COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE GAS)
RATES OF THE UNION LIGHT,)
HEAT AND POWER COMPANY)

CASE NO. 2005-00042

NOTICE OF FILING AND CERTIFICATION OF SERVICE

I hereby give notice that I have filed the original and ten true copies of the Testimonies and their Exhibits with the Executive Director of the Kentucky Public Service Commission at 211 Sower Boulevard, Frankfort, Kentucky, 40601 this the 8th day of June, 2005, and certify that this same day I have served the parties by mailing a true copy, postage prepaid, to the following:

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COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF THE UNION LIGHT, HEAT	)	
AND POWER COMPANY FOR AUTHORITY TO	)	**CASE NO. 2005-00042**
INCREASE ITS RATES FOR GAS SERVICE TO ALL	)	
JURISDICTIONAL CONSUMERS	)	

DIRECT TESTIMONY

AND EXHIBITS

OF

ROBERT J. HENKES

ON BEHALF OF THE OFFICE OF RATE INTERVENTION
OF THE ATTORNEY GENERAL FOR
THE COMMONWEALTH OF KENTUCKY

June 8, 2005

Union Light, Heat and Power Company
Case No. 2005-00042
Direct Testimony and Exhibits of Robert J. Henkes

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I. STATEMENT OF QUALIFICATIONS

Q. WOULD YOU STATE YOUR NAME AND ADDRESS?

A. My name is Robert J. Henkes, and my business address is 7 Sunset Road, Old Greenwich, Connecticut, 06870.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. I am Principal and founder of Henkes Consulting, a financial consulting firm that specializes in utility regulation.

Q. WHAT IS YOUR REGULATORY EXPERIENCE?

A. I have prepared and presented numerous testimonies in rate proceedings involving electric, gas, telephone, water and wastewater companies in jurisdictions nationwide including Arkansas, Delaware, District of Columbia, Georgia, Kentucky, Maryland, New Jersey, New Mexico, Pennsylvania, Vermont, the U.S. Virgin Islands, and before the Federal Energy Regulatory Commission. A complete listing of jurisdictions and rate proceedings in which I have been involved is provided in Appendix I attached to this testimony.

Q. WHAT OTHER PROFESSIONAL EXPERIENCE HAVE YOU HAD?

A. Prior to founding Henkes Consulting in 1999, I was a Principal of The Georgetown Consulting Group, Inc. for over 20 years. At Georgetown Consulting, I performed the same type of consulting services that I am currently rendering through Henkes Consulting.

Prior to my association with Georgetown Consulting, I was employed by the American Can Company as Manager of Financial Controls. Before joining the American Can Company, I was employed by the management consulting division of Touche Ross & Company (now Deloitte & Touche) for over six years. At Touche Ross, my experience, in addition to regulatory work, included numerous projects in a wide variety of industries and financial disciplines such as cash flow projections, bonding feasibility, capital and profit forecasting, and the design and implementation of accounting and budgetary reporting and control systems.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I hold a Bachelor degree in Management Science received from the Netherlands School of Business, The Netherlands in 1966; a Bachelor of Arts degree received from the University of Puget Sound, Tacoma, Washington in 1971; and an MBA degree in Finance received from Michigan State University, East Lansing, Michigan in 1973. I have also completed the CPA program of the New York University Graduate School of Business.

II. SCOPE AND PURPOSE OF TESTIMONY

Q. WHAT IS THE SCOPE AND PURPOSE OF YOUR TESTIMONY?

A. I was engaged by the Office of Rate Intervention of the Attorney General of Kentucky ("AG") to conduct a review and analysis and present testimony regarding the petition of Union Light Heat and Power Company ("ULHP" or the "Company") for an increase in its base rates for gas service.

The purpose of this testimony is to present to the Kentucky Public Service Commission ("KPSC" or "the Commission") the appropriate capitalization, rate base and pro forma operating income, as well as the appropriate revenue requirement for the Company in this proceeding.

In the determination of the recommended revenue requirement for ULHP in this proceeding, I have relied on and incorporated the recommendations of the following other AG witnesses:

- Dr. J. Randall Woolridge, concerning the appropriate capital structure, cost rates for long- and short-term debt, return on equity rate and overall rate of return for the Company in this proceeding;
- Mr. Michael J. Majoros, Jr., concerning the appropriate depreciation expenses to be reflected for ratemaking purposes in this proceeding; and

- Mr. David Brown Kinloch, concerning adjustments to the Company's proposed weather normalization adjustment, Firm Transportation sales, and certain Other Operating Revenues.

Q. WHAT INFORMATION HAVE YOU RELIED UPON IN THE DEVELOPMENT OF YOUR TESTIMONY?

A. In developing this testimony, I have reviewed and analyzed the Company's petition; testimonies, exhibits, workpapers and filing requirements; responses to AG and PSC initial and supplemental interrogatories and other relevant financial documents and data.

III. SUMMARY OF FINDINGS AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS IN THIS CASE

A. The findings and conclusions reached by me in this case are as follows:

1. Based on previously established KPSC ratemaking policy, the appropriate capital structure to be used for rate making purposes in ULHP's base rate proceedings should be determined by the application of the appropriate gas jurisdictional rate base ratio to ULHP's total capitalization exclusive of non-jurisdictional capital.

   In accordance with this calculation method, the Company's appropriate gas jurisdictional capital structure in this case amounts to $162,296,080. This is $3,423,113 lower than the Company's proposed gas jurisdictional capital structure of $165,719,193 (Schedule RJH-1, line 1 and Schedule RJH-3).

2. The appropriate pro forma gas jurisdictional rate base amounts to $162,980,160 which is $4,519,079 lower than the Company's proposed pro forma gas jurisdictional rate base of $167,499,239. The corresponding ratio of gas jurisdictional rate base to total company jurisdictional rate base is 25.337% (Schedule RJH-4).

3. The AG's expert rate of return witness, Dr. J. Randall Woolridge, has

recommended an overall rate of return of 7.285%, including a return on equity of 8.7%, for ULHP in this proceeding. This is equivalent to a rate of return of 7.254%[1] as measured based on the Company's gas jurisdictional rate base.

By comparison, the Company has proposed an overall rate of return of 8.787%, which is equivalent to a rate of return of 8.69%[2] as measured based on the Company's proposed gas jurisdictional rate base.

4. The appropriate pro forma net after-tax operating income amounts to $9,756,674, which is $3,443,978 higher than ULHP's proposed net after-tax operating income of $6,312,696 (Schedule RJH-1, line 4 and Schedule RJH-8).

5. The appropriate gross revenue conversion factor to be used for rate making purposes in this case is 1.6769492 (Schedule RJH-1, Line 6). This recommended conversion factor, which incorporates a reduced 7% Kentucky income tax rate, is lower than ULHP's proposed conversion factor of 1.6997957, which includes a Kentucky income tax rate of 8.25% (Schedule RJH-1, line 6).

6. The application of the recommended overall rate of return of 7.285% to the recommended gas jurisdictional capital structure of $162,296,080, combined

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[1] Sch. RJH-1, line 3: $11,823,511 divided by rate base of $162,980,160 (Sch. RJH-4) = 7.254%

[2] Sch. RJH-1, line 3: $14,561,745 divided by rate base of $167,499,239 (Sch. RJH-4) = 8.69%

with the recommended pro forma test period operating income of $9,756,674 and the revenue conversion factor of 1.6769492 indicates that the Company has the need for an annual rate increase of $3,465,981. This is $10,555,717 lower than the Company's proposed rate increase request of $14,021,698 (Schedule RJH-1, lines 1-7).

IV. REVENUE REQUIREMENT ISSUES

A. COST OF CAPITAL

Q. PLEASE DESCRIBE THE AG'S RECOMMENDED OVERALL COST OF CAPITAL.

A. As shown on Schedule RJH-2, the AG's expert rate of return witness, Dr. J. Randall Woolridge, has recommended a return on equity rate of 8.7%, an embedded cost of long-term debt rate of 6.302%, and a short-term debt cost rate of 3.875%. At the time this testimony was being prepared,[1] Dr. Woolridge's analysis of the appropriate capital structure to be used in this case was still in progress. Therefore, at this time I have reflected the same capital structure ratios as proposed by ULHP[2] for purposes of determining the overall rate of return resulting from Dr. Woolridge's capital cost rate recommendations. As shown on Schedule RJH-2, the resulting recommended overall rate of return is 7.285%. This overall rate of return number is to be considered preliminary and subject to change. To the extent that Dr. Woolridge recommends different capital structure ratios than currently shown on Schedule RJH-2, the preliminary overall rate of return number of 7.285% will be changed to reflect his recommended capital structure ratios.

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[1] Because of the change in the procedural schedule ordered by the PSC on April 28, 2005, the filing date of the AG's testimonies was shifted to 6/8/05 at which date I would be out of the country. As a result, I prepared this testimony at a time prior to the finalization of the testimonies of other AG witnesses, including Dr. Woolridge. My return to the USA was not until after the testimonies of these other AG witnesses were prepared and submitted.

[2] That is, ULHP's originally proposed capital structure, adjusted for the impact of the reduced KY income tax rate as per the Company's response to PSC-2-21.

B. GAS JURISDICTIONAL CAPITALIZATION

Q. PLEASE DESCRIBE THE METHODOLOGY USED BY THE COMPANY TO DETERMINE ITS PROPOSED GAS JURISDICTIONAL CAPITAL STRUCTURE IN THIS CASE.

A. As shown in the first column of Schedule RJH-3, line 1, the starting point of the Company's proposed gas jurisdictional capital structure is ULHP's projected 13-month average total company long-term and short-term debt and common equity balances for the Forecasted Test Period ended September 30, 2006. The Company then removed the capital associated with non-jurisdictional investment in order to determine the total company jurisdictional capitalization. Next, the Company applied its proposed gas jurisdictional rate base allocation factor to the total company jurisdictional capitalization in order to arrive at the gas jurisdictional capitalization. Finally, the Company added the gas jurisdictional Accumulated Job Development Tax Credit ("JDTC") balance to arrive at its proposed 13- month average Forecasted Test Period JDTC-adjusted gas jurisdictional capitalization.

Q. DO YOU AGREE WITH THIS COMPANY-PROPOSED METHODOLOGY TO DETERMINE THE APPROPRIATE ADJUSTED GAS JURISDICTIONAL CAPITALIZATION BALANCE FOR RATEMAKING PURPOSES IN THIS CASE?

A. Yes, I do. The previously described calculation methodology is in accordance with the method prescribed by the KPSC in the Company's prior gas rate case, Case No.

2001-092

Q. COULD YOU NOW DESCRIBE THE AG'S RECOMMENDED GAS JURISDICTIONAL CAPITALIZATION BALANCE IN THIS CASE?

A. Yes. The AG's recommended gas jurisdictional capitalization for the Forecasted Test Period is shown in the third column of Schedule RJH-3. It has been calculated in a manner consistent with the previously described methodology proposed by ULHP. The only reason why the AG's recommended total company and non-jurisdictional capitalization balances on lines 1 and 2 are different from the corresponding Company-proposed balances is that the AG's recommended capitalization balances reflect the impact of the reduced Kentucky income tax rate of 7%, whereas the Company's proposed capitalization balances reflect the old Kentucky income tax rate of 8.25%. Another calculation component difference (shown on line 4) is the fact that the AG's recommended gas jurisdictional rate base allocation factor is 25.337% as compared to ULHP's proposed gas jurisdictional rate base allocation factor of 25.899%. The derivation of the AG's recommended gas jurisdictional rate base allocation factor is explained in detail in the next section of this testimony.

In summary, as shown on Schedule RJH-3, line 7, the AG's recommended adjusted gas jurisdictional capitalization balance amounts to $162,296,080, which is $3,423,113 lower than the Company's proposed gas jurisdictional capitalization balance of $165,719,193

C. GAS JURISDICTIONAL RATE BASE

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED AND THE AG'S RECOMMENDED GAS JURISDICTIONAL RATE BASE LEVELS FOR THE TEST YEAR IN THIS CASE.

A. The Company's proposed gas jurisdictional rate base of $167,499,239 is summarized by specific gas jurisdictional rate base component in column A of Schedule RJH-4. As shown in column B of Schedule RJH-4, I have recommended four rate base adjustments concerning the rate base components for utility plant in service, prepayments, cash working capital, and accumulated deferred income taxes. The recommended rate base adjustments reduce the Company's proposed gas jurisdictional rate base by $4,519,080 to a recommended gas jurisdictional rate base level of $162,980,160. Each of the recommended rate base adjustments will be discussed in detail in the subsequent sections of this testimony.

Q. WHAT IS THE RECOMMENDED RATIO OF THE AG'S RECOMMENDED GAS JURISDICTIONAL RATE BASE AS COMPARED TO THE TOTAL COMPANY JURISDICTIONAL RATE BASE?

A. The total company jurisdictional rate base consists of the combined total of the gas jurisdictional rate base to be used for rate making purposes in this case and the electric jurisdictional rate base. As I previously discussed, the recommended gas jurisdictional rate base amounts to $162,980,160. The appropriate electric jurisdictional rate base to be used in this ratio analysis amounts to $480,256,899. This electric jurisdictional rate base comes straight from the Company's filing schedule WPA-1d with the following adjustments: (1) the removal of the entire electric jurisdictional prepayment[3] balance; and (2) a reduction in the Company's proposed electric jurisdictional Accumulated Deferred Income Tax balance to reflect the reduction in the Kentucky income tax rate from 8.25% to 7.00%. Comparing the gas jurisdictional rate base of $162,980,159 to the sum of the gas and electric jurisdictional rate base amounts of $643,237,058 (Schedule RJH-4, column E) indicates an appropriate gas jurisdictional rate base ratio of 25.337%.

- **<u>Utility Plant in Service</u>**

Q. HOW DID THE COMPANY DERIVE ITS PROPOSED AVERAGE FORECASTED TEST PERIOD UTILITY PLANT IN SERVICE BALANCE?

A. The Company derived its proposed average forecasted period utility plant in service balance by taking the projected plant balance as of May 31, 2005, the end of the base period, as the starting point and then adding to this balance the projected plant additions from its construction budget for the months of June 2005 through September 2006 and subtracting from this balance the projected plant retirements for this same time period. The Company then calculated the 13-month average of the projected plant balances from September 2005 through September 2006.

Q. IS IT IMPORTANT THAT THE PROPOSED PLANT IN SERVICE

[3] The entire electric jurisdictional prepayment balance consists of KPSC assessments which ULHP claims to be prepayments.

PROJECTIONS BE REVIEWED FOR ACCURACY IN SETTING THE RATES FOR THIS COMPANY?

A. Yes. Since the Company has chosen to base this rate filing on a fully-forecasted test period, it is particularly important to conduct analyses to verify whether the Company's projections are reasonably on target. Since the non-Company parties in this proceeding do not have access to all of the details and assumptions underlying the Company's construction budget and the projected closings to plant of the numerous construction projects, the only way for these parties to verify the accuracy of the Company's projections is to perform an historic analysis to determine how the Company's past projections have compared to actual results.

Q. HAS INFORMATION REGARDING SUCH A COMPARATIVE ANALYSIS BEEN REQUESTED IN THIS CASE?

A. Yes. In data requests PSC-1-12 and PSC-2-105, the Commission Staff requested information showing a comparison of actual versus originally budgeted construction expenditures for each of the last 10 years from 1995 through 2004. The actual-to-budget ratios produced by these comparisons are referred to as "slippage factors." The slippage factor calculations were requested for three plant categories: (1) the non-AMRP plant projects, (2) the AMRP plant projects, and (3) the total non-AMRP and AMRP plant projects. Information provided by the Company in response to these PSC requests indicates the following results:

- With regard to the <u>non-AMRP</u> plant projects, the Company's actual construction expenditures during the 10-year period 1995 – 2004 were below the originally projected construction expenditures. The slippage factor was 9.380% on a cumulative weighted basis and 6.048% on a mathematic average basis.

- With regard to the AMRP plant projects, the Company's actual construction expenditures during the 4-year period 2001 – 2004[4] were also below the originally projected construction expenditures. The slippage factor was 2.850% on a cumulative weighted basis and 0.932% on a mathematic average basis.
- With regard to the total non-AMRP and AMRP plant projects, the slippage factors were 2.955% on a cumulative weighted basis and 5.385% on a mathematic average basis.

Q. WHAT IS YOUR RECOMMENDATION BASED ON YOUR REVIEW OF THE SLIPPAGE FACTOR ANALYSES?

A. Each of the slippage factor analyses indicates that the Company has generally over-projected its construction expenditures during the most recent 10 years. Based on my review of the previously described slippage factor analyses, I recommend that the Company's proposed average forecasted test period plant in service balance be reduced to reflect the mathematic average non-AMRP slippage factor of 6.048% experienced during the most recent 10-year period.

Q. PLEASE EXPLAIN WHY YOU RECOMMEND THE USE OF THE MATHEMATIC AVERAGE NON-AMRP SLIPPAGE FACTOR OF 6.048%.

A. First, I have chosen the use of the lower 6.048% mathematic average slippage factor rather

[4] The AMRP program has only been in effect since 2001.

than the cumulative weighted slippage factor of 9.380% because I do not believe it appropriate that the determination of the slippage factor should be influenced by the dollar amount magnitude of the annual construction program variances in the analysis period.

Second, I believe that the slippage factor for the AMRP plant projects should be disregarded in the determination of the appropriate slippage factor to be applied to the forecasted period plant in service balance. There are several reasons for that. Rider AMRP is a rate mechanism through which the Company is allowed guaranteed, dollar-for-dollar rate recovery of very specific AMRP project construction expenditures with significantly reduced regulatory lag. Construction expenditure decisions made under this regulatory concept are potentially much different than -- and, therefore, should not be considered representative of -- the construction decisions made for the Company's non-AMRP projects, the costs of which are recovered in base rates. Moreover, Rider AMRP expires prior to the start of the forecasted period in this case and all of the projected construction expenditures from the end of the base period (5/31/05) to the end of the forecasted period (9/30/06) are subject to base rate recovery rather than Rider AMRP rate recovery. Finally, the AMRP slippage factor experience is only available for a period of 4 years (2001-2004) which, in my opinion, is too short a period to make reliable slippage factor determinations.

Q. DID YOU ASK THE COMPANY TO CALCULATE THE IMPACT OF THE APPROPRIATE SLIPPAGE FACTOR ON THE FORECASTED PERIOD 13-MONTH AVERAGE PLANT IN SERVICE BALANCE AND OTHER RATE BASE COMPONENTS?

A. Yes, I requested this more than once. The first request was in AG-1-169(b) and (c):

> The response to PSC-1-12 contains construction data that indicate that for the 10-year period 1995 through 2004, the Company's total cumulative actual construction expenditures were $137,574,457 as compared to total cumulative budgeted construction expenditures of $145,401,307, for an actual-to-budget variance of ($7,823,850), or (5.38%). In this regard, please provide the following information:
>
> b. Under the assumption that the Company's construction expenditures from 1/1/05 through 9/31/06 (upon which the 13-month average Forecasted Test Period Gas Utility Plant balance and Gas CWIP balance are based) are, on average, 5.38% lower, please provide the impact of this assumption on the average Forecasted Test Period Jurisdictional Gas Utility Plant balance of $277.747 million, Non-Jurisdictional Gas Utility Plant balance of $11.103 million and Jurisdictional Gas CWIP balance of $4.120 million. Please provide all underlying calculations.
>
> c. If the assumption described in part b above also impacts other Forecasted Test Period Jurisdictional and Non-Jurisdictional gas rate base balances (shown on WPA-1d), please provide the impact of the assumption on these other Forecasted Test Period Jurisdictional and Non-Jurisdictional gas rate base balances. Please provide all underlying calculations.

The Company's response to this request was as follows:

> b. ULH&P has not performed this analysis.
>
> c. See response to AG-DR-01-169(b).

The second request was in AG-2-6(b) and (c):

> With regard to the Company's response to PSC-2-105, please provide the following information:
>
> b. Please re-calculate the Forecasted Period jurisdictional gas plant in service balance of $277,747,000 and CWIP balance of $4,120,000 assuming the 10-year average slippage factor shown for Non-AMRP capital construction projects shown on page 1 of 3 of the response.
>
> c. If the Slippage factor assumption referenced in part b above also impacts

other gas jurisdictional rate base items, please re-calculate such other gas jurisdictional rate base items based on the same 10-year average slippage factor as referenced in part b above.

The Company's response to this second request was as follows:

b. ULH&P has not performed this analysis.

c. See response to AG-DR-02-006(b).

Thus, even though these type of slippage factor analyses and calculations have regularly been requested and applied by the KPSC in prior rate cases of Kentucky utilities using fully-forecasted test period, the Company has refused to make these requested slippage factor calculations.

Q. SINCE THE COMPANY HAS REFUSED TO PERFORM THESE SLIPPAGE FACTOR CALCULATIONS, HAVE YOU MADE YOUR OWN CALCULATIONS?

A. Yes. Based on the information available to me at this time, I have calculated the AG's recommended slippage factor impact on the Company's proposed 13-month average forecasted test period plant in service balance. My calculations are shown on Schedule RJH-5. As shown on lines 1 through 5 of Schedule RJH-5, I have calculated the forecasted period plant in service slippage factor adjustment by applying the recommended mathematic average non-AMRP slippage factor of 6.048% to the net plant in service growth from the end of the base period (5/31/05) to the 13-month average for the forecasted period.

Q. WHAT IS THE IMPACT OF YOUR SLIPPAGE FACTOR CALCULATION ON THE COMPANY'S FORECASTED PERIOD PLANT IN SERVICE BALANCE AND DEPRECIATION EXPENSE?

A. As shown on line 5, my slippage factor calculation indicates a recommended plant in service slippage factor adjustment of $1,152,749. On lines 6 – 9 of Schedule RJH-5, I show that this plant in service slippage factor adjustment reduces the forecasted period depreciation expenses by $28,461 which, in turn, increases the forecasted period net after-tax operating income by approximately $17,205.

Q. WHY HAVE YOU NOT APPLIED THE RECOMMENDED SLIPPAGE FACTOR ADJUSTMENT TO THE FORECASTED PERIOD RATE BASE BALANCES FOR CONSTRUCTION WORK IN PROGRESS ("CWIP") AND CUSTOMER ADVANCES FOR CONSTRUCTION?

A. The average forecasted period CWIP balance of $4,120,000 is 100% subject to AFUDC accrual at a rate equivalent to the overall rate of return to be authorized by the Commission in this case. Since this AFUDC accrual is reflected as above-the-line income, there is no revenue requirement associated with the inclusion of CWIP in rate base. Thus, changes to the CWIP balance as a result of the slippage factor adjustment would not affect the revenue requirement in this case.

With regard to customer advances for construction, filing schedule B-1 shows that the Company's projected 13-month average forecasted period balance of $2,721,042 is the same as the projected balance at the end of the base period (5/31/05). Since there is no projected growth in this balance between the end of the base period and the 13-month average forecasted period, there should be no impact on this balance from the recommended slippage factor adjustment.

Q. WHAT ABOUT THE POTENTIAL IMPACT OF THE RECOMMENDED SLIPPAGE FACTOR ADJUSTMENT ON OTHER RATE BASE COMPONENTS?

A. The only other rate base components that may be somewhat impacted by the recommended slippage factor adjustment are the depreciation reserve and accumulated deferred income tax balances. Recognizing that I would not have the required data available to calculate the possible impact of the slippage factor adjustment on these rate base components, I requested the Company to do so in the previously quoted data requests AG-1-169(c) and AG-2-6(c). However, the Company has refused to make these calculations. Therefore, any impact of the slippage factor adjustment on the 13-month average forecasted period depreciation reserve and accumulated deferred income tax balances has not been reflected in this testimony.

- **<u>Prepayments</u>**

Q. PLEASE EXPLAIN YOUR RECOMMENDED REMOVAL OF THE COMPANY'S PROPOSED $105,675 PREPAYMENT BALANCE FROM THE GAS JURISDICTIONAL RATE BASE THAT YOU SHOW ON SCHEDULE RJH-4, LINE 7.

A. The gas jurisdictional balance of $105,675 represents PSC assessments which the

Company claims to be prepaid. I have removed this amount from the gas jurisdictional rate base to reflect PSC policy that such PSC assessment balances are not considered to be prepayments. For purposes of calculating the appropriate gas jurisdictional rate base ratio, I have also removed the corresponding prepayment balance from the Company's electric jurisdictional rate base.

- **Cash Working Capital**

Q. PLEASE DESCRIBE THE METHODOLOGY USED BY THE COMPANY TO DETERMINE ITS PROPOSED CASH WORKING CAPITAL IN THIS CASE.

A. The Company has proposed to calculate the cash working capital in this case based on the so-called "1/8th formula" method. This method assumes that 1/8th of the pro forma test year operation and maintenance expenses, net of gas supply costs, represents a reasonable cash working capital approximation. I believe that only a properly performed detailed lead/lag study would generate an accurate approximation of a utility's cash working capital. However, based on my review of the Company's prior base rate proceedings, it is my understanding that the Commission has consistently allowed this Company's cash working capital to be determined based on this modified 1/8th method. I have therefore chosen not to challenge this method in this case.

As shown on schedule RJH-6, the appropriate cash working capital requirement based on this 1/8th method amounts to $2,282,526. This is $101,811 lower than the Company's proposed cash working capital.

Q. HOW DID YOU DERIVE THE RECOMMENDED CASH WORKING CAPITAL AMOUNT?

A. The starting point of the analysis is the AG's recommended Forecasted Test Period total gas O&M expense amount in this case. The derivation of this recommended total gas O&M expense level is shown in detail on Schedule RJH-19. I then removed the purchased gas costs from this recommended total gas O&M expense level and applied a ratio of .125 to the resulting net gas O&M expense balance to arrive at the recommended gas cash working capital amount.

- <u>Accumulated Deferred Income Taxes ("ADIT")</u>

Q. ARE THERE ISSUES ASSOCIATED WITH THE COMPANY'S PROPOSED GAS JURISDICATIONAL 13-MONTH AVERAGE NET ADIT BALANCE FOR THE FORECASTED PERIOD?

A. Yes. As shown on Schedule RJH-7, line 1, the Company's proposed gas jurisdictional 13-month average net ADIT balance amounts to $33,244,980, and this balance has been treated as a rate base deduction. I recommend that two adjustments be made to this proposed net ADIT balance. First, the Company's proposed ADIT balance should be reduced to reflect the impact of the reduction in the Kentucky income tax rate from 8.25% to 7.00%. This recommended adjustment, shown on Schedule RJH-7, line 2, reduces the

Company's proposed forecasted period gas jurisdictional 13-month average net ADIT balance by $339,459 to $32,905,521. As shown on the second column of Schedule RJH-7, this Kentucky income tax rate adjustment also reduces the Company's forecasted period electric jurisdictional 13-month average net ADIT balance from $119,478,969 to $118,258,991.

The second recommended ADIT adjustment concerns the removal of the Account 283/284 negative (prepaid) ADIT associated with unbilled revenues from the Company's proposed forecasted period gas jurisdictional 13-month average net ADIT balance. As shown on Schedule RJH-7, line 4, and further detailed in footnote (3) of that schedule, this recommended adjustment increases the forecasted period gas jurisdictional 13-month average net ADIT balance by $3,498,304 while leaving the Company's proposed forecasted period electric jurisdictional 13-month average net ADIT balance unaffected.

Q. PLEASE EXPLAIN HOW YOU DERIVED THIS RECOMMENDED ADJUSTMENT FOR THE NEGATIVE (PREPAID) GAS JURISDICTIONAL ADIT ASSOCIATED WITH UNBILLED GAS REVENUES.

A. Filing workpaper WPD-6a shows that the gas Account 283/284 ADIT balance for each of the months December 2004 through May 2005 consists of a net negative (prepaid) ADIT amount of approximately $3 million. The actual trial balances for the months of January and March 2005 included in response to PSC-1-30 show that these monthly net prepaid gas ADIT balances of approximately $3 million are made up of *positive* ADIT associated with

Capitalized CIS and Losses on Reacquired Debt,[5] offset by *negative (prepaid)* ADIT associated with unbilled gas revenues. The actual positive Account 283/284 ADIT associated with Capitalized CIS and Losses on Reacquired Debt has consistently been close to $500,000.[6]

Filing workpaper WPD-6b shows that the Company's projected 13-month average gas Account 283/284 ADIT balance for the forecasted period continues to be a net negative (prepaid) ADIT balance of approximately $3 million.[7] When the AG asked[8] the Company to provide a detailed component breakout of this Account 283/284 ADIT balance in the same format and detail as the Company had presented for its test period Account 283/284 ADIT balance on filing schedule B-6, page 1 in its prior rate case, Case No. 2001-092, the Company responded as follows:

> The prior gas case was based on an historical test period with a date certain prior to the filing date. Actual balances were available for that case by account. The Company's forecasting tool does not track Balance Sheet amounts by account. The beginning Accumulated Deferred Income Tax balance is incremented for the deferred tax activity calculated on the income statement each month in total. Therefore, the only detail of Accumulated Deferred Income Taxes available for the forecasted period is that presented on WPB-6b.

In essence, what the Company is saying here is that while it can provide a component breakout for any actual Account 283/284 ADIT balances to date (say, for the actual base period-ending month of May 2005), it is incapable of providing a similar component breakout for any projected Account 283/284 ADIT balances following the end of the base

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[5] See Schedule RJH-7, footnote (3) for details.

[6] Approximately $486,000 in January 2005 and $481,000 in March 2005.

[7] To be exact, the 13-month average forecasted period net negative (prepaid) ADIT balance is $3,017,383.

[8] See data request AG-1-177.

period. Since the Company has taken this (rather unreasonable) position, I have performed my own analysis of what the likely components are of the forecasted period 13-month average Account 283/284 net negative (prepaid) ADIT balance of approximately $3 million. This analysis is shown in footnote (3) of Schedule RJH-7. As shown there, I have first assumed that the Company's forecasted period Account 283/284 will include positive ADIT of approximately $481,000. Since the Company's total projected Account 283/284 balance is a negative (prepaid) balance of $3,017,383, it follows that the negative (prepaid) ADIT associated with unbilled gas revenues for the forecasted period amounts to $3,498,304.

Q. IS IT NECESSARY TO MAKE A SIMILAR UNBILLED REVENUE RELATED ADJUSTMENT TO THE COMPANY'S 13-MONTH AVERAGE FORECASTED PERIOD ELECTRIC JURISDICTIONAL ADIT BALANCE?

A. No. As confirmed in the response to PSC-1-30, the Company does not carry ADIT balances associated with unbilled electric revenues on its books.

Q. COULD YOU NOW EXPLAIN WHY YOU BELIEVE THAT ADIT ASSOCIATED WITH UNBILLED REVENUES SHOULD BE REMOVED FOR RATEMAKING PURPOSES IN THIS CASE?

A. Yes. For ratemaking purposes, the Company has assumed that all forecasted period gas revenues are billed revenues. To that end, the Company has made a specific adjustment in this case to remove unbilled gas revenues from the forecasted period. This adjustment is shown on filing schedule D-2.24. The removal of any ADIT associated with unbilled gas revenues would be consistent with this position.

D. PRO FORMA OPERATING INCOME

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED AND THE AG'S RECOMMENDED FORECASTED PERIOD PRO FORMA NET AFTER-TAX OPERATING INCOME LEVELS.

A. The Company has proposed a pro forma net after-tax operating income level for the forecasted test period of $6,312,696. On Schedule RJH-8, lines 2 through 15, I show that I have made 14 adjustments to the Company's proposed pro forma operating income. Each of these recommended net after-tax operating income adjustments will be discussed in the following sections of this testimony.

Schedule RJH-8, line 17 shows that, after considering all of the recommended pro forma operating income adjustments, the AG's recommended pro forma operating income for the forecasted period amounts to $9,756,674.

- <u>Kentucky Income Tax Rate Reduction</u>

Q. PLEASE EXPLAIN THE RECOMMENDED FORECASTED PERIOD OPERATING INCOME ADJUSTMENT FOR THE KENTUCKY INCOME TAX RATE REDUCTION, SHOWN ON SCHEDULE RJH-8, LINE 2.

A. As part of House Bill 272 that was passed by the Kentucky General Assembly and signed by the Governor on March 15, 2005, the Kentucky corporate income tax rate of 8.25% was reduced to 7.00% for the years 2005 and 2006 and will be further reduced to 6.00% effective January 1, 2007. Since the current ULHP rate filing is still based on the old income tax rate of 8.25%, the Company was asked to re-state its forecasted test period filing schedules and workpapers based on a Kentucky income tax rate of 7.00%. These filing revisions, which were calculated and presented by ULHP in its response to PSC-2-21, changed the Company's original filing results in the following respects:

1. Decrease in the gross revenue conversion factor from 1.6997957 to 1.6769492. The impact of this conversion factor reduction has been reflected on Schedule RJH-1, line 6;
2. Increase of $551,744 in the equity component of the forecasted period 13-month average total company jurisdictional capitalization. The impact of this capitalization increase has been reflected on Schedule RJH-3, line 3;
3. Decreases of $339,459 and $1,219,978, respectively, in the forecasted period 13-month average gas jurisdictional and electric jurisdictional ADIT balances. The impacts of these ADIT balance reductions have been reflected on Schedule RJH-7, line 2; and
4. A reduction of $24,363 in the forecasted period Kentucky income taxes.

The impact of this latter forecasted period Kentucky income tax reduction has been reflected as a recommended net after-tax operating income adjustment on Schedule RJH-8, line 2.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING THE COMPANY'S CALCULATED FILING REVISIONS RESULTING FROM THE KENTUCKY INCOME TAX REDUCTION TO 7.00%?

A. Yes. Considering the relatively small impact of the Kentucky income tax reduction on the forecasted test period net operating income (an increase of less than $25,000), I find it curious that the average forecasted period common equity balance in the jurisdictional capitalization (i.e., the retained earnings component of the common equity balance) increases by approximately $552,000 (see Schedule RJH-3, line 3). When the Company was asked in AG-2-31 to explain this apparent discrepancy, it responded that the approximate $25,000 operating income increase is for the Company's jurisdictional *gas* operations only, whereas the approximate $552,000 operating income increase that was added to the 13-month average jurisdictional common equity balance represents a *total company* retained earnings addition. Even with this explanation, I continue to question the appropriateness of the $552,000 common equity increase for purposes of calculating the gas jurisdictional capitalization. Given that the Company's gas jurisdictional capitalization is 25.335% of the total company jurisdictional capitalization (see Schedule RJH-3, line 4), this means that the 13-month average forecasted period gas jurisdictional capitalization is being increased by almost $140,000 ($552,000 x 25.355%) for the effect of the Kentucky income tax rate reduction. This appears to be disproportionately large when compared to the forecasted period gas jurisdictional operating income increase of only approximately $25,000 for this same event. While I have not made an adjustment for this questionable item at this time, I recommend that the Commission order the Company to further explain this apparent discrepancy and to make any appropriate changes that may be in order as a result of this additional explanation.

- **Weather Normalization Adjustment**

Q. HAS THE COMPANY PROPOSED A WEATHER NORMALIZATION ADJUSTMENT IN THIS CASE?

A. Yes. The Company has proposed an adjustment to restate the forecasted period sales for the weather-sensitive customer classes based on "normal" weather for the ULHP service territory.

Q. DID THE COMPANY USE A WEATHER NORMALIZATION METHODOLOGY IN THIS CASE DIFFERENT FROM THE WEATHER NORMALIZATION METHODOLOGY THE COMMISSION HAS TRADITIONALLY USED IN ALL OF ULHP'S PRIOR GAS RATE CASES?

A. Yes. The Company weather-normalized its forecasted period sales using 10-year average NOAA[9] Heating Degree Days ("HDDs") of 4,950. In all of the Company's prior gas rate cases, including ULHP's prior gas rate case in Case No. 2001-092, the Commission weather-normalized the Company's test period sales for ratemaking purposes using 30-year average NOAA HDDs.

Q. IS THE 10-YEAR PERIOD USED BY THE COMPANY TO CALCULATE ITS PROPOSED WEATHER NORMAL HDD LEVEL OF 4,950 THE MOST RECENT

[9] National Oceanic and Atmospheric Administration.

10-YEAR PERIOD AVAILABLE AT THIS TIME?

A. No. While Mr. Riddle claims on page 6 of his testimony that the Company has used "a recent 10-year period", the reality is that the 10-year period used by the Company is the period 1991 – 2000, which is the same 10-year period that was rejected as a weather-normalization period by the Commission in Case No. 2001-092.[10]

Q. WHAT WEATHER NORMALIZATION APPROACH IS THE AG RECOMMMENDING IN THIS CASE?

A. For all of the reasons explained in the testimony of David Brown Kinloch, the AG recommends that the forecasted period sales be weather-normalized based on 30-year average NOAA HDDs for the most recent 30-year period 1975 - 2004. This recommended weather normalization methodology is consistent with the methodology used by the Commission in Case No. 2001-092. Mr. Brown-Kinloch has determined that the annual normal HDD level for the 30-year period 1975 – 2004 is 5,133.

Q. DID YOU ASK THE COMPANY TO CALCULATE THE WEATHER NORMALIZATION ADJUSTMENT IN THIS CASE BASED ON 30-YEAR NORMAL HDDs FOR THE MOST RECENT 30-YEAR PERIOD 1975 – 2004?

A. Yes. This request was made of the Company in AG-1-195(b):

> Provide the incremental impact on the Forecasted Test Period unadjusted base revenues of $37,671,000 from using the 30-year annual normal HDD level for the most recent 30-year period 1975 – 2004 (to be provided in response to part c of the prior data request) as opposed to the 10-year annual normal HDD level of 4,950 (1995 – 2004) that was used by the Company to determine the Forecasted Test Period unadjusted base revenues. In addition,

> provide the associated incremental impact on the Company's Forecasted Test Period unadjusted uncollectible expenses, KYPSC maintenance taxes, federal and state income taxes and resulting net operating income.

The Company's response to this request was that "ULH&P has not performed this analysis."

Q. SINCE THE COMPANY HAS REFUSED TO CALCULATE THE WEATHER-NORMALIZATION ADJUSTMENT BASED ON WEATHER-NORMAL HDD DATA FOR THE MOST RECENT 30-YEAR PERIOD 1975 – 2004, HAVE YOU APPROXIMATED THE IMPACT OF THIS RECOMMENDED WEATHER NORMALIZATION APPROACH ON THE COMPANY'S PROPOSED FORECASTED PERIOD BASE REVENUES?

A. Yes. In responses to AG-1-195(a) and PSC-2-51(a), the Company provided the impact on its proposed forecasted period operating income from using a HDD level of 5,200 rather than the 4,950 HDDs used by the Company to weather-normalize the forecasted period. As shown on Schedule RJH-9, this 250 HDD difference produced a base revenue increase of $999,339. Mr. Brown Kinloch's recommended weather normal HDD level of 5,133 represents a 183 HDD difference from the Company's proposed weather normal HDD level of 4,950. Taking the ratio between this183 HDD difference and the 250 HDD difference and applying this ratio to the base revenue increase of $999,339 resulting from the 250 HDD difference produces a base revenue increase amount of $731,516. This represents my approximation of the base revenue impact of the AG's recommended weather normalization approach in this case.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S PROPOSED FORECASTED PERIOD NET AFTER-TAX OPERATING INCOME?

A. As shown on Schedule RJH-9, lines 5–10, after taking into account the associated impact of the recommended base revenue adjustment on uncollectible expenses, KPSC maintenance fees, and income taxes, my quantification of the AG's recommended weather normalization adjustment increases the Company's proposed forecasted period net after-tax operating income by $415,500.

- **Firm Transportation Sales**

Q. PLEASE EXPLAIN THE OPERATING INCOME ADJUSTMENT WITH REGARD TO FIRM TRANSPORTATION SALES SHOWN ON SCHEDULE RJH-8, LINE 4.

A. As detailed on Schedule RJH-10, Mr. Brown Kinloch has recommended forecasted period Firm Transportation sales adjustments that have the effect of increasing the Company's proposed forecasted period base revenues by $1,148,833. Taking into account the associated impact on uncollectible expenses, KPSC maintenance fees and income taxes, this recommended revenue adjustment increases the Company's proposed forecasted period net after-tax operating income by $685,073.

- **Bad Check and Reconnection Charge Revenues**

Q. PLEASE EXPLAIN THE OPERATING INCOME ADJUSTMENT WITH REGARD

TO BAD CHECK AND RECONNECTION CHARGES SHOWN ON SCHEDULE RJH-8, LINE 5.

A. As detailed on Schedule RJH-11, Mr. Brown Kinloch has recommended forecasted period bad check and reconnection charge revenues that have the effect of reducing the Company's proposed forecasted period revenues by $12,659. Taking into account the associated impact on uncollectible expenses, KPSC maintenance fees and income taxes, this recommended revenue adjustment decreases the Company's proposed forecasted period net after-tax operating income by $7,549.

- **<u>I&D Expense Normalization</u>**

Q. WHAT IS ULHP'S PROPOSED POSITION IN THIS CASE WITH REGARD TO THE FORECASTED PERIOD INJURY AND DAMAGE ("I&D") EXPENSES?

A. As shown in WPD-2.15a, the Company has proposed to "normalize" the forecasted period I&D expenses by replacing these budgeted expenses with an historic 10-year average I&D expense level, grossed up with a CPI inflation factor. This proposed normalization adjustment increases the forecasted period I&D expenses by approximately $144,000.

Q. DO YOU AGREE WITH THIS PROPOSAL?

A. No, I do not. Given the fact that the Company in this case has elected to base its rate filing on a fully-forecasted test period, I do not believe it appropriate to "normalize" selected forecasted period expense items based on an historic average. While such an expense normalization adjustment may be appropriate in a rate case using an historic test year, it should not be applied when using a forecasted test year. For this reason, I recommend that the Commission reject the Company's proposed I&D expense normalization adjustment.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S FORECASTED PERIOD NET AFTER-TAX OPERATING INCOME?

A. As shown on Schedule RJH-12 and Schedule 8, line 6, my recommendation increases the Company's proposed forecasted period net after-tax operating income by $87,022.

- **Base Payroll Expenses**

Q. PLEASE EXPLAIN THE OPERATING INCOME ADJUSTMENT REGARDING BASE PAYROLL EXPENSES SHOWN ON SCHEDULE RJH-8, LINE 7.

A. In its response to PSC-2-73, the Company has provided information indicating that the general wage increases for the union employees in the forecasted period will be 3.0% rather than the 3.2% that was reflected by ULHP in the rate filing. The response to AG-2-22 confirms that the impact on the forecasted period gas O&M expenses of substituting the 3.0% wage increase for the 3.2% wage increase is $9,900. On Schedule RJH-13, I have calculated that the reflection of this recommended expense adjustment increases the Company's proposed forecasted period net after-tax operating income by $5,985.

- **Incentive Compensation**

Q. DOES THE FORECASTED PERIOD INCLUDE INCENTIVE COMPENSATION EXPENSES?

A. Yes. As confirmed in the response to AG-1-204, the forecasted period includes the following types of incentive compensation program expenses:

	Gas-Allocated O&M Expense
- AIP (Annual Incentive Plan)	$451,116
- UEIP (Union Employees' Incentive Plan	80,460
- (LTIP) Long-Term Incentive Compensation Plan	125,121
- Total	$656,697

Q. PLEASE DESCRIBE YOUR UNDERSTANDING OF EACH OF THESE INCENTIVE COMPENSATION PLANS.

A. The AIP is an incentive plan applicable to manager level employees and up that allows these employees to receive cash payments if certain pre-determined performance goals are achieved during any particular calendar year. The overall performance goal for the AIP is divided into three parts: 50% corporate performance goal, 25% group specific goals, and 25% individual goals. The 25% group specific goals and 25% individual goals also include corporate performance goals. The corporate performance goal is based on Cinergy Corporation's net income.

The UEIP is an incentive plan for union employees of ULHP and Cinergy Services that allows these employees to receive cash payments if Cinergy Corporation attains certain corporate performance goals or if their business units attains certain performance goals during any particular calendar year. The overall performance goals for the UEIP is 50% corporate performance goal and 50% business unit goals. The 50% business unit goals also include corporate performance goals. The corporate performance goal is based on Cinergy Corporation's net income.

As described on pages 14 – 15 of Mr. Verhagen's testimony, the nature and purpose of the LTIP are as follows:

> The LTIP is a vehicle through which equity-based compensation is paid to executive employees and non-employee directors n a manner that aligns their interests with the long-term interests of Cinergy Corp. and its affiliates, including ULH&P. The purpose of the LTIP is: (1) to assist in attracting, retaining and motivating executives by keeping the Companies' compensation package competitive; and (2) to align a portion of the executive compensation with corporate interests by encouraging and enabling executives to acquire Cinergy Corp. stock....
>
> Under the LTIP, certain key employees and non-employee directors may be granted incentive and non-qualified stock options, stock appreciation rights, restricted stock, dividend equivalents, performance shares and certain other stock-based awards.....
>
> The Value Creation Plan portion of the LTIP consists of a target grant of performance shares for each cycle. These performance shares vest only to the extent that the corporation meets its total shareholder return (TSR) targets for the cycle, as compared with the TSR of a peer group of utility companies established by Standard & Poor's. TSR means share price appreciation plus dividends, divided by the stock price at the beginning of the cycle.

Q. WHAT WAS THE COMMISSION'S RULING WITH REGARD TO THE INCENTIVE COMPENSATION EXPENSES THE COMPANY CLAIMED IN ITS PRIOR RATE CASE, CASE NO. 2001-092?

A. As described on pages 15–19 of the Commission's March 13, 2002 Rehearing Order in Case No. 2001-092, the Commission ruled that the Company's incentive compensation expenses claimed in that case be removed for ratemaking purposes because the corporate performance goals in ULHP's incentive compensation plans placed more weight on the interests of shareholders than customers, and because the Company did not provide enough information about the business unit and individual goals to enable the Commission to evaluate whether the Company's incentive programs *in total* placed more weight on the interests of shareholders than ratepayers.

Q. BASED ON YOUR REVIEW OF THE COMPANY'S INCENTIVE PROGRAM INFORMATION THAT IS AVAILABLE IN THE CURRENT CASE, DO YOU BELIEVE THAT THE COMMISSION'S RULING ON THE COMPANY'S INCENTIVE COMPENSATION EXPENSES IN THE PRIOR CASE SHOULD CONTINUE TO BE APPLIED IN THE CURRENT CASE?

A. Yes, I do. I believe that the corporate performance goals in the Company's overall AIP, UEIP and LTIP incentive programs place more weight on the interests of ULHP's stockholders than the Company's ratepayers.

With regard to the LTIP, the criteria for determining the incentive awards to paid out to the Company's top executives and directors under the plan are solely based on total shareholder return (TSR) performance and are intended to more closely align these executives' interests with the long-term interests of the Company's stockholders. Thus, this incentive program clearly places more emphasis on the interests of the shareholders.

With regard to the AIP and UEIP incentive programs, the largest portions of the award criteria for payments to be made under these programs consists of the attainment of corporate performance goals that are based on Cinergy Corp.'s net income, the "maximization of net income" and the achievement of "receiving constructive regulatory treatment." In this regard, the response to PSC-2-79 indicates that almost 70% of the payments to be made under the AIP incentive program are based on the achievement of (1) Cinergy Corp.'s net income goals (50%), (2) "maximize net income" and "receive constructive regulatory treatment" goals (10%),[11] and (3) "financial" and "compliance" goals (8.75%).[12] In my opinion, this information indicates that these two incentive programs also place more weight on the Company's shareholders than ratepayers.

For the aforementioned reasons, the Company's shareholders, as the primary beneficiaries of these incentive compensation programs, should be responsible for the costs associated with these programs, consistent with the ruling made by the Commission with regard to the Company's incentive compensation programs in ULHP's prior gas rate case, Case No. 2001-092.

Q. WHAT IMPACT DOES YOUR RECOMMENDATION HAVE ON THE COMPANY'S PROPOSED FORECASTED PERIOD NET AFTER-TAX OPERATING INCOME?

A. As shown on Schedule RJH-14, my recommendation to remove all of the Company's proposed incentive compensation program expenses increases the Company's proposed forecasted period net after-tax operating income by $396,973.

[11] 45% of the 25% AIP award portion for business unit goals.
[12] 35% of the 25% AIP award portion for individual goals.

- **Miscellaneous Expense Adjustments**

Q. PLEASE EXPLAIN THE MISCELLANEOUS EXPENSE ADJUSTMENTS YOU SHOW ON SCHEDULE RJH-15.

A. The first adjustment item concerns $11,196 worth of governmental affairs expenses that are included in the Company's proposed above-the-line forecasted period operating expenses. In its response to PSC-3-57, the Company describes the nature and purpose of these expenses as follows:

> These expenses are for Governmental Affairs activities which include meetings with elected officials for information and educational purposes, and civic activities such as board memberships/meetings …

I recommend that these expenses be removed for ratemaking purposes since they have nothing to do with the provision of safe, adequate and reliable gas service.

The next two expense adjustment items concern lobbying and corporate sponsorship expenses that the Company included in its above-the-line forecasted period operating expenses. In its responses to PSC-3-57(e) and (g), the Company agrees that these expenses should have been charged below-the-line.

As shown on Schedule RJH-15, line 6, these recommended miscellaneous expense adjustments have the effect of increasing the Company's proposed forecasted period net after-tax operating income by $38,371.

- **Depreciation Expenses**

Q. PLEASE EXPLAIN THE OPERATING INCOME ADJUSTMENT WITH REGARD TO DEPRECIATION EXPENSES SHOWN ON SCHEDULE RJH-8, LINE 10.

A. This forecasted period operating income adjustment reflects my adoption of the depreciation expense recommendations contained in the testimony of Michael Majoros, the AG's expert depreciation witness. As shown on Schedule RJH-16, Mr. Majoros' depreciation recommendations reduce the Company's proposed forecasted period depreciation expenses by $2,013,365 which, in turn, increases ULHP's proposed forecasted period net after-tax income by $1,217,079.

- **Slippage Factor Depreciation Expense Adjustment**

Q. PLEASE EXPLAIN THE RECOMMENDED OPERATING INCOME ADJUSTMENT OF $22,299 SHOWN ON SCHEDULE RJH-8, LINE 11 REGARDING THE SLIPPAGE FACTOR DEPRECIATION EXPENSE ADJUSTMENT.

A. The reasons for this recommended operating income adjustment were explained in detail in the prior "Utility Plant In Service" testimony section in which I address the utility plant slippage factor.

- **Property Taxes**

Q. WHAT IS THE COMPANY'S PROPOSED PROPERTY TAX EXPENSE FOR THE

FORECASTED PERIOD?

A. As shown on filing schedule C-2.1, page 13, the Company's proposed forecasted period property taxes amount to $2,550,000.

Q. HOW DOES THIS PROJECTED FORECASTED PERIOD PROPERTY TAX AMOUNT COMPARE TO THE BASE PERIOD PROPERTY TAXES AND ACTUAL PROPERTY TAXES BOOKED BY ULHP IN THE RECENT PAST?

A. The Company's base period and recent actual property taxes are as follows:[13]

2003	$1,394,004
2004	907,327
12 Mos. Ended 3/31/05	1,103,878
Base Period	1,193,154

Thus, the Company's proposed forecasted period property taxes of $2,550,000 are more than twice as high as the base period taxes and actual taxes booked by the Company in the last two years.

Q. WHAT IS THE REASON WHY THE FORECASTED PERIOD PROPERTY TAXES ARE SO MUCH HIGHER THAN THE BASE PERIOD AND ACTUAL 2003 AND 2004 PROPERTY TAXES?

A. The Company's response to AG-1-187 indicates that one of the major reasons why the forecasted period property taxes are so much higher than the base period and recent actual property taxes is that, in determining the forecasted period property taxes, the Company has assumed that it will not be able to obtain assessment values lower than net book value. In this regard, the Company explains in its response to AG-1-87(4):

[13] See filing schedule C-2.1, page 6 and response to AG-1-187.

> In recent years, the Company has been successful in negotiations with the Kentucky Revenue Department in obtaining a unit value assessment that is below the net book value of the Company. The Company does not assume it will continue to obtain assessment values lower than net book value.

This assumption has added $535,245 to the Company's proposed forecasted period property taxes. To say it differently, under the assumption that the Company will be equally successful in its negotiations with the Kentucky Revenue Department to obtain assessment values below net book value as the Company has been in recent years, the forecasted period property taxes would be lower by $535,245.

Q. WHAT HAS BEEN THE RECENT EXPERIENCE WITH REGARD TO THE COMPANY'S SUCCESS IN ITS NEGOTIATIONS WITH THE KENTUCKY DEPARTMENT OF REVENUE TO OBTAIN ASSESSMENT VALUES BELOW BOOK VALUE?

A. As shown in the response to AG-2-13(a), the Company has actually experienced the following property tax savings in each of the last three years:

	Tax Savings
2002	$ 852,446
2003	$ 557,104
2004	$1,122,296
3-yr average	$ 843,949

The property tax savings listed in the above table represent the difference between the preliminary property tax assessments prior to negotiations with the Kentucky Department of Revenue and the final property tax assessments after the negotiations with the Department of Revenue to obtain assessment values below book value. The Company's proposed forecasted period property taxes of $2,550,000 represent preliminary property tax assessments prior to negotiations with the Kentucky Department of Revenue to obtain assessment values below book value.

Q. BASED ON THE FOREGOING INFORMATION, WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Company's forecasted period property taxes be reduced by $535,245 under the assumption that the Company will continue to be successful in its negotiations with the Department of Revenue to obtain a reduced final tax bill, consistent with the Company's recent experience. While the Company states in its response to AG-2-13 that it "does not anticipate that the Kentucky Revenue Cabinet will continue to allow the Company to be assessed at below net book value," this anticipation is merely based on "discussions with the Kentucky Revenue Cabinet." There are no formal, written statements from the Kentucky Revenue Cabinet that would confirm that the Cabinet will no longer allow the Company to be assessed at below net book value.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S FORECASTED PERIOD NET AFTER-TAX OPERATING INCOME?

A. As shown on Schedule RJH-17, my recommendation to reduce the Company's proposed property taxes by $535,245 increases the Company's proposed forecasted period net after-tax operating income by $323,556.

- **<u>Interest Synchronization Adjustment</u>**

Q. IN THE FIRST COLUMN OF SCHEDULE RJH-18 YOU HAVE SUMMARIZED THE COMPANY'S PROPOSED INTEREST SYNCHRONIZATION ADJUSTMENT. DO YOU AGREE WITH THIS PROPOSED ADJUSTMENT?

A. While I agree with the approach and calculation components of the Company's proposed interest synchronization adjustment, there are three adjustments that I recommend be made to the Company's proposed calculations. Two of the calculation adjustments, shown on Schedule RJH-18, lines 1 and 4, are merely "flow-through" adjustments resulting from the differences between the Company's proposed and AG's recommended gas capitalization balances and weighted cost of debt percentages. The third adjustment, shown on line 6, is to correct for the fact that the Company used the wrong forecasted period "per books" interest amount. The need for this correction was confirmed by the Company in its response to AG-1-183:

> In Schedule D-2.18b, the Interest Synchronization amount of $4,352,570 was measured against a "book" interest amount of $4,558,827 to determine the amount of the adjustment. This forecasted "book" interest amount was incorrect. The correct amount of forecasted "book" interest is [as] shown on Schedule E-1, column 3, and on WPE-1a, is $4,071,000.

Q. WHAT IS YOUR RECOMMENDED INTEREST SYNCHRONIZATION ADJUSTMENT AMOUNT AFTER REFLECTING THESE THREE ADJUSTMENTS?

A. As shown in the third column of Schedule RJH-18, the appropriate interest synchronization adjustment decreases the Company's forecasted period net after-tax operating income by $16,305. This recommended operating income adjustment number is $65,887 higher than the Company's proposed interest synchronization adjustment.

- **<u>ITC Amortization</u>**

Q. PLEASE EXPLAIN THE RECOMMENDED OPERATING INCOME ADJUSTMENT OF $69,130 SHOWN ON SCHEDULE RJH-8, LINE 14.

A. In its responses to AG-1-182 and AG-2-11, the Company confirms that the forecasted period 4% and 10% investment tax credit amortization of $69,130 was not, but should have been, included in the filing schedules for the forecasted period. The operating income adjustment of $69,130 on Schedule RJH-8, line 14 corrects for this oversight.

- **<u>Five-Year Amortization of Unprotected Excess Deferred Taxes</u>**

Q. PLEASE EXPLAIN THE RECOMMENDED OPERATING INCOME ADJUSTMENT OF $105,384 FOR THE FIVE-YEAR AMORTIZATION OF UNPROTECTED EXCESS ADIT, SHOWN ON SCHEDULE RJH-8, LINE 15.

A. The reduction in the Kentucky income tax rate from 8.25% to 7.00% has created excess deferred income taxes for the Company. These excess deferred income taxes consist of two categories: (1) so-called "protected" excess deferred taxes that are associated with depreciation related timing differences; and (2) "unprotected" excess deferred taxes associated with all other timing differences. While the protected excess deferred income takes must be flowed back through the so-called Average Rate Assumption method, I understand that it has been KPSC ratemaking policy to use a 5-year amortization period to flow back the unprotected excess deferred income taxes.

The response to AG-2-33 indicates that the forecasted period unprotected excess deferred income taxes resulting from the Kentucky income tax rate reduction amount to $526,919. The response also indicates that, in preparing the revised filing for the Kentucky income tax reduction, the Company used the Average Rate Assumption Method rather than the 5-year amortization method to flow back the unprotected excess deferred income taxes. As shown in the response to AG-2-33, the 5-year amortization of this forecasted period unprotected excess deferred tax balance would increase the Company's forecasted period net after-tax operating income by $105,384. This recommended operating income adjustment has been reflected on Schedule RJH-8, line 15.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THIS ISSUE?

A. Yes. The recommended operating income adjustment amount of $105,384 should be offset by the operating income impact of the Average Rate Assumption amortization of the unprotected excess deferred income taxes that, presumably, was reflected by the Company in the revised filing schedules for the forecasted period as a result of the Kentucky income tax reduction. Since I do not know this latter forecasted period excess deferred tax amortization amount, I have not been able to reflect this offsetting entry.

Q. MR. HENKES, DOES THIS CONCLUDE YOUR DIRECT TESTIMONY IN THIS CASE?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

The Application of The Union Light, Heat and Power Company for Authority to Increase its Rates for Gas) Service to all Jurisdictional Consumers	)))	Case No. 2005-00042

AFFIDAVIT

Comes the Affiant, Robert J. Henkes, and being duly sworn states as follows:
The prepared Direct Testimony, together with supporting schedules, exhibits, and/or
appendices attached thereto constitute the direct testimony of Affiant in the above styled case. Affiant further states that to the best of his information and belief, all statements made and matters contained therein are true and correct. Further Affiant saith not.

STATE OF CONNECTICUT
COUNTY OF Fairfield
Subscribed and sworn to before me by Robert J. Henkes this the 25th day of May, 2005.
MY COMMISSION EXPIRES: ~~MARIA RIGAKOS~~
NOTARY PUBLIC
My Commission Expires January 31, 2008

Maria Rigakos
Notary Public, State at Large

APPENDIX I

PRIOR REGULATORY EXPERIENCE OF ROBERT J. HENKES

* = Testimonies prepared and submitted

ARKANSAS

Southwestern Bell Telephone Company Divestiture Base Rate Proceeding*	Docket 83-045-U	09/1983

DELAWARE

Delmarva Power and Light Company Electric Fuel Clause Proceeding	Docket 41-79	04/1980
Delmarva Power and Light Company Electric Fuel Clause Proceeding	Docket 80-39	02/1981
Delmarva Power and Light Company Sale of Power Station Generation	Complaint Docket 279-80	04/1981
Delmarva Power and Light Company Electric Base Rate Proceeding	Docket 81-12	06/1981
Delmarva Power and Light Company Gas Base Rate Proceeding*	Docket 81-13	08/1981
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 82-45	04/1983
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 83-26	04/1984
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 84-30	04/1985
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 85-26	03/1986
Delmarva Power and Light Company Report of DP&L Operating Earnings*	Docket 86-24	07/1986
Delmarva Power and Light Company Electric Base Rate Proceeding*	Docket 86-24	12/1986 01/1987
Delmarva Power and Light Company Report Re. PROMOD and Its Use in	Docket 85-26	10/1986

Fuel Clause Proceedings*		
Diamond State Telephone Company Base Rate Proceeding*	Docket 86-20	04/1987
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 87-33	06/1988
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 90-35F	05/1991
Delmarva Power and Light Company Electric Base Rate Proceeding*	Docket 91-20	10/1991
Delmarva Power and Light Company Gas Base Rate Proceeding*	Docket 91-24	04/1992
Artesian Water Company Water Base Rate Proceeding*	Docket 97-66	07/1997
Artesian Water Company Water Base Rate Proceeding*	Docket 97-340	02/1998
United Water Delaware Water Base Rate Proceeding*	Docket 98-98	08/1998
Delmarva Power and Light Company Revenue Requirement and Stranded Cost Reviews	Not Docketed	12/1998
Artesian Water Company Water Base Rate Proceeding*	Docket 99-197 (Direct Test.)	09/1999
Artesian Water Company Water Base Rate Proceeding*	Docket 99-197 (Supplement. Test)	10/1999
Tidewater Utilities/ Public Water Co. Water Base Rate Proceedings*	Docket No. 99-466	03/2000
Delmarva Power & Light Company Competitive Services Margin Sharing Proceeding*	Docket No. 00-314	03/2001
Artesian Water Company Water Base Rate Proceeding*	Docket No. 00-649	04/2001
Chesapeake Gas Company	Docket No. 01-307	12/2001

Gas Base Rate Proceeding*		
Tidewater Utilities Water Base Rate Proceeding*	Docket No. 02-28	07/2002
Artesian Water Company Water Base Rate Proceeding*	Docket No. 02-109	09/2002
Delmarva Power & Light Company Electric Cost of Service Proceeding	Docket No. 02-231	03/2003
Delmarva Power & Light Company Gas Base Rate Proceeding*	Docket No. 03-127	08/2003
Artesian Water Company Water Base Rate Proceeding*	Docket No. 04-42	08/2004

DISTRICT OF COLUMBIA

District of Columbia Natural Gas Co. Gas Base Rate Proceeding*	Formal Case 870	05/1988
District of Columbia Natural Gas Co. Gas Base Rate Proceeding*	Formal Case 890	02/1990
District of Columbia Natural Gas Co. Waiver of Certain GS Provisions	Formal Case 898	08/1990
Chesapeake and Potomac Telephone Co. Base Rate Proceeding*	Formal Case 850	07/1991
Chesapeake and Potomac Telephone Co. Base Rate Proceeding*	Formal Case 926	10/1993
Bell Atlantic - District of Columbia SPF Surcharge Proceeding	Formal Case 926	06/19/94
Bell Atlantic - District of Columbia Price Cap Plan and Earnings Review	Formal Case 814 IV	07/1995

GEORGIA

Southern Bell Telephone Company Base Rate Proceeding	Docket 3465-U	08/1984

Southern Bell Telephone Company Base Rate Proceeding	Docket 3518-U	08/1985
Georgia Power Company Electric Base Rate and Nuclear Power Plant Phase-In Proceeding*	Docket 3673-U	08/1987
Georgia Power Company Electric Base Rate and Nuclear Power Plant Phase-In Proceeding*	Docket 3840-U	08/1989
Southern Bell Telephone Company Base Rate Proceeding	Docket 3905-U	08/1990
Southern Bell Telephone Company Implementation, Administration and Mechanics of Universal Service Fund*	Docket 3921-U	10/1990
Atlanta Gas Light Company Gas Base Rate Proceeding*	Docket 4177-U	08/1992
Southern Bell Telephone Company Report on Cash Working Capital*	Docket 3905-U	03/1993
Atlanta Gas Light Company Gas Base Rate Proceeding*	Docket No. 4451-U	08/1993
Atlanta Gas Light Company Gas Base Rate Proceeding	Docket No. 5116-U	08/1994
Georgia Independent Telephone Companies Earnings Review and Show Cause Proceedings	Various Dockets	1994
Georgia Power Company Earnings Review - Report to GPSC*	Non-Docketed	09/1995
Georgia Alltel Telecommunication Companies Earnings and Rate Reviews	Docket No. 6746-U	07/1996
Frontier Communications of Georgia Earnings and Rate Review	Docket No. 4997-U	07/1996
Georgia Power Company Electric Base Rate / Accounting Order Proceeding	Docket No. 9355-U	12/1998

Savannah Electric Power Company Electric Base Rate Case/Alternative Rate Plan*	Docket No. 14618-U	03/2002
Georgia Power Company Electric Base Rate / Alternative Rate Plan Proceeding*	Docket No. 18300-U	12/2004
Savannah Electric Power Company Electric Base Rate Case/Alternative Rate Plan*	Docket No. 19758-U	03/2005

FERC

Philadelphia Electric/Conowingo Power Electric Base Rate Proceeding*	Docket ER 80-557/558	07/1981

KENTUCKY

Kentucky Power Company Electric Base Rate Proceeding*	Case 8429	04/1982
Kentucky Power Company Electric Base Rate Proceeding*	Case 8734	06/1983
Kentucky Power Company Electric Base Rate Proceeding*	Case 9061	09/1984
South Central Bell Telephone Company Base Rate Proceeding*	Case 9160	01/1985
Kentucky-American Water Company Base Rate Proceeding*	Case 97-034	06/1997
Delta Natural Gas Company Base Rate Proceeding*	Case 97-066	07/1997
Kentucky Utilities and LG&E Company Environmental Surcharge Proceeding	97-SC-1091-DG	01/1999
Delta Natural Gas Company Experimental Alternative Regulation Plan*	Case No. 99-046	07/1999
Delta Natural Gas Company Base Rate Proceeding*	Case No. 99-176	09/1999
Louisville Gas & Electric Company	Case No. 2000-080	06/2000

Gas Base Rate Proceeding*		
Kentucky-American Water Company Base Rate Proceeding*	Case No. 2000-120	07/2000
Jackson Energy Cooperative Corporation Electric Base Rate Proceeding*	Case No. 2000-373	02/2001
Kentucky-American Water Company Base Rate Rehearing*	Case No. 2000-120	02/2001
Kentucky-American Water Company Rehearing Opposition Testimony*	Case No. 2000-120	03/2001
Union Light Heat and Power Company Gas Base Rate Proceeding*	Case No. 2001-092	09/2001
Louisville Gas & Electric Company and Kentucky Utilities Company Deferred Debits Accounting Order	Case No. 2001-169	10/2001
Fleming-Mason Energy Cooperative Electric Base Rate Proceeding	Case No. 2001-244	05/2002
Northern Kentucky Water District Water District Base Rate Proceeding	Case No. 2003-0224	02/2004
Louisville Gas & Electric Company Electric Base Rate Proceeding*	Case No. 2003-0433	03/2004
Louisville Gas & Electric Company Gas Base Rate Proceeding*	Case No. 2003-0433	03/2004
Delta Natural Gas Company Base Rate Proceeding*	Case No. 2004-00067	07/2004

<u>MAINE</u>

Continental Telephone Company of Maine Base Rate Proceeding	Docket 90-040	12/1990
Central Maine Power Company Electric Base Rate Proceeding	Docket 90-076	03/1991
New England Telephone Corporation - Maine	Docket 94-254	12/1994

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MARYLAND

Potomac Electric Power Company Electric Base Rate Proceeding*	Case 7384	01/1980
Delmarva Power and Light Company Electric Base Rate Proceeding*	Case 7427	08/1980
Chesapeake and Potomac Telephone Company Western Electric and License Contract	Case 7467	10/1980
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7467	10/1980
Washington Gas Light Company Gas Base Rate Proceeding	Case 7466	11/1980
Delmarva Power and Light Company Electric Base Rate Proceeding*	Case 7570	10/1981
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7591	12/1981
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7661	11/1982
Chesapeake and Potomac Telephone Company Computer Inquiry II*	Case 7661	12/1982
Chesapeake and Potomac Telephone Company Divestiture Base Rate Proceeding*	Case 7735	10/1983
AT&T Communications of Maryland Base Rate Proceeding	Case 7788	1984
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7851	03/1985
Potomac Electric Power Company Electric Base Rate Proceeding	Case 7878	1985
Delmarva Power and Light Company Electric Base Rate Proceeding	Case 7829	1985

NEW HAMPSHIRE

Granite State Electric Company Electric Base Rate Proceeding	Docket DR 77-63	1977

NEW JERSEY

Elizabethtown Water Company Water Base Rate Proceeding	Docket 757-769	07/1975
Jersey Central Power and Light Company Electric Base Rate Proceeding	Docket 759-899	09/1975
Middlesex Water Company Water Base Rate Proceeding	Docket 761-37	01/1976
Jersey Central Power and Light Company Electric Base Rate Proceeding	Docket 769-965	09/1976
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings	Docket 761-8	10/1976
Atlantic City Electric Company Electric Base Rate Proceeding*	Docket 772-113	04/1977
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket 7711-1107	05/1978
Public Service Electric and Gas Company Raw Materials Adjustment Clause	Docket 794-310	04/1979
Rockland Electric Company Electric Base Rate Proceeding*	Docket 795-413	09/1979
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 802-135	02/1980
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 8011-836	02/1981
Rockland Electric Company Electric Base Rate Proceeding*	Docket 811-6	05/1981

Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 8110-883	02/1982
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket 812-76	08/1982
Public Service Electric and Gas Company Raw Materials Adjustment Clause	Docket 812-76	08/1982
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 8211-1030	11/1982
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 829-777	12/1982
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket 837-620	10/1983
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 8311-954	11/1983
AT&T Communications of New Jersey Base Rate Proceeding*	Docket 8311-1035	02/1984
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 849-1014	11/1984
AT&T Communications of New Jersey Base Rate Proceeding*	Docket 8311-1064	05/1985
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket ER8512-1163	05/1986
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket ER8512-1163	07/1986
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER8609-973	12/1986
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER8710-1189	01/1988
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket ER8512-1163	02/1988
United Telephone of New Jersey	Docket TR8810-1187	08/1989

Base Rate Proceeding		
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER9009-10695	09/1990
United Telephone of New Jersey Base Rate Proceeding	Docket TR9007-0726J	02/1991
Elizabethtown Gas Company Gas Base Rate Proceeding*	Docket GR9012-1391J	05/1991
Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER9109145J	11/1991
Jersey Central Power and Light Company Electric Fuel Clause Proceeding	Docket ER91121765J	03/1992
New Jersey Natural Gas Company Gas Base Rate Proceeding*	Docket GR9108-1393J	03/1992
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket ER91111698J	07/1992
Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER92090900J	12/1992
Middlesex Water Company Water Base Rate Proceeding*	Docket WR92090885J	01/1993
Elizabethtown Water Company Water Base Rate Proceeding*	Docket WR92070774J	02/1993
Public Service Electric and Gas Company Electric Fuel Clause Proceeding	Docket ER91111698J	03/1993
New Jersey Natural Gas Company Gas Base Rate Proceeding*	Docket GR93040114	08/1993
Atlantic City Electric Company Electric Fuel Clause Proceeding	Docket ER94020033	07/1994
Borough of Butler Electric Utility Various Electric Fuel Clause Proceedings	Docket ER94020025	1994
Elizabethtown Water Company Water Base Rate Proceeding	Non-Docketed	11/1994

Public Service Electric and Gas Company Electric Fuel Clause Proceeding	Docket ER 94070293	11/1994
Rockland Electric Company Electric Fuel Clause Proceeding and Purchased Power Contract By-Out	Docket Nos. 940200045 and ER 9409036	12/1994
Jersey Central Power & Light Company Electric Fuel Clause Proceeding	Docket ER94120577	05/1995
Elizabethtown Water Company Purchased Water Adjustment Clause Proceeding*	Docket WR95010010	05/1995
Middlesex Water Company Purchased Water Adjustment Clause Proceeding	Docket WR94020067	05/1995
New Jersey American Water Company* Base Rate Proceeding	Docket WR95040165	01/1996
Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER95090425	01/1996
United Water of New Jersey Base Rate Proceeding*	Docket WR95070303	01/1996
Elizabethtown Water Company Base Rate Proceeding*	Docket WR95110557	03/1996
New Jersey Water and Sewer Adjustment Clauses Rulemaking Proceeding*	Non-Docketed	03/1996
United Water Vernon Sewage Company Base Rate Proceeding*	Docket WR96030204	07/1996
United Water Great Gorge Company Base Rate Proceeding*	Docket WR96030205	07/1996
South Jersey Gas Company Base Rate Proceeding	Docket GR960100932	08/1996
Middlesex Water Company Purchased Water Adjustment Clause Proceeding*	Docket WR96040307	08/1996
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER96030257	08/1996

Public Service Electric & Gas Company and Atlantic City Electric Company Investigation into the continuing outage of the Salem Nuclear Generating Station*	Docket Nos. ES96039158 & ES96030159	10/1996
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket No.EC96110784	01/1997
Consumers New Jersey Water Company Base Rate Proceeding*	Docket No.WR96100768	03/1997
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER97020105	08/1997
Public Service Electric & Gas Company Electric Restructuring Proceedings*	Docket Nos. EX912058Y, EO97070461, EO97070462, EO97070463	11/1997
Atlantic City Electric Company Limited Issue Rate Proceeding*	Docket No.ER97080562	12/1997
Rockland Electric Company Limited Issue Rate Proceeding	Docket No.ER97080567	12/1997
South Jersey Gas Company Limited Issue Rate Proceeding	Docket No.GR97050349	12/1997
New Jersey American Water Company Limited Issue Rate Proceeding	Docket No.WR97070538	12/1997
Elizabethtown Water Company and Mount Holly Water Company Limited Issue Rate Proceedings	Docket Nos. WR97040288, WR97040289	12/1997
United Water of New Jersey, United Water Toms River and United Water Lambertville Limited Issue Rate Proceedings	Docket Nos.WR9700540, WR97070541, WR97070539	12/1997
Public Service Electric & Gas Company Electric Restructuring Proceedings*	Docket Nos. EX912058Y, EO97070461, EO97070462, EO97070463	01/1998
Consumers New Jersey Water Company Base Rate Proceeding*	Docket No. WR97080615	01/1998

New Jersey-American Water Company Base Rate Proceeding*	Docket No.WR98010015	07/1998
Consumers New Jersey Water Company Merger Proceeding	Docket No.WM98080706	12/1998
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER98090789	02/1999
Middlesex Water Company Base Rate Proceeding*	Docket No.WR98090795	03/1999
Mount Holly Water Company Base Rate Proceeding - Phase I*	Docket No. WR99010032	07/1999
Mount Holly Water Company Base Rate Proceeding - Phase II*	Docket No. WR99010032	09/1999
New Jersey American Water Company Acquisitions of Water Systems	Docket Nos. WM9910018 WM9910019	09/1999 09/1999
Mount Holly Water Company Merger with Homestead Water Utility	Docket No. WM99020091	10/1999
Applied Wastewater Management, Inc. Merger with Homestead Treatment Utility	Docket No.WM99020090	10/1999
Environmental Disposal Corporation (Sewer) Base Rate Proceeding*	Docket No.WR99040249	02/2000
Elizabethtown Gas Company Gas Cost Adjustment Clause Proceeding DSM Adjustment Clause Proceeding	 Docket No.GR99070509 Docket No. GR99070510	 03/2000 03/2000
New Jersey American Water Company Gain on Sale of Land	Docket No. WM99090677	04/2000
Jersey Central Power & Light Company NUG Contract Buydown	Docket No. EM99120958	04/2000
Shore Water Company Base Rate Proceeding	Docket No. WR99090678	05/2000
Shorelands Water Company Water Diversion Rights Acquisition	Docket No. WO00030183	05/2000

Mount Holly and Elizabethtown Water Companies Computer and Billing Services Contracts	Docket Nos. WO99040259 WO9904260	06/2000 06/2000
United Water Resources, Inc. Merger with Suez-Lyonnaise	Docket No. WM99110853	06/2000
E'Town Corporation Merger with Thames, Ltd.	Docket No. WM99120923	08/2000
Consumers Water Company Water Base Rate Proceeding*	Docket No. WR00030174	09/2000
Atlantic City Electric Company Buydown of Purchased Power Contract	Docket No. EE00060388	09/2000
Applied Wastewater Management, Inc. Authorization for Accounting Changes	Docket No. WR00010055	10/2000
Elizabethtown Gas Company Gas Cost Adjustment Clause Proceeding DSM Adjustment Clause Proceeding	 Docket No. GR00070470 Docket No. GR00070471	 10/2000 10/2000
Trenton Water Works Water Base Rate Proceeding*	Docket No. WR00020096	10/2000
Middlesex Water Company Water Base Rate Proceeding*	Docket No. WR00060362	11/2000
New Jersey American Water Company Land Sale - Ocean City	Docket No. WM00060389	11/2000
Pineland Water Company Water Base Rate Proceeding*	Docket No. WR00070454	12/2000
Pineland Wastewater Company Wastewater Base Rate Proceeding*	Docket No. WR00070455	12/2000
Elizabethtown Gas Company Regulatory Treatment of Gain on Sale of Property*	 Docket No. GR00070470	 02/2001
Wildwood Water Utility Water Base Rate Proceeding*	Docket No. WR00100717	04/2001
Roxbury Water Company Water Base Rate Proceeding	Docket No. WR01010006	06/2001

SB Water Company Water Base Rate Proceeding	Docket No. WR01040232	06/2001
Pennsgrove Water Company Water Base Rate Proceeding*	Docket No. WR00120939	07/2001
Public Service Electric & Gas Company Gas Base Rate Proceeding* Direct Testimony	Docket No. GR01050328	08/2001
Public Service Electric & Gas Company Gas Base Rate Proceeding* Surrebuttal Testimony	Docket No. GR01050328	09/2001
Elizabethtown Water Company Water Base Rate Proceeding*	Docket No. WR01040205	10/2001
Middlesex Water Company Financing Proceeding	Docket No. WF01090574	12/2001
New Jersey American Water Company Financing Proceeding	Docket No. WF01050337	12/2001
Consumers New Jersey Water Company Stock Transfer/Change in Control Proceeding	Docket No. WF01080523	01/2002
Consumers New Jersey Water Company Water Base Rate Proceeding	Docket No. WR02030133	07/2002
New Jersey American Water Company Change of Control (Merger) Proceeding*	Docket No. WM01120833	07/2002
Borough of Haledon – Water Department Water Base Rate Proceeding*	Docket No. WR01080532	07/2002
New Jersey American Water Company Change of Control (Merger) Proceeding	Docket No. WM02020072	09/2002
Public Service Electric & Gas Company Electric Base Rate Proceeding Direct Testimony*	Docket No. ER02050303	10/2002
United Water Lambertville Land Sale Proceeding	Docket No. WM02080520	11/2002

United Water Vernon Hills & Hampton Management Service Agreement	Docket No. WE02080528	11/2002
United Water New Jersey Metering Contract With Affiliate	Docket No. WO02080536	12/2002
Public Service Electric & Gas Company Electric Base Rate Proceeding Surrebuttal and Supplemental Surrebuttal Testimonies*	Docket No. ER02050303	12/2002
Public Service Electric & Gas Company Minimum Pension Liability Proceeding	Docket No. EO02110853	12/2002
Public Service Electric & Gas Company Electric Base Rate Proceeding Supplemental Direct Testimony*	Docket No. ER02050303	12/2002
Public Service Electric & Gas Company Electric Deferred Balance Proceeding Direct Testimony*	Docket No. ER02050303	01/2003
Rockland Electric Company Electric Base Rate Proceeding Direct Testimony*	Docket No. ER02100724	01/2003
Public Service Electric & Gas Company Supplemental Direct Testimony*	Docket No. ER02050303	02/2003
Rockland Electric Company Electric Base Rate Proceeding Supplemental Direct Testimony*	Docket No. ER02100724	02/2003
Consumers New Jersey Water Company Acquisition of Maxim Sewerage Company	Docket No. WM02110808	05/2003
Rockland Electric Company Audit of Competitive Services	Docket No. EA02020098	06/2003
New Jersey Natural Gas Company Audit of Competitive Services	Docket No. GA02020100	06/2003
Public Service Electric & Gas Company Audit of Competitive Services	Docket No. EA02020097	06/2003
Mount Holly Water Company Water Base Rate Proceeding*	Docket No. WR03070509	12/2003

Elizabethtown Water Company Water Base Rate Proceeding*	Docket No. WR03070510	12/2003
New Jersey-American Water Company Water and Sewer Base Rate Proceeding*	Docket No. WR03070511	12/2003
Applied Wastewater Management, Inc. Water and Sewer Base Rate Proceeding*	Docket No. WR03030222	01/2004
Middlesex Water Company Water Base Rate Proceeding	Docket No. WR03110900	04/2004
Consumers New Jersey Water Company Water Base Rate Proceeding	Docket No. WR02030133	07/2004
Roxiticus Water Company Purchased Water Adjustment Clause	Docket No. WR04060454	08/2004
Rockland Electric Company Societal Benefit Charge Proceeding	Docket No. ET04040235	08/2004
Wildwood Water Utility Water Base Rate Proceeding - Interim Rates	Docket No. WR04070620	08/2004
United Water Toms River Litigation Cost Accounting Proceeding	Docket No. WF04070603	11/2004
Lake Valley Water Company Water Base Rate Proceeding	Docket No. WR04070722	12/2004
Public Service Electric & Gas Company Customer Account System Proceeding	Docket No. EE04070718	02/2005
Jersey Central Power and Light Company Various Land Sales Proceedings	Docket No. EM04101107 Docket No. EM04101073 Docket No. EM04111473	02/2005 02/2005 03/2005
Environmental Disposal Corporation Water Base Rate Proceeding	Docket No. WR040080760	05/2005
Universal Service Fund Compliance Filing For 7 New Jersey Electric and Gas Utilities	Docket No. EX00020091	05/2005

NEW MEXICO

Southwestern Public Service Company Electric Base Rate Proceeding*	Case 1957	11/1985
El Paso Electric Company Rate Moderation Plan	Case 2009	1986
El Paso Electric Company Electric Base Rate Proceeding	Case 2092	06/1987
Gas Company of New Mexico Gas Base Rate Proceeding*	Case 2147	03/1988
El Paso Electric Company Electric Base Rate Proceeding*	Case 2162	06/1988
Public Service Company of New Mexico Phase-In Plan*	Case 2146/Phase II	10/1988
El Paso Electric Company Electric Base Rate Proceeding*	Case 2279	11/1989
Gas Company of New Mexico Gas Base Rate Proceeding*	Case 2307	04/1990
El Paso Electric Company Rate Moderation Plan*	Case 2222	04/1990
Generic Electric Fuel Clause - New Mexico Amendments to NMPSC Rule 550	Case 2360	02/1991
Southwestern Public Service Company Rate Reduction Proceeding	Case 2573	03/1994
El Paso Electric Company Base Rate Proceeding	Case 2722	02/1998

<u>OHIO</u>

Dayton Power and Light Company Electric Base Rate Proceeding	Case 76-823	1976

<u>PENNSYLVANIA</u>

Duquesne Light Company Electric Base Rate Proceeding*	R.I.D. No. R-821945	09/1982
AT&T Communications of Pennsylvania Base Rate Proceeding*	Docket P-830452	04/1984
AT&T Communications of Pennsylvania Base Rate Proceeding*	Docket P-830452	11/1984
National Fuel Gas Distribution Company Gas Base Rate Proceeding*	Docket R-870719	12/1987

RHODE ISLAND

Blackstone Valley Electric Company Electric Base Rate Proceeding	Docket No. 1289	
Newport Electric Company Report on Emergency Relief		

VERMONT

Continental Telephone Company of Vermont Base Rate Proceeding	Docket No. 3986	
Green Mountain Power Corporation Electric Base Rate Proceeding	Docket No. 5695	01/1994
Central Vermont Public Service Corp. Rate Investigation	Docket No. 5701	04/1994
Central Vermont Public Service Corp. Electric Base Rate Proceeding*	Docket No. 5724	05/1994
Green Mountain Power Corporation Electric Base Rate Proceeding*	Docket No. 5780	01/1995
Green Mountain Power Corporation Electric Base Rate Proceeding*	Docket No. 5857	01/1996

VIRGIN ISLANDS

Virgin Islands Telephone Corporation	Docket 126	

Base Rate Proceeding*

UNION LIGHT HEAT AND POWER COMPANY

CASE NO. 2005-00042

SCHEDULES RJH-1 THROUGH RJH-19

Test Period Ended 9/30/06
Case No. 2005-00042

UNION LIGHT HEAT AND POWER COMPANY
REVENUE DEFICIENCY

	ULHP (1)	Adjustment	AG	
1. Capitalization Allocated to Gas	$ 165,719,193	$ (3,423,113)	$ 162,296,080	Sch. RJH-3
2. Rate of Return	8.787%		7.285%	Sch. RJH-2
3. Operating Income Requirement	14,561,745		11,823,511	
4. Pro Forma Operating Income	6,312,696	3,443,978	9,756,674	Sch. RJH-8
5. Operating Income Deficiency	8,249,049		2,066,837	
6. Gross Revenue Conversion Factor	1.6997957		1.6769492	(3)
7. Revenue Deficiency	$ 14,021,698 (2)	$ (10,555,717)	$ 3,465,981	

(1) Filing Schedule A
(2) Response to AG-1-150
(3) Response to PSC-2-21, p. 1 of 40. Reflects KY income tax rate of 7%.

Test Period Ended 9/30/06
Case No. 2005-00042

UNION LIGHT HEAT AND POWER COMPANY
RATE OF RETURN

ULHP PROPOSED RATE OF RETURN	Ratios	Cost Rates	Weighted Cost Rates
	(1)	(1)	(1)
Common Equity	54.415%	11.200%	6.094%
Long-Term Debt	38.196%	6.302%	2.407%
Short-Term Debt	7.389%	3.875%	0.286%
Total	100.000%		8.787%

AG's RECOMMENDED RATE OF RETURN	Ratios	Cost Rates	Weighted Cost Rates
	(2)		
Common Equity	54.454%	8.700% (3)	4.737%
Long-Term Debt	38.164%	5.926% (3)	2.262%
Short-Term Debt	7.382%	3.875% (3)	0.286%
Total	100.000%		7.285%

(1) Filing Schedule J-1, page 2.
(2) Response to PSC-2-21, p. 39 of 40.
(3) Testimony of Dr. J. Randall Woolridge

Test Period Ended 9/30/06
Case No. 2005-00042

Sch. RJH-3

UNION LIGHT HEAT AND POWER COMPANY
GAS-ALLOCATED CAPITALIZATION

	ULHP (1)	Adjustment	AG (2)	
1. Total Capitalization	$ 647,845,631		$ 648,387,631	
2. Less: Non-Jurisdictional Plant	(13,316,453)		(13,306,709)	
3. Jurisdictional Capitalization	634,529,178	551,744	635,080,922	
4. Gas Jurisdictional Rate Base Allocation %	25.899%		25.337%	Sch. RJH-4
5. Gas Jurisdictional Capitalization	164,336,712	(3,423,113)	160,913,599	
6. Plus: Jurisdictional Gas ITC	1,382,481		1,382,481	
7. Adjusted Gas Jurisdictional Capitalization	$ 165,719,193	$ (3,423,113)	$ 162,296,080	

(1) WPA-1c
(2) Response to PSC-2-21, page 2.

Test F d Ended 9/30/06
Case No. 2005-00042

UNION LIGHT HEAT AND POWER COMPANY
GAS-ALLOCATED JURISDICTIONAL RATE BASE

	A	B	C		D		E
	Gas Jursidictional Rate Base				Electric Jursidictional Rate Base		Total Co. Jursidictional Rate Base
	ULHP	Adjustment	AG				
	(1)		[A+B]		(1)		[C+D]
1. Utility Plant in Service	$ 277,747,000	$(1,152,749)	$ 276,594,251	(2)	$ 1,077,104,000		$ 1,353,698,251
2. CWIP	4,120,000		4,120,000		22,572,000		26,692,000
3. Fuel Inventory	-		-		5,710,000		5,710,000
4. Propane Inventory	677,245		677,245		-		677,245
5. Other Materials and Supplies	232,273		232,273		9,611,727		9,844,000
6. Gas Stored Underground	5,462,513		5,462,513		-		5,462,513
7. Prepayments	105,675	(105,675)	-	(3)	-	(3)	-
8. Cash Working Capital	2,384,337	(101,811)	2,282,526	(4)	9,883,163		12,165,689
9. Depreciation Reserve	(87,230,000)		(87,230,000)		(526,365,000)		(613,595,000)
10. Accumulated Deferred Income Taxes	(33,244,980)	(3,158,845)	(36,403,825)	(5)	(118,258,991)	(5)	(154,662,816)
11. Customer Advances for Construction	(2,721,042)		(2,721,042)		-		(2,721,042)
12. Investment Tax Credit	(33,782)		(33,782)		-		(33,782)
13. Total	$ 167,499,239	$(4,519,079)	$ 162,980,160		$ 480,256,899		$ 643,237,059
14. Ratio of Gas Jurisdictional to Total Company Jurisdictional [C/E]:			25.337%				

(1) WPA-1d
(2) Sch. RJH-5, L5
(3) Elimination of prepaid KPSC assessments from rate base.
(4) Sch. RJH-6
(5) Sch. RJH-7

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UNION LIGHT HEAT AND POWER COMPANY
SLIPPAGE FACTOR ADJUSTMENT

	Jurisdictional Gas Plant	
IMPACT ON RATE BASE:		
1. End of Base Period (5/31/05)	$ 258,687,000	WPA-1b
2. 13-Month Average Forecasted Period	277,747,000	WPA-1d
3. Projected Plant Additions from 5/31/05 to 13-Month Average for Forecasted Period [L2 - L1]	19,060,000	
4. Non-AMRP Slippage Factor	-6.048%	(1)
5. Plant in Service Slippage Factor Adj. [L3 x L4]	(1,152,749)	
IMPACT ON OPERATING INCOME:		
6. Composite Depreciation Rate	2.469%	(2)
7. Depreciation Expense Adjustment [L5 x L6}	(28,461)	
8. Composite After-Tax Income Rate	60.45%	(3)
9. Impact of After-Tax Operating Income	$ 17,205	

(1) Response to PSC-2-105, page 1 of 3: 10-year mathematical average of 93.952% vs. 100.000% = 6.048%

(2) Per Sch. B-3.2, pp. 1-4:

Forecasted period depreciation expense recommended by Majoros	$ 6,827,000	Sch. RJH-16
Average forecasted period depreciable plant (excluding land and land rights)	276,480,000	
Composite depreciation rate	2.469%	

(3) Composite of SIT of 7% and FIT of 35% = 39.55%. 1 - 39.55% = 60.45%

UNION LIGHT HEAT AND POWER COMPANY
CASH WORKING CAPITAL

	ULHP (1)	Adjustment	AG	
1. Total Pro Forma O&M Expense	$ 110,924,695	$ (814,485)	$ 110,110,210	Sch. RJH-19, L10
2. Less: Purchased Gas Costs	(91,850,000)		(91,850,000)	
3. Net Pro Forma O&M Expense	19,074,695		18,260,210	
4. CWC Ratio	0.125	0.125	0.125	
5. Cash Working Capital	$ 2,384,337	$ (101,811)	$ 2,282,526	

(1) WPB-5.1a

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Sch. RJH-7

UNION LIGHT HEAT AND POWER COMPANY
ACCUMULATED DEFERRED INCOME TAXES (ADIT)

	Gas Jurisdictional	Electric Jurisdictional	
1. ULHP's Forecasted Period ADIT	$ (33,244,980)	$ (119,478,969)	(1)
2. Impact of KY Income Tax Reduction to 7%	339,459	1,219,978	
3. Adjusted Forecasted Period ADIT	(32,905,521)	(118,258,991)	(2)
4. Remove Prepaid Unbilled Revenue ADIT	(3,498,304) (3)	-	(4)
5. AG-Recommended Forecasted Period ADIT	$ (36,403,825)	$ (118,258,991)	

(1) WPA-1d
(2) Response to PSC-2-21, page 3 of 40, line 25

(3) Account 283/284 ADIT Components	1/31/05 - Actual	3/31/05 - Actual	Forecasted Period
- 283150 - CIS Capitalized (FIT)	$ 135	$ 135	$ 135
- 283300 - CIS Loss Hedge Trans 6 (FIT)	(144,147)	(144,147)	(144,147)
- 283730 - Loss R/A Debt 1st (FIT	(89,503)	(89,503)	(89,503)
- 283780 - Loss R/A Debt Gas (FIT)	(86,218)	(81,928)	(81,928)
- 284150 - CIS Capitalized (SIT)	(84,028)	(84,028)	(84,028)
- 284300 - CIS Loss Hedge Trans 6 (SIT)	(37,080)	(37,080)	(37,080)
- 284730 - Loss R/A Debt 1st (SIT)	(23,024)	(23,024)	(23,024)
- 284780 - Loss R/A Debt Gas (SIT)	(22,178)	(21,346)	(21,346)
Account 283/284 w/o Unbilled Revenues	(486,043)	(480,921)	(480,921)
- 283350/284350 - Unbilled Revenues			3,498,304
Total Account 283/284 ADIT			$ 3,017,383

(4) Per responses to PSC-1-30, p. 8 of 20 and updated PSC-1-30, p. 8 of 32: all total company unbilled revenue ADIT is for gas operations.

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Sch. RJH-8

UNION LIGHT HEAT AND POWER COMPANY
PRO FORMA OPERATING INCOME

1. Pro Forma Operating Income Proposed by ULHP	$ 6,312,696	(1)
AG-Recommended Operating Income Adjustments:		
2. Incremental Income Impact of 7% KY Income Tax Rate	24,363	(2)
3. Weather Normalization Adjustment	415,500	Sch. RJH-9
4. Firm Transportation Sales Adjustment	685,073	Sch. RJH-10
5. Bad Check and Reconnection Charge Revenues	(7,549)	Sch. RJH-11
6. Remove Proposed I&D Expense Normalization Adjustment	87,022	Sch. RJH-12
7. Base Payroll Expense Adjustment	5,985	Sch. RJH-13
8. Incentive Compensation Adjustments	396,973	Sch. RJH-14
9. Miscellaneous Expense Adjustments	38,371	Sch. RJH-15
10. Depreciation Expense Adjustment	1,217,079	Sch. RJH-16
11. Slippage Factor Depreciation Expense Adjustment	17,205	Sch. RJH-5, L9
12. Property Tax Adjustment	323,556	Sch. RJH-17
13. Interest Synchronization Adjustment	65,887	Sch. RJH-18
14. ITC Amortization Adjustment	69,130	(3)
15. Five-Year Amortization of Unprotected Excess ADIT	105,384	(4)
16. AG-Recommended Income Adjustments	$ 3,443,978	
17. AG-Recommended Pro Forma Operating Income	$ 9,756,674	

(1) Filing Schedule C-2
'(2) Response to PSC-2-21, p. 9 of 40: revised income of $6,337,059 vs. original income of $6,312,696
(3) Responses to AG-1-182 and AG2-11.
(4) Response to AG-2-33

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Sch. RJH-9

UNION LIGHT HEAT AND POWER COMPANY
WEATHER NORMALIZATION ADJUSTMENT

	HDDs	Revenues at Current Rates	
1. Filing Schedule M-2.2	4,950	$ 38,371,656	
2. Response to PSC-2-51(a)	5,200	$ 39,370,995	
3. Difference from Filing	250	$ 999,339	
4. 1975-2004 Average HDDs	5,133		(1)
5. Difference from Filing	183	$ 731,516	[L3*(L5/L3)]
6. Impact on Uncollectibles		38,524	(2)
7. Impact on KPSC Assessments		5,648	(3)
8. Impact on Pre-Tax Operating Income [L1 -L2 - L3]		687,344	
9. Composite After-Tax Income Rate		60.45%	(4)
10. Impact on Operating Income		$ 415,500	

(1) Testimony of David Brown-Kinloch
(2) ($731,516/$999,339) x $52,628 (see resp. to AG-1-195a) = $38,524
(3) ($731,516/$999,339) x $7,716 (see resp. to AG-1-195a) = $5,648.
(4) Composite of SIT of 7% and FIT of 35% = 39.55%. 1 - 39.55% = 60.45%

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Sch. RJH-10

UNION LIGHT HEAT AND POWER COMPANY
FIRM TRANSPORTATION REVENUE ADJUSTMENT

1. Firm Transportation Base Revenue Adjustment	$	1,148,833	(1)
2. Impact on Uncollectible Expense @ 1.18%		13,556	
3. Impact on KYPSC Maintenance Fees @ .173%		1,987	
4. Impact on Operating Income Before Income Taxes [L1 -L2 - L3]		1,133,289	
5. Composite After-Tax Income Rate		60.45%	(2)
6. Impact on Operating Income	$	685,073	

(1) Testimony of David Brown-Kinloch
(2) Composite of SIT of 7% and FIT of 35% = 39.55%. 1 - 39.55% = 60.45%

UNION LIGHT HEAT AND POWER COMPANY
BAD CHECK AND RECONNECTION CHARGES

	ULHP (1)	Adjustment	AG (2)
1. Forecasted Period Bad Check Charges	$ 18,182	$ (8,182)	$ 10,000
2. Forecasted Period Reconnection Charges	11,667	(4,477)	7,190
3. Total	$ 29,849	(12,659)	$ 17,190
4. Impact on Uncollectible Expense @ 1.18%		(149)	
5. Impact on KYPSC Maintenance Fees @ .173%		(22)	
4. Impact on Operating Income Before Income Taxes [L3 - L4 - L5]		(12,488)	
5. Composite After-Tax Income Rate		60.45%	(3)
6. Impact on Operating Income		$ (7,549)	

(1) Schedule M.
(2) Testimony of David Brown-Kinloch
(3) Composite of SIT of 7% and FIT of 35% = 39.55%. 1 - 39.55% = 60.45%

UNION LIGHT HEAT AND POWER COMPANY
INJURY AND DAMAGE EXPENSE NORMALIZATION ADJUSTMENT

1. ULHP's Proposed I&D Expense Normalization Adjustment	$	143,957	(1)
2. Composite After-Tax Income Rate		60.45%	(2)
3. Impact on Operating Income from Removal of Expense Adjustment	$	87,022	

(1) Schedule D-2.15
(2) Composite of SIT of 7% and FIT of 35% = 39.55%. 1 - 39.55% = 60.45%

UNION LIGHT HEAT AND POWER COMPANY
BASE PAYROLL EXPENSE ADJUSTMENT

1. Impact of Reflecting Wage Increase of 3.0% vs. 3.2% Increase Reflected by ULHP for the Forecasted Test Period	$	(9,900)	(1)
2. Composite After-Tax Income Rate		60.45%	(2)
2. Impact on Operating Income	$	5,985	

(1) Response to AG-2-22
(2) Composite of SIT of 7% and FIT of 35% = 39.55%. 1 - 39.55% = 60.45%

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Sch. RJH-14

UNION LIGHT HEAT AND POWER COMPANY
INCENTIVE COMPENSATION ADJUSTMENTS

1. Remove Forecasted Test Period AIP Expenses	$	(451,116)	(1)
2. Remove Forecasted Test Period UEIP Expenses		(80,460)	(1)
3. Remove Forecasted Test Period LTIP Expenses		(125,121)	(1)
4. Total Incentive Compensation Expense Removal	$	(656,697)	
5. Composite After-Tax Income Rate		60.45%	(2)
6. Impact on Operating Income	$	396,973	

(1) Response to AG-1-204
(2) Composite of SIT of 7% and FIT of 35% = 39.55%. 1 - 39.55% = 60.45%

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Sch. RJH-15

UNION LIGHT HEAT AND POWER COMPANY
MISCELLANEOUS EXPENSE ADJUSTMENTS

1. Remove Governmental Affairs Expenses	$	(11,196)	(1)
2. Remove Lobbying Expenses		(12,159)	(1)
3. Remove Corporate Sponsorship Expenses		(40,120)	(1)
4. Total Miscellaneous Expense Adjustments		(63,475)	
5. Composite After-Tax Income Rate		60.45%	(2)
6. Impact on Operating Income	$	38,371	

(1) Response to PSC-3-57
(2) Composite of SIT of 7% and FIT of 35% = 39.55%. 1 - 39.55% = 60.45%

UNION LIGHT HEAT AND POWER COMPANY
DEPRECIATION EXPENSES

	ULHP	Adjustment	AG	
	(1)		(2)	
1. Forecasted Period Depreciation Expenses	$ 8,840,365	$ (2,013,365)	$ 6,827,000	
2. Composite After-Tax Income Rate		60.45%		(3)
3. Impact on Operating Income		$ 1,217,079		

(1) Schedule C-1, line 5
(2) Testimony of Michael Majoros
(3) Composite of SIT of 7% and FIT of 35% = 39.55%. 1 - 39.55% = 60.45%

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Sch. RJH-17

UNION LIGHT HEAT AND POWER COMPANY
PROPERTY TAX ADJUSTMENT

1. Remove Forecasted Test Period Property Tax For "Anticipated Increase in Valuation"	$	535,245	(1)
2. Composite After-Tax Income Rate		60.45%	(2)
3. Impact on Operating Income	$	323,556	

(1) Responses to AG-1-187b and AG-2-13c
(2) Composite of SIT of 7% and FIT of 35% = 39.55%. 1 - 39.55% = 60.45%

UNION LIGHT HEAT AND POWER COMPANY
INTEREST SYNCHRONIZATION ADJUSTMENT

	ULHP (1)	Adjustment	AG	
1. Gas-Allocated Capitaliation	$ 165,798,581	$ (3,502,501)	$ 162,296,080	Sch. RJH-3
2. Less: CWIP Subject to AFUDC	(4,120,000)		(4,120,000)	
3. Net Capitalization	161,678,581	(3,502,501)	158,176,080	
4. Weighted Debt Cost Rates:				
a. Long Term Debt	2.405%		2.262%	Sch. RJH-2
b. Short Term Debt	0.286%		0.286%	Sch. RJH-2
c. Total Weighted Debt Cost	2.691%		2.548%	
5. Pro Forma Interest [L3 x L4c]	4,351,010	(321,235)	4,029,775	
6. Forecasted Period Per Books Interest	4,558,827	(487,827)	4,071,000	(2)
7. Tax-Deductible Interest Adjustment	(207,817)	166,592	(41,225)	
8. Composite Income Tax Rate	39.55%	39.55%	39.55%	(3)
9. Impact of Operating Income	$ (82,192)	$ 65,887	$ (16,305)	

(1) Response to PSC-2-21, p. 27 of 40. Reflects KY income tax rate of 7%.
(2) Responses to AG-1-183 and PSC-2-21, page 37 of 40, line 5
(3) Composite of SIT of 7% and FIT of 35% = 39.55%.

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Sch. RJH-19

UNION LIGHT HEAT AND POWER COMPANY
RECOMMENDED ADJUSTED OPERATION AND MAINTENANCE EXPENSE LEVEL

1.	Pro Forma O&M Expenses Proposed by ULHP	$110,924,695	(1)
	<u>AG-Recommended O&M Expense Adjustments:</u>		
2.	Weather Normalization Adjustment	44,172	Sch. RJH-9, L2 + L3
3.	Firm Transportation Sales Adjustment	15,544	Sch. RJH-10, L2 + L3
4.	Bad Check and Reconnection Charge Adjustment	(171)	Sch. RJH-11, L2 + L3
5.	I&D Expense Normalization Adjustment	(143,957)	Sch. RJH-12, L1
6.	Base Payroll Expense Adjustment	(9,900)	Sch. RJH-13, L1
7.	Incentive Compensation Adjustments	(656,697)	Sch. RJH-14, L4
8.	Miscellaneous Expense Adjustments	(63,475)	Sch. RJH-15, L4
9.	Pro Forma O&M Expenses Recommended by AG	$110,110,210	

(1) Schedule C-1