for corporations from 46 percent to 34 percent, the 1986 Act produced an "excess deferred tax reserve" because the deferred tax reserve for accelerated depreciation that was set aside at a rate of 46 percent could now be paid back at the 34 percent rate. Section 203(e) of the 1986 Act provided that under a normalization method, the excess deferred tax reserve could not be flowed through to reduce the cost of service component of current rates more rapidly than over the remaining regulatory lives of the utility's assets. In 1987 and again in 1989, this Committee revisited the decision to require normalization of the effect of the 1986 change in income tax rates, and on both occasions Congress left in place its 1986 decision that the excess deferred tax reserves should be normalized.

[7]A typical CIAC is a utility line that a customer constructs and contributes to the utility, or pays the utility to construct, as a condition of receiving utility services. Prior to 1986, CIACs were generally excluded from the utility's income as nonshareholder contributions to capital under Code section 118(a). The 1986 Act added section 118(b), which provides that CIACs received from a customer or potential customer are not covered by section 118(a). Thus, these CIACs must be included currently in the utility's gross income under section 61.

In summary, Congress has enacted normalization requirements with respect to the regulatory treatment of three tax benefits: accelerated depreciation and investment tax credits claimed for public utility property and the 1986 reduction in corporate tax rates. Prior to the publication of the proposed regulations concerning consolidated tax savings -- which are the subject of this hearing -- the Internal Revenue had published normalization requirements for only one additional item: post-1986 CIACs.

Consolidated Tax Savings

In recent years, the Treasury and Internal Revenue Service have been asked whether the normalization requirements of the Code apply to restrict the regulatory treatment of the reduction in Federal income taxes resulting from utilities filing a consolidated return with unregulated affiliates. Utilities, like other corporate taxpayers, are permitted to file a consolidated tax return with other commonly controlled corporations. When a consolidated return is filed, the tax liability of the affiliated group generally is determined as if the members of the group were a single corporation. A utility, for example, may thereby shelter its income from current taxation by offsetting tax losses (or excess credits) of other affiliated corporations engaged in unregulated businesses (for example, leasing and gas exploration). If the affiliated corporations did not file a consolidated return, the losses of the unregulated companies generally would not be used to reduce taxes until the later years in which the loss companies become profitable.

State ratemaking authorities generally have used two different approaches to determine the tax expense of a utility that files a consolidated return. Under an "actual taxes paid" approach, the tax savings that result from filing a consolidated return are flowed through to utility customers through lower rates that result from including only the utility's share of actual taxes paid in the utility's cost of service. The United States Supreme Court upheld the Federal Power Commission's use of such an "actual taxes paid" approach in 1967, two years before the depreciation normalization rules were first added to the

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However, notwithstanding the 1986 change in the tax law, most utilities disregard the receipt of a CIAC for ratemaking purposes. Thus, the 1986 Act created a timing difference between ratemaking and tax accounting for CIACs, and Notice 87-82 required that difference to be normalized so that the prepayment of tax on CIACs would be shared between current and future ratepayers. The Notice requires a utility to increase its rate base by the amount of the CIAC or treat the CIAC as a loss of zero-cost capital in computing the return on capital component of current rates. We are not aware of any utilities or ratemakers who have complained about Notice 87-82.

Internal Revenue Code. Federal Power Commission v. United Gas Pipe Line Co., 386 U.S. 237 (1967).

Under an alternative "stand-alone" approach, the ratemaking authority determines the utility's tax expense for purposes of setting rates as if the utility had filed a separate return. Thus, for example, under stand-alone accounting, if a utility that has taxable income files a consolidated return with an affiliate whose losses completely shelter that income from current taxation, the utility's cost of service for ratemaking purposes reflects the tax that the utility would have paid if it had filed a separate return. The United States Court of Appeals for the District of Columbia Circuit upheld the Federal Energy Regulatory Commission's use of such an approach in City of Charlottesville v. Federal Energy Regulatory Commission, 774 F.2d 1205 (D.C. Cir. 1985), cert. denied, 475 U.S. 1108 (1986).[8]

In the 1980s, the Internal Revenue Service issued several private letter rulings holding that the normalization provisions of the Code require regulatory authorities to use a stand-alone approach. One of these rulings was issued to Contel, a utility doing business in Pennsylvania. Notwithstanding this ruling, the Pennsylvania Public Utility Commission set Contel's rates using an "actual taxes paid" approach. Contel then appealed the Commission's decision to the Commonwealth Court of Pennsylvania, which affirmed the Commission's position. Continental Telephone Company of Pennsylvania v. Pennsylvania Public Utility Commission, 548 A.2d 344 (Pa. Commw. 1988), appeal denied, 557 A.2d 345 (Pa. 1989). The Pennsylvania court rejected the conclusion of the private letter ruling that Contel would be in violation of the normalization rules if it followed the Commission's rate order.[9]

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[8]The Federal Power Commission (FERC's predecessor) decided in 1972 to abandon consolidated tax savings adjustments in favor of a stand-alone approach. Dismissing as dicta the Supreme Court's statements in United Gas Pipeline about FPC's "duty" to limit the cost of service component of rates to real expenses, Judge Scalia rejected Charlottesville's argument that the "actual taxes paid" doctrine prevented FERC from using a stand-alone method. 774 F. 2d at 1216. In essence, the court held that it was within FERC's ratemaking authority to require either a flowthrough or stand-alone method of accounting for consolidated tax savings.

[9]According to the Pennsylvania court, the letter ruling did not rest upon compelling law or logic, and "in itself cannot provide a legal basis for invalidation of a PUC order." 548 A.2d at 351. The court relied instead upon the holdings of the Pennsylvania Supreme Court in Barasch v. Pennsylvania Public Utility Commission, 493 A.2d 653 (Pa. 1985)(the commission was not entitled to include in rates "hypothetical" Federal and State income taxes that were not actually incurred), and in Barasch v.

Following the Pennsylvania Court's decision, decisionmakers at the Internal Revenue Service were forced to consider whether to maintain the position taken in the private letter ruling, which would have treated Contel as violating the normalization requirement, thereby requiring disallowance of accelerated depreciation on its public utility property that would produce large tax deficiencies against Contel. In May 1989, the Service published Notice 89-63, 1989-1 C.B. 720, to inform utilities and ratemakers that it was developing proposed regulations to address whether the use of consolidated tax adjustments violates the normalization requirements of the Code. At that time, the Service also withdrew two of the private rulings -- including the one issued to Contel -- that had addressed the issue.

Issuance and Withdrawal of Proposed Regulations

On November 27, 1990, the Service proposed regulations attempting to apply the general policies of the normalization method of accounting to consolidated tax savings. These proposed regulations would have prohibited current flowthrough of consolidated tax savings by denying a utility the use of accelerated depreciation on its public utility property -- the only sanction permissible under the statute -- unless the utility's tax expense in determining its cost of service for ratemaking purposes is determined on a stand-alone basis. Thus, the proposed regulations would have prohibited regulatory commissions from taking consolidated tax savings into account in computing ratemaking tax expense. However, the proposed regulations would not have prohibited a commission from adjusting the utility's rate base to treat the affiliated group's 14 tax savings from filing a consolidated return as cost-free capital until the loss affiliate becomes profitable.

This approach generally regards the taxable income generated by the utility as serving to permit current use of the offsetting losses (or credits) of unregulated affiliates and treats the benefits of filing a consolidated return as a deferral, rather than a permanent reduction, of tax liability. The normalization requirements of the proposed regulations were similar to those under the Code for the tax savings from accelerated depreciation. As with statutory normalization of accelerated depreciation, the proposed regulations would not have required ratemakers to adjust the rate base by a utility's share of the affiliated group's consolidated tax savings, but would have permitted them to do so. The proposed regulations specified a method, based on the

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Pennsylvania Public Utility Commission and Pennsylvania Power Co., 491 A.2d 94, 103 (Pa. 1985)("hypothetical" taxes could only be included in rates if the failure to normalize would result in the loss of accelerated depreciation deductions and leave current ratepayers even worse off than they are under normalization).

consolidated return regulations, for determining the utility's share of the affiliated group's consolidated tax savings.

Subject to specific exceptions for cases where consolidated tax savings had previously been flowed through to customers, the proposed regulations would not have permitted any tax savings from prior years to be flowed through to customers or to be treated by regulatory commissions as cost-free capital. These provisions were intended to minimize the effect of the proposed regulations by limiting any sudden changes in utility rates.

The Internal Revenue Service received about 100 written comments on the proposed regulations and held a public hearing on February 8, 1991, at which about 30 witnesses testified. Not one commenter endorsed the basic approach of the proposed regulations.

Representatives of public utility commissions argued that the Service lacked authority under the normalization rules to issue regulations to require use of a stand-alone approach in computing cost of service, because the normalization rules of the Code apply only to accelerated depreciation of public utility property. Ratemakers contended that the Service exceeded its regulatory authority by attempting to dictate the ratemaking treatment of an item, such as consolidated tax savings, that does not necessarily involve either accelerated depreciation or public utility assets. The ratemakers maintained that if Congress had intended to treat consolidated tax adjustments as a violation of normalization, it would have done so explicitly and would have adopted a different statutory penalty for violating normalization -- something other than the loss of accelerated depreciation on utility property. State regulatory authorities indicated that they intended to challenge in court the validity of the regulations if finalized.

Representatives of public utilities opposed the proposed regulations on the grounds that the normalization rules of the Code do not permit any reduction of rate base due to consolidated tax savings. They argued that any reduction of rate base inappropriately allows utility customers to enjoy the tax benefits associated with losses of an unregulated affiliate when the customers did not bear the burden of those losses.

On March 29, 1991, the Office of Management and Budget ("OMB") informed the Treasury Department that it had designated any final regulations in this area as a "major rule" under Executive order 12291. That designation requires the Department to submit the text of the final regulations, along with a Regulatory Impact Analysis of the costs and benefits of the rule and of any alternative regulatory approaches, for review by OMB

Furthermore, the designation of the final regulations as a "major rule" under Executive order 12291 automatically makes any final regulations a "significant regulatory action" under Executive order 12498. That designation would have required the final regulations to be described in the published Regulatory Program of the U.S. Government.[11]

The Treasury Department is not aware of another circumstance when OMB has designated a tax regulation as a "major rule" under Executive order 12291. Performing the kinds of cost-benefit analyses required by these Executive orders would be difficult in any circumstances, but in the instant context such analyses would be particularly forbidding. First, the factual variations are manifold. For example, tax savings resulting from the filing of consolidated tax returns by affiliated groups that include a regulated utility may or may not be due to the use of specific tax incentives, such as accelerated depreciation or deduction of intangible drilling costs, and may vary in their relationship to the provision of utility services. Second, the costs and benefits may be different in different sections of the country and will depend, at least in part, on the State regulatory process relating both to consolidated tax savings and other issues.[12] Third, this issue raises important issues of both Federal-State relations and utility ratemaking regulatory policy

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[11]That description must include:

1. An identification of the problem to be solved;

2. A statement of the need for a Federal solution to the problem;

3. A summary of the approach taken by the rule; and

4. A tabular presentation of the currently projected monetary costs and benefits of the rule, as well as that of potential alternative approaches to the rule, including transfer costs and benefits resulting from the rule. (OMB has indicated to the Treasury Department that a narrative description of costs and benefits associated with a final regulation might be acceptable in lieu of a tabular monetary analysis in certain cases.)

[12]As Emil Sunley, Deputy Assistant Secretary of Treasury, reported to this Committee more than a decade ago: "While the [normalization] tax rules prescribe accounting rules, they do not authorize an inquiry into the motivation for regulators choosing a particular rate of return. This means there are limits as to how far the tax rules can be enforced in the regulatory process." Hearings before the Subcommittee on Oversight of the House Committee on Ways and Means, 96th Cong., 1st Sess., 515 (March 28, 1979).

that are difficult, if not impossible, to quantify and about which the Internal Revenue Service and the Office of Tax Policy claim no special expertise. Finally, the adverse commentary on the proposed regulations made it clear that neither the State regulatory authorities nor the affected utilities approved of the approach of the regulations and for opposite reasons: The State commissions regarded the proposed regulations as overreaching and illegal, while the utilities complained that the proposed regulations did not sufficiently constrain the regulators' discretion. In these circumstances, we had little reason to believe that any cost-benefit analysis we performed would be convincing to the affected parties. On April 25, 1991, the Internal Revenue Service withdrew the proposed regulations pending congressional guidance.

Current State of the Law

Attached as an Appendix to this statement is a memorandum to me from Abraham N.M. Shashy, Jr., Chief Counsel, Internal Revenue Service, that describes the Service's current ruling policy concerning whether a consolidated tax adjustment by a regulated utility violates the normalization requirements of the Internal Revenue Code. It is the position of the Service that, in the absence of regulations specifically prohibiting consolidated tax adjustments, these adjustments can be made without violating the normalization requirements of the Code. Therefore, if requested in an appropriate circumstance, the Service would rule that these adjustments do not violate the normalization requirements of the Code, provided that the adjustments are applied only to the extent of current ratemaking tax expense and not to the deferred tax reserve applicable to accelerated depreciation on public utility property.

Conclusion

We did not view the proposed regulations as a complete or final product. We saw them as a general rule and a framework within which a number of more specific issues could be resolved. We had expected that as a result of comments by the affected parties, the proposed regulations might be revised. For example, comments suggested that the rules for determining the utility's deemed share of the consolidated tax savings of the affiliated group merited change, such as by taking into account, where appropriate, tax sharing arrangements among the regulated and unregulated affiliated corporations. The comments we received on the proposed regulations also identified other issues to be considered, such as situations where there are several unregulated affiliates and situations where regulated and unregulated activities are performed within a single corporation.

Notwithstanding contentions to the contrary in comments on the proposed regulations, the Internal Revenue Service and the utility as enabling the consolidated group to use the losses sooner than if the affiliate were to file its tax return on a stand-alone basis. This measure of the utility's contribution may be captured in a rate base adjustment, which provides the utility's ratepayers with a benefit reflecting the time value of the more rapid use of the unregulated affiliates' losses or excess credits made possible by the utility's taxable income or tax liability.[14] Under the proposed regulations, the unregulated affiliates would have been no worse off than they would be had the utility not been part of the consolidated group. Since the utility's cost of capital reflects the activities of its unregulated affiliates, there seemed to be no reason to allocate the benefits resulting from the accelerated use of their losses or excess credits entirely to the unregulated affiliates, as would be the result if rate base reductions were prohibited. Thus, we concluded that we should not attempt to prohibit regulatory commissions from permitting utility customers to share in the benefit produced by consolidated tax savings through a rate base adjustment. However, because the assets that generated the tax loss are not utility property, we concluded that the losses generated by those assets should not be used to adjust the utility's current tax expense. If they were so used, the shareholders would be subsidizing the cost of the service provided by the utility. For this reason, the proposed regulations held that the current tax expense of the utility should be calculated as if it had filed a separate return.

Even when the statutory language is directly applicable and congressional policy is clear, the normalization requirements of the Code have proved to be something of a blunt instrument. On the prior important occasion when a State regulatory authority refused to accede to the statutory structure, Congress ultimately was forced to legislate to clarify the rules and forgave over $2 billion in tax liability that would have been due had the Service disallowed accelerated depreciation deductions as contemplated by the statute.[15] In the current context, certain State regulatory commissions made clear their intention to challenge the validity of these regulations if finalized and may well have disregarded them in the interval. The Service's ability to sustain disallowances of accelerated depreciation deductions in circumstances where the State commissions refuse to adhere to the proposed regulations is far from certain, and the failure to do so might erode the Service's ability to enforce normalization

[14]Even when the tax savings are generated from a transaction that does not automatically "reverse" (i.e., where the tax loss incurred by the unregulated affiliate does not simply represent a timing difference), the component of no-cost capital in the utility's rate base will be reduced when the unregulated affiliate earns income.

[15]<u>See</u> H. Rep. No. 97-987, 97th Cong., 2d Sess.(1982) and the discussion at note 5, supra.

APPENDIX

OFFICE OF
CHIEF COUNSEL

DEPARTMENT OF THE TREASURY
INTERNAL REVENUE SERVICE
WASHINGTON, D.C. 20224

SEP 09 1991

MEMORANDUM FOR: **Michael Graetz**
Deputy Assistant Secretary (Tax Policy)

FROM: **Abraham N.M. Shashy, Jr.**
Chief Counsel

Abraham N.M. Shashy, Jr.

SUBJECT: **Internal Revenue Service Ruling Position on the Treatment of Consolidated Tax Adjustments Under the Normalization Rules**

You have asked for a statement of the Internal Revenue Service ruling policy concerning whether a consolidated tax adjustment by a regulated utility violates the normalization requirements of the Internal Revenue Code. In the absence of regulations specifically prohibiting consolidated tax adjustments, it is the position of the Service that these adjustments can be made without violating the normalization requirements of the Code. Therefore, if requested in an appropriate circumstance, the Service would rule that these adjustments do not violate the normalization requirements of the Code.

Background

Over the last several years, the Service has faced the question of whether the calculation of ratemaking tax expense on a consolidated group basis is inconsistent under section 168(i)(9)(B)(i) with the normalization requirements, or, if not, whether it should be treated as inconsistent by exercise of the Service's broad regulatory authority under section 168(i)(9)(B)(iii) and former section 167(l)(5). When computed on a consolidated group basis, ratemaking tax expense is reduced to reflect the savings from filing a consolidated return with affiliated companies. These savings might arise, for example, from the credits, losses, or deferred transactions of affiliated companies.

Under one variation - the "consolidated tax savings adjustment" - the ratemaker first determines the utility's total tax expense on a separate return basis and then reduces it by the utility's share of the consolidated tax savings. Under another variation, the ratemaker computes an "effective tax rate" by dividing the tax liability of the group by the sum of the taxable incomes of all members with positive taxable incomes. The ratemaker then applies this "effective tax rate" to the utility's taxable income to compute its current tax expense.

Between 1983 and 1988, the Service issued a series of private letter rulings holding that these practices ("consolidated tax savings adjustments" or "effective tax rates") violate the normalization requirements of Section 168(i)(9) and its predecessors. After the refusal of the Pennsylvania Public Utility Commission and the state courts to follow one of these rulings in 1988, the Service began to reexamine the issue. See Continental Telephone Co. of Pennsylvania v. Pennsylvania Public Utility Commission, 120 Pa. Commw. 25, 548 A.2d 344 (1988), appeal denied, 521 Pa. 613, 557 A.2d 345 (1989). In May 1989, the Service issued Notice 89-63, 1989-1 C.B. 720, announcing that regulations would be issued providing the extent to which consolidated tax adjustments violate the normalization rules and that these regulations generally would not provide that rate orders made final before July 1989 violate normalization merely because they involve such adjustments. Accordingly, several of the normalization rulings were revoked, including the one issued to Continental Telephone of Pennsylvania that was the subject of the litigation referred to above. On November 27, 1990, the Service published proposed regulations in the Federal Register addressing the issue. 55 Fed. Reg. 49294 (Nov. 27, 1990). Under the proposed regulations, a consolidated tax adjustment was treated as a violation of the Code's normalization requirements, pursuant to the authority of Section 168(i)(9)(B)(iii). On the other hand, an adjustment to rate base was permitted for tax amounts not actually paid to the federal government. Following public comment and a hearing, the proposed regulations were withdrawn in April 1991. 56 Fed. Reg. 19825 (Apr. 30, 1991).

We believe that existing law, as reflected in statutory language, legislative history, and current regulations, leads to the conclusion that consolidated tax adjustments do not violate normalization, provided that the adjustments are applied only to the extent of current ratemaking tax expense and not to the deferred tax reserve applicable to accelerated depreciation on public utility property. In the absence of a change in that law, our ruling policy must conform to that conclusion.

Analysis: Statutory Requirement of Section 168(i)(9)(A)

Section 168(i)(9)(A) requires that, in order to be eligible for accelerated depreciation on "public utility property" (as defined in section 168(i)(10)) a public utility must compute its tax expense for ratemaking purposes using the same method and period for such property as it uses for computing its depreciation expense for ratemaking purposes. Under section 168(i)(9)(A)(ii), the difference between the tax expense so computed and the utility's actual current tax liability must be treated as a deferred tax expense, which is considered a cost-free source of capital. This cost-free capital may be used to reduce the rate base on which the utility is permitted to earn a return.

Section 168(i)(9)(A) does not impose any other restriction on the computation of tax expense for ratemaking purposes. Thus, if a utility computes its ratemaking tax expense on a consolidated basis, taking into account the losses of its affiliates (and thus taking into account the tax savings resulting from those losses), but also computes its tax expense as though it used its book method and period for determining depreciation deductions on public utility property, it would not be in violation of the literal requirements of section 168(i)(9)(A).

It has been argued that the statutory requirement that "the taxpayer must, in computing its tax expense . . ." necessarily contemplates determination of ratemaking tax expense on a "stand-alone" basis. We do not believe, however, that Congress intended to address this issue by using those words. At the time that the words were first added to the Code in 1969, consolidated tax adjustments (or equivalent procedures) were a widespread and accepted ratemaking practice and had been upheld by the Supreme Court as within the authority of the Federal Power Commission. See FPC v. United Gas Pipeline Co., 386 U.S. 237 (1967). We do not believe that it is plausible that Congress would have deliberately prohibited or discouraged such a widespread practice without a more explicit reference in the statute or legislative history.

Consistency Requirement of Section 168(i)(9)(B)

Section 168(i)(9)(B) prohibits (or authorizes Treasury to prohibit by regulation) ratemaking practices that undermine the purpose of the normalization rules while complying with their literal terms. This provision was enacted in 1982 in response to a specific ratemaking practice called the "averaged annual adjustment" or "AAA" method. See S. Rep. No. 1038, 96th cong. 2d Sess. 11 (1980). The AAA method purported to comply with the literal statutory requirements of the normalization rules, while at the same time undermining the requirement to provide for deferred taxes; the method did so by making an unreasonable adjustment to current tax expense, explainable only by an intent to circumvent the normalization rules.

Although the Service, in PLR 7838038 and PLR 7838048, ruled that the AAA method violated normalization, some utility commissions and courts refused to follow these rulings. In 1982, Congress concluded that the AAA method was inconsistent with normalization and that a clarifying statutory change was appropriate. Accordingly, section 168(i)(9)(B)(i) was enacted, providing that "[o]ne way in which the requirements of [section 168(i)(9)(A)] are not met is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with the requirements of [section 168(i)(9)(A)]." The phrase "inconsistent with the requirements" of normalization apparently was taken from regulations in effect at the time (section 1.167(l)-1(h)(4)(ii)), upon which the Service had relied in ruling that the AAA method violated normalization.

In order to make clear that the AAA method was "inconsistent with the requirements" of normalization, Congress also enacted section 168(i)(9)(B)(ii), which provided that "[t]he procedures and adjustments which are to be treated as inconsistent for purposes of [section 168(i)(9)(B)(i)] shall include any procedure or adjustment for ratemaking purposes which uses an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under [section 168(i)(9)(A)(ii)] unless such adjustment or projection is also used, for ratemaking purposes, with respect to the other 2 such items and with respect to the rate base."

PLR 8711050 (subsequently revoked) reasoned that section 168(i)(9)(B)(ii) prohibits consolidated tax adjustments because it requires that, if depreciation on property owned by an affiliate is not taken into account in setting rates (which it is not), the losses of that affiliate attributable to depreciation on such property cannot be taken into account in computing the utility's ratemaking tax expense.

We do not believe that this reasoning is persuasive for two reasons. First, the practice of taking affiliate losses into account does not involve an "estimate or projection" of tax expense as Congress used those words in section 168(i)(9)(B)(ii). The term "estimate or projection" as used in the statute clearly was intended to be more narrow than the term "procedure or adjustment", and it was intended to refer to assumed changes in a particular account or item between a test year and the subsequent years covered by a rate order. See S. Rep. No. 643, 97th Cong., 2d Sess. 7 (1982); H.R. Rep. No. 827, 97th Cong. 2d Sess. 7 (1982). Therefore, we do not believe that consolidated tax adjustments constitute an "estimate or projection" of depreciation expense within the meaning of section 168(i)(9)(B)(ii).

Second, this reasoning implies that the normalization rules prohibit flow-through of the tax benefit of accelerated depreciation on any property if depreciation expense on that property is not taken into account in computing utility rates. The normalization provisions are, by their terms, limited to accelerated depreciation on public utility property. There is no evidence in the legislative history of section 168(i)(9)(B)(ii) indicating that Congress contemplated that this provision would have the effect of applying the normalization rules to non-public utility property.

In any event, even if the reasoning of this ruling were to be accepted, it would not support the view that no affiliate losses can be taken into account in computing ratemaking tax expense; it would only support the view that losses attributable to accelerated depreciation deductions on affiliate property can not be taken into account. Thus, this reasoning would not prohibit as being inconsistent with the normalization requirements the flow-through of affiliate losses attributable to intangible drilling costs, for example. In any case, we do not believe Congress intended the literal scope of the normalization requirements to extend beyond accelerated depreciation on public utility property.

These arguments do raise a concern that a consolidated tax adjustment might be used to offset a utility's deferred tax reserve from normalization or might be used to flow through the accelerated depreciation benefit of another regulated utility in the same consolidated group. These concerns are worthy of further study. Until they are resolved we can only say with confidence that consolidated tax adjustments do not violate normalization, provided that the adjustments are applied only to the extent of current ratemaking tax expense and not to the deferred tax reserve applicable to accelerated depreciation on public utility property, and provided that the taxable income of any other regulated utilities used in the calculation of the adjustments is computed on a normalized basis.

Regulatory Authority of Section 168(i)(9)(B)(iii)

In 1982, Congress also authorized Treasury to prohibit procedures and adjustments other than the AAA method by enacting the predecessor to section 168(i)(9)(B)(iii). It provides that the "Secretary may by regulations prescribe procedures and adjustments (in addition to those specified in [section 168(i)(9)(B)(ii)]) which are to be treated as inconsistent for purposes of [section 168(i)(9)(B)(i)]." The preamble to the now-withdrawn proposed regulations explicitly states that the regulations were issued pursuant to this authority. In the absence of such a regulatory provision, however, the normalization requirements do not prohibit consolidated tax adjustments as a general rule.

Therefore, it is the current ruling position of the Internal Revenue Service that consolidated tax adjustments, as a general rule, are not inconsistent with the normalization requirements of the Code. (Similarly, it is the current ruling position of the Internal Revenue Service, that, in the absence of any reduction of cost of service for consolidated tax savings, an appropriate reduction of rate base for consolidated tax savings is also not inconsistent with the normalization requirements of the Code.)