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

DIRECT TESTIMONY OF MICHAEL J. MAJOROS, JR.
ON BEHALF OF
THE ATTORNEY GENERAL OF THE COMMONWEALTH OF KENTUCKY

Date: June 8, 2005

Direct Testimony
Of
Michael J. Majoros, Jr.

Introduction

Q. Please state your name, position and business address.

A. My name is Michael J. Majoros, Jr. I am Vice President of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"), located at 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. Please describe Snavely King.

A. Snavely King is a progressive economic consulting firm founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. Snavely King represents the interests of government agencies, businesses, and individuals who are consumers of telecom, public utility, and transportation services.

Snavely King has a professional staff of 15 economists, accountants, engineers and cost analysts. Most of our work involves the development, preparation and presentation of expert witness testimony before Federal and state regulatory agencies. Over the course of our 35-year history, members of the firm have participated in more than 1,000 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. Have you prepared a summary of your qualifications and experience?

A. Yes. Appendix A is a summary of my qualifications and experience. Appendix B contains a tabulation of my appearances as an expert witness before state and Federal regulatory agencies.

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Attorney General of the Commonwealth of Kentucky ("AG").

Q. What is the subject of your testimony?

A. This testimony addresses depreciation.

Q. Do you have any specific experience in the field of public utility depreciation?

A. Yes. I and other members of my firm specialize in the field of public utility depreciation. We have appeared as expert witnesses on this subject before the regulatory commissions of almost every state in the country. I have testified in over one hundred proceedings on the subject of public utility depreciation and represented various clients in several other proceedings in which depreciation was an issue but was settled. I have also negotiated on behalf of clients in fifteen of the Federal Communications Commissions' ("FCC") Triennial Depreciation Represcription conferences.

Q. Does your experience specifically include gas company depreciation?

A. Yes. I have testified in several proceedings on the subject of gas company depreciation, and I have prepared testimony in several other gas proceedings in which depreciation was ultimately settled.

<u>Purpose of Testimony</u>

Q. What is the purpose of your testimony?

A. The AG asked me to review the depreciation rates and proposals of the Union Light, Heat and Power Company ("ULH&P," "Union" or "the Company"), and express an opinion regarding the reasonableness of those depreciation rates and expense proposals. I was also asked to make alternative recommendations if warranted.

ULH&P's Present Depreciation Rates

Q. When were the Company's present depreciation rates approved?

A. The present depreciation rates were approved in ULH&P's last rate case, Case No. 2001-00092.[1] The present rates were based on a study prepared by Mr. Spanos of Gannett Fleming and presented by the Company to this Commission. It does not appear that the rates were challenged during the course of that case.[2]

Q. How did Mr. Spanos calculate the present depreciation rates?

A. According to Mr. Spanos, the present rates are straight-line remaining life depreciation rates, using the equal life group procedure.[3]

ULH&P's Proposed Depreciation Rates

Q. Will you please summarize the Company's depreciation proposal in this proceeding?

A. Yes. Again, Mr. John Spanos sponsors ULH&P's depreciation study. Mr. Spanos' proposals would decrease annual depreciation expense by $270 thousand relative to current depreciation rates based on September 30, 2004 plant balances. Exhibit___ (MJM-1) summarizes Mr. Spanos' proposals by plant account and also compares the proposals to the present rates.

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[1] Response to AG-DR-01-045.

[2] I/M/O Adjustment of Gas Rates of the Union Light, Heat and Power Company, Case No. 2001-00092, Order, Issued January 31, 2002, page 29.

[3] Depreciation Study ("Study"), page I-4..

Q. Have you included any additional versions of Mr. Spanos' proposed depreciation rates?

A. Yes. Exhibit___ (MJM-2) shows Mr. Spanos' proposed depreciation rates broken into two rates which sum to his proposed depreciation rate for each account. I have shown Mr. Spanos' rates relating to capital recovery and his rates relating to estimated future cost of removal for each account. I am providing these specifically identified depreciation rates in order to facilitate external reporting and for regulatory analysis and rate setting purposes. I will address the need for this information in more detail later.

However, should the KPSC disagree with everything I have to say below, and approve Mr. Spanos' proposals in their entirety, I still would recommend that ULH&P be required to apply the separated rates such that ratepayers at least will have the ability to know how much they are paying for capital recovery versus future cost of removal. This does not require any change to current accounting, it merely provides more and better information.

Conclusions

Q. Do you disagree with Mr. Spanos' proposal?

A. Yes, even though Mr. Spanos proposes a decrease in depreciation expense, I disagree with certain aspects of his proposal and his rationale. Mr. Spanos' proposal results in *excessive depreciation* expense and charges to ratepayers. It is obvious that even Mr. Spanos recognizes that ULH&P's present depreciation rates are excessive because he is proposing a decrease, but the decrease proposed is not enough. My conclusion is based on my depreciation study, my analysis, certain information brought to light by Staff data requests, and by this Company's prior actions as a result of recent accounting pronouncements. My recommendations result in a $1.9 million reduction based on September 30, 2004 plant balances.

Q. On what do you base your conclusions and recommendations?

A. As I stated above, I have conducted a depreciation study which provides one basis for my conclusions and recommendations. My study addresses lives, life spans and survivor curves. I have also reviewed net salvage data in my study, and I have used the study to implement the depreciation rate and reserve separation procedures that I will discuss in more detail below. I have also given heavy weight to the Company's responses to Staff data requests, this Commission's prior Orders, and to this Company's past actions regarding depreciation collected from its ratepayers.

<u>Excessive Depreciation</u>

Q. You have used the phrase "*excessive depreciation.*" Have you provided any background information on the concept of *excessive depreciation*?

A. Yes. An *excessive depreciation rate* is one that produces more depreciation expense than necessary to return the cost of a company's capital asset over the life of the asset. Exhibit___ (MJM-3) is a brief summary of a landmark U.S. Supreme Court decision on depreciation. I am not an attorney and I do not present this as a legal argument or conclusion. I merely present this to demonstrate that the concept of *excessive depreciation* is not a new one. I have also included a discussion of, and quotations from, the accounting profession's SFAS No. 143 which demonstrates that that profession is also at least cognizant of excessive depreciation.

Q. Mr. Majoros, does the fact that accumulated depreciation is deducted from rate base moot the concept of excess depreciation?

A. No. If ratepayers are required to pay too much for depreciation expense, they will have paid too much. The fact that ratepayers are not required to pay a return on prior excessive charges does not mean that those charges were not excessive it merely means that insult has not been added to injury.

Depreciation Concepts

Q. Does your testimony include a discussion of the depreciation concepts that are relevant to your testimony?

A. Yes. Exhibit___ (MJM-4) is a brief discussion of depreciation concepts that are relevant to my testimony. I have submitted this discussion as a separate exhibit in an attempt to minimize the technical aspects of my direct testimony. However, I believe that discussion may be helpful to understanding this testimony.

Depreciation Parameters

Q. What are depreciation parameters?

A. Depreciation parameters are the basic assumptions upon which depreciation rate calculations are based. ULH&P's proposed depreciation rates are based on three fundamental parameters, all of which are estimates: an average service life, a retirement dispersion pattern and a net salvage ratio. These are discussed in much more detail in Exhibit___ (MJM-4).

The two most significant parameters in this case are the average service life and the net salvage ratio; the shorter the service life – the higher the resulting depreciation rate. Similarly, the more negative the net salvage ratio – the higher the resulting depreciation rate. In both cases, the higher depreciation rate is charged to ratepayers.

As I stated above, another parameter is the estimated retirement dispersion pattern. Mr. Spanos used "Iowa Curves" to define these patterns. These patterns have relevance in estimating average lives and they have a direct impact on Mr. Spanos' remaining life calculations, particularly since he used the equal life group ("ELG") procedure to calculate remaining lives. ELG, is very sensitive to the Iowa Curve shape and results in a shorter remaining life calculation, ergo a higher depreciation rate than other alternative procedures which are typically used in Kentucky.

Q. Are you accepting the ELG procedure in this proceeding?

A. No, I am not accepting the ELG procedure in this proceeding. However, I am cognizant that Mr. Spanos says that it was accepted by the KPSC in ULH&P's last study. It is my understanding that no intervenor objected to any part of that study. The fact that no one objected is not a ringing endorsement of the ELG procedure; it merely reflects budgeting constraints and how funds were allocated to witnesses. I recommend that the KPSC not consider ULH&P's use of ELG to be established as a precedent.

Recommended Parameters

Q. Please summarize your recommended depreciation parameters.

A. I recommend the following:

	ULH&P Proposed		AG Recommended	
Account	ASL/ Survivor Curve	Net Salvage	ASL/ Survivor Curve	Net Salvage
2050 – Structures & Improvements	50-R4	(5)	83-R4	(5)
2110 – Liquid Petroleum Gas Equip.	35-S1.5	(5)	59-S1.5	(5)
2741 – Rights of Way - General	65-R4	0	100-R4	0
2761 – Mains - Cast Iron, Copper, All Valves	41-R2.5	(20)	6 RL	(5)
2762 – Mains - Steel	53-R2	(20)	53-R2	(5)
2763 – Mains - Plastic	50-R2.5	(20)	70-R1.5	(5)
2801 – Services - Cast Iron, Copper and Valves	40-R1.5	(35)	6 RL	0
2802 – Services - Steel	38-R1	(35)	38-R1	(5)
2803 – Services - Plastic	42-R1.5	(35)	42-R1.5	(5)

I have accepted the Company's proposed parameters for all other accounts.

Q. Will you please explain each of these recommendations in detail?

A. Yes.

<u>Account 2050 – Production Plant Structures and Improvements</u> – The current depreciation rate for this account is based on a 45-year average service life and an R3 Iowa curve (45-R3). Mr. Spanos proposes to lengthen the average service life to 50 years (50-R4), which results in a 41.2 year remaining life. Mr. Spanos' life analysis for this account is shown on page III-13 of his study. I have included his chart in my Exhibit___ (MJM-5) which is my analysis of this account. Mr. Spanos' chart demonstrates a relatively long life indication compared to his 50-R4 proposal.

Staff questioned Mr. Spanos about his recommendation.[4] Staff asked Mr. Spanos to "explain why ULH&P considers the Iowa curve 50-R4 to be the best match for this account." Staff also asked Mr. Spanos to "indicate whether an Iowa curve that provides a better match for this account exists and provide a copy of that curve." Mr. Spanos' response is included in Exhibit___ (MJM-5). Mr. Spanos responded:

> The original survivor curve for Account 2050 does not have an Iowa curve that will reasonably match the points statistically. The 50-R4 Iowa curve was selected as the most reasonable estimate given the nature of the assets, the past estimate for this account, and the estimates by other utilities for similar assets. The 50-R4 was determined by judgment.

[4] KyPSC-DR-02-012.

> There is no Iowa curve that provides a better match statistically because the points basically are a straight line.[5]

Mr. Spanos did not provide any other curve fits.

I conducted an independent statistical analysis of account 2050. It is included in Exhibit___ (MJM-5). My analysis indicates that Mr. Spanos' proposed R4 curve is the best fit curve, but the life is 83 years rather than 50 years. In Exhibit__(MJM-5), I have included my graph comparing the original observed life table to Mr. Spanos 50-R4 and to the best fitting 83-R4. My graph clearly demonstrates that the 83-R4 fits the data better than a 50-R4. Therefore, I recommend an 83-R4 life and curve. This results in a 44.4 year remaining life rather than Mr. Spanos' 41.2 year remaining life.

Account 2110 – Production Plant Liquid Petroleum Gas Equipment – The current depreciation rate for this account is based on a 35-year average service life (35-S1.5) and a net salvage factor of negative 5 percent, and Mr. Spanos has proposed no change in the parameters. The 35-S1.5 life and curve combination result in a 23.7 year remaining life. Mr. Spanos' life study for this account is shown on page III-16 of his study. I have included this chart in my Exhibit___ (MJM-6) which is my analysis of this account. Again, Mr. Spanos' chart indicates that a better fit to the data would result in a longer life.

Staff noted that "the Iowa curve 35-S1.5 does not appear to represent a good match to the survival intervals."[6] It asked Mr. Spanos to "indicate

[5] Spanos response to KyPSC-DR-02-012. See Exhibit___(MJM-5)
[6] KyPSC-DR-02-013.

whether an Iowa curve that provides a better match for this account exists and provide a copy of that curve." Staff also asked, "Would ULH&P agree that if a better fitting Iowa curve is chosen for Account 2110, the depreciation rate would be lower than the 2.45 percent proposed in the depreciation study? Explain the response."

Once again, Mr. Spanos did not provide any additional curves. Mr. Spanos' response is included in Exhibit___ (MJM-6). Mr. Spanos stated:

> There are possible Iowa curves that would statistically match the original survivor curve better than the 35-S1.5; however, determining the most appropriate survivor curve for each account is more than just a statistical match. The 31-S1.5 curve was determined to be the most appropriate Iowa for this account because the average service life and survivor curve is the best estimation of the life characteristics of the assets within the account. The life and curve combination is comparable to estimates of other electric utilities as well.
>
> I would not agree that all other possible Iowa curves would lower the 2.45% depreciation rate for Account 2110. There are many survivor curves with a high mode that could produce a higher rate depending on the average service life and the surviving age distribution at the time of calculation.[7]

I conducted an independent life analysis for account 2110. It is included in Exhibit___ (MJM-6). The best fit is actually a 100 R0.5 life and curve as opposed to Mr. Spanos' proposed 35 S1.5. The best fit life indication for the S1.5 curve is actually 59 years. Therefore, I recommend the use of a 59-S1.5 life/curve for this account. My chart for this account, also included in Exhibit___ (MJM-6), demonstrates graphically that the 59 S1.5 life and curve is a superior fit than Mr. Spanos' proposed 31.5 S1.5 combination. My recommendation indicates a 37.6 year remaining life rather than Mr. Spanos' proposed 23.7 years.

Account 2741 – Distribution Plant Rights of Way – The current depreciation rate for this account is based on a 65-year average service life (65-R4) and a net salvage factor of zero percent. As with Account 2110, Mr. Spanos has proposed keeping the existing parameters. His 65-R4 life and curve combination result in his 40.8 year remaining life proposal. Mr. Spanos' life study for this account is shown on page III-21 to 24 of his study. I have included copies of these in my Exhibit___ (MJM-7) which is my analysis of this account. Mr. Spanos' chart shows a horizontal line across the top meaning that all life indications are very long. A further review of his analysis reveals that he studied age intervals as old as 94 years, but there was only one retirement of $152 in all of that time.

Staff noted that "the Iowa curve 65-R4 shifts inward while the plotted data points reflect a constant straight line."[8] It asked Mr. Spanos to "indicate whether an Iowa curve that provides a better match for this account exists and provide a copy of that curve." Staff also asked, "Would ULH&P agree that an Iowa curve with a better match would result in a depreciation rate lower than the proposed 1.39 percent? Explain the response." Staff asked Mr. Spanos to

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[7] Spanos response to KyPSC-DR-02-013, see Exhibit___(MJM-6).
[8] KyPSC-DR-02-014.

"explain why ULH&P considers the Iowa curve 65-R4 to be the best match for this account?"

Once again, Mr. Spanos did not provide any additional Iowa curve fits to the data. Mr. Spanos responded:

> There is no Iowa curve that will statistically match the original curve for Account 2741. The 65-R4 was selected based on judgment, given the nature of the assets, the past estimate for this account, and the estimates by other utilities for similar assets.
>
> There is no Iowa curve that would better match the original survivor curve; therefore, there are many combinations that would produce a lower depreciation rate than the proposed 1.39% and many combinations that could produce a higher depreciation rate. The Iowa curve for this account can only be determined judgmentally.[9]

I conducted an independent life analysis for account 2741. It is included in Exhibit___ (MJM-7). The best fit is actually a 94 SQ life and curve as opposed to Mr. Spanos' proposed 65-R4. The best fit life indication for the R4 curve is actually 100 years. If fact the best fit for almost all of the curves in my analysis is 100 years. That is because I use a range of lives, shortest to longest, to fit within for each curve. I set the upper limit at 100 years. Due to UHL&P's insignificant retirement activity in this account and the nature of the assets in this account, the 100 year result is the best fit life for UHL&P. Therefore, I recommend the use of a 100-R4 life/curve for this account. My

[9] Spanos response to KyPSC-DR-02-014.

recommendation indicates a 70.4 year remaining life rather than Mr. Spanos' proposed 40.8 years.

<u>Accounts 2761 and 2801– Distribution Plant Mains and Services – Cast Iron, Copper and All Valves</u> – The current depreciation rate for account 2761 is based on a 41-year average service life (41-R2.5) and a net salvage factor of negative 20 percent. Mr. Spanos has proposed retaining the existing parameters. The current depreciation rate for account 2801 is based on a 33-year average service life (33-R0.5) and a net salvage factor of negative 30 percent. Mr. Spanos has proposed lengthening the average service life to 40-R1.5 and increasing the net salvage factor to negative 35 percent.

Both of these accounts are subject to the Company's Accelerated Main Replacement Program ("AMRP"), which is scheduled to be completed in 2010. Therefore, since the study was conducted in 2004 I recommend the use of a 6-year remaining life for both accounts. This reflects a common sense approach.

I also recommend a zero percent net salvage factor for both accounts. First of all, the cost of removal for these accounts is a very small proportion of the overall replacement expenditures and can be easily absorbed into those expenditures. Second, it is not even clear that the net salvage that Mr. Spanos studied for the services account even relates to these types of services. Finally, and most importantly, collectively the two accounts are over-depreciated by $443 thousand. Thus, I see no reason to artificially increase the depreciation rates for arbitrary allocations of the replacement costs to cost of removal. Exhibit___ (MJM-8) contains the data necessary to support the findings I have explained above.

Account 2763 – Distribution Plant Mains – Plastic – The current depreciation rate for this account is based on a 50-year average service life (50-R2.5) and a net salvage factor of negative 20 percent. Mr. Spanos has proposed retaining the existing parameters. As a result, Mr. Spanos proposes a 36.3 year remaining life for plastic mains. Staff questioned both Mr. Spanos' proposed life and his proposed net salvage factor.

Mr. Spanos' life study for this account is contained on page III-37 of his study. I have included this in my Exhibit___ (MJM-9) which is my study of this account. Examination of that table indicates that Mr. Spanos appears to have disregarded the "tail" of his own data curve. Staff noted that "the proposed remaining life appears to be conservative and the resulting depreciation rate appears to be high."[10]

Regarding his 50 year life, Staff asked Mr. Spanos to "indicate whether an Iowa curve that provides a better match for this account exists and provide a copy of that curve." Staff asked, "Would ULH&P agree that the estimated service life for this account is relatively short? Explain the response." Staff also asked Mr. Spanos "if ULH&P considers the Iowa curve 50-R2 to be the best match for this account? Explain the response." Again, Mr. Spanos did not provide any additional curve fits. He responded as follows:

[10] KyPSC-DR-02-015.

> Based on all the factors considered in determining an Iowa curve for this account, it is my judgment that the 50-R2 represents the life characteristics for account 2763. The estimate for this account was determined by many factors beyond just statistics.

> No, I would not agree that the estimated service life for this account is relatively short. As shown by the life table, plastic mains have only been in existence for 39 years; therefore, estimating a 50-year average of assets that have only 39 years of existence requires judgment. Given the available historical analysis and expectations of service life for plastic main, the 50-R2 is a reasonable estimate.

> It is possible to fit other curves to the statistical data through 2004; however, I feel the 50-R2 is the best estimate considering all factors relating to retirement.[11]

I conducted an independent life analysis for account 2763. It is included in Exhibit___ (MJM-9). The best fit is actually a 70-R1.5 rather than Mr. Spanos' 50-R2 proposal. Since ratepayers have to pay the bill, I believe that much more than Mr. Spanos' judgment is needed to support a life that is twenty years shorter than the data and analysis indicate. Therefore, I recommend the use of a 70-R1.5 life/curve for this account. My recommendation indicates a 44.3 year remaining life which is certainly more reasonable than Mr. Spanos' 36.3 year remaining life proposal.

Account 2760-Distribution Mains Net Salvage - Mr. Spanos proposes a negative 20 percent net salvage for all of ULH&P' mains sub-accounts. I recommend a zero net salvage ratio for Cast Iron mains for the reasons

[11] Spanos response to KyPSC-DR-02-015.

explained above. I also object to the negative 20 percent for the other two mains sub-accounts for the following reasons.

Pages III-95 and 96 of Mr. Spanos study are his cost of removal analyses for the overall mains accounts: 276.1 Cast Iron etc., 276.2 Steel, and 276.3 Plastic. I have included those pages in my Exhibit___ (MJM-10) which is my analysis of this account. Steel mains is ULH&P's largest account in terms of money, followed closely by plastic mains, and then by plastic services.

Staff noted that Mr. Spanos' "summary of book salvage for the period 1980-2003 supports a net salvage amount percentage of a negative 5 percent. However, ULH&P is proposing a net salvage amount percentage for this account of a negative 20 percent, which reflects the average of the period 1999 [1980] -2003."[12]

Staff asked Mr. Spanos to "explain in detail why the negative 20 percent was chosen instead of the negative 5 percent." It also asked Mr. Spanos to "provide the depreciation rate and annual accrual amount for Account 2760 using a net salvage amount percentage of negative 5 percent." Finally, Staff asked Mr. Spanos about a statement he made in his study. Specifically, "page II-28 of the depreciation study states 'the net salvage percent based on the overall period 1980 through 2004 is 5 percent negative net salvage which includes and unusual occurrence in 1995.' The summary of book salvage shown on page III-95 does not appear to indicate any unusual occurrence in

1995. Describe the unusual occurrence from 1995 and explain why the summary of book salvage does not appear to reflect such an occurrence."[13]

Mr. Spanos responded as follows:

> Net salvage estimates are determined by statistics, past estimates, estimates by other utilities and judgment. In this particular account, the trend of the most recent five-year period is the best estimate for years to come. Therefore, the negative 20 percent was chosen.
>
> The depreciation rate and annual accrual amount for the sub-accounts for Account 2760 using a net salvage factor of negative five percent are as follows: (See Exhibit___ (MJM-10).
>
> The statement on page II-28 of the depreciation study refers to the sudden low levels of gross salvage since 1995. This change reflects a new trend for net salvage since 1995, which I felt to be more indicative of the future than the entire 25-year period.[14]

The problems with this account are the levels of cost of removal relative to additions and/or plant balances as opposed to retirements. The drop in gross salvage is an insignificant factor. Mr. Spanos relies on the average of negative net salvage to retirements for the five years ending 2003. The total average retirements during those years were $629,398 and the total average cost of removal was $127,253 as shown on page III-96 of Mr. Spanos study (See Exhibit___ (MJM-10). These are miniscule amounts relative to the annual plant balances, and yet those are the balances to which Mr. Spanos

[12] KyPSC-DR-02-016.
[13] Id.

applies his negative 20 percent to in order to calculate the depreciation rate. This vastly overstates charges to ratepayers.

This result is not surprising; it results from the Traditional Inflated Future Cost Approach ("TIFCA") used by Mr. Spanos and most other utility-sponsored depreciation witnesses. TIFCA results in grossly overstated charges to ratepayers for future cost of removal as a result of manipulating the inflation which has been experienced in cost of removal. Exhibit___ (MJM-13) is a more detailed discussion of how TIFCA accomplishes this overcharge.

As a result of these considerations and the Staff concerns about Mr. Spanos' negative 20 percent proposal, I recommend a negative 5 percent net salvage ratio for accounts 2762 Steel Mains and 2763 Plastic Mains. This is based on Mr. Spanos' own summary and it is a reasonable surrogate for stating the net present value for this account at its net present value.

<u>Account 2801 – Distribution Services – Net Salvage</u> – Mr. Spanos proposes a negative 35 percent net salvage ratio for all of the Services sub-accounts. As explained earlier, I recommend a zero net salvage ratio for the Cast Iron Services subject to the AMRP, but I also disagree with Mr. Spanos' negative 35 percent for the two other Services sub-accounts. Mr. Spanos' proposal suffers from the same types of distortion and results in the same type of overcharges as in the Mains accounts as a result of his use of TIFCA.

Mr. Spanos cost of removal summary for Account 2380 is shown on pages III-101 to 102 of his study, which is included in Exhibit___ (MJM-11).

[14] Spanos response to KyPSC-DR-02-016.

Mr. Spanos used the negative 35 percent from the last five years as his recommendation and he applied this to the entire Services account. It appears, however, based on data responses provided by Mr. Hebbler, rather than Mr. Spanos, that the retirements in his summary represent only a small portion of the overall Services account. These responses are included in Exhibit___ (MJM-11). Mr. Hebbeler explains that:

> UHL&P does not physically remove retired mains or services. Mains are purged and capped when removed from service. At the time the new main is tied into the existing system, Union Light charges 75% of the tie in costs to the new main. The remaining 25% of the cost is applied to cost of removal.[15]

> The work order form does not contain a space for the allocation requested. The 75%--25% allocation is a guideline that has been verbally communicated to field personnel.[16]

> Construction & Maintenance division is tying the new mains into the system. At the time the new main is tied into the existing system, Union Light charges 75% of the tie-in costs to the new main. The remaining 25% of the cost is applied to cost of removal. *There is no cost of removal applied to main to curb services.*[17]

> *The cost of removal expenditures in the account shown [Mr. Spanos page III-101] are for individual main-to-curb services abandoned and not renewed. The majority of these types of instances are due to dwellings being razed.* Question AG-DR-054 specifically states replacement projects. *There is no*

[15] Hebbeler response to AG-DR-01-030.
[16] Id., response to AG-DR-02-037.
[17] Id., response to AG-DR-01-054, emphasis added.

> *cost of removal applied to main-to-curb services on replacement projects.*[18]

Mr. Hebbeler's responses bring Mr. Spanos' recommendations into doubt. All of Mr. Spanos' net salvage data relates to abandoned services that were not removed and were related to instances where the dwellings were razed. Furthermore, a majority of ULH&P's services additions are replacements and no cost of removal is applied to the main-to-curb Service in those circumstances. Thus, not only does Mr. Spanos' negative 20 percent proposal suffer from the distortions resulting form TIFCA, it is contrary to the practice of ULH&P. I recommend the same negative 5 percent for Services that I am recommending for Mains, and based on what Mr. Hebbeler explains, this is a generous recommendation.

Recommended Depreciation Rates

Q. Have you provided your recommended depreciation rates?

A. Yes. My recommended depreciation rates are included in Exhibit___ (MJM-12). Again, I have provided my recommendations in two formats. The first is on a single rate per account basis, and the other shows the rates separated between capital recovery and cost of removal for each account. The two rates sum to the single rate.

New Information and New Issues

Q. Please identify and explain the new information.

[18] Id., response to AG-DR-02-035, emphasis added.

A. The Financial Accounting Standards Board's ("FASB") Statement of Financial Accounting Standard No. 143 ("SFAS No. 143") addresses asset retirement obligations ("AROs") associated with long-lived plant. The Federal Energy Regulatory Commission's ("FERC") Order No. 631 is that agency's implementation of SFAS No. 143 for regulatory purposes.

When a company has a <u>legal ARO</u>, SFAS No. 143 requires that the discounted fair value of the liability be capitalized and depreciated as a component of the original asset cost. If it is determined that the utility has collected too much past depreciation relating to the ARO, the excess is to be reported as a regulatory liability.[19] Also, if a utility has collected for future cost of removal in its depreciation rates, but does not have a legal obligation to spend the money SFAS No. 143 requires these excesses to be reported as a regulatory liability.[20]

FERC identified these latter amounts as "non-legal" asset retirement obligations, meaning that utilities do not have actual legal obligations and liabilities to incur these costs in the future. This is consistent with the SFAS No. 143 requirement to report excessive accumulated depreciation associated with legal AROs as a regulatory liability.

[19] SFAS No. 143.
[20] Id., paragraph B.73.

ULH&P's December 31, 2004 10K Report shows the following regulatory liabilities in compliance with SFAS No. 143:

Union Light, Heat and Power
Summary of New Information
Regulatory Liabilities Resulting from Non-Legal AROs
($millions)[21]

December 31, 2003 Balance	$27
December 31, 2004 Balance	$30

Notice that the liability increased by $3 million in one year. That is the amount that ULH&P collected from ratepayers, over and above its actual removal costs in 2004.

Q. Please explain the new issues that result from this new information provided by SFAS No. 143 and FERC Order No. 631.

A. The KPSC has partially dealt with each of these issues in prior proceedings. I am providing some additional information and suggestions here, but I assure the Commission that none of my specific recommendations relating to SFAS No. 143 has any impact on ULH&P's depreciation rates in this proceeding. My recommendations merely add certain protections for ratepayers and provide enhanced reporting.

There are basically four new issues. The most important new issue is the need for the Kentucky Public Service Commission to specifically **recognize a regulatory liability** for regulatory and ratemaking purposes.

From there, the Commission should **require separate identification and reporting** of these amounts. Then the Commission should consider the issue of what to do about this regulatory liability, and finally, in light of the regulatory liability, the Commission should consider what to include in depreciation on a going-forward basis. In summary:

Summary of New Issues

1. The KPSC should recognize the SFAS No. 143 regulatory liability for regulatory and ratemaking purposes in Kentucky.
2. The KPSC should specify separate identification and regulatory reporting in Kentucky.
3. The KPSC should consider the future regulatory liability for regulatory and ratemaking purposes.
4. The KPSC should consider how to treat cost of removal and dismantlement on a going-forward basis.

The KPSC Should Specifically Recognize the SFAS No. 143 Regulatory Liability

Q. How does GAAP define a regulatory liability?

A. SFAS No. 71 – Accounting for the Effects of Certain Types of Regulation defines regulatory liabilities from a GAAP perspective. Paragraph 11, which is summarized below, defines a regulatory liability. Please pay particular attention to paragraphs 11 and 11. b.

[21] The Union Light, Heat and Power Company, December 31, 2004 10K Report, page 126.

SFAS No. 71 – Regulatory Liabilities[22]

> 11. Rate actions of a regulator can impose a liability on a regulated enterprise. Such liabilities are usually obligations to the enterprise's customers. The following are the usual ways in which liabilities can be imposed and the resulting accounting:
>
> a. A regulator may require refunds to customers. ...
>
> b. A regulator can provide current rates intended to recover costs that are expected to be incurred in the future with the understanding that if those costs are not incurred future rates will be reduced by corresponding amounts. If current rates are intended to recover such costs and the regulator requires the enterprise to remain accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose, the enterprise shall not recognize as revenues amounts charged pursuant to such rates. Those amounts shall be recognized as liabilities and taken to income only when associated costs are incurred.
>
> c. A regulator can require that a gain or other reduction of net allowable costs be given to customers over future periods. ...

Q. Does ULH&P agree that its collections for non-legal AROs result in a regulatory liability?

A. Although ULH&P recognized these amounts as regulatory liabilities in its 2004 10K Report, they have not been specifically recognized as regulatory liabilities for regulatory and ratemaking purposes. In fact, ULH&P is silent on the matter in its rate case filing.

Furthermore, ULH&P has not disclosed that these amounts are to be specifically identified in separate sub-accounts of depreciation expense and

[22] SFAS No. 71, paragraph 11. Only the first sentence of each subparagraph is included.

accumulated depreciation. In fact, ULH&P's 2003 Form 2 does not show these amounts as regulatory liabilities:

<u>2003 FERC Form 2 Reference</u>

> **ULH&P** adopted Statement 143 on January 1, 2003. *Accumulated depreciation* at adoption included $25 million of accumulated cost of removal related to **ULH&P's** utility plant in service assets which represent regulatory liabilities after adoption. While the adoption of Statement 143 on January 1, 2003, requires these amounts to be presented as Regulatory Liabilities in accordance with GAAP, the Comparative Balance Sheets prepared in accordance with the requirements of FERC's Docket No. RM02-7-000, Order, No. 631, "Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations," presents accrued accumulated removal of costs for other than legal retirement obligations as part of the depreciation accrual account number 108. The increases in assets and liabilities from adopting Statement 143 were not material to ULH&P's financial position.[23]

Not only are these amounts not shown as regulatory liabilities in ULH&P's 2003 Form 2 report, they are not broken out in the detail of ULH&P's accumulated depreciation account. At this time, ULH&P's 2004 Form 2 report is not yet available. Therefore, I do not know how ULH&P will report these amounts in its 2004 Form 2.

Regardless of being included in accumulated depreciation under FERC, these amounts are dollars <u>already</u> collected from ratepayers for future cost of removal. There is no reason that the utility should be entitled to keep these dollars if it turns out they are never spent on future costs of removal.

Therefore, it is obvious that the funds represent a refundable liability to ratepayers until they are spent on their intended purpose. Now that they have been identified, thanks to SFAS No. 143, they should be recognized as the regulatory liability they are.

Q. Why is it necessary for the KPSC to specifically recognize the regulatory liability?

A. The Edison Electric Institute ("EEI") and individual utilities fought hard to avoid having either the FASB or FERC require the identification and reporting of the regulatory liability that I have just described. Exhibit___ (MJM-14) contains a few pages from the Company's response to AG-DR-01-070, which requested copies of all correspondence with outside consultants/agencies regarding SFAS No. 143 and FERC Order No. 631. The pages in question relate to a survey conducted by EEI regarding the Form 1 classification of non-FAS 143 accumulated cost of removal.

As described in the email on page 15 of 172, Mr. David Stringfellow of EEI, on behalf of Mr. Jim Guest of FERC, solicited comments from EEI members on how they "would prefer to report this non-143 accumulated cost of removal – leave it in Account 108 or reclassify it as a regulatory liability for the FERC Form 1 balance sheet."[24] Note that Cinergy responded that they would prefer to leave the amount in Account 108.

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[23] ULH&P 2003 Form 2, page 122.6.
[24] Exhibit___(MJM-14).

Also included in the exhibit is the completed survey, as provided to FERC.[25] Among the comments supporting the continued inclusion of these amounts in Account 108 are the following:

> For reporting this item in our FERC Form 1, [my company] prefers to keep the accumulated cost of removal in Account 108. <u>We believe moving this to a regulatory liability will create difficulties in rate cases before the state commissions, and may be a catalyst to consumer advocates suggesting rapid refunds to customers.</u>
>
> We think FERC should NOT change the current requirements regarding accounting and reporting for cost of removal. ... Additionally, some regulators could use this as an opportunity to require utilities to refund some or all of the removal amounts to customers even though companies will still continue to incur costs to remove/retire assets.

These comments indicate that some companies are fearful of the potential of losing their past excess cost of removal collections. A large regulatory liability reported in their FERC Form 1 or 2 reports would likely be considered in their next rate case. I am not advocating such a refund in this case.

On the other hand, the KPSC should be aware that ULH&P and virtually all other utilities consider amounts in accumulated depreciation, even excessive amounts, to be their money, with no refund obligation. It is certainly fair and reasonable for any Commission to at least recognize excessive cost of removal collections as a refundable regulatory liability until such time as they are actually spent on their intended purpose.

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[25] Id.

Q. Can you demonstrate that ULH&P and its parent, Cinergy Corp., considers these excess collections to be their money?

A. Yes. ULH&P's sister company, CG&E has already demonstrated this by virtue of its treatment of the excess removal costs it collected from Ohio ratepayers relating to the plants, some of which are being transferred to ULH&P. CG&E took these amounts into "income."

Q. How do you know CG&E took past accruals for cost of removal into income?

A. The Company states as much in its 2003 Annual Report to Shareholders.

> We adopted Statement 143 on January 1, 2003, and recognized a gain of $39 million (net of tax) for the cumulative effect of this change in accounting principle. **Substantially all this adjustment reflects the reversal of previously accrued cost of removal for CG&E's generating assets, which do not apply the provisions of Statement 71.**[26]

Q. Does a portion of this $39 million (net of tax) gain relate to cost of removal that was collected for the three generating plants that are now slated to be transferred to ULH&P, and re-regulated?

A. Yes. Data request AG-DR-01-075, attached as Exhibit___(MJM-15), addressed this issue:

> b. Does any of this amount [$39 million gain] relate to the assets being transferred from CG&E to ULH&P (East Bend, Woodsdale and Miami Fort Generating Stations)? If so, please provide the calculation of the portion of the $39 million gain that was attributable to the reversal of cost of

[26] Cinergy Corp. 2003 Annual Report to Shareholders, page 60. (emphasis added).

> removal collected for these assets. Please include the before-tax calculation of the amount as well.

In its response to this question, ULH&P provided a calculation which shows that the portion of the $39 million gain attributable to the transferred stations is approximately $16.5 million before-tax, or $10 million net of tax. I say "approximately" because the calculation includes Miami Fort Unit 5, which is not being transferred.[27]

Q. What is the significance of this reversal of cost of removal relating to these transferred plants?

A. These plants were deregulated in January, 2001.[28] As required by GAAP, CG&E converted its prior collections from ratepayers for cost of removal into corporate income. Now the plants are to be re-regulated. They are to be recorded by ULH&P at their original cost, less accumulated depreciation (net book value).[29] However, due to the reversal of the cost of removal collections, the book value increased.[30] Had these excess collections been established as a regulatory liability, there may have been a better chance that they would have followed the assets.

Q. What do you make of this?

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[27] See Attachment AG-DR-01-075b, attached to this testimony as Exhibit___(MJM-15). The total for Miami Fort Units 5 and 6 is only $3.9 million (before-tax). East Bend is responsible for $10 million of the total, with Woodsdale contributing $2.6 million.

[28] I/M/O Application of Union Light, Heat and Power Company for a Certificate of Public Convenience to Acquire Certain Generation Resources and Related Property..., Case No. 2003-00252, Interim Order, Issued December 5, 2003, page 16.

[29] Id., page 31.

[30] See response to AG-DR-01-075d.

A. Cinergy, through CG&E, collected excess cost of removal amounts from Ohio ratepayers. Upon deregulation in Ohio, it took those collections into income. Now the plants in question are to go back into regulation in Kentucky at a price that does not take into account the previous cost of removal collections. Cinergy, through ULH&P, will now begin to collect cost of removal again, this time from Kentucky ratepayers. If UHL&P's collections are not specified as regulatory liabilities for ratemaking purposes they, too, will be taken into income if the plants are deregulated again.

Q. Have other electric utilities taken past collections of cost of removal into income?

A. Yes. This is exactly what other electric utilities did when their production plants were deregulated. For example American Electric Power, which had several of its production plants deregulated, immediately took $473 million from accumulated depreciation and transferred it into income relating to those deregulated plants.[31]

In another example, Tucson Electric Power Company ("TEP") stated that:

> TEP had accrued $113 million for final decommissioning of its generating facilities.. ... this amount was reversed for 2002 and included as part of the cumulative effect adjustment of accounting adjustment when FAS 143 was adopted on January 1, 2003.[32]

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[31] AEP 2003 Annual Report to Shareholders, page 69.

[32] Tucson Electric Power Company December 31, 2004 10 K Report, page K-59.

This means that TEP took non-legal AROs into income.

TEP applied SFAS No. 71 - Accounting for the Effects of Certain Types of Regulation - to its regulated operations, which include the transmission and distribution portions of its business. As a result TEP recorded the cost of removal collected for regulated non-legal AROs as a regulatory liability. According to TEP's December 31, 2004 10K Report

> As of December 31, 2004, TEP had accrued $67 million for the net cost of removal of the interim retirements from its transmission, distribution and general plant. As of December 31, 2003, TEP had accrued $60 million for these removal costs. The amount is recorded as a regulatory liability.[33]

However, also according to TEP's December 31, 2004 10K Report:

> If TEP stopped applying FAS 71 to its remaining regulated operations, it would write off the related balances of its regulatory assets as an expense and its regulatory liabilities as income on its income statement.[34]

Q. Does ULH&P make a similar statement regarding the disposition of regulatory liabilities if they are no longer regulated?

A. ULH&P discusses SFAS No. 71 in its 2004 Annual Report to Shareholders.

> In accordance with Statement 71, we record regulatory assets and liabilities (expenses deferred for future recovery from customers or amounts provided in current rates to cover costs to be incurred in the future, respectively) on our Balance Sheets.[35]

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[33] Id., page K-60.
[34] Id.
[35] Cinergy Corp. 2004 Annual Report, page 74.

> However, to the extent Indiana or Kentucky implements deregulation legislation, the application of Statement 71 will need to be reviewed.[36]

Q. Have any other industries taken non-legal ARO amounts into income that had been previously collected from ratepayers?

A. Yes. While it was still regulated, the telephone industry collected substantial amounts of future cost of removal through depreciation, just as ULH&P is proposing here. Upon deregulation and the adoption of SFAS No. 143, the major telephone companies took $11.5 billion from accumulated depreciation into net income.[37]

Q. Earlier you mentioned FERC Order No. 631. What is FERC Order No. 631?

A. FERC Order No. 631 reflects that agencies' adoption of SFAS No. 143.

Q. Does FERC Order No. 631 require non-legal AROs to be reported as regulatory liabilities?

A. FERC does not require that non-legal AROs be classified or reported as regulatory liabilities. Although the FERC has recognized and identified the amounts involved and requires separate accounting for those amounts, the FERC has deferred to the states regarding recognition of the regulatory liability. FERC Order No. 631 requires that jurisdictional entities such as ULH&P to:

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[36] Id.

[37] Pre-tax gains of SBC ($5.9 billion), Verizon ($3.5 billion), Qwest ($0.4 billion), BellSouth ($1.3 billion) and Sprint ($0.4 billion). See Companies' 2003 10K Reports and 2003 Annual Reports to Shareholders.

> maintain separate subsidiary records for cost of removal for non-legal retirement obligations that are included as specific identifiable allowances recorded in accumulated depreciation in order to separately identify such information to facilitate external reporting and for regulatory analysis, and rate setting purposes. Therefore, the Commission [amended] the instructions of accounts 108 ...in Parts 101 ... to require jurisdictional entities to maintain separate records for the purposes of identifying the amount of specific allowances collected in rates for non-legal retirement obligations included in the depreciation accruals."[38]

Q. Why is it necessary for the Kentucky PSC to specifically recognize a regulatory liability for the non-legal cost of removal and dismantlement amounts?

A. Although FERC Order No. 631 provides a new transparency by requiring identification of the amounts and maintenance of separate subsidiary records for regulatory analysis and rate setting purposes, it did not establish a regulatory liability for non-legal asset retirement obligations. Therefore, at the moment, there is no regulatory recognition of such a liability and there is no provision for a refund to ratepayers if the amounts they have paid are not spent on cost of removal or dismantlement.

In other words, nothing holds ULH&P directly accountable for these excess collections from a regulatory standpoint. Note that regardless of the transparency provided by FERC, the issue is not even mentioned in ULH&P's depreciation study or its rate case filing in general. This is wrong. Experience indicates that it is highly unlikely that these amounts will be spent for cost of removal in the magnitude that they have been collected. Nevertheless, even if

[38] FERC Docket No. RM02-7-000, Order No. 631, paragraph 38.

it was highly probable that this money would all be spent for cost of removal, it is fair and reasonable for the Kentucky PSC to specifically recognize the ratepayers' security interest in these monies until they are actually spent on their intended purpose. <u>Unless they are explicitly identified as "subject to refund," they are merely hidden potential income to ULH&P.</u>

<u>Need For Kentucky PSC to Require Separate Identification and Regulatory Reporting</u>

Q. Do you recommend that the Kentucky PSC require that ULH&P separately identify this regulatory liability in filings before it?

A. Yes. The Kentucky PSC should require that ULH&P explicitly identify and report this regulatory liability and all related activity in all future reports, rate cases, and depreciation studies that it files with the PSC. Furthermore, the PSC's explicit recognition of this amount as a regulatory liability should be prominently disclosed in ULH&P's Form 2.

Q. Would it be sufficient to report the item as a "deferred credit" of some sort?

A. No. Treatment as a deferred credit would defeat the purpose. ULH&P could easily assert in the future that ratepayers have no claim to a deferred credit, in other words, ULH&P could claim that a deferred credit is its money, not ratepayer's money. The item must be specifically recognized by the PSC and reported by ULH&P as a regulatory liability for regulatory and ratemaking purposes.

<u>How to Treat Existing Regulatory Liability</u>

Q. What is the appropriate treatment of the existing regulatory liability resulting from ULH&P's past collection of non-legal AROs?

A. The regulatory liability should be separated from normal accumulated depreciation. However, in recognition of prior KPSC Orders, I recommend that the regulatory liability be specifically identified as a refundable component of accumulated depreciation.

Q. What should be done with the regulatory liability on a going-forward basis?

A. Once recognized and protected as a regulatory liability there are alternatives to the treatment of the regulatory liability on a going-forward basis. It could be left alone as a permanent rate base offset representing customer-provided capital. It could be amortized back to ratepayers over some specified amortization period. It could be used to develop an ongoing remaining life cost of removal rate which is added to or subtracted from a pure capital recovery depreciation rate.

<u>How to Treat Non-legal AROs on a Going-Forward Basis</u>

Q. What should the Kentucky PSC do about non-legal AROs on a going-forward basis?

A. On a going-forward basis, the PSC should, at a minimum, require separation and specific identification of non-legal AROs included in ULH&P's annual depreciation expense. The term "non-legal" is the FERC's characterization of charges for future cost of removal for which the utility has no legal obligation. It does not mean that the utility is violating the law.

Q. Is it possible to separately identify the non-legal AROs included in ULH&P's annual depreciation rates and allowance?

A. Yes. At page 4 in my testimony I explained Exhibit___(MJM-2) which separates the capital recovery components from the non-legal ARO components in Mr. Spanos' proposed depreciation rates. This calculation also incorporates the non-legal ARO liability. The result is two rates for each account which sum to the rate ULH&P has requested. The same is true for my recommended rates in Exhibit___ (MJM-12).

Q. Does that mean that you have provided all of the information, calculations and depreciation rates necessary for the PSC to recognize the regulatory liability, provide separation within accumulated depreciation and depreciation expense, regardless of whether UHL&P's or your recommended parameters are found to be more reasonable?

A. Yes.

Q. Has this Commission already addressed this issue in a prior proceeding?

A. Yes, the KPSC has addressed the issue, in part, in Case No. 2003-00434, involving Kentucky Utilities Company. The Commission said,

> The language in FERC Order No. 631 clearly does not require the separation of the net salvage component from depreciation rates or the creation of a net salvage allowance as advocated by the AG. The requirement that separate subsidiary records be maintained is significantly different from requiring separation of depreciation rates.[39]

[39] KPSC June 30, 2004 Order, Case No. 2003-00434, page 30.

I think that language ultimately related to another recommendation I made to establish a separate net salvage allowance amount. I am not making that recommendation here because it was rejected by the KPSC.

However, as I explained above, the Company has demonstrated by its own actions the necessity for very detailed accounting and reporting relating to future cost of removal. The recommendations here provide the enhanced accounting and reporting that should be implemented in light of the demonstrable need for the enhanced accounting and reporting. This recommendation causes no harm to ULH&P. What it does accomplish is more effective regulation and more accountability.

Summary of Recommendations

Q. Please summarize your recommendations.

A. I recommend that depreciation rates be split into separate capital recovery and cost of removal components. I recommend the alternative parameters discussed in my testimony be adopted. I recommend that the regulatory liability resulting from ULH&P's collection of excessive non-legal ARO charges be specifically recognized by the Kentucky PSC as a regulatory liability for regulatory reporting, regulatory analysis, and ratemaking purposes in Kentucky. Finally, I recommend that the KPSC strongly consider an alternative to TIFCA on a going-forward basis.

Q. Does this conclude your testimony?

A. Yes, it does.

Washington,)
: ss.
District of Columbia)

AFFIDAVIT

I, Michael J. Majoros, Jr., hereby swear and affirm that the foregoing testimony and any accompanying exhibits were prepared by me or under my direction and that the information contained therein is, to the best of my information and belief, true and correct.

Michael J. Majoros, Jr.

Washington,
District of Columbia

Subscribed and sworn to before me this 6th day of June, 2005, by Michael J. Majoros, Jr.

Notary Public

My Commission Expires: March 14, 2006

Experience

Snavely King Majoros O'Connor & Lee, Inc.

Vice President and Treasurer (1988 to Present)
Senior Consultant (1981-1987)

Mr. Majoros provides consultation specializing in accounting, financial, and management issues. He has testified as an expert witness or negotiated on behalf of clients in more than one hundred thirty regulatory federal and state regulatory proceedings involving telephone, electric, gas, water, and sewerage companies. His testimony has encompassed a wide array of complex issues including taxation, divestiture accounting, revenue requirements, rate base, nuclear decommissioning, plant lives, and capital recovery. Mr. Majoros has been responsible for developing the firm's consulting services on depreciation and other capital recovery issues into a major area of practice. In addition to traditional regulatory engagements, Mr. Majoros has also provided consultation to the U.S. Department of Justice. His expertise has been called upon to address the accounting and plant life effects of electric plant modifications in environmental proceedings and lawsuits, and to estimate economic damages suffered by black farmers in discrimination suits.

Van Scoyoc & Wiskup, Inc., *Consultant (1978-1981)*

Mr. Majoros conducted and assisted in various management and regulatory consulting projects in the public utility field, including preparation of electric system load projections for a group of municipally and cooperatively owned electric systems; preparation of a system of accounts and reporting of gas and oil pipelines to be used by a state regulatory commission; accounting system analysis and design for rate proceedings involving electric, gas, and telephone utilities. Mr. Majoros provided onsite management accounting and controllership assistance to a municipal electric and water utility. Mr. Majoros also assisted in an antitrust proceeding involving a major electric utility. He submitted expert testimony in FERC Docket No. RP79-12 (El Paso Natural Gas Company), and he co-authored a study entitled Analysis of Staff Study on Comprehensive Tax Normalization that was submitted to FERC in Docket No. RM 80-42.

Handling Equipment Sales Company, Inc.

Controller/Treasurer (1976-1978)

Mr. Majoros' responsibilities included financial management, general accounting and reporting, and income taxes.

Ernst & Ernst, *Auditor (1973-1976)*

Mr. Majoros was a member of the audit staff where his responsibilities included auditing, supervision, business systems analysis, report preparation, and corporate income taxes.

University of Baltimore - *(1971-1973)*

Mr. Majoros was a full-time student in the School of Business.

During this period Mr. Majoros worked consistently on a part-time basis in the following positions: Assistant Legislative Auditor – State of Maryland, Staff Accountant – Robert M. Carney & Co., CPA's, Staff Accountant – Naron & Wegad, CPA's, Credit Clerk – Montgomery Wards.

Central Savings Bank, *(1969-1971)*

Mr. Majoros was an Assistant Branch Manager at the time he left the bank to attend college as a full-time student. During his tenure at the bank, Mr. Majoros gained experience in each department of the bank. In addition, he attended night school at the University of Baltimore.

Education

University of Baltimore, School of Business, B.S. – Concentration in Accounting

Professional Affiliations

American Institute of Certified Public Accountants
Maryland Association of C.P.A.s
Society of Depreciation Professionals

Publications, Papers, and Panels

"Analysis of Staff Study on Comprehensive Tax Normalization," FERC Docket No. RM 80-42, 1980.

"Telephone Company Deferred Taxes and Investment Tax Credits -- A Capital Loss for Ratepayers," Public Utility Fortnightly, September 27, 1984.

"The Use of Customer Discount Rates in Revenue Requirement Comparisons," Proceedings of the 25th Annual Iowa State Regulatory Conference, 1986

"The Regulatory Dilemma Created By Emerging Revenue Streams of Independent Telephone Companies," Proceedings of NARUC 101st Annual Convention and Regulatory Symposium, 1989.

"BOC Depreciation Issues in the States," National Association of State Utility Consumer Advocates, 1990 Mid-Year Meeting, 1990.

"Current Issues in Capital Recovery" 30th Annual Iowa State Regulatory Conference, 1991.

"Impaired Assets Under SFAS No. 121," National Association of State Utility consumer Advocates, 1996 Mid-Year Meeting, 1996.

"What's 'Sunk' Ain't Stranded: Why Excessive Utility Depreciation is Avoidable," with James Campbell, Public Utilities Fortnightly, April 1, 1999.

"Local Exchange Carrier Depreciation Reserve Percents," with Richard B. Lee, Journal of the Society of Depreciation Professionals, Volume 10, Number 1, 2000-2001

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Federal Regulatory Agencies

Date	Agency	Docket	Utility
1979	FERC-US 19/	RP79-12	El Paso Natural Gas Co.
1980	FERC-US 19/	RM80-42	Generic Tax Normalization
1996	CRTC-Canada 30/	97-9	All Canadian Telecoms
1997	CRTC-Canada 31/	97-11	All Canadian Telecoms
1999	FCC 32/	98-137 (Ex Parte)	All LECs
1999	FCC 32/	98-91 (Ex Parte)	All LECs
1999	FCC 32/	98-177 (Ex Parte)	All LECs
1999	FCC 32/	98-45 (Ex Parte)	All LECs
2000	EPA 35/	CAA-00-6	Tennessee Valley Authority
2003	FERC 48/	RM02-7	All Utilities
2003	FCC 52/	03-173	All LECs
2003	FERC	ER03-409-000, ER03-666-000	Pacific Gas and Electric Co.
2005	US District Court, Northern District of AL, Northwestern Division 55/56/57/	CV 01-B-403-NW	Tennessee Valley Authority

State Regulatory Agencies

Date	Agency	Docket	Utility
1982	Massachusetts 17/	DPU 557/558	Western Mass Elec. Co.
1982	Illinois 16/	ICC81-8115	Illinois Bell Telephone Co.
1983	Maryland 8/	7574-Direct	Baltimore Gas & Electric Co.
1983	Maryland 8/	7574-Surrebuttal	Baltimore Gas & Electric Co.
1983	Connecticut 15/	810911	Woodlake Water Co.
1983	New Jersey 1/	815-458	New Jersey Bell Tel. Co.
1983	New Jersey 14/	8011-827	Atlantic City Sewerage Co.
1984	Dist. Of Columbia 7/	785	Potomac Electric Power Co.
1984	Maryland 8/	7689	Washington Gas Light Co.
1984	Dist. Of Columbia 7/	798	C&P Tel. Co.
1984	Pennsylvania 13/	R-832316	Bell Telephone Co. of PA
1984	New Mexico 12/	1032	Mt. States Tel. & Telegraph
1984	Idaho 18/	U-1000-70	Mt. States Tel. & Telegraph
1984	Colorado 11/	1655	Mt. States Tel. & Telegraph
1984	Dist. Of Columbia 7/	813	Potomac Electric Power Co.
1984	Pennsylvania 3/	R842621-R842625	Western Pa. Water Co.
1985	Maryland 8/	7743	Potomac Edison Co.
1985	New Jersey 1/	848-856	New Jersey Bell Tel. Co.
1985	Maryland 8/	7851	C&P Tel. Co.
1985	California 10/	I-85-03-78	Pacific Bell Telephone Co.
1985	Pennsylvania 3/	R-850174	Phila. Suburban Water Co.

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1985	Pennsylvania 3/	R850178	Pennsylvania Gas & Water Co.
1985	Pennsylvania 3/	R-850299	General Tel. Co. of PA
1986	Maryland 8/	7899	Delmarva Power & Light Co.
1986	Maryland 8/	7754	Chesapeake Utilities Corp.
1986	Pennsylvania 3/	R-850268	York Water Co.
1986	Maryland 8/	7953	Southern Md. Electric Corp.
1986	Idaho 9/	U-1002-59	General Tel. Of the Northwest
1986	Maryland 8/	7973	Baltimore Gas & Electric Co.
1987	Pennsylvania 3/	R-860350	Dauphin Cons. Water Supply
1987	Pennsylvania 3/	C-860923	Bell Telephone Co. of PA
1987	Iowa 6/	DPU-86-2	Northwestern Bell Tel. Co.
1987	Dist. Of Columbia 7/	842	Washington Gas Light Co.
1988	Florida 4/	880069-TL	Southern Bell Telephone
1988	Iowa 6/	RPU-87-3	Iowa Public Service Company
1988	Iowa 6/	RPU-87-6	Northwestern Bell Tel. Co.
1988	Dist. Of Columbia 7/	869	Potomac Electric Power Co.
1989	Iowa 6/	RPU-88-6	Northwestern Bell Tel. Co.
1990	New Jersey 1/	1487-88	Morris City Transfer Station
1990	New Jersey 5/	WR 88-80967	Toms River Water Company
1990	Florida 4/	890256-TL	Southern Bell Company
1990	New Jersey 1/	ER89110912J	Jersey Central Power & Light
1990	New Jersey 1/	WR90050497J	Elizabethtown Water Co.
1991	Pennsylvania 3/	P900465	United Tel. Co. of Pa.
1991	West Virginia 2/	90-564-T-D	C&P Telephone Co.
1991	New Jersey 1/	90080792J	Hackensack Water Co.
1991	New Jersey 1/	WR90080884J	Middlesex Water Co.
1991	Pennsylvania 3/	R-911892	Phil. Suburban Water Co.
1991	Kansas 20/	176, 716-U	Kansas Power & Light Co.
1991	Indiana 29/	39017	Indiana Bell Telephone
1991	Nevada 21/	91-5054	Central Tele. Co. – Nevada
1992	New Jersey 1/	EE91081428	Public Service Electric & Gas
1992	Maryland 8/	8462	C&P Telephone Co.
1992	West Virginia 2/	91-1037-E-D	Appalachian Power Co.
1993	Maryland 8/	8464	Potomac Electric Power Co.
1993	South Carolina 22/	92-227-C	Southern Bell Telephone
1993	Maryland 8/	8485	Baltimore Gas & Electric Co.
1993	Georgia 23/	4451-U	Atlanta Gas Light Co.
1993	New Jersey 1/	GR93040114	New Jersey Natural Gas. Co.
1994	Iowa 6/	RPU-93-9	U.S. West – Iowa
1994	Iowa 6/	RPU-94-3	Midwest Gas
1995	Delaware 24/	94-149	Wilm. Suburban Water Corp.
1995	Connecticut 25/	94-10-03	So. New England Telephone
1995	Connecticut 25/	95-03-01	So. New England Telephone
1995	Pennsylvania 3/	R-00953300	Citizens Utilities Company
1995	Georgia 23/	5503-0	Southern Bell

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1996	Maryland 8/	8715	Bell Atlantic
1996	Arizona 26/	E-1032-95-417	Citizens Utilities Company
1996	New Hampshire 27/	DE 96-252	New England Telephone
1997	Iowa 6/	DPU-96-1	U S West – Iowa
1997	Ohio 28/	96-922-TP-UNC	Ameritech – Ohio
1997	Michigan 28/	U-11280	Ameritech – Michigan
1997	Michigan 28/	U-112 81	GTE North
1997	Wyoming 27/	7000-ztr-96-323	US West – Wyoming
1997	Iowa 6/	RPU-96-9	US West – Iowa
1997	Illinois 28/	96-0486-0569	Ameritech – Illinois
1997	Indiana 28/	40611	Ameritech – Indiana
1997	Indiana 27/	40734	GTE North
1997	Utah 27/	97-049-08	US West – Utah
1997	Georgia 28/	7061-U	BellSouth – Georgia
1997	Connecticut 25/	96-04-07	So. New England Telephone
1998	Florida 28/	960833-TP et. al.	BellSouth – Florida
1998	Illinois 27/	97-0355	GTE North/South
1998	Michigan 33/	U-11726	Detroit Edison
1999	Maryland 8/	8794	Baltimore Gas & Electric Co.
1999	Maryland 8/	8795	Delmarva Power & Light Co.
1999	Maryland 8/	8797	Potomac Edison Company
1999	West Virginia 2/	98-0452-E-GI	Electric Restructuring
1999	Delaware 24/	98-98	United Water Company
1999	Pennsylvania 3/	R-00994638	Pennsylvania American Water
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2000	Delaware 24/	99-466	Tidewater Utilities
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2000	Florida 28/	990649-TP	BellSouth -Florida
2000	New Jersey 1/	WR30174	Consumer New Jersey Water
2000	Pennsylvania 3/	R-00994868	Philadelphia Suburban Water
2000	Pennsylvania 3/	R-0005212	Pennsylvania American Sewerage
2000	Connecticut 25/	00-07-17	Southern New England Telephone
2001	Kentucky 36/	2000-373	Jackson Energy Cooperative
2001	Kansas 38/39/40/	01-WSRE-436-RTS	Western Resources
2001	South Carolina 22/	2001-93-E	Carolina Power & Light Co.
2001	North Dakota 37/	PU-400-00-521	Northern States Power/Xcel Energy
2001	Indiana 29/41/	41746	Northern Indiana Power Company
2001	New Jersey 1/	GR01050328	Public Service Electric and Gas
2001	Pennsylvania 3/	R-00016236	York Water Company
2001	Pennsylvania 3/	R-00016339	Pennsylvania America Water
2001	Pennsylvania 3/	R-00016356	Wellsboro Electric Coop.
2001	Florida 4/	010949-EL	Gulf Power Company
2001	Hawaii 42/	00-309	The Gas Company
2002	Pennsylvania 3/	R-00016750	Philadelphia Suburban

Michael J. Majoros, Jr.

2002	Nevada 43/	01-10001 &10002	Nevada Power Company
2002	Kentucky 36/	2001-244	Fleming Mason Electric Coop.
2002	Nevada 43/	01-11031	Sierra Pacific Power Company
2002	Georgia 27/	14361-U	BellSouth-Georgia
2002	Alaska 44/	U-01-34,82-87,66	Alaska Communications Systems
2002	Wisconsin 45/	2055-TR-102	CenturyTel
2002	Wisconsin 45/	5846-TR-102	TelUSA
2002	Vermont 46/	6596	Citizen's Energy Services
2002	North Dakota 37/	PU-399-02-183	Montana Dakota Utilities
2002	Kansas 38/	02-MDWG-922-RTS	Midwest Energy
2002	Kentucky 36/	2002-00145	Columbia Gas
2002	Oklahoma 47/	200200166	Reliant Energy ARKLA
2002	New Jersey 1/	GR02040245	Elizabethtown Gas Company
2003	New Jersey 1/	ER02050303	Public Service Electric and Gas Co.
2003	Hawaii 42/	01-0255	Young Brothers Tug & Barge
2003	New Jersey 1/	ER02080506	Jersey Central Power & Light
2003	New Jersey 1/	ER02100724	Rockland Electric Co.
2003	Pennsylvania 3/	R-00027975	The York Water Co.
2003	Pennsylvania /3	R-00038304	Pennsylvania-American Water Co.
2003	Kansas 20/ 40/	03-KGSG-602-RTS	Kansas Gas Service
2003	Nova Scotia, CN 49/	EMO NSPI	Nova Scotia Power, Inc.
2003	Kentucky 36/	2003-00252	Union Light Heat & Power
2003	Alaska 44/	U-96-89	ACS Communications, Inc.
2003	Indiana 29/	42359	PSI Energy, Inc.
2003	Kansas 20/ 40/	03-ATMG-1036-RTS	Atmos Energy
2003	Florida 50/	030001-E1	Tampa Electric Company
2003	Maryland 51/	8960	Washington Gas Light
2003	Hawaii 42/	02-0391	Hawaiian Electric Company
2003	Illinois 28/	02-0864	SBC Illinois
2003	Indiana 28/	42393	SBC Indiana
2004	New Jersey 1/	ER03020110	Atlantic City Electric Co.
2004	Arizona 26/	E-01345A-03-0437	Arizona Public Service Company
2004	Michigan 27/	U-13531	SBC Michigan
2004	New Jersey 1/	GR03080683	South Jersey Gas Company
2004	Kentucky 36/	2003-00434,00433	Kentucky Utilities, Louisville Gas & Electric
2004	Florida 50/ 54/	031033-EI	Tampa Electric Company
2004	Kentucky 36/	2004-00067	Delta Natural Gas Company
2004	Georgia 23/	18300, 15392, 15393	Georgia Power Company
2004	Vermont 46/	6946, 6988	Central Vermont Public Service Corporation
2004	Delaware 24/	04-288	Delaware Electric Cooperative
2004	Missouri 58/	ER-2004-0570	Empire District Electric Company
2005	Florida 50/	041272-EI	Progress Energy Florida, Inc.

Michael J. Majoros, Jr.

PARTICIPATION AS NEGOTIATOR IN FCC TELEPHONE DEPRECIATION RATE REPRESCRIPTION CONFERENCES

COMPANY	YEARS	CLIENT
Diamond State Telephone Co. 24/	1985 + 1988	Delaware Public Service Comm
Bell Telephone of Pennsylvania 3/	1986 + 1989	PA Consumer Advocate
Chesapeake & Potomac Telephone Co. - Md. 8/	1986	Maryland People's Counsel
Southwestern Bell Telephone – Kansas 20/	1986	Kansas Corp. Commission
Southern Bell – Florida 4/	1986	Florida Consumer Advocate
Chesapeake & Potomac Telephone Co.-W.Va. 2/	1987 + 1990	West VA Consumer Advocate
New Jersey Bell Telephone Co. 1/	1985 + 1988	New Jersey Rate Counsel
Southern Bell - South Carolina 22/	1986 + 1989 + 1992	S. Carolina Consumer Advocate
GTE-North – Pennsylvania 3/	1989	PA Consumer Advocate

Michael J. Majoros, Jr.

PARTICIPATION IN PROCEEDINGS WHICH WERE SETTLED BEFORE TESTIMONY WAS SUBMITTED

STATE	DOCKET NO.	UTILITY
Maryland 8/	7878	Potomac Edison
Nevada 21/	88-728	Southwest Gas
New Jersey 1/	WR90090950J	New Jersey American Water
New Jersey 1/	WR900050497J	Elizabethtown Water
New Jersey 1/	WR91091483	Garden State Water
West Virginia 2/	91-1037-E	Appalachian Power Co.
Nevada 21/	92-7002	Central Telephone - Nevada
Pennsylvania 3/	R-00932873	Blue Mountain Water
West Virginia2/	93-1165-E-D	Potomac Edison
West Virginia2/	94-0013-E-D	Monongahela Power
New Jersey 1/	WR94030059	New Jersey American Water
New Jersey 1/	WR95080346	Elizabethtown Water
New Jersey 1/	WR95050219	Toms River Water Co.
Maryland 8/	8796	Potomac Electric Power Co.
South Carolina 22/	1999-077-E	Carolina Power & Light Co.
South Carolina 22/	1999-072-E	Carolina Power & Light Co.
Kentucky 36/	2001-104 & 141	Kentucky Utilities, Louisville Gas and Electric
Kentucky 36/	2002-485	Jackson Purchase Energy Corporation
Florida 50/ 54/	030157-EI	Progress Energy Florida

Michael J. Majoros, Jr.

Clients

1/ New Jersey Rate Counsel/Advocate	33/ Michigan Attorney General
2/ West Virginia Consumer Advocate	34/ New Mexico Attorney General
3/ Pennsylvania OCA	35/ Environmental Protection Agency Enforcement Staff
4/ Florida Office of Public Advocate	36/ Kentucky Attorney General
5/ Toms River Fire Commissioner's	37/ North Dakota Public Service Commission
6/ Iowa Office of Consumer Advocate	38/ Kansas Industrial Group
7/ D.C. People's Counsel	39/ City of Witchita
8/ Maryland's People's Counsel	40/ Kansas Citizens' Utility Rate Board
9/ Idaho Public Service Commission	41/ NIPSCO Industrial Group
10/ Western Burglar and Fire Alarm	42/ Hawaii Division of Consumer Advocacy
11/ U.S. Dept. of Defense	43/ Nevada Bureau of Consumer Protection
12/ N.M. State Corporation Comm.	44/ GCI
13/ City of Philadelphia	45/ Wisc. Citizens' Utility Rate Board
14/ Resorts International	46/ Vermont Department of Public Service
15/ Woodlake Condominium Association	47/ Oklahoma Corporation Commission
16/ Illinois Attorney General	48/ National Association of Utility Consumer Advocates
17/ Mass Coalition of Municipalities	49/ Nova Scotia Utility and Review Board
18/ U.S. Department of Energy	50/ Florida Office of Public Counsel
19/ Arizona Electric Power Corp.	51/ Maryland Public Service Commission
20/ Kansas Corporation Commission	52/ MCI
21/ Public Service Comm. – Nevada	53/ Transmission Agency of Northern California
22/ SC Dept. of Consumer Affairs	54/ Florida Industrial Power Users Group
23/ Georgia Public Service Comm.	55/ Sierra Club
24/ Delaware Public Service Comm.	56/ Our Children's Earth Foundation
25/ Conn. Ofc. Of Consumer Counsel	57/ National Parks Conservation Association, Inc.
26/ Arizona Corp. Commission	58/ Missouri Office of the Public Counsel
27/ AT&T	
28/ AT&T/MCI	
29/ IN Office of Utility Consumer Counselor	
30/ Unitel (AT&T – Canada)	
31/ Public Interest Advocacy Centre	
32/ U.S. General Services Administration	

Michael J. Majoros, Jr.

Federal Regulatory Agencies

Date	Agency	Docket	Utility
1979	FERC-US 19/	RP79-12	El Paso Natural Gas Co.
1980	FERC-US 19/	RM80-42	Generic Tax Normalization
1996	CRTC-Canada 30/	97-9	All Canadian Telecoms
1997	CRTC-Canada 31/	97-11	All Canadian Telecoms
1999	FCC 32/	98-137 (Ex Parte)	All LECs
1999	FCC 32/	98-91 (Ex Parte)	All LECs
1999	FCC 32/	98-177 (Ex Parte)	All LECs
1999	FCC 32/	98-45 (Ex Parte)	All LECs
2000	EPA 35/	CAA-00-6	Tennessee Valley Authority
2003	FERC 48/	RM02-7	All Utilities
2003	FCC 52/	03-173	All LECs
2003	FERC	ER03-409-000, ER03-666-000	Pacific Gas and Electric Co.
2005	US District Court, Northern District of AL, Northwestern Division 55/56/57/	CV 01-B-403-NW	Tennessee Valley Authority
	State Regulatory Agencies		
1982	Massachusetts 17/	DPU 557/558	Western Mass Elec. Co.
1982	Illinois 16/	ICC81-8115	Illinois Bell Telephone Co.
1983	Maryland 8/	7574-Direct	Baltimore Gas & Electric Co.
1983	Maryland 8/	7574-Surrebuttal	Baltimore Gas & Electric Co.
1983	Connecticut 15/	810911	Woodlake Water Co.
1983	New Jersey 1/	815-458	New Jersey Bell Tel. Co.
1983	New Jersey 14/	8011-827	Atlantic City Sewerage Co.
1984	Dist. Of Columbia 7/	785	Potomac Electric Power Co.
1984	Maryland 8/	7689	Washington Gas Light Co.
1984	Dist. Of Columbia 7/	798	C&P Tel. Co.
1984	Pennsylvania 13/	R-832316	Bell Telephone Co. of PA
1984	New Mexico 12/	1032	Mt. States Tel. & Telegraph
1984	Idaho 18/	U-1000-70	Mt. States Tel. & Telegraph
1984	Colorado 11/	1655	Mt. States Tel. & Telegraph
1984	Dist. Of Columbia 7/	813	Potomac Electric Power Co.
1984	Pennsylvania 3/	R842621-R842625	Western Pa. Water Co.
1985	Maryland 8/	7743	Potomac Edison Co.
1985	New Jersey 1/	848-856	New Jersey Bell Tel. Co.
1985	Maryland 8/	7851	C&P Tel. Co.
1985	California 10/	I-85-03-78	Pacific Bell Telephone Co.
1985	Pennsylvania 3/	R-850174	Phila. Suburban Water Co.

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1985	Pennsylvania 3/	R850178	Pennsylvania Gas & Water Co.
1985	Pennsylvania 3/	R-850299	General Tel. Co. of PA
1986	Maryland 8/	7899	Delmarva Power & Light Co.
1986	Maryland 8/	7754	Chesapeake Utilities Corp.
1986	Pennsylvania 3/	R-850268	York Water Co.
1986	Maryland 8/	7953	Southern Md. Electric Corp.
1986	Idaho 9/	U-1002-59	General Tel. Of the Northwest
1986	Maryland 8/	7973	Baltimore Gas & Electric Co.
1987	Pennsylvania 3/	R-860350	Dauphin Cons. Water Supply
1987	Pennsylvania 3/	C-860923	Bell Telephone Co. of PA
1987	Iowa 6/	DPU-86-2	Northwestern Bell Tel. Co.
1987	Dist. Of Columbia 7/	842	Washington Gas Light Co.
1988	Florida 4/	880069-TL	Southern Bell Telephone
1988	Iowa 6/	RPU-87-3	Iowa Public Service Company
1988	Iowa 6/	RPU-87-6	Northwestern Bell Tel. Co.
1988	Dist. Of Columbia 7/	869	Potomac Electric Power Co.
1989	Iowa 6/	RPU-88-6	Northwestern Bell Tel. Co.
1990	New Jersey 1/	1487-88	Morris City Transfer Station
1990	New Jersey 5/	WR 88-80967	Toms River Water Company
1990	Florida 4/	890256-TL	Southern Bell Company
1990	New Jersey 1/	ER89110912J	Jersey Central Power & Light
1990	New Jersey 1/	WR90050497J	Elizabethtown Water Co.
1991	Pennsylvania 3/	P900465	United Tel. Co. of Pa.
1991	West Virginia 2/	90-564-T-D	C&P Telephone Co.
1991	New Jersey 1/	90080792J	Hackensack Water Co.
1991	New Jersey 1/	WR90080884J	Middlesex Water Co.
1991	Pennsylvania 3/	R-911892	Phil. Suburban Water Co.
1991	Kansas 20/	176, 716-U	Kansas Power & Light Co.
1991	Indiana 29/	39017	Indiana Bell Telephone
1991	Nevada 21/	91-5054	Central Tele. Co. – Nevada
1992	New Jersey 1/	EE91081428	Public Service Electric & Gas
1992	Maryland 8/	8462	C&P Telephone Co.
1992	West Virginia 2/	91-1037-E-D	Appalachian Power Co.
1993	Maryland 8/	8464	Potomac Electric Power Co.
1993	South Carolina 22/	92-227-C	Southern Bell Telephone
1993	Maryland 8/	8485	Baltimore Gas & Electric Co.
1993	Georgia 23/	4451-U	Atlanta Gas Light Co.
1993	New Jersey 1/	GR93040114	New Jersey Natural Gas. Co.
1994	Iowa 6/	RPU-93-9	U.S. West – Iowa
1994	Iowa 6/	RPU-94-3	Midwest Gas
1995	Delaware 24/	94-149	Wilm. Suburban Water Corp.
1995	Connecticut 25/	94-10-03	So. New England Telephone
1995	Connecticut 25/	95-03-01	So. New England Telephone
1995	Pennsylvania 3/	R-00953300	Citizens Utilities Company
1995	Georgia 23/	5503-0	Southern Bell

Michael J. Majoros, Jr.

1996	Maryland 8/	8715	Bell Atlantic
1996	Arizona 26/	E-1032-95-417	Citizens Utilities Company
1996	New Hampshire 27/	DE 96-252	New England Telephone
1997	Iowa 6/	DPU-96-1	U S West – Iowa
1997	Ohio 28/	96-922-TP-UNC	Ameritech – Ohio
1997	Michigan 28/	U-11280	Ameritech – Michigan
1997	Michigan 28/	U-112 81	GTE North
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2001	Indiana 29/41/	41746	Northern Indiana Power Company
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New Jersey Bell Telephone Co. 1/	1985 + 1988	New Jersey Rate Counsel
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West Virginia 2/	91-1037-E	Appalachian Power Co.
Nevada 21/	92-7002	Central Telephone - Nevada
Pennsylvania 3/	R-00932873	Blue Mountain Water
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West Virginia 2/	94-0013-E-D	Monongahela Power
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New Jersey 1/	WR95080346	Elizabethtown Water
New Jersey 1/	WR95050219	Toms River Water Co.
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South Carolina 22/	1999-077-E	Carolina Power & Light Co.
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Kentucky 36/	2002-485	Jackson Purchase Energy Corporation
Florida 50/ 54/	030157-EI	Progress Energy Florida

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3/ Pennsylvania OCA	35/ Environmental Protection Agency Enforcement Staff
4/ Florida Office of Public Advocate	36/ Kentucky Attorney General
5/ Toms River Fire Commissioner's	37/ North Dakota Public Service Commission
6/ Iowa Office of Consumer Advocate	38/ Kansas Industrial Group
7/ D.C. People's Counsel	39/ City of Witchita
8/ Maryland's People's Counsel	40/ Kansas Citizens' Utility Rate Board
9/ Idaho Public Service Commission	41/ NIPSCO Industrial Group
10/ Western Burglar and Fire Alarm	42/ Hawaii Division of Consumer Advocacy
11/ U.S. Dept. of Defense	43/ Nevada Bureau of Consumer Protection
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14/ Resorts International	46/ Vermont Department of Public Service
15/ Woodlake Condominium Association	47/ Oklahoma Corporation Commission
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21/ Public Service Comm. – Nevada	53/ Transmission Agency of Northern California
22/ SC Dept. of Consumer Affairs	54/ Florida Industrial Power Users Group
23/ Georgia Public Service Comm.	55/ Sierra Club
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25/ Conn. Ofc. Of Consumer Counsel	57/ National Parks Conservation Association, Inc.
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27/ AT&T	
28/ AT&T/MCI	
29/ IN Office of Utility Consumer Counselor	
30/ Unitel (AT&T – Canada)	
31/ Public Interest Advocacy Centre	
32/ U.S. General Services Administration	

EXHIBITS OF
MICHAEL J. MAJOROS, JR.

Union Light, Heat and Power Company
Comparison of Company Proposed Depreciation Parameters, Rates and Accruals
As of September 30, 2004

		Current				Proposed				
Account	**Original Cost**	**Survivor Curve**	**Net Salvage**	**Annual Accrual Rate**	**Annual Accrual Amount**	**Survivor Curve**	**Net Salvage**	**Annual Accrual Rate**	**Annual Accrual Amount**	**Difference**
(1)	(2)	(3)	(4)	(5)	(6)=(2)*(5)	(7)	(8)	(9)	(10)=(2)*(9)	(11)=(10)-(6)
Common Plant										
190.00 Structures & Improvements										
Florence Service Building	4,725,458	100-R1.5	0	3.37	159,248	100-R1.5	0	2.24	105,850	(53,398)
Covington Office Building (Sold)	1,548,747			-	-	100-R1.5	47	-	-	-
Kentucky Services Building	1,694,442	100-R1.5	0	4.05	68,625	100-R1.5	0	3.97	67,269	(1,356)
Minor Structures	7,832	40-R3	(5)	3.80	298	40-R3	(5)	2.96	232	(66)
Total Structures & Improvements	7,976,479				228,170				173,351	(54,819)
191.00 Office Furniture & Equipment	705,033	20-SQ	0	6.01	42,372	20-SQ	0	6.49	45,757	3,384
191.10 Office Furniture & Equipment - EDP Equip.	12,981	5-SQ	0	66.67	8,655	5-SQ	0	-	-	(8,655)
192.00 Autos and Trucks	5,078	10-R2.5	0	-	-	9-R3	5	-	-	-
193.00 Stores and Equipment	5,563	20-SQ	0	39.67	2,207	20-SQ	0	47.53	2,644	437
194.00 Tools, Shop and Garage Equipment	169,528	25-SQ	0	4.61	7,815	25-SQ	0	4.79	8,120	305
197.00 Communication Equipment	62,935	15-SQ	0	6.67	4,198	15-SQ	0	7.20	4,531	334
198.00 Miscellaneous Equipment	14,910	15-SQ	0	12.16	1,813	20-SQ	0	2.09	312	(1,501)
Total Common Plant	**8,952,508**				**295,230**				**234,715**	**(60,515)**
Production Plant										
204.10 Rights of Way	24,439	50-SQ	0	-	-	50-SQ	0	-	-	-
205.00 Structures & Improvements	1,554,581	45-R3	(10)	0.60	9,327	50-R4	(5)	0.40	6,218	(3,109)
211.00 Liquid Petroleum Gas Equipment	3,619,035	35-S1.5	(5)	0.63	22,800	35-S1.5	(5)	2.45	88,666	65,866
Total Production Plant	**5,198,055**				**32,127**				**94,885**	**62,757**
Distribution Plant										
274.10 Rights of Way - General	1,020,156	65-R4	0	1.50	15,302	65-R4	0	1.39	14,180	(1,122)
275.00 Structures & Improvements - General	157,012	45-R3	(10)	0.94	1,476	50-R2.5	(10)	1.12	1,759	283
Mains										
276.10 Cast Iron, Copper and All Valves	2,535,274	41-R2.5	(20)	4.08	103,439	41-R2.5	(20)	1.65	41,832	(61,607)
276.20 Steel	85,376,092	50-R2	(20)	2.90	2,475,907	53-R2	(20)	2.56	2,185,628	(290,279)
276.30 Plastic	63,062,653	50-R2.5	(20)	2.96	1,866,655	50-R2.5	(20)	2.97	1,872,961	6,306
Total Mains	150,974,019				4,446,000				4,100,421	(345,580)
278.00 M&R - General - System - Excl. Elect. Equip.	2,711,732	35-R1	(5)	2.00	54,235	40-R1	(5)	2.08	56,404	2,169
278.10 M&R - General - System - Elect. Equip.	389,078	15-S2.5	(5)	7.48	29,103	15-S2.5	(5)	1.39	5,408	(23,695)
278.20 Measuring & Regulating - General - District	635,340	50-S0.5	(75)	4.35	27,637	50-R2	(75)	3.71	23,571	(4,066)

Union Light, Heat and Power Company
Comparison of Company Proposed Depreciation Parameters, Rates and Accruals
As of September 30, 2004

			Current				Proposed				
	Account	**Original Cost**	**Survivor Curve**	**Net Salvage**	**Annual Accrual Rate**	**Annual Accrual Amount**	**Survivor Curve**	**Net Salvage**	**Annual Accrual Rate**	**Annual Accrual Amount**	**Difference**
	(1)	(2)	(3)	(4)	(5)	(6)=(2)*(5)	(7)	(8)	(9)	(10)=(2)*(9)	(11)=(10)-(6)
	Services										
280.10	Cast Iron, Copper and Valves	2,663,011	33-R0.5	(30)	1.42	37,815	40-R1.5	(35)	0.88	23,434	(14,380)
280.20	Steel	3,241,998	36-R1	(30)	3.46	112,173	38-R1	(35)	2.70	87,534	(24,639)
280.30	Plastic	59,458,831	45-R1	(30)	3.61	2,146,464	42-R1.5	(35)	3.97	2,360,516	214,052
	Total Services	65,363,841				2,296,452				2,471,484	175,032
281.00	Meters	10,054,175	34-R3	15	3.15	316,707	37-R3	10	2.71	272,468	(44,238)
282.00	Meter Installations	6,711,388	34-R3	0	3.47	232,885	37-R3	0	3.16	212,080	(20,805)
283.00	House Regulators	3,057,627	39-R1.5	30	2.42	73,995	44-R1.5	10	2.87	87,754	13,759
284.00	House Regulator Installations	2,247,320	39-R1.5	0	3.45	77,533	44-R1.5	0	3.02	67,869	(9,663)
285.00	Industrial M&R Station Equip.	427,495	25-R2	(10)	5.90	25,222	32-R2	(10)	3.22	13,765	(11,457)
285.10	Industrial M&R Station Equip. - Comm.	41,727	25-R3	(10)	4.71	1,965	32-R2	(10)	2.58	1,077	(889)
287.00	Other Equip.	86,637	20-R2	0	6.60	5,718	12-L2.5	0	10.77	9,331	3,613
287.10	Other Equip. - Street Lighting	30,411	30-S2.5	0	3.80	1,156	30-S2.5	0	3.73	1,134	(21)
	Total Distribution Plant	**243,907,958**				**7,605,385**				**7,338,705**	**(266,680)**
	General Plant										
291.00	Office Furniture & Equipment	35,343	20-SQ	0	13.12	4,637	20-SQ	0	5.48	1,937	(2,700)
292.00	Autos and Trucks	37,758	10-R2.5	0	1.74	657	9-R3	5	-	-	(657)
292.10	Trailers	96,158	15-SQ	0	5.94	5,712	10-R2	5	4.59	4,414	(1,298)
294.00	Tools, Shop and Garage Equipment	1,699,499	25-SQ	0	3.68	62,542	25-SQ	0	4.01	68,150	5,608
296.00	Power Operated Equip.	47,221	12-R3	0	-	-	11-R2.5	0	-	-	-
298.00	Miscellaneous Equipment	18,430	20-SQ	0	36.10	6,653	20-SQ	0	-	-	(6,653)
	Total General Plant	**1,934,409**				**80,201**				**74,500**	**(5,700)**
	Total Depreciable Plant	**259,992,930**				**8,012,944**				**7,742,805**	**(270,138)**

Sources:
Col. 2 - Study, pages III-4 and III-5.
Cols. 3, 4, 5, 7, 8, 9 - Response to KyPSC-DR-02-011.

Union Light, Heat and Power Company
Spanos Depreciation Rates Separated into Capital Recovery and COR Rates
As of September 30, 2004

Acct #	Account Description (1)	GROSS PLANT Sep 30, 2004 (2) Company 1/	Capital Recovery /2 RL Rate (3) %	RL Accrual (4) $	Cost of Removal /3 RL Rate (5) %	RL Accrual (6) $	Combined /4 RL Rate (7) % (3)+(5)	RL Accrual (8) $ (4)+(6)
	Common Plant							
190.00	Structures & Improvements							
	Florence Service Building	4,725,458			0.00		0.00	
	Covington Office Building (Sold)	1,548,747			0.00		0.00	
	Kentucky Services Building	1,694,442			0.00		0.00	
	Minor Structures	7,832			0.00		0.00	
	Total Structures & Improvements	7,976,479	2.17	172,944	0.01	539	2.17	173,482
191.00	Office Furniture & Equipment	705,033	6.45	45,474	0.00	0	6.45	45,474
191.10	Office Furniture & Equipment - EDP Equip.	12,981	0.00	0	0.00	0	0.00	0
192.00	Autos and Trucks	5,078	0.00	0	0.00	0	0.00	0
193.00	Stores and Equipment	5,563	47.29	2,631	0.00	0	47.29	2,631
194.00	Tools, Shop and Garage Equipment	169,528	4.80	8,129	0.00	0	4.80	8,129
197.00	Communication Equipment	62,935	7.20	4,530	0.03	20	7.23	4,550
198.00	Miscellaneous Equipment	14,910	2.06	308	0.00	0	2.06	308
	Total Common Plant	**8,952,508**	**2.61**	**234,015**	**0.01**	**559**	**2.62**	**234,574**
	Production Plant							
204.10	Rights of Way	24,439	0.00	0	0.00	0	0.00	0
205.00	Structures & Improvements	1,554,581	0.48	7,387	-0.08	(1,168)	0.40	6,218
211.00	Liquid Petroleum Gas Equipment	3,619,035	2.35	85,083	0.10	3,454	2.45	88,536
	Total Production Plant	**5,198,055**	**1.78**	**92,470**	**0.04**	**2,285**	**1.82**	**94,755**
	Distribution Plant		0.00	0	0.00	0	0.00	0
274.10	Rights of Way - General	1,020,156	1.39	14,146	0.00	0	1.39	14,146
275.00	Structures & Improvements - General	157,012	1.02	1,596	0.10	158	1.12	1,754
	Mains							
276.10	Cast Iron, Copper and All Valves	2,535,274	1.71	43,449	-0.06	(1,467)	1.66	41,983
276.20	Steel	85,376,092	2.14	1,826,951	0.41	354,190	2.55	2,181,141
276.30	Plastic	63,062,653	2.50	1,579,454	0.47	297,490	2.98	1,876,945
	Total Mains	150,974,019	2.29	3,449,855	0.43	650,214	2.72	4,100,069
278.00	M&R - General - System - Excl. Elect. Equip.	2,711,732	1.93	52,237	0.15	4,167	2.08	56,404

Union Light, Heat and Power Company
Spanos Depreciation Rates Separated into Capital Recovery and COR Rates
As of September 30, 2004

Acct	Account Description	GROSS PLANT	Capital Recovery /2		Cost of Removal /3		Combined /4	
278.10	M&R - General - System - Elect. Equip.	389,078	1.45	5,640	-0.06	(218)	1.39	5,422
278.20	Measuring & Regulating - General - District	635,340	1.88	11,929	1.83	11,654	3.71	23,583
	Services						0.00	0
280.10	Cast Iron, Copper and Valves	2,663,011	0.55	14,772	0.33	8,777	0.88	23,549
280.20	Steel	3,241,998	1.92	62,259	0.78	25,447	2.71	87,706
280.30	Plastic	59,458,831	2.87	1,707,752	1.10	653,069	3.97	2,360,821
	Total Services	65,363,841	2.73	1,784,782	1.05	687,294	3.78	2,472,076
281.00	Meters	10,054,175	2.73	274,432	-0.02	(1,797)	2.71	272,636
282.00	Meter Installations	6,711,388	3.16	212,404	0.00	(14)	3.16	212,389
283.00	House Regulators	3,057,627	2.89	88,481	-0.02	(630)	2.87	87,851
284.00	House Regulator Installations	2,247,320	3.03	68,095	-0.01	(159)	3.02	67,936
285.00	Industrial M&R Station Equip.	427,495	2.87	12,277	0.35	1,513	3.23	13,790
285.10	Industrial M&R Station Equip. - Comm.	41,727	2.41	1,006	0.17	71	2.58	1,077
287.00	Other Equip.	86,637	10.68	9,251	0.00	0	10.68	9,251
287.10	Other Equip. - Street Lighting	30,411	3.74	1,137	0.00	0	3.74	1,137
	Total Distribution Plant	**243,907,958**	**2.45**	**5,987,268**	**0.55**	**1,352,252**	**3.01**	**7,339,520**
	General Plant							
291.00	Office Furniture & Equipment	35,343	5.51	1,948	0.00	0	5.51	1,948
292.00	Autos and Trucks	37,758	0.00	0	0.00	0	0.00	0
292.10	Trailers	96,158	4.60	4,425	0.00	0	4.60	4,425
294.00	Tools, Shop and Garage Equipment	1,699,499	4.01	68,205	0.00	0	4.01	68,205
296.00	Power Operated Equip.	47,221	0.00	0	0.00	0	0.00	0
298.00	Miscellaneous Equipment	18,430	0.00	0	0.00	0	0.00	0
	Total General Plant	**1,934,409**	**3.86**	**74,579**	**0.00**	**0**	**3.86**	**74,579**
	Total Depreciable Plant	**259,992,930**	**2.46**	**6,388,332**	**0.52**	**1,355,096**	**2.98**	**7,743,428**

1/ Study, pages III-4 and III-5.
2/ Capital Recovery Calculation
3/ Cost of Removal Calculation
4/ Slight differences due to rounding and calculation differences

Union Light, Heat and Power Company
Estimated Rates and Accruals
Spanos Parameters Capital Recovery
As of September 30, 2004

Account		Original Cost	Survivor Curve	Rem. Life	Book Reserve LESS COR	Positive Net Salvage	Future Accruals	Cap. Rec. Accrual Rate	Annual Accrual Amount
	(1)	(2) 1/	(3)	(4)	(5) 2/	(6)	(7) = (2) + (2)*(6) - (5)	(8)= (9)/(2)	(9)=(7)/(4)
	Common Plant								
190.00	Structures & Improvements								
	Florence Service Building	4,725,458	100-R1.5	32.7					
	Covington Office Building (Sold)	1,548,747	100-R1.5	-		47	(727,911)		
	Kentucky Services Building	1,694,442	100-R1.5	7.6					
	Minor Structures	7,832	40-R3	31.9					
	Total Structures & Improvements	7,976,479		23.0	3,270,867		3,977,701	2.17	172,944
191.00	Office Furniture & Equipment	705,033	20-SQ	5.5	454,928		250,105	6.45	45,474
191.10	Office Furniture & Equipment - EDP Equip.	12,981	5-SQ	-	12,981		0	-	-
192.00	Autos and Trucks	5,078	9-R3	-	5,078	5	(254)	-	-
193.00	Stores and Equipment	5,563	20-SQ	9.8	(20,219)		25,782	47.29	2,631
194.00	Tools, Shop and Garage Equipment	169,528	25-SQ	9.7	90,673		78,855	4.80	8,129
197.00	Communication Equipment	62,935	15-SQ	10.7	14,466		48,469	7.20	4,530
198.00	Miscellaneous Equipment	14,910	20-SQ	3.8	13,740		1,170	2.06	308
	Total Common Plant	**8,952,508**			**3,842,515**		**4,381,828**	**2.61**	**234,015**
	Production Plant								
204.10	Rights of Way	24,439	50-SQ	-	24,439		(0)	-	-
205.00	Structures & Improvements	1,554,581	50-R4	41.2	1,250,244		304,337	0.48	7,387
211.00	Liquid Petroleum Gas Equipment	3,619,035	35-S1.5	23.7	1,602,571		2,016,464	2.35	85,083
	Total Production Plant	**5,198,055**			**2,877,254**		**2,320,801**	**1.78**	**92,470**
	Distribution Plant								
274.10	Rights of Way - General	1,020,156	65-R4	40.8	442,998		577,158	1.39	14,146
275.00	Structures & Improvements - General	157,012	50-R2.5	30.1	108,982		48,030	1.02	1,596
	Mains								
276.10	Cast Iron, Copper and All Valves	2,535,274	41-R2.5	16.1	1,835,739		699,535	1.71	43,449
276.20	Steel	85,376,092	53-R2	31.0	28,740,607		56,635,486	2.14	1,826,951
276.30	Plastic	63,062,653	50-R2.5	36.3	5,728,460		57,334,193	2.50	1,579,454
	Total Mains	150,974,019			36,304,805		114,669,214	2.29	3,449,855
278.00	M&R - General - System - Excl. Elect. Equip.	2,711,732	40-R1	23.7	1,473,708		1,238,024	1.93	52,237

Union Light, Heat and Power Company
Estimated Rates and Accruals
Spanos Parameters Capital Recovery
As of September 30, 2004

Account		Original Cost	Survivor Curve	Rem. Life	Book Reserve LESS COR	Positive Net Salvage	Future Accruals	Cap. Rec. Accrual Rate	Annual Accrual Amount
	(1)	(2) 1/	(3)	(4)	(5) 2/	(6)	(7) = (2) + (2)*(6) - (5)	(8)= (9)/(2)	(9)=(7)/(4)
278.10	M&R - General - System - Elect. Equip.	389,078	15-S2.5	10.0	332,682		56,396	1.45	5,640
278.20	Measuring & Regulating - General - District	635,340	50-R2	25.4	332,346		302,994	1.88	11,929
	Services								
280.10	Cast Iron, Copper and Valves	2,663,011	40-R1.5	13.6	2,462,117		200,894	0.55	14,772
280.20	Steel	3,241,998	38-R1	22.1	1,866,074		1,375,924	1.92	62,259
280.30	Plastic	59,458,831	42-R1.5	25.6	15,740,384		43,718,448	2.87	1,707,752
	Total Services	65,363,841			20,068,575		45,295,265	2.73	1,784,782
281.00	Meters	10,054,175	37-R3	23.9	2,489,827	10	6,558,930	2.73	274,432
282.00	Meter Installations	6,711,388	37-R3	24.5	1,507,499		5,203,889	3.16	212,404
283.00	House Regulators	3,057,627	44-R1.5	25.3	513,292	10	2,238,572	2.89	88,481
284.00	House Regulator Installations	2,247,320	44-R1.5	26.0	476,852		1,770,468	3.03	68,095
285.00	Industrial M&R Station Equip.	427,495	32-R2	17.8	208,958		218,537	2.87	12,277
285.10	Industrial M&R Station Equip. - Comm.	41,727	32-R2	19.0	22,614		19,113	2.41	1,006
287.00	Other Equip.	86,637	12-L2.5	5.8	32,981		53,656	10.68	9,251
287.10	Other Equip. - Street Lighting	30,411	30-S2.5	19.9	7,778		22,633	3.74	1,137
	Total Distribution Plant	**243,907,958**			**64,323,897**		**178,272,881**	**2.45**	**5,987,268**
	General Plant								
291.00	Office Furniture & Equipment	35,343	20-SQ	8.7	18,391		16,952	5.51	1,948
292.00	Autos and Trucks	37,758	9-R3	-	38,535	5	(2,665)	-	-
292.10	Trailers	96,158	10-R2	5.0	69,224	5	22,126	4.60	4,425
294.00	Tools, Shop and Garage Equipment	1,699,499	25-SQ	15.1	669,604		1,029,895	4.01	68,205
296.00	Power Operated Equip.	47,221	11-R2.5	-	47,221		(0)	-	-
298.00	Miscellaneous Equipment	18,430	20-SQ	-	18,430		0	-	-
	Total General Plant	**1,934,409**			**861,405**		**1,066,308**	**3.86**	**74,579**
	Total Depreciable Plant	**259,992,930**			**71,905,070**		**186,041,818**	**2.46**	**6,388,332**

Sources:
1/ Study, pages III-4 and III-5. Slight differences due to rounding and calculation differences.
2/ See SK calculation -- Removal of COR from Book Reserve

Union Light, Heat and Power Company
Estimated Rates and Accruals
Spanos Parameters Cost of Removal
As of September 30, 2004

Account		Original Cost ($)	Survivor Curve	Rem. Life	Spanos COR (%)	Inflated Future COR ($)	COR in Reserve ($)	Future Accruals ($)	COR Accrual Rate	Annual Accrual Amount ($)
	(1)	(2) 1/	(3) 1/	(4) 1/	(5) 1/	(6)=(2)*(-5)	(7) 2/	(8)=(5)-(4)	(9)= (10)/(2)	(10)=(6)/(8)
	Common Plant									
190.00	Structures & Improvements									
	Florence Service Building	4,725,458	100-R1.5	32.7						
	Covington Office Building (Sold)	1,548,747	100-R1.5	-						
	Kentucky Services Building	1,694,442	100-R1.5	7.6						
	Minor Structures	7,832	40-R3	31.9	(5.0)	392				
	Total Structures & Improvements	7,976,479		22.9		392	(11,946)	12,338	0.01	539
191.00	Office Furniture & Equipment	705,033	20-SQ	5.5		-	-	-	0.00	-
191.10	Office Furniture & Equipment - EDP Equip.	12,981	5-SQ	-		-	-	-	0.00	-
192.00	Autos and Trucks	5,078	9-R3	-		-	-	-	0.00	-
193.00	Stores and Equipment	5,563	20-SQ	9.8		-	-	-	0.00	-
194.00	Tools, Shop and Garage Equipment	169,528	25-SQ	9.7		-	-	-	0.00	-
197.00	Communication Equipment	62,935	15-SQ	10.7		-	(216)	216	0.03	20
198.00	Miscellaneous Equipment	14,910	20-SQ	3.8		-	-	-	0.00	-
	Total Common Plant	**8,952,508**				**392**	**(12,163)**	**12,555**	**0.01**	**559**
	Production Plant									
204.10	Rights of Way	24,439	50-SQ	-		-	-	-	0.00	-
205.00	Structures & Improvements	1,554,581	50-R4	41.2	(5.0)	77,729	125,866	(48,137)	-0.08	(1,168)
211.00	Liquid Petroleum Gas Equipment	3,619,035	35-S1.5	23.7	(5.0)	180,952	99,103	81,849	0.10	3,454
	Total Production Plant	**5,198,055**				**258,681**	**224,969**	**33,712**	**0.04**	**2,285**
	Distribution Plant									
274.10	Rights of Way - General	1,020,156	65-R4	40.8		-	-	-	0.00	-
275.00	Structures & Improvements - General	157,012	50-R2.5	30.1	(10.0)	15,701	10,950	4,751	0.10	158
	Mains									
276.10	Cast Iron, Copper and All Vaives	2,535,274	41-R2.5	16.1	(20.0)	507,055	530,665	(23,611)	-0.06	(1,467)
276.20	Steel	85,376,092	53-R2	31.0	(20.0)	17,075,218	6,095,322	10,979,896	0.41	354,190
276.30	Plastic	63,062,653	50-R2.5	36.3	(20.0)	12,612,531	1,813,637	10,798,894	0.47	297,490
	Total Mains	150,974,019				30,194,804	8,439,625	21,755,179	0.43	650,214
278.00	M&R - General - System - Excl. Elect. Equip.	2,711,732	40-R1	23.7	(5.0)	135,587	36,827	98,760	0.15	4,167

Union Light, Heat and Power Company
Estimated Rates and Accruals
Spanos Parameters Cost of Removal
As of September 30, 2004

Account		Original Cost ($)	Survivor Curve	Rem. Life	Spanos COR (%)	Inflated Future COR ($)	COR in Reserve ($)	Future Accruals ($)	COR Accrual Rate	Annual Accrual Amount ($)
	(1)	(2) 1/	(3) 1/	(4) 1/	(5) 1/	(6)=(2)*(-5)	(7) 2/	(8)=(5)-(4)	(9)= (10)/(2)	(10)=(6)/(8)
278.10	M&R - General - System - Elect. Equip.	389,078	15-S2.5	10.0	(5.0)	19,454	21,632	(2,178)	-0.06	(218)
278.20	Measuring & Regulating - General - District	635,340	50-R2	25.4	(75.0)	476,505	180,501	296,004	1.83	11,654
	Services									
280.10	Cast Iron, Copper and Valves	2,663,011	40-R1.5	13.6	(35.0)	932,054	812,683	119,371	0.33	8,777
280.20	Steel	3,241,998	38-R1	22.1	(35.0)	1,134,699	572,322	562,378	0.78	25,447
280.30	Plastic	59,458,831	42-R1.5	25.6	(35.0)	20,810,591	4,092,017	16,718,574	1.10	653,069
	Total Services	65,363,841				22,877,344	5,477,022	17,400,323	1.05	687,294
281.00	Meters	10,054,175	37-R3	23.9		-	42,942	(42,942)	-0.02	(1,797)
282.00	Meter Installations	6,711,388	37-R3	24.5		-	351	(351)	0.00	(14)
283.00	House Regulators	3,057,627	44-R1.5	25.3		-	15,946	(15,946)	-0.02	(630)
284.00	House Regulator Installations	2,247,320	44-R1.5	26.0		-	4,129	(4,129)	-0.01	(159)
285.00	Industrial M&R Station Equip.	427,495	32-R2	17.8	(10.0)	42,749	15,819	26,930	0.35	1,513
285.10	Industrial M&R Station Equip. - Comm.	41,727	32-R2	19.0	(10.0)	4,173	2,826	1,347	0.17	71
287.00	Other Equip.	86,637	12-L2.5	5.8		-	-	-	0.00	-
287.10	Other Equip. - Street Lighting	30,411	30-S2.5	19.9		-	-	-	0.00	-
	Total Distribution Plant	**243,907,958**				**53,766,317**	**14,248,570**	**39,517,747**	**0.55**	**1,352,252**
	General Plant									
291.00	Office Furniture & Equipment	35,343	20-SQ	8.7		-	-	-	0.00	-
292.00	Autos and Trucks	37,758	9-R3	-		-	-	-	0.00	-
292.10	Trailers	96,158	10-R2	5.0		-	-	-	0.00	-
294.00	Tools, Shop and Garage Equipment	1,699,499	25-SQ	15.1		-	-	-	0.00	-
296.00	Power Operated Equip.	47,221	11-R2.5	-		-	-	-	0.00	-
298.00	Miscellaneous Equipment	18,430	20-SQ	-		-	-	-	0.00	-
	Total General Plant	**1,934,409**				**-**	**-**	**-**		**-**
	Total Depreciable Plant	**259,992,930**				**54,025,390**	**14,461,377**	**39,564,013**	**0.52**	**1,355,096**

Sources:
Study, pages III-4 and III-5. Slight differences due to rounding and calculation differences.
1/ See SK calculation -- Removal of COR from Book Reserve

Union Light, Heat and Power Company
Removal of COR from Book Reserve
As of September 30, 2004

	Account	Original Cost	Book Reserve	COR in Reserve		Book Reserve Less COR
	(1)	(2)	(3)	(4)		(5)=(3)-(4)
	Common Plant					
190.00	Structures & Improvements					
	Florence Service Building	4,725,458	1,256,998			
	Covington Office Building (Sold)	1,548,747	820,835			
	Kentucky Services Building	1,694,442	1,180,267			
	Minor Structures	7,832	821			
	Total Structures & Improvements	7,976,479	3,258,921	(11,946)		3,270,867
191.00	Office Furniture & Equipment	705,033	454,928	-		454,928
191.10	Office Furniture & Equipment - EDP Equip.	12,981	12,981	-		12,981
192.00	Autos and Trucks	5,078	5,078	-		5,078
193.00	Stores and Equipment	5,563	(20,219)	-		(20,219)
194.00	Tools, Shop and Garage Equipment	169,528	90,673	-		90,673
197.00	Communication Equipment	62,935	14,250	(216)		14,466
198.00	Miscellaneous Equipment	14,910	13,740	-		13,740
	Total Common Plant	**8,952,508**	**3,830,352**	**(12,163)**		**3,842,515**
	Production Plant					
204.10	Rights of Way	24,439	24,439	-		24,439
205.00	Structures & Improvements	1,554,581	1,376,110	125,866		1,250,244
211.00	Liquid Petroleum Gas Equipment	3,619,035	1,701,674	99,103		1,602,571
	Total Production Plant	**5,198,055**	**3,102,223**	**224,969**		**2,877,254**
	Distribution Plant					
274.10	Rights of Way - General	1,020,156	442,998	-		442,998
275.00	Structures & Improvements - General	157,012	119,932	10,950		108,982
	Mains					
276.10	Cast Iron, Copper and All Valves	2,535,274	2,366,404	530,665		1,835,739
276.20	Steel	85,376,092	34,835,929	6,095,322	1/	28,740,607
276.30	Plastic	63,062,653	7,542,097	1,813,637	2/	5,728,460
	Total Mains	150,974,019	44,744,430	8,439,625		36,304,805
278.00	M&R - General - System - Excl. Elect. Equip.	2,711,732	1,510,535	36,827		1,473,708
278.10	M&R - General - System - Elect. Equip.	389,078	354,314	21,632		332,682
278.20	Measuring & Regulating - General - District	635,340	512,847	180,501		332,346
	Services					
280.10	Cast Iron, Copper and Valves	2,663,011	3,274,800	812,683		2,462,117
280.20	Steel	3,241,998	2,438,396	572,322	3/	1,866,074
280.30	Plastic	59,458,831	19,832,401	4,092,017	4/	15,740,384
	Total Services	65,363,841	25,545,597	5,477,022		20,068,575
281.00	Meters	10,054,175	2,532,769	42,942	5/	2,489,827
282.00	Meter Installations	6,711,388	1,507,850	351	6/	1,507,499
283.00	House Regulators	3,057,627	529,238	15,946	7/	513,292
284.00	House Regulator Installations	2,247,320	480,981	4,129	8/	476,852
285.00	Industrial M&R Station Equip.	427,495	224,777	15,819		208,958
285.10	Industrial M&R Station Equip. - Comm.	41,727	25,440	2,826		22,614
287.00	Other Equip.	86,637	32,981	-		32,981
287.10	Other Equip. - Street Lighting	30,411	7,778	-		7,778
	Total Distribution Plant	**243,907,958**	**78,572,467**	**14,248,570**		**64,323,897**

Union Light, Heat and Power Company
Removal of COR from Book Reserve
As of September 30, 2004

	Account	Original Cost	Book Reserve	COR in Reserve	Book Reserve Less COR
	(1)	(2)	(3)	(4)	(5)=(3)-(4)
	General Plant				
291.00	Office Furniture & Equipment	35,343	18,391	-	18,391
292.00	Autos and Trucks	37,758	38,535	-	38,535
292.10	Trailers	96,158	69,224	-	69,224
294.00	Tools, Shop and Garage Equipment	1,699,499	669,604	-	669,604
296.00	Power Operated Equip.	47,221	47,221	-	47,221
298.00	Miscellaneous Equipment	18,430	18,430	-	18,430
	Total General Plant	**1,934,409**	**861,405**	**-**	**861,405**
	Total Depreciable Plant	**259,992,930**	**86,366,447**	**14,461,377**	**71,905,070**

Sources:
Cols. (2) and (3) - Study, pages III-4 and III-5.
Col. (4) - Response to AG-DR-01-076, Attachment pages 1 and 2, "Ending Reserve" column. Column (4) amounts as of 12/31/04.

1/ Includes COR for accounts 276.2 (Gas Main Dist Line Steel), 276.5 (Gas Main Feed Line Steel and 276.7 (Capex Gas Main Steel)
2/ Includes COR for accounts 276.3 (Gas Main Dist. Plastic) and 276.8 (Capex Gas Mains Plastic)
3/ Includes COR for accounts 280.2 (Gas Services Steel) and 280.4 (Capex Services M-C Steel)
4/ Includes COR for accounts 280.3 (Gas Services Plastic), 280.5 (Services M-C Plastic), 280.6 (Services C-M Plastic) and 280.7 (Capex Services C-M Plastic)
5/ Includes COR for accounts 281.0 (Gas Meters) and 281.1 (Leased Gas Meters)
6/ Includes COR for accounts 282.0 (Gas Meter Installations) and 282.1 (Leased Gas Meter Installations)
7/ Includes COR for accounts 283.0 (Gas House Regulators) and 283.1 (Gas House Regs. Leased)
8/ Includes COR for accounts 284.0 (Gas House Regulator Installations) and 284.1 (Gas House Reg. Install. Leased)

Excessive Depreciation

An excessive depreciation rate is one that produces depreciation expense which is more than necessary to return a company's capital investment over the life of the asset. The concept of excessive depreciation is not new, and in fact was explained by the U.S. Supreme Court in a landmark 1934 decision, Lindheimer v. Illinois Bell Telephone Company, as follows:

> If the predictions of service life were entirely accurate and retirements were made when and as these predictions were precisely fulfilled, the depreciation reserve would represent the consumption of capital, on a cost basis, according to the method which spreads that loss over the respective service periods. But if the amounts charged to operating expenses and credited to the account for depreciation reserve are excessive, to that extent subscribers for the telephone service are required to provide, in effect, capital contributions, not to make good losses incurred by the utility in the service rendered and thus to keep its investment unimpaired, but to secure additional plant and equipment upon which the utility expects a return.
>
> Confiscation being the issue, the company has the burden of making a convincing showing that the amounts it has charged to operating expenses for depreciation have not been excessive. That burden is not sustained by proof that its general accounting system has been correct. The calculations are mathematical, but the predictions underlying them are essentially matters of opinion. They proceed from studies

> of the "behavior of large groups" of items. These studies are beset with a host of perplexing problems. Their determination involves the examination of many variable elements and opportunities for excessive allowances, even under a correct system of accounting, are always present. The necessity of checking the results is not questioned. The predictions must meet the controlling test of experience.[1]

Excessive depreciation rates produce excessive depreciation expense. In other words, if an excessive depreciation rate is applied to the plant balance, it results in excessive depreciation expense. Since depreciation expense flows dollar-for-dollar into the revenue requirement, excessive depreciation expense results in an excessive revenue requirement.

Excessive depreciation also flows dollar-for-dollar into the accumulated depreciation reserve account. This can result in a depreciation reserve actually exceeding the gross plant balance. That is because the depreciation rate is excessive; it is more than necessary to fully depreciate the plant. This is what the Court was talking about in Lindheimer. Therefore, at the end of its life, the results in an accumulated depreciation account which *exceeds* the original cost in the plant account.

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[1] Lindheimer v. Illinois Bell Telephone Company, 292 U.S. 151, 168-170, 54 S.Ct. 658, 665-666 (1934). (Emphasis added; footnote deleted.)

The public accounting profession, through the Financial Accounting Standards Board ("FASB") has also addressed accumulated reserve excesses in its SFAS No. 143.[2] Paragraph B22 says the following:

> B22. Paragraph 37 of Statement 19 states that "estimated dismantlement, restoration, and abandonment costs … shall be taken into account in determining amortization and depreciation rates." Application of that paragraph has the effect of accruing an expense irrespective of the requirements for liability recognition in the FASB Concepts Statements. In doing so, it results in recognition of accumulated depreciation that can exceed the historical cost of a long-lived asset. The Board concluded that an entity should be precluded from including an amount for and asset retirement obligation in the depreciable base of a long-lived asset unless that amount also meets the recognition criteria in this Statement. When an entity recognizes a liability for an asset retirement obligation, it also will recognize an increase in the carrying amount of the related long-lived asset. <u>Consequently, depreciation of that asset will not result in the recognition of accumulated depreciation in excess of the historical cost of a long-lived asset</u>.[3]

As one can see from the above, as recently as 2002, the public accounting profession does not approve of depreciating an asset beyond its original cost. It actually uses the word "excess," and it is obvious that it frowns upon accumulated depreciation balances that exceed the original cost of plant.

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[2] Statement of Financila Accounting Standards No. 143 ("SFAS No. 143") – Accounting for Asset Retirement Obligations

[3] SFAS No. 143, paragraph B22, (emphasis added).

GAAP does not control ratemaking, but the rationale described above is both informative and makes sense.

Ultimately, ratepayers pay for excessive depreciation rates. As the U.S. Supreme Court said, the result is the extraction of capital contributions from ratepayers, which the Court decided was inappropriate. Current GAAP accounting rules highlight these amounts associated with negative net salvage and require that they be reported as Regulatory Liabilities ("amounts owed") to ratepayers.