COMMONWEALTH OF KENTUCKY

OFFICE OF THE ATTORNEY GENERAL

GREGORY D. STUMBO
ATTORNEY GENERAL

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FRANKFORT, KY 40601-8204

July 29, 2004

RECEIVED

JUL 29 2004

PUBLIC SERVICE
COMMISSION

Beth O'Donnell
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601

Re: An Adjustment of the Rates of Delta Natural Gas Company, Inc., PSC Case No. 2004-00067

Dear Ms. O'Donnell,

Pursuant to Commission Order dated July 16, 2004, the Original and 8 true copies of the Attorney General's Responses to the data requests contained in that Order are hereby filed with the Commission. Copies of these responses have been served on the parties this same day.

Pursuant to Commission Order dated April 23, 2004, seven copies of the Attorney General's Responses to the data requests of Delta Natural Gas Company, Inc. are hereby filed with the Commission. One copy has been treated as an original for the purposes of including voluminous materials not included in the remaining copies. Copies of these filings have been served on the parties this same day.

Respectfully submitted,

Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive, Suite 200
Frankfort, Kentucky 40601-8204
(502) 696-5453

cc: Robert Watt III
Leslye Bowman
John Hall
Marian Carpenter
Connie King

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

AN ADJUSTMENT OF THE RATES OF DELTA NATURAL GAS COMPANY, INC.	)) CASE NO. 2004-00067)

ATTORNEY GENERAL'S RESONSES TO DELTA NATUAL GAS COMPANY'S DATA REQUESTS

Response of the Attorney General
To Delta Natural Gas Company
Case No. 2004-00067

Responding Witness:
Robert J. Henkes

1. Please produce portions of the transcripts of the testimony of Robert J. Henkes (direct, rebuttal, cross-examination or otherwise) presented during the last 10 years during which the following subjects were discussed, including the identification of the case and the date on which the testimony was offered:

   a. Pro forma test year-end customer growth adjustment;
   b. Interest on customer deposits;
   c. Pension expenses;
   d. Directors' fees and expenses;
   e. Expenses related to compliance with the Sarbanes/Oxley Act;
   f. American Gas Association or Edison Electric Institute dues;
   g. Depreciation expense for local gas distribution companies.

Response:

Copies of Mr. Henkes' prior testimonies regarding the subjects listed in parts a, c and g of the above request were previously provided to Mr. Watt of Stoll, Keenon & Park in response to LG&E's data request No. 1 to Mr. Henkes in the recently concluded LG&E rate case, Case No. 2003-00433.

Mr. Henkes' position on customer deposits and interest on customer deposits in all of his prior testimonies is described in detail in response to Delta's data request No. 3 to Mr. Henkes, Case No. 2004-00067.

Mr. Henkes' only prior testimony addressing directors fees and expenses was in Kentucky's Jackson Energy Cooperative Corporation rate case, Case No. 2000-373. Copies of relevant testimony pages are attached.

Mr. Henkes has not addressed Sarbanes/Oxley related issues in any of his prior testimonies.

Responding Witness:
Robert J. Henkes

Mr. Henkes has addressed AGA related issues in three prior rate cases: LG&E, KPSC Case No. 2003-00433; Delmarva Power & Light Company, DPSC Docket No. 03-127; and Public Service Electric & Gas Company, BPU Docket No. GR01050328. Copies of relevant testimony pages in each of these 3 rate cases are attached.

Edison Electric Institute dues are not at issue in this gas rate case and have not been addressed as an issue in Mr. Henkes' testimony.

Given the volume of the requested testimonies, they are being provided only with the Original filed with the Commission, the Copy provided to Mr. Watt, and the Copy provided to Mr. Hall and the Copy provided to Ms. Bowman. Further copies will be provided only on request.

Response of the Attorney General
To Delta Natural Gas Company
Case No. 2004-00067

Responding Witness:
Robert J. Henkes

2. Please produce copies of articles from books, scholarly works, trade publications or professional publications written, in whole or in part, by Robert J. Henkes during the last 10 years in which the following subjects were discussed, including the identification of the publication and the date on which it was published:

a. Pro forma test year-end customer growth adjustment;
b. Interest on customer deposits;
c. Pension expenses;
d. Directors' fees and expenses;
e. Expenses related to compliance with the Sarbanes/Oxley Act;
f. American Gas Association or Edison Electric Institute dues;
g. Depreciation expense for local gas distribution companies.

Response:

Mr. Henkes did not write or otherwise prepare any of the material referenced in the above request for information and, therefore, is not in the position to provide the requested information.

Response of the Attorney General
To Delta Natural Gas Company
Case No. 2004-00067

Responding Witness:
Robert J. Henkes

3. Does Mr. Henkes believe that, in determining the revenue requirement, if interest associated with customer deposits is excluded from operating expenses, then customer deposits should be included in rate base? Please explain your answer.

Response:

No. Mr. Henkes believes that if interest associated with customer deposits is excluded from above-the-line operating expenses for ratemaking purposes, then customer deposits should be excluded as a component of rate base (alternative #1). Conversely, if interest associated with customer deposits is included in above-the-line operating expenses for ratemaking purposes, then customer deposits should be treated as a rate base deduction (alternative #2).

Mr. Henkes believes the most appropriate ratemaking treatment of the two alternatives described above is the alternative #2 treatment. This is because this approach properly recognizes that the Company has the use of these non-investor supplied funds at a cost (6%) that is lower than the Company's overall rate of return. Mr. Henkes first argued for this customer deposit ratemaking treatment in Delta's Case No. 97-066 but the Commission did not adopt this ratemaking approach. Mr. Henkes again spent considerable testimony in Delta's prior rate case, Case No. 99-176, in an attempt to convince the Commission to adopt the alternative #2 rate treatment for Delta's customer deposits. However, the Commission again ruled against this rate treatment and, instead, decided that the alternative #1 customer deposit rate treatment was the most appropriate ratemaking approach for customer deposits. The Commission made this determination based on the fact that customer deposits represent a liability that eventually has to repaid to the customer.

Thus, in all other rate cases in which Mr. Henkes' testimony addresses customer deposits, Mr. Henkes has either reflected the alternative #2 customer deposit rate treatment or has reflected customer deposits as a component of the capital structure for purpose of determining the appropriate overall rate of return for the particular utility involved. The only exception is in the Kentucky jurisdiction where Mr. Henkes now reflects the alternative #1 customer deposit rate treatment in accordance with (what would appear to be) firmly established KPSC ratemaking policy.

Response of the Attorney General
To Delta Natural Gas Company
Case No. 2004-00067

Responding Witness:
Robert J. Henkes

4. Please provide on a diskette or compact disk a working copy of all Excel spreadsheets used to prepare the exhibits to Mr. Henkes's testimony.

Response:

Mr. Henkes did not use or prepare Excel spreadsheets or, for that matter, any workpapers/spreadsheets in the preparation of his testimony and testimony schedules. All information contained in Mr. Henkes' testimony and testimony schedules is based on Delta's filing material and responses to data requests issued by the AG and PSC Staff and is clearly referenced in the testimony text and in the testimony and schedule footnote.

Response of the Attorney General
To Delta Natural Gas Company
Case No. 2004-00067

Responding Witness:
Michael J. Majoros Jr.

5. Please provide a copy of all written testimony submitted by Mr. Majoros in the following proceedings:

a. Florida – Docket No. 031033-El, Tampa Electric Company;

b. New Jersey – Docket No. GR03080683, South Jersey Gas Company;

c. Maryland, Docket No. 8960, Washington Gas Light;

d. Kentucky, Case No. 2003-00252, Union Light Heat & Power;

e. Kansas, Docket No. 03-KGSG-602-RTS, Kansas Gas Service;

f. Kentucky, Docket No. 2002-00145, Columbia Gas.

Response: Please see files provided on the compact disc labeled SK Resp to Delta DRs.

Responding Witness:
Michael J. Majoros Jr.

6. Please provide on a diskette or compact disk a working copy of all spreadsheets and any working computer models used to prepare Exhibit____(MJM-1) and Exhibit____(MJM-2).

Response: Please see files provided on the compact disc labeled SK Resp to Delta DRs. The computer software Mr. Majoros uses to conduct his SPR analyses is proprietary, hence a copy has not been provided.

Responding Witness:
Michael J. Majoros Jr.

7. Please provide paper copies of all work papers used in the preparation of Exhibit____(MJM-1) and Exhibit____(MJM-2) that were not included in the exhibits to Mr. Majoros's testimony. If no other work papers exist, please so indicate.

Response: Please see files provided on the compact disc labeled SK Resp to Delta DRs. SPR workpapers and GMTs have been provided in electronic format (SPR Workpapers.xls and GMTs.xls, respectively).

Responding Witness:
Michael J. Majoros Jr.

8. Did Mr. Majoros perform Simulated Property Record Balances ("SPR") analyses of Account Nos. 369, 376, 382 or any other plant account? If so, please provide copies of the analyses and all work papers.

Response: Mr. Majoros performed SPR analyses on the following accounts: 367, 369, 376, 382, 383 and 385. Please see Data Request No. 7 for electronic copies of the SPR analyses.

Responding Witness:
Michael J. Majoros Jr.

9. Please provide a copy of all analyses conducted by Mr. Majoros of individual plant accounts other than for Account Nos. 369, 376, and 382.

Response: Please see the response to Data Request No. 7 for electronic copies of all analyses conducted by Mr. Majoros. This includes both SPR analyses and GMT analyses.

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Responding Witness:
Michael J. Majoros Jr.

10. Please indicate whether Mr. Majoros performed an analysis such as those included in Exhibit____(MJM-1) for any account other than Account Nos. 369, 376, and 382.

a. If such an analysis was not conducted, please explain in detail why Mr. Majoros did not perform such an analysis for other accounts.

b. If such an analysis was not conducted, please provide a detailed explanation of why Mr. Majoros performed such an analysis of Account Nos. 369, 376, and 382, but not for other accounts.

Response: Mr. Majoros performed GMT analyses for all accounts for which he was provided data from the Company in response to PSC-2-17. After reviewing the GMT analyses and available data, he conducted SPR analyses on those accounts where the results of his GMT analysis differed substantially from the SPR analysis conducted by Delta. Of these, Mr. Majoros' SPR analyses supported those conducted by Delta on all but three accounts. For Accounts 369, 376 and 382, Mr. Majoros selected a life based on the results of his SPR analysis and then prepared a generation arrangement to calculate the remaining life for that account.

Responding Witness:
Charles King

11. For each of the ten (10) most recent gas, electric and water rate cases in which Mr. King provided testimony on rate of return on common equity, please provide;

   a. Mr. King's recommended return, or range of returns, on common equity;
   b. The rate of return on common equity approved by the regulatory commission (or court);
   c. The name of the utility;
   d. The name of the regulatory commission (or court);
   e. The case number;
   f. The date of the order in which the regulatory commission (or court) approved the rate of return on equity.

Response

Please see the attached tabulation.

Charles W. King
Recommended and Approved Returns to Equity

State	Case	Utility Company	Utility Type	King Recommended Equity Return	Outcome
Illinois	02-0690	Illinois-American Water Company	Water	9.10%	Client, City of O'Fallon, settled with utility and withdrew from the case.
Kentucky	2002-145	Columbia Gas Companhy	Gas	10.3%	The parties settled on a $7.8 million reduction. No ROE was stated.
North Dakota	PU-399-02-183	Montana-Dakota Utilities	Gas	10.5%	Commission awarded 11.329%
Wisconsin	2055-TR-102	CenturyTel of Wisconsin	Telephone	10.25%	Commission awarded 12.25%
Wisconsin	5846-TR-102	Telephone USA	Telephone	10.25%	Commission awarded 12.25%
North Dakota	PU-399-02-186	Montana-Dakota Utilities	Electric	11.7%	Commission awarded 11.8%
North Dakota	PU-400-00-521	Excel Energy	Gas	11.3%	The parties settled at 11.5%
FCC	98-166	Regional Bell Operating Companies	Telephone	11.4%	The Commission never completed the case.
Delaware	94-149	Wilmington Suburban Water Co.	Water	10.5%	The parties settled at 11.45%
Delaware	94-164	Artesian Water Company	Water	11.3%	We have no record of the outcome of this case.

1

Response of the Attorney General
To Delta Natural Gas Company
Case No. 2004-00067

Responding Witness:
Charles King

12. Please provide a copy of all written testimony submitted by Mr. King in the following proceedings:

g. District of Columbia; Docket No. 989; Washington Gas Light Company;
h. District of Columbia; Docket No. 1016; Washington Gas Light Company;
i. Georgia; Docket No. 14311-U; Atlanta Gas Light Company;
j. Georgia; Docket No. 17066-U; Georgia Power Company;
k. Illinois; Docket No. 02-0690; Illinois-American Water Company;
l. Kentucky; Docket No. 2002-00145; Columbia Gas Company of Kentucky;
m. Kentucky; Docket No. 2003-00252; The Union Light, Heat and Power Company;
n. Maryland; Docket No. 8855; Baltimore Gas & Electric Company;
o. Michigan; Docket No. U-13808; Detroit Edison Company.

Response

Mr. King's testimony in Maryland P.S.C. Docket No. 8855 cannot be provided because it was file under seal. Copies of the all other requested testimonies are provided in: the Original of the Responses filed with the Public Service Commission; the Copy of the Response filed with John Hall of Delta Natural Gas: the Copy of the Response filed with Robert M. Watt III, Counsel for Delta Natural Gas. The copies are voluminous and will otherwise be provided only request.

1

Responding Witness:
David H. Brown Kinloch

13. Please provide on a diskette or compact disk a working copy of all Excel spreadsheets used to prepare the exhibits to Mr. Brown-Kinloch's testimony.

Response:

The attached compact disk contains all Excel spreadsheets used in the preparation of testimony. The CD is being provided with the Original of the Responses filed with the Public Service Commission and with those copies of the Responses provided to the Honorable Robert M. Watt III, Mr. John Hall and the Honorable Leslye M. Bowman. Further copies will be provided on request.

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Response of the Attorney General
To Delta Natural Gas Company
Case No. 2004-00067

Responding Witness:
David H. Brown Kinloch

14. Please provide paper copies of all work papers used in the preparation of Mr. Brown-Kinloch's testimony and exhibits that were not included as a part of his testimony.

Response:

The compact disk attached to Response 13 contains all Excel spreadsheets used in the preparation of testimony. There are no other work papers. The CD is being provided with the Original of the Responses filed with the Public Service Commission and with those copies of the Responses provided to the Honorable Robert M. Watt III, Mr. John Hall and the Honorable Leslye M. Bowman. Further copies will be provided on request.

1

Responding Witness:
David H. Brown Kinloch

15. On page 5, lines 6-7, of his testimony, Mr. Brown-Kinloch states, "Compared to similar calculations done on other utilities this customer portion is very high. A customer portion around 20% is more typical …."

a. Please provide a copy of all of the "similar calculation done on other utilities" and provide the name of the utility, the date when the calculations were performed, and the analyst or witness who performed the calculations.

Response:

Please see Delta's Response to the Attorney General's Initial Data Request, Items 157 and 159.

b. For each such "similar calculation," please describe the methodology that was used; specifically, indicate whether a weighted or unweighted regressions analysis was used.

Response:

All similar calculations referred to used a weighted analysis.

Responding Witness:
David H. Brown Kinloch

c. Please provide all research on which Mr. Brown-Kinloch relied, other than the example in the *NARUC Gas Distribution Rate Design Manual*, to support the statement that a "customer portion around 20% is more typical."

Response:

This statement is based on Mr. Brown Kinloch's participation in a number of gas distribution rate cases over the past 20 years. Please see pages 2 and 3 of Mr. Brown Kinloch's testimony for a list of those cases.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE	)	
RATES OF DELTA NATURAL	)	Case No. 2004-00067
GAS COMPANY, INC.	)	

Attorney General's Response to Delta Natural Gas Company Inc.
Data Request #1

Response of the Attorney General
To Delta Natural Gas Company
Case No. 2004-00067

Responding Witness:
Robert J. Henkes

1. Please produce portions of the transcripts of the testimony of Robert J. Henkes (direct, rebuttal, cross-examination or otherwise) presented during the last 10 years during which the following subjects were discussed, including the identification of the case and the date on which the testimony was offered:

a. Pro forma test year-end customer growth adjustment;

b. Interest on customer deposits;

c. Pension expenses;

d. Directors' fees and expenses;

e. Expenses related to compliance with the Sarbanes/Oxley Act;

f. American Gas Association or Edison Electric Institute dues;

g. Depreciation expense for local gas distribution companies.

Response:

Copies of Mr. Henkes' prior testimonies regarding the subjects listed in parts a, c and g of the above request were previously provided to Mr. Watt of Stoll, Keenon & Park in response to LG&E's data request No. 1 to Mr. Henkes in the recently concluded LG&E rate case, Case No. 2003-00433.

Mr. Henkes' position on customer deposits and interest on customer deposits in all of his prior testimonies is described in detail in response to Delta's data request No. 3 to Mr. Henkes, Case No. 2004-00067.

Mr. Henkes' only prior testimony addressing directors fees and expenses was in Kentucky's Jackson Energy Cooperative Corporation rate case, Case No. 2000-373. Copies of relevant testimony pages are attached.

Mr. Henkes has not addressed Sarbanes/Oxley related issues in any of his prior testimonies.

AG

STATE OF VERMONT
PUBLIC SERVICE BOARD
DOCKET NO. 5695

APR 1 5 2004

IN THE MATTER OF THE PETITION OF
GREEN MOUNTAIN POWER CORPORATION
FOR APPROVAL OF AN INCREASE IN RATES
AND REVISIONS TO ITS RULES,
REGULATIONS AND EXISTING TARIFFS

DIRECT TESTIMONY OF ROBERT J. HENKES
ON BEHALF OF THE
DEPARTMENT OF PUBLIC SERVICE

JANUARY 18, 1994

In addition, a further slide in GMP's gasoline prices is likely to occur after October 1993. As widely reported, crude oil prices fell to a 5-year low (below $15 per barrel) in December 1993 as a result of OPEC's refusal to cut production and gasoline prices have followed suit by dropping over 20% since October 1993.

Q.135 SINCE THE AVERAGE COST PER GALLON REFLECTED IN THE HISTORIC TEST YEAR IS $1.132 AND GIVEN THE CURRENT TREND IN GASOLINE PRICES, WOULD A PRO FORMA ADJUSTMENT TO <u>REDUCE</u> GMP'S TEST YEAR GASOLINE EXPENSES BE MORE REASONABLE THAN GMP'S PROPOSED GASOLINE EXPENSE INCREASE?

A.135 Yes, it would. However, to be conservative, I am not proposing such a pro forma gasoline expense reduction adjustment in this case. I am merely recommending that GMP's proposed expense increase be rejected. The previously discussed evidence clearly supports this recommendation. The impact of my recommendation on GMP's proposed cost of service is shown on Exhibit RJH-1, Schedule 2.

19. <u>Depreciation Expenses</u>

Q.136 PLEASE DESCRIBE GMP'S PROPOSED PRO FORMA DEPRECIATION EXPENSE ADJUSTMENT RELATED TO ITS PROPOSED POST-TEST YEAR PLANT ADDITIONS AND RETIREMENTS.

A.136 As shown on GMP workpapers COS 5.1 and 5.2, the Company is proposing a pro forma net depreciation expense increase of $617,331, broken out as follows:

- Depreciation expense increase associated with projected post-test year plant additions:	$687,788
- Depreciation expense decrease associated with estimated post-test year plant in service retirements	(70,457)
- Net depreciation expense increase	$617,331

Q.137 ARE YOU RECOMMENDING AMENDMENTS TO THE ABOVE-DESCRIBED PRO FORMA NET DEPRECIATION EXPENSE INCREASE PROPOSED BY GMP?

A.137 Yes, First, I recommend that GMP's proposed depreciation expense increase of $687,788 be reduced by approximately $25,000 as a direct result of my recommended adjustments to GMP's proposed projected post-test year plant additions described earlier in this testimony. As further detailed and explained on Exhibit RJH-1, Schedule 7A, my recommended depreciation expense decrease of $25,000 relates to the following post-test year plant in service addition adjustments made by me:

	Depreciation Expense Decrease
1. Plant in service reductions for contributions associated with Distribution workorders Nos. 90548; 91699; 91742; 91769; 92146; 92181 and 92207	$18,058
2. Plant in service reduction for workorder No. 92205-Digital S/S Upgrade	$ 3,537
3. Removal of depreciation expense related to the G33 transmission reinforcement	$ 3,540
Total depreciation expense decrease	$25,135

Second, I recommend that GMP's proposed depreciation expense decrease of $70,457 related to estimated post-test year retirements be amended to a decrease amount of $192,511. Thus, this recommendation would further decrease GMP's proposed pro forma net depreciation expense increase by approximately $122,000, as summarized on Exhibit RJH-1, Schedule 7 and further detailed on Exhibit RJH-1, Schedule 7B.

Q.138 WHY DO YOU RECOMMEND THAT GMP'S PROPOSED DEPRECIATION EXPENSE DECREASE OF $70,457 FOR ESTIMATED POST-TEST YEAR RETIREMENTS BE AMENDED TO A DECREASE AMOUNT OF $192,511?

A.138 As shown on GMP workpapers 5.5 and 5.6, GMP calculated its proposed depreciation expense decrease of $70,457 for estimated post-test year retirements as follows:

- Annual plant in service retirements:	
• 1988	$1,757,432
• 1989	1,002,261
• 1990	2,446,132
• 1991	2,915,085
• 1992	4,179,601
- 5-year average	2,460,102
- 50% factor	.50x
- 50% of 5-year average	1,230,051
- Composite depreciation rate	5.728% x
- Depreciation expense decrease	$ 70,457

The first adjustment that should be made to this calculation is to remove the "50% factor". In response to VDPS 1-23, GMP confirmed that the application of this "50% factor" was incorrect and that the Company would be "willing to make an adjustment to cost of service to reflect a 100% ratio". The removal of this "50%

factor" would already change GMP's proposed depreciation expense decrease from $70,457 to $140,914.

Additionally, the Company's assumption that the estimated post-test year annual plant in service retirement level should be set at the average retirement level during the 5-year period 1988-1992 is unreasonable. As evident from the above table, GMP has experienced a discernable trend of increases in its annual plant in-service retirements. As confirmed in the Company's response to VDPS 1-24, this "trend of increases in annual retirements can be attributed to changes in accounting policy and better inventory methods used by GMP to identify retirements". Given these changes, I believe it is more reasonable to estimate the post-test year annual plant in service retirement level based on more recent retirement experience. Accordingly, I recommend that the estimated post-test year retirement level be determined based on the average retirement level experienced during the 3-year period 1990-1992. This results in an average retirement level of $3,180,273, which is still $1 million lower than the most recent available retirement level of $4,179,601 in 1992. As further detailed in Exhibit RJH-1, Schedule 7B, my two recommended adjustments to GMP's proposed depreciation expense decrease for post-test year retirements result in an annual depreciation expense decrease of $192,511. The calculations underlying this recommended depreciation expense decrease amount are summarized below:

- Annual plant in service retirements:	
• 1990	$2,446,132
• 1991	2,915,085
• 1992	4,179,601
- 3-year average	3,180,273
- Composite depreciation rate	6.0533% x
- Depreciation expense decrease	$ 192,511

Q.139 IN SUMMARY, WHAT IS THE TOTAL IMPACT OF YOUR RECOMMENDED DEPRECIATION EXPENSE ADJUSTMENTS ON GMP'S PROPOSED PRO FORMA COST OF SERVICE IN THIS CASE?

A.139 The previously described recommended depreciation expense adjustments reduce GMP's proposed pro forma cost of service by a total amount of approximately $147,000, as shown on Exhibit RJH-1, Schedule 7.

20. Income Taxes

Q.140 PLEASE DESCRIBE GMP'S EMPLOYED METHODOLOGY TO DETERMINE ITS PROPOSED PRO FORMA INCOME TAXES IN THIS CASE.

A.140 The calculations underlying GMP's proposed pro forma income taxes are shown on GMP's Attachment B, Schedule 4. As it has done in its past rate cases, GMP has used the so-called "bottoms-up" approach to calculate its pro forma income taxes in this case. This approach is described in detail on pages 16 and 17 of GMP witness Kvedar's direct testimony. I generally agree that this is an appropriate method to determine pro forma income taxes for ratemaking purposes. It should be noted that GMP's proposed pro forma income taxes incorporate a federal income tax rate of 34% rather than 35%. As confirmed in GMP response to VDPS 1-49, this is because GMP has determined that it will not be subject to the 35% FIT rate as it estimates its taxable income to be less than $10 million in the near future. Since all future

STATE OF VERMONT
PUBLIC SERVICE BOARD
DOCKET NO. 5724

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
REQUEST TO INCREASE RATES 8.9%
TO TAKE EFFECT NOVEMBER 1, 1994

DIRECT TESTIMONY OF ROBERT J. HENKES
ON BEHALF OF THE
DEPARTMENT OF PUBLIC SERVICE

MAY 27, 1994

adjustments, but take this into account when calculating the appropriate rate year recurring C&LM payroll and payroll overhead expense level in COS adjustment No. 23. I believe that the first approach represents the "cleanest" way of resolving this issue. In this way, the parties and the Board do not constantly have to keep the $175,000 double-count in mind in determining the appropriate rate year recurring C&LM expense level.

My recommendation to reduce the Company's proposed cost of service by $175,000 is detailed on Exhibit RJH-1, Schedule 4.

12. Officer Retirements Expense Removal

Q. PLEASE EXPLAIN YOUR RECOMMENDED COST OF SERVICE REDUCTION TO REFLECT ADDITIONAL EXPENSE REMOVALS FOR OFFICER RETIREMENTS.

A. During the 1993 test year, three of CVPS's officers retired. While CVPS reduced its adjusted test year cost of service by removing the salaries, 401(k) and FICA tax expenses associated with these retired officers, it did not remove other payroll overhead expenses related to these officers, such as pension, FAS 106, active medical and group life insurance expenses. In response to VDPS 3-34, the Company conceded that this should have been done. As shown on Exhibit RJH-1, Schedule 5, the removal of such additional expenses from the adjusted test year results would reduce CVPS's proposed cost of service by approximately $33,000.

treatment it has applied in Green Mountain Power Company's recent rate cases by allocating 50% of the MIP expenses to the Company's stockholders. In its Docket No. 5428 Order, the Board provided the following rationale for this particular treatment:

> Because shareholders and ratepayers share the benefits of improved performance encouraged by the Management Incentive Plan, they should also share its costs.[16]

Q. WHERE IS YOUR RECOMMENDATION REFLECTED IN YOUR TESTIMONY SCHEDULES?

A. My recommendation to reduce CVPS's proposed cost of service by $201,300 for these disallowed MIP expenses is reflected on Exhibit RJH-1, Schedule 2, column 5.

14. <u>Other Post-Retirement Benefits (FAS 106)</u>

a. <u>Expense Impact</u>

Q. COULD YOU PROVIDE SOME BACKGROUND REGARDING THE COMPANY'S FAS 106 COSTS?

A. Yes. In December 1990, the Financial Accounting Standards Board issued its statement of Financial Accounting Standards (FAS) No. 106, entitled <u>Employer's Accounting for Postretirement Benefits Other Than Pensions (OPRB)</u>, requiring companies to account for their OPRB costs based on an accrual method rather than the so-called "pay-as-you-

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[16] Public Utilities Reports - 119 PUR 4th, page 86, §140.

go" (cash) accounting method, effective with fiscal years starting after December 1992. Under the pay-as-you-go method of recognizing OPRBs, companies' books reflect the cost of OPRBs as those benefit costs are actually paid on behalf of their retirees. Under the FAS 106 accrual method, companies' books reflect a cost that is not equal to the actual payment of benefits; rather, the OPRB costs are essentially based on the present value of estimated future benefit payments which is accrued during the employees' years of service, as determined through an FAS 106 actuary study.

Prior to 1993, CVPS accounted for its OPRB costs on the pay-as-you-go basis, although during 1992 the Company started accruing $450,000 of FAS 106 expenses in anticipation of adopting FAS 106 in 1993. This resulted in the following OPRB cost levels for 1990 through 1992:

	Pay-As-You-Go Costs[17]	FAS 106 Accruals[18]	Total OPRB Costs
1990	$362,000	-	$362,000
1991	$537,000	-	$537,000
1992	$546,000	$450,000	$996,000

Effective January 1, 1993, CVPS adopted the new FAS 106 required accounting method for its OPRB expenses. As a result, the Company's 1993 OPRB cost level, as booked according to the FAS 106 accrual method, amounted to approximately $1,085,000[19]. This 1993 FAS 106 cost was determined in a study performed by the Company's actuary, Towers Perrin, and included the amortization of the Transition

[17] CVPS 1992 Annual Report, page 41 (before transfer allocations).

[18] CVPS response to VDPS 1-45, Docket 5701 (before transfer allocations).

[19] CVPS response to VDPS 2-34, Docket 5701 (before transfer allocations).

Benefit Obligation (TBO) over a 20-year period. For 1994 and 1995 the Company expects to book annual FAS 106 expenses of $1,171,000[20] and $1,241,000[20], respectively. Both of these cost levels were also calculated through a Towers Perrin actuary study based on input assumptions provided by CVPS.

Q. WHAT LEVEL OF FAS 106 COSTS HAS CVPS PROPOSED FOR RATEMAKING PURPOSES IN THIS CASE?

A. In this proceeding, CVPS is proposing rate year FAS 106 expenses of approximately $1,229,000[21]. The Company determined this amount by taking 2/12th of its expected 1994 FAS 106 costs of $1,171,000 and 10/12th of its projected 1995 FAS 106 costs of $1,241,000.

Q. IN RESPONSE TO THE BOARD'S EXPRESSED CONCERNS IN DOCKET NO. 5701 REGARDING WAYS TO MINIMIZE AND CONTAIN FAS 106 COSTS, WHAT ARE SOME EXAMPLES OF STEPS THAT COULD BE TAKEN TO ACHIEVE SUCH OBJECTIVES?

A. There are a number of ways for a utility to implement cost savings that would work towards minimizing and containing its FAS 106 costs, depending upon the utility's

[20] Exhibit RJH-1, Sch. 6, lines 1(c) and 2(c). The 1994 amount of $1,171,000 includes $80,000 and the 1995 amount of $1,241,000 includes $120,000 for the originally estimated "on-going impact" of the VRP. These amounts were later updated by the actuary.

[21] CVPS workpaper C 9-1 (before transfer allocations) and Exhibit RJH-1, Schedule 6, line 3.

ability to successfully negotiate such cost saving measures with its union and non-union employees. Some of the more important examples of such cost saving initiatives are:

- increasing the deductible portion of the annual medical claims submitted by each employee under the medical plan;

- increasing the maximum annual medical payment limit for which each employee is held responsible;

- increasing the co-insurance percentage (e.g. that percentage of medical costs after the deductible to be paid by the employee) for the utility's employees;

- limiting the growth in the utility's future OPRB liability by shifting the burden of future medical inflationary increases to the retirees;

- changing the requirements for each employee to become eligible for OPRB accruals and payments.

Q. WHAT ARE YOUR FINDINGS REGARDING INITIATIVES TAKEN BY CVPS TO MINIMIZE AND CONTAIN ITS FAS 106 COSTS?

A. Based on my review and analysis of this matter, it appears that CVPS, up to this time, has taken some positive steps in an attempt to minimize its current FAS 106 costs and contain future growth in these costs.

First, the Company has chosen a 20-year amortization period for the Transition Benefit Obligation which is the longest amortization period permitted pursuant to paragraph 112 of FAS 106. This is a contributing factor towards mitigating the Company's current FAS 106 cost impact.

Second, through recently completed bargaining sessions, the Company was able to negotiate the following changes to its OPRB program[22]:

- the current OPRB program will remain essentially unchanged until the end of 1995. As a result, the Company's annual FAS 106 costs (without the "on-going impact" of the VRP) will only experience small increases from 1993 through 1995:

	Gross FAS 106 Cost	% Increase
1993	$1,085,000	
1994	$1,091,000	0.55%
1995	$1,121,000	2.75%

[22] Based on information contained in the direct testimony of Ms. Jacquel-Anne Chouinard, pp. 6-8, Docket No. 5701 and in the direct testimony of Mr. Jonathan Day, pp. 5-6, Docket No. 5724.

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- After December 31, 1995, the Company's OPRB program will be "frozen" through the implementation of the provision that all employees retiring after 1995 will pay the increased cost of their medical coverage above the 1995 cost.

The Company claims that without these negotiated OPRB program changes, its current annual gross FAS 106 cost of approximately $1.1 million would have been approximately $1.9 million[23]. It should be noted, though, that in exchange for this negotiated FAS 106 cost reduction claimed by CVPS, the Company agreed with the Union to enhance certain other benefit programs for its employees, thereby resulting in cost increases for CVPS. For example, in exchange for the previously described future cap on retiree medical payment, CVPS increased its "match" in the 401(K) plan from 3% to 4%, resulting in an approximate annual cost increase of $175,000. Ms. Chouinard points out on page 7 of her direct testimony in Docket No. 5701 that this is an economic exchange for CVPS and its ratepayers because the 401(K) match is directly tied to wages and salaries which increase at a much slower and controllable rate than do medical costs.

Third, as described in Ms. Chouinard's direct testimony pages 7 and 8 in Docket No. 5701, starting in 1993 CVPS increased the employees' medical deductible from $150 to a range of $150-$300 and increased its employees' maximum individual medical out-of-pocket limit from $1,000 to a range of $1,200-$3,000 per year,

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[23] Testimony of Ms. Chouinard, page 6, Docket No. 5701.

depending upon income. These implemented changes would aid in containing FAS 106 costs for retirees who are currently under 65 years of age.

Q. SHOULD THE BOARD REQUIRE THAT CVPS'S FAS 106 COSTS BE FUNDED, TO THE MAXIMUM EXTENT POSSIBLE, IN OUTSIDE TAX-ADVANTAGED FUNDING VEHICLES?

A. Yes. The requirement to segregate these funds in outside trust funds provides the assurance that the funds will indeed be available when actual OPRB payments are required to be made. In addition, there are several outside funding vehicles available which allow for certain tax advantages that are not available in the case of unfunded plans. The maximum use of such tax-advantaged funding vehicles has the effect of lowering a company's future FAS 106 costs.

Q. WHAT ARE THE MOST TAX-ADVANTAGED FUNDING VEHICLES THAT ARE CURRENTLY AVAILABLE TO FUND OPRB COSTS?

A. These are the so-called 401(H) and collectively bargained VEBA (Voluntary Employee Benefit Association) plans. Both of these OPRB funding vehicles offer the following tax advantages: (1) contributions to the funds are immediately tax-deductible; (2) the earnings on the fund assets are tax-exempt; and (3) the benefits paid out of the funds are not taxable to the recipient retirees. It should be noted, though, that the IRS has imposed certain limitations as to the maximum amounts that could be contributed to these funding vehicles, based on a company's pension trust contributions.

Q. ARE THERE ANY OTHER OPRB FUNDING VEHICLES AVAILABLE?

A. Yes, but these available funding vehicles do not offer tax advantages to the same extent as the previously discussed 401(H) and collectively bargained VEBA plans. For example, another available plan is the non-collectively bargained VEBA plan which could be used to fund the postretirement benefits for employees not subject to collective bargaining. While the contributions to this funding vehicle are immediately tax deductible and the benefits paid out of the fund are tax exempt, the fund earnings are not tax exempt. Therefore, any OPRB funding through vehicles other than the 401(H) and collectively bargained VEBA plans would be less economic to a utility and its ratepayers.

Q. WHAT IS THE COMPANY'S CURRENT PLAN WITH REGARD TO THE FUNDING ASPECTS OF ITS FAS 106 ACCRUALS?

A. Effective December 1994, the Company plans to fund its FAS 106 liability through outside tax-advantaged funding vehicles. Specifically, CVPS intends to use the 401(H) plan to fund its non-union FAS 106 accruals and a collectively bargained VEBA trust to fund its union employees' FAS 106 accruals.[24] Based on the current status of its pension trust contributions, the Company expects that it will be able to fund approximately 90% of its prospective non-union FAS 106 accruals through the 401(H) plan and all of its prospective union FAS 106 accruals through the VEBA trust. Therefore, the Company's plan to fund almost all of its prospective FAS 106 costs

[24] Direct testimony of Mr. Pennington, page 3.

through the most tax-advantaged outside funding vehicles that are currently available would represent another positive step to contain its future FAS 106 costs.

Q. WHAT ARE UNFUNDED FAS 106 COSTS AND HOW SHOULD THEY BE TREATED FOR RATEMAKING PURPOSES?

A. Unfunded FAS 106 costs represent FAS 106 liability accruals on the Company's books that have not been paid out to the retirees and have not been transferred (funded) to an outside trust fund such as a VEBA or 401(H) trust. To the extent that ratepayers have paid for such unfunded FAS 106 costs, these costs should be treated as a rate base deduction for ratemaking purposes. This will be discussed in more detail later on.

Q. BASED ON YOUR PREVIOUS DISCUSSIONS REGARDING THE EXPENSE IMPACT OF CVPS'S OPRB LIABILITY UNDER FAS 106, WHAT IS YOUR RECOMMENDATION?

A. Based on the FAS 106 precedents established by the Board in Green Mountain Power's rate cases in Docket Nos. 5428 and 5532 and based on my previously discussed findings regarding CVPS's FAS 106 cost containment efforts, I recommend that a projected rate year FAS 106 cost level (before transfer allocations) of $1,183,000 be allowed for ratemaking purposes in this case. This recommended expense level of $1,183,000 is $46,000 lower than CVPS's originally proposed expense level of $1,229,000. The recommended $46,000 expense adjustment is a direct result of an update recently provided[25] by CVPS's actuary with regard to the "ongoing impact of the VRP" on the projected rate year FAS 106 expenses. As shown on Exhibit RJH-1, Schedule 6, after taking transfer allocations into account, my recommended rate year FAS 106 O&M expense level results in a cost of service O&M expense adjustment of $34,000.

Q. FINALLY, DO YOU BELIEVE THAT CVPS'S CURRENT RATES ALREADY INCLUDE AN ALLOWANCE FOR THE COMPANY'S FAS 106 EXPENSE ACCRUALS?

A. Yes I do. This will be discussed in more detail in the following testimony section.

b. <u>Rate Base Impact</u>

Q. WHAT IS CVPS'S PROPOSED POSITION WITH REGARD TO THE FAS 106 RELATED RATE BASE IMPACT DURING THE RATE YEAR?

A. As summarized on Exhibit RJH-1, Schedule 25, page 1, CVPS has determined that during the rate year it will have a <u>negative</u> 13-month average unfunded FAS 106 accrual balance of $598,460 and proposes that this balance of $598,460 be treated as a rate base addition. In coming up with this proposed position, CVPS has completely ignored the pre-rate year unfunded FAS 106 accruals that have been and will continue to be accumulated on its books through October 1994. The Company has taken this

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[25] Provided by CVPS to the DPS during 5/4/94 informal data conference.

pro-forma position because it is of the opinion that all of its per books unfunded FAS 106 accruals accumulated through October 1994 have not been collected in rates from the ratepayers.

Q. WHAT IS YOUR RECOMMENDED RATE BASE TREATMENT FOR CVPS'S ACCUMULATED UNFUNDED FAS 106 ACCRUALS?

A. As summarized on Exhibit RJH-1, Schedule 25, page 1, I recommend that the Company's rate year rate base be reduced by $767,612, representing the rate year's 13-month average positive unfunded FAS 106 accrual balance that will actually be recorded on the Company's books. An important aspect of this recommendation is my belief that all of CVPS's pre-rate year accumulated unfunded FAS 106 accruals have been paid for in rates by the ratepayers.

Q. BEFORE FURTHER DISCUSSING THIS LATTER POINT, COULD YOU FIRST EXPLAIN HOW THE COMPANY'S PROPOSED AND YOUR RECOMMENDED UNFUNDED FAS 106 ACCRUAL BALANCES FOR THE RATE YEAR SHOWN ON EXHIBIT RJH-1, SCHEDULE 25, PAGE 1 WERE DERIVED?

A. Yes. The derivation of these balances is shown in detail on Exhibit RJH-1, Schedule 25, page 2. The first column on this schedule shows CVPS's FAS 106 OPRB payments and funding contributions from 1992 through the end of the rate year, October 1995. The second column shows the Company's FAS 106 OPRB expense accruals for the same time period. The third column shows the monthly differences

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between payments/fund contributions and expense accruals; these differences represent the unfunded FAS 106 accruals. The fourth column shows the monthly accumulated balances for CVPS's unfunded FAS 106 accruals. These monthly accumulated balances are actually being recorded on the Company's books.

As can be seen from this schedule, at the beginning of the rate year, November 1994, CVPS's books will actually show an accumulated unfunded FAS 106 accrual balance of $1,511,648. In December 1994, this per books accumulated unfunded FAS 106 accrual balance will be reduced to $467,731 due to the Company's plan to make a large one-time contribution to its outside trust funds. This $467,731 unfunded accrual balance will then grow again during the remaining portion of the rate year as a result of the excess of rate year FAS 106 expense accruals over FAS 106 payments.

The fifth column of this schedule shows CVPS's proposed pro forma position. As discussed previously, CVPS has ignored the actual per books unfunded FAS 106 accrual balance of $1,511,648 in November 1994 because it believes that this balance was never paid for by the ratepayers. Instead, the Company proposes to start a brand-new unfunded FAS 106 accrual balance in November 1994. Thus, for November 1994 the Company's proposed starting balance will be $47,084, i.e. the excess of FAS 106 expense accruals over FAS 106 payments during that month. In December 1994, this unfunded accrual balance will change to a negative amount of $996,833[26] (i.e. a <u>prepayment</u> position) as a result of the planned one-time contribution to its outside trust funds. This prepayment balance of $996,833 will then decline during the remaining

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[26] Calculated from the accumulation of column (3): $47,084 + ($1,043,917) = ($996,833)

portion of the rate year as a result of the excess of rate year FAS 106 expense accruals over FAS 106 payments.

Q. COULD YOU NOW EXPLAIN WHY YOU BELIEVE THAT, FOR PURPOSES OF DETERMINING THE APPROPRIATE RATE YEAR UNFUNDED FAS 106 ACCRUAL BALANCES, THE BOARD SHOULD USE THE COMPANY'S PER BOOKS UNFUNDED ACCRUAL BALANCES?

A. Yes. It is my opinion that the Company's per books unfunded FAS 106 accruals have been and will continue to be paid for by the ratepayers. As shown on the first line of Exhibit RJH-1, Schedule 25, page 2, during 1992 CVPS recorded $450,000 of FAS 106 expense accruals on its books. However, even with this expense included, the Company earned 12.7%[27] on the equity invested in its utility operations during 1992. It should also be noted that the Company's 1992 operating income was reduced by a $4.9 million reserve booking for the Cleveland Avenue site and that its 1992 return on utility equity would have been 14.86% absent this reserve booking. Since CVPS's VPSB-authorized return on equity during 1992 was 12.5%, it is my opinion that the ratepayers have paid for the $450,000 FAS 106 expense accrual in 1992.

During 1993, CVPS recorded FAS 106 expense accruals of $1,085,000 on its books, as shown on Exhibit RJH-1, Schedule 25, page 2. On April 28, 1993, CVPS and the DPS jointly filed a settlement agreement with regard to CVPS's cost of service

[27] CVPS response to VDPS 1-12, Docket No. 5701 and 1992 annual report to the stockholders, page 3.

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and retail rates at that time. In this stipulation, the parties essentially agreed that no rate change was required. Since CVPS was already booking its $1,085,000 FAS 106 expense accruals at that time and the parties agreed that there were no reasons for the rates to change, the conclusion should be that the rates established in that settlement (which are still in effect today and will be until November 1, 1994) included a full allowance of CVPS's FAS 106 expense accruals. Furthermore, in this April 28, 1993 settlement CVPS also agreed to a return on utility equity of 12%, effective January 1, 1993, and to credit its DSM deferrals with any excess earnings over 12%. CVPS, under its own proposed calculations, earned 12%[28] on its utility equity during 1993 and, therefore, has not proposed to provide the ratepayers with the benefits of DSM deferral credits. It should be recognized, however, that the 1993 FAS 106 accruals of $1,085,000 recorded on CVPS's books were included as expenses (income reductions) in CVPS's calculation of its 1993 utility equity return of 12%. Without the 1993 FAS 106 expense booking of $1,085,000, CVPS's 1993 utility equity return, under its own calculations, would have been <u>12.43%</u> which, in turn, would have resulted in a ratepayer benefit, in the form of DSM deferral credits, of an amount approximately equal to the 1993 FAS 106 expense of $1,085,000. Thus, on the one hand CVPS proposes to disregard its per books FAS 106 expense accruals in depriving the ratepayers of a rate base deduction in this case for the associated per books unfunded FAS 106 accruals. However, on the other hand CVPS proposes to recognize the same

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[28] CVPS response to VDPS 1-12, Docket No. 5701 and 1993 annual report to the stockholders, page 2. In a previous section of this testimony I discuss that the appropriately calculated return on utility equity for 1993 was 12.32%.

per books FAS 106 expense accruals in, again, depriving the ratepayer of deferred DSM credit benefits resulting from the excess earnings over its authorized return on equity of 12%. In my opinion, this proposition is inconsistent and inequitable. Given that CVPS's calculated 1993 return on utility equity of 12% was equal to the authorized return level, and given that the 1993 FAS 106 expenses of $1,085,000 were included in the 12% return calculations and were not returned to the ratepayers through DSM deferral credits, one must conclude that the ratepayers have paid for CVPS's booked FAS 106 expenses.

In summary, the ratepayers have paid and will be paying for all of CVPS's FAS 106 expense accruals since 1992. Therefore, all the per books accumulated unfunded FAS 106 accrual balances shown in column (4) of Exhibit RJH-1, Schedule 25, page 2 should be used by the Board to determine the Company's appropriate rate year rate base impact of such unfunded accruals. My recommendation represents another appropriate step the Board should implement in order to minimize the rate impact on the ratepayers of CVPS's change to FAS 106 accrual accounting for its OPRBs.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDED POSITION ON CVPS'S PROPOSED RATE YEAR RATE BASE IN THIS CASE?

A. As shown on Exhibit RJH-1, Schedule 25, page 1, my recommendation reduces CVPS's proposed rate year rate base by approximately $1,366,000.

15. <u>Other Post-Employment Benefits (FAS 112)</u>

Q. WHAT ARE OTHER POST-EMPLOYMENT BENEFITS?

A. Other Post-Employment Benefits (OPEB) represent long-term disability and medical benefits for former or inactive employees of CVPS prior to their retirement. Employees who go on long-term disability before their retirement age are considered inactive employees and time on disability counts toward the accrual of retiree disability and medical benefits. These other Post-Employment Benefits are different from other Post-Retirement Benefits (OPRB) which represent medical benefits to be paid to employees after their retirement and which are now accounted for by CVPS under the FAS 106 accrual method as previously described in this testimony.

Q. HOW IS CVPS ACCOUNTING FOR ITS OPEB LIABILITIES?

A. Prior to 1993, CVPS accounted for its OPEBs based on the pay-as-you-go (cash) method. In other words, the Company expensed on its books the amounts it actually paid out in OPEBs. However, statement of Financial Accounting Standards No. 112 (FAS 112) - Employers' Accounting for Post-Employment Benefits, now requires companies to use the accrual method for their OPEBs. In compliance with FAS 112, CVPS started booking its OPEBs under the accrual method effective January 1, 1994.

Q. HAS THE CHANGE-OVER TO ACCRUAL ACCOUNTING FOR THE COMPANY'S OPEB COSTS CREATED A SO-CALLED TRANSITION BENEFIT OBLIGATION (TBO) FOR CVPS?

A. Yes. Although much smaller than the FAS 106 related TBO, the FAS 112 accrual method has resulted in an unamortized TBO amount of $771,967 (after allocations)[29] at the beginning of the rate year (November 1, 1994) in this case. While FAS 106 provided for specific transition rules for the FAS 106 related TBO,[30] there are no transition rules applicable to the FAS 112 related TBO. Because of the absence of such transition rules, CVPS would have to expense its entire FAS 112 related TBO in 1994, unless ratemaking treatment allows amortization recovery of this TBO over a specific period of time. As described on pages 4 and 5 of Mr. Pennington's direct testimony, in this case CVPS is proposing to amortize its FAS 112 related TBO over a 3-year period and .... "specifically requests this ratemaking treatment exception in order to reduce the initial impact on ratepayers".

Q. PLEASE DESCRIBE THE ADJUSTMENT CALCULATED BY CVPS IN ITS FILING RESULTS IN THIS CASE TO REFLECT ITS ADOPTION OF FAS 112 IN 1994.

A. During the 1993 test year, CVPS booked $113,848 of OPEB expenses based on the pay-as-you-go method. In order to reflect the adoption of FAS 112 in 1994, CVPS has proposed a FAS 112 rate year expense of $303,238, thereby resulting in a proforma test

[29] CVPS response to VDPS 3-33.

[30] FAS 106 paragraph 112 provides that the FAS 106 related TBO may be amortized over a period up to 20 years.

year expense increase of $189,390. CVPS's calculation of this expense increase can be summarized as follows:

	1993 Test Year	Rate Year	Expense Increase
- Pay-as-you-go	$ 113,848		
- FAS 112 Expense:			
• "Current" Expense		$ 10,936	
• 3-Yr. Amortization of TBO		$ 292,302	
- Total	$ 113,848	$ 303,238	$ 189,390

Q. SHOULD CVPS's PROPOSED RATE YEAR FAS 112 EXPENSE OF $303,238 BE CORRECTED FOR A CALCULATION ERROR?

A. Yes. In response to VDPS request 3-33, CVPS conceded that its proposed amount of $292,302 for the 3-year amortization of the TBO should have been $257,322.[31] Therefore, on a corrected basis, CVPS's proposed rate year FAS 112 expense should be $268,258 ($10,936 + $257,322) and the resulting proposed test year expense increase should be $154,410, or $34,980 lower than the $189,390 reflected in Company's filing results.

Q. DO YOU RECOMMEND THAT THIS CORRECTED FAS 112 RATE YEAR EXPENSE INCREASE OF $154,450 BE ADOPTED BY THE BOARD FOR RATEMAKING PURPOSES IN THIS PROCEEDING?

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[31] Unamortized TBO @ 10/31/94 of $771,967 divided by 3 equals $257,322.

A. No, I do not. The only reason for this proposed expense increase of $154,410 is the fact that the Company has chosen a 3-year amortization period for the FAS 112 TBO. As previously discussed, there are no specific transition rules for this TBO. The only rationale provided by CVPS for its particular choice of a 3-year amortization period is that it wishes to minimize the rate impact of the FAS 112 adoption on its ratepayers. Pursuant to this objective, I would recommend that the Board adopt an amortization period of approximately 7 1/2 years for CVPS's FAS 112 TBO amount. In so doing, the Board would equalize the rate year OPEB expenses under FAS 112 to the test year OPEB expenses under pay-as-you-go. I believe that the use of a 7 1/2 year amortization period for the FAS 112 TBO is reasonable. It is much shorter than the 20-year amortization period chosen by CVPS for its (larger) FAS 106 TBO and, at the same time, completely removes the initial rate impact of FAS 112 on CVPS's current ratepayers without being punitive to the Company's stockholders. Below, I show how my recommendation would result in no rate impact of FAS 112 on the ratepayers:

	1993 Test Year	Rate Year	Expense Increase
- Pay-as-you-go expense	$ 113,848		
- FAS 112 Expense:			
• "Current" Expense:		$ 10,936	
• Approx. 7 1/2 Yr. Amort. of TBO		$ 102,912[32]	
- Total	$ 113,848	$ 113,848	$ 0

Q. IN SUMMARY, WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S PROPOSED ADJUSTED TEST YEAR FILING RESULTS IN THIS CASE?

A. First, my recommendation reduces CVPS's proposed adjusted test year cost of service by approximately $189,000. Second, consistent with my recommendation I have also removed CVPS's proposed FAS 112 related rate base reduction of $125,000, thereby resulting in an increase in the Company's proposed rate base of $125,000. The recommended rate base adjustment is shown on Exhibit RJH-1, Schedule 18, line 26. The recommended expense adjustment is shown on Exhibit RJH-1, Schedule 2, column 7.

[32] $771,967 ÷ 7.5 = $102,912

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A. Yes. On Exhibit RJH-1, Schedule 2, column 16, I have reflected those recommended purchased power adjustments that were quantified by DPS power witnesses at the time I prepared this testimony.

25. Depreciation Expenses

Q. HAVE YOU MADE ADJUSTMENTS TO THE COMPANY'S PROPOSED ADJUSTED TEST YEAR DEPRECIATION EXPENSES?

A. Yes. As detailed on Exhibit RJH-1, Schedule 15, I recommend that CVPS's proposed adjusted test year depreciation expenses of $16,351,000 be reduced by $63,000 to a recommended depreciation expense level of $16,288,000. Of this recommended reduction, an amount of $25,000 is a direct result of recommended disallowances for certain pro forma plant in service additions that were proposed by CVPS in this case, as discussed elsewhere in this testimony. These recommended depreciation expense reductions are shown on lines 2 through 5 of Exhibit RJH-1, Schedule 15. The remaining depreciation expense reduction of $38,000 results from my recommendation to use a 5-year amortization rate of 20% for CVPS's proposed CIS - Phases II & III plant in service additions rather than the amortization rate of 30% used by CVPS.

Q. COULD YOU EXPLAIN THIS ADJUSTMENT IN MORE DETAIL?

A. Yes. For all of its so-called "Limited Term Electric Plant", representing data processing and other electric systems,[39] CVPS employs a 5-year amortization rate of 20%. The Company is also currently amortizing its CIS - Phase I project, which was placed in service in February 1992, at a rate of 20%. However, for the CIS - Phase II & III projects, which were respectively placed in service in September 1993 and December 1993, CVPS is proposing amortization rates of 30%. The rationale for this was explained in the Company's response to VDPS 1-56 in Docket No. 5701:

> These projects are additional phases of the CIS project (Phase II and III). Therefore, these two projects are being amortized over the remaining 41 months and 38 months, respectively, of the amortization period for the initial phase of the CIS system.

I do not agree with this proposed amortization treatment. CIS - Phases II and III represent separate and distinct CIS system enhancements requiring additional investments of more than $400,000 that were placed in service almost 2 years after the in-service date of CIS Phase I. I do not believe it is reasonable to assume that the economic lives of Phases II and III are reduced from 5 years to approximately 3 years merely because Phase I has already gone through a 2-year amortization period. In addition, the Company's tax workpapers show that it is using a 5-year amortization rate of 20% for tax amortization purposes. I therefore recommend that CIS - Phases II and III be amortized at the 5-year amortization rate of 20% consistent with the rate applied by CVPS to CIS - Phase I and all other "Limited Term Electric Plant".

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[39] Such as basic records, general ledger, client/server, work order management, network infrastructure, C&LM monitoring, SAS, electronic mail, etc.

A. This allocation factor is calculated through a complicated model using multi-step functional assignment and jurisdictional allocation procedures for all of CVPS's cost of service components. I do not have this model available. In addition, I do not know, at this time, the recommendations to be made by the DPS with regard to functional assignments and jurisdictional allocations for purposes of determining the appropriate overall wholesale allocation factor. Therefore, at this time and for presentation purposes only, I have used a wholesale allocation factor of 5.26%, which is the same factor as used by CVPS to allocate its "as filed" adjusted test year cost of service to wholesale. Once the final adjusted test year cost of service amounts found to be appropriate by the Board in this case have been determined, the wholesale allocation factor should be recalculated based on such final cost of service data and should take into account wholesale allocation recommendations made by the DPS.

31. Restructuring Adjustment

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED AND THE DPS RECOMMENDED POSITIONS WITH REGARD TO THE IMPACT OF THE RESTRUCTURING ON THE ADJUSTED TEST YEAR COST OF SERVICE RESULTS.

A. The Company's February 15, 1994 requested rate increase of $17.9 million incorporated cost of service reductions of $1,782,000 for estimated restructuring savings and $4,788,000 for a proposed ceiling adjustment. Since the restructuring had not yet taken place on the 2/15/94 filing date, the Company indicated in its filing letter to the Board that (1) it would update the originally estimated restructuring adjustment for actual results; and (2) if the actual restructuring results were to result in a restructuring cost of service credit higher than $1,782,000, it would reduce its proposed $4,788,000 ceiling adjustment by the "excess" restructuring savings over $1,782,000, thereby leaving its requested rate increase of $17.9 million unchanged.

On May 10, 1994, CVPS filed supplemental testimonies, exhibits and workpapers describing and quantifying the actual results of the restructuring. The Company's calculations of this restructuring update indicate a total rate year net cost of service credit of $2,170,000 rather than the originally estimated "as filed" amount of $1,782,000. Based on my review of CVPS's updated restructuring saving calculations, I have concluded that certain adjustments are in order which would increase the Company's updated restructuring saving amount of $2,170,000 to a DPS recommended amount of $2,543,000.

As summarized by specific net restructuring saving components on Exhibit RJH-1, Schedule 28, page 1, my recommended updated net restructuring saving amount of $2,543,000 is $761,000 higher than CVPS's original "as filed" amount of $1,782,000. Schedule 28, page 1, shows that the recommended net savings amount of $2,543,000 consists of annual rate year benefits of $3,441,000 for payroll and payroll overhead expense savings and $128,000 for return on rate base savings, offset by $1,026,000 for annual rate year amortization costs. The rate year amortization cost of $1,026,000 represents the 5 - year amortization of the total restructuring cost incurred by CVPS which has been deferred and is being amortized by the Company as of June 1, 1994 in accordance with the restructuring accounting order.

Q. ARE YOU RECOMMENDING THAT CVPS'S PROPOSED "AS FILED" CEILING ADJUSTMENT OF $4,788,000 BE REDUCED BY THE $761,000 "EXCESS" OF YOUR RECOMMENDED RESTRUCTURING ADJUSTMENT OF $2,543,000 OVER CVPS'S PROPOSED "AS FILED" RESTRUCTURING ADJUSTMENT OF $1,782,000?

A. Yes. This will be further discussed in the next section ("The Management Challenge") of this testimony.

Q. COULD YOU NOW DISCUSS IN MORE DETAIL HOW YOU DETERMINED YOUR RECOMMENDED NET RESTRUCTURING SAVINGS ADJUSTMENT OF $2,543,000?

A. Yes. I derived my recommended restructuring saving amount of $2,543,000 by making two adjustments to CVPS's proposed updated restructuring saving amount of $2,170,000.

The first adjustment concerns CVPS's calculations for payroll and payroll overhead savings. As shown on Exhibit RJH-1, Schedule 28, page 2, CVPS first calculated that the total annual payroll and payroll overhead savings amount to $4,691,000. Of this total amount, CVPS then removed:

(1) $1,086,000 representing "capital savings", i.e., the amount of plant capitalizations that will not be incurred during the adjusted test year as a result of the restructuring;

(2) $164,000 representing the savings to be allocated to its non-regulated subsidiaries; and

(3) $248,000 for the savings portion of the $4,691,000 which CVPS assumed to have already been incorporated in its proposed rate year recurring C&LM payroll and payroll overhead amount in its cost of service adjustment No. 23.

As a result, CVPS proposes that its rate year cost of service should be reduced by a net amount of $3,193,000 for its updated restructuring payroll and payroll overhead. The only disagreement I have is with CVPS's assumption that $248,000 of the total restructuring payroll and payroll overhead savings is already included in its cost of service adjustment No. 23 for C&LM.

Q. WHY DO YOU DISAGREE?

a. As part of its original 2/15/94 filing results, CVPS claimed a projected rate year C&LM recurring payroll and payroll overhead amount of $1,196,000[42] In calculating its originally estimated restructuring savings adjustment of $1,782,000, CVPS made the assumption that $300,796 of these restructuring savings were already incorporated in the $1,196,000 amount for projected rate year recurring C&LM payroll and payroll overheads. To further investigate and verify this assumption, I issued the following data request to CVPS with the following Company response:

[42] CVPS filing workpaper C23-2.

Q6-85. Re. C 23-2, calculation of net recurring C&LM salaries and overheads for the rate year of $1,196,001:

a. How many C&LM people were assumed in the calculation of this rate year amount and compare this to the C&LM people underlying the actual C&LM salaries and overheads of $2,234,269 shown on C 23-6 (ID Nos. 010-060).

b. Show whether, and to what extent, the calculated amount of $1,196,001 was impacted by the C&LM savings amount of $300,796 on C 34-4.

A6-85. a&b. The number of C&LM people assumed in calculating the rate year recurring C&LM salaries and overheads of $1,196,001 is not available. ID expenditure rates (see workpaper C23-3) were used to determine the amount of recurring C&LM expenditures attributable to salaries and overheads. Based on updated information related to the severance packages and programs, the estimated split between recurring salary and related overheads and support costs may be revised. As such, the $1,196,001 may be adjusted either upward or downward. The total recurring amount of $2,555,274 will not change.

Thus, the above-referenced response indicates that CVPS does not know whether its originally calculated restructuring savings portion of $300,796 (which it assumed to have already been incorporated in the recurring C&LM rate year amount of $1,196,000) was indeed specifically included in its calculation of the $1,196,000. In fact, CVPS apparently does not even know the specific level of C&LM people and any other details underlying the amount of $1,196,000.

While the restructuring update resulted in significant changes from the original estimate, CVPS's proposed rate year recurring C&LM payroll and payroll overhead amount of $1,196,000 was not changed. In calculating its updated restructuring adjustment, the Company has now assumed that $248,000 of these updated restructuring savings were already incorporated in the rate year C&LM payroll and payroll overhead amount of $1,196,000.

Based on the aforementioned information, I have concluded that CVPS's assumption that a specific amount of $248,000 of the updated restructuring savings was already incorporated in its proposed rate year recurring C&LM payroll and payroll overhead amount of $1,196,000 is not only unreasonable, but also does not appear to be known and measurable. I therefore recommend that this $248,000 not be removed from the cost of service credit amount to be recognized as the restructuring adjustment in this case. My recommendation is reflected on Exhibit RJH-1, Schedule 28, page 2.

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

A. Yes. It is CVPS's proposal in this case to defer any actual recurring C&LM payroll and payroll overhead costs in excess of the amount of $1,196,000 for which it has requested rate recovery. This was confirmed by CVPS in response to VDPS 4-39:

> Q. 4-39(a) Will CVPS defer any actual C&LM recurring salary and related overhead costs in excess of the amount of $1,196,000 to be built into rates?
>
> A. 4-39(a) Yes.

Thus, to the extent that CVPS's actual recurring C&LM payroll and payroll overhead costs exceed the allowed rate recovery, CVPS will be completely made whole under this proposal. My recommendation to leave the $248,000 as part of the restructuring cost of service adjustment, rather than making the unsupported assumption that this saving was already incorporated in the $1,196,000, would therefore not be punitive to CVPS.

Q. WHY HAVE YOU MADE THE SMALL ADJUSTMENT OF $4,000 TO CVPS'S PROPOSED UPDATED RESTRUCTURING AMORTIZATION COSTS, AS SHOWN ON EXHIBIT RJH-1, SCHEDULE 28, PAGE 2?

A. The reason for this adjustment is that my previously discussed $248,000 payroll and payroll overhead savings adjustment directly results in a slight subsidiary allocation change for the restructuring amortization costs.

Q. COULD YOU NOW DESCRIBE YOUR RECOMMENDED RESTRUCTURING COST SAVINGS RESULTING FROM THE REDUCTION IN RETURN ON UTILITY RATE BASE?

A. Yes. As detailed on Exhibit RJH-1, Schedule 28, page 3, the restructuring also results in a number of rate base reductions and additions. In calculating its originally proposed restructuring adjustment of $1,782,000, CVPS recognized and reflected these rate base related net cost savings (see Schedule 28, page 1, line 2). However, in its updated calculations, CVPS did not incorporate such rate base related net cost savings.

The restructuring related rate base reduction and addition amounts shown on Schedule 28, page 3, lines 1-3, were calculated by CVPS and provided to me on May 16, 1994. During recent conversations I have had with Company personnel, CVPS appeared to admit that the reflection of these three rate base adjustments would be appropriate. The Company has also agreed that the cash working capital reduction directly flowing from the restructuring adjustment should be recognized for ratemaking purposed in this case.[43] On line 5 of Schedule 28, page 3, I have reflected a rate base reduction of $325,000 for the cash working capital impact of my recommended restructuring adjustment. The only restructuring related rate base adjustment proposed by me that appears to be at issue is the $543,000 rate base reduction shown on line 4 of Schedule 28, page 3 for the capital savings.

Q. COULD YOU ELABORATE ON THIS ISSUE?

A. Yes. As previously discussed by me and as shown on Schedule 28, page 2, line 2, CVPS will experience capital savings of $1,086,000, representing capitalized plant which will no longer be incurred by CVPS as a result of the restructuring. I have therefore reflected a rate base reduction of one-half of this capital savings amount of $1,086,000, or $543,000, to recognize the impact of this saving on the average adjusted test year rate base. CVPS made the exact same type of rate base adjustment in calculating its original restructuring adjustment, but now appears to be taking the position that such a rate base adjustment is not appropriate. I believe it is appropriate. The purpose of making pro forma adjustments to the historic test year results used in a rate proceeding is to restate the test year results as if the changes causing the pro forma adjustments had been in effect during the entire historic test year. If one assumes that the restructuring had been in effect during the entire historic test year, CVPS's test

[43] CVPS response to VDPS 4-4(d).

year rate base would have been lower by $543,000. CVPS is essentially taking the inappropriate position that $1,086,000 of its actual restructuring payroll and payroll overhead savings are "phantom" savings that will never be realized.

Q. WILL CVPS'S RESTRUCTURING EFFORT RESULT IN NET O&M EXPENSE SAVINGS DURING THE 6-MONTH PERIOD MAY 1, 1994 (THE APPROXIMATE STARTING POINT OF THE RESTRUCTURING IMPLEMENTATION) UNTIL NOVEMBER 1, 1994 (THE START OF THE RATE EFFECTIVE DATE OF THIS CASE)?

A. Yes. Starting in May 1994 and continuing through October 1994, CVPS no longer pays the payroll and payroll overhead of the people removed as a result of the restructuring program, however, the rates collected by CVPS during this period do not reflect these cost reductions. On the other hand, CVPS will start amortizing the restructuring costs as of June 1, 1994 and the rates from 6/1/94 - 10/31/94 do not reflect these cost increases. In addition, as described on page 2 of Mr. Pennington's supplemental direct testimony, CVPS also projects other restructuring related costs [44](not included as part of the restructuring accounting order) which "could approach $500,000 in 1994". I requested the Company to provide the net restructuring savings to be experienced prior

[44] Such as costs for outplacement, consulting, training, workshops, employee relocation, etc.

to the rate year as a result of the previously described pre-rate year cost savings and cost increases. The Company responded with the following information:

	$000's
• O&M salary and benefit savings	$ 1,175
• Amortization costs	(426)
• Other costs (estimate)	(500)
• Net savings	$ 249

Q. DO YOU RECOMMEND THAT THESE PRE-RATE YEAR NET O&M SAVINGS ASSOCIATED WITH THE RESTRUCTURING BE TAKEN INTO ACCOUNT FOR RATEMAKING PURPOSES?

A. No, I do not. However, this information does show that CVPS's actual restructuring cost amount of $5,377,000 (see Schedule 28, page 2, line 6) which it has deferred in accordance with the restructuring accounting order is really lower by $249,000.

Q. DO YOU HAVE ANY FINAL COMMENTS REGARDING THE RESTRUCTURING ISSUE?

A. Yes. The Company has made numerous statements to the Board and other parties that the savings from its restructuring program would be significantly in excess of the restructuring implementation costs. This was also the major factor listed and detailed by CVPS in its November 24, 1993 letter to the Board in which it requested the Board's approval of an accounting order for the restructuring costs. The accounting order eventually approved by the Board on March 11, 1994 specifically recognized that this order would allow CVPS to book and recognize, for financial reporting purposes, its restructuring costs during a time period that the associated cost savings will be realized.[45]

The accounting order also provides in § 7:

> This Order is <u>limited to the accounting treatment for the subject restructuring costs</u> and does not bar any party from contesting, or the Board from determining, or disallowing, the reasonableness or prudence of such costs, in whole or in part, in any rate proceeding. (Emphasis supplied).

In other words, while the accounting order allows the deferral and amortization of CVPS's restructuring costs for book purposes, this does not mean that any of such amortization costs are therefore automatically allowed for ratemaking purposes.

In the current case, the DPS is recommending that the Board give rate recognition to the restructuring amortization costs because the associated restructuring savings to be recognized for ratemaking purposes are clearly significantly in excess of the amortization costs. However, pursuant to § 7 of the accounting order, the DPS reserves the right to contest the reasonableness or prudence of continuing the rate recognition of such amortization costs in future CVPS rate proceedings if it appears that the "matching" savings, for some reason, are no longer being realized.

32. <u>Ceiling Adjustment - The "Management Challenge"</u>

Q. HAS THE COMPANY PROPOSED A SO-CALLED CEILING ADJUSTMENT IN THIS CASE?

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[45] Restructuring accounting order § 5.

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ADJUSTMENTS OF RATES OF DELTA NATURAL GAS COMPANY, INC.	)))	Case No. 97-066

DIRECT TESTIMONY OF ROBERT J. HENKES ON BEHALF OF THE OFFICE OF RATE INTERVENTION OF THE ATTORNEY GENERAL FOR THE COMMONWEALTH OF KENTUCKY

JULY 18, 1997

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C. OPERATING INCOME

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED AND YOUR RECOMMENDED PRO FORMA OPERATING INCOME FOR THE TEST YEAR IN THIS CASE.

A. The Company's proposed and my recommended pro forma operating income positions are summarized on Schedule RJH-9. The Company has proposed a total pro forma test year operating income amount of $4,579,880. I have made a large number of adjustments to the Company's proposed operating revenues, expenses and taxes which, in total, had the effect of increasing the Company's proposed operating income by $483,443 for a total recommended pro forma test year operating income amount of $5,063,323. Each of my recommended operating revenue, expense and tax adjustments will be discussed below.

<u>Residential Retail Revenue and Cost of Gas Adjustments</u>

Q. HOW DID THE COMPANY DETERMINE ITS PROPOSED PRO FORMA RESIDENTIAL RETAIL REVENUE AND ASSOCIATED COST OF GAS EXPENSES FOR THE TEST YEAR IN THIS CASE?

A. As shown on FR #6-h, Schedule 2, page 1, lines 4 and 5 and as summarized under the first column of schedule RJH-11, the Company's proposed pro forma residential retail revenues for the test year consist of two revenue categories: (1) customer charge revenues of $2,168,424, and (2) gas usage revenues of $18,427,648. The proposed customer charge revenues of $2,168,424, are based on the actual per books 1996 number of customer bills

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of 364,441[5] times the current customer charge rate per bill of $5.95. The proposed gas usage revenues of $18,427,648 are based on the actual 1996 residential retail Mcf sales, adjusted for normal weather, of 2,490,492 Mcf times the current total base and GCR rate per Mcf of $7.3992. The actual weather-normalized 1996 sales of 2,490,492 was generated by the actual 1996 average number of residential retail customers of 30,370.

Q. IS THERE AN ISSUE WITH REGARD TO THE COMPANY'S PROPOSAL TO BASE ITS PROPOSED TEST YEAR RESIDENTIAL RETAIL REVENUES ON THE 1996 AVERAGE NUMBER OF RESIDENTIAL RETAIL CUSTOMERS AND ASSOCIATED ACTUAL TOTAL NUMBER OF RESIDENTIAL RETAIL BILLS?

A. Yes. The issue is that the Company has not annualized its proposed test year residential retail revenues for the growth in its residential retail number of customers and related total number of residential retail bills. Because of this, the Company's proposed test year residential retail revenues are not properly "matched" with the Company's proposal to use a test year-end rate base in this proceeding.

Q. COULD YOU EXPLAIN THIS IN MORE DETAIL?

A. Yes. As discussed before, the Company's proposed test year residential revenues are based on the actual 1996 average number of customers of 30,370 and the related actual total number of bills of 364,441. In this regard, it is important to recognize that *the plant*

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[5] Actual 1996 average number of customers of 30,370 times 12 monthly bills = actual total 1996 number of bills of 364,441.

investment that has supported the Company's 1996 average number of customers and related total number of bills is the Company's average 1996 plant, not the December 31, 1996 plant investment level. As shown in the response to data request AG 2-20, the Company's average 1996 plant in service level exclusive of the Canada Mountain project amounted to $89,578,390. This is $5,457,477 lower than the Company's proposed December 31, 1996 plant in service level exclusive of the Canada Mountain project of $95,035,867. Thus, the Company's proposal to reflect the test year-end as opposed to the average 1996 plant in service balance has resulted in a revenue requirement increase of approximately $853,000:

		Rev. Req. Impact
- Plant in Service Increase:	$5,457,477	
- Delta's After-Tax Rate of Return:	7.71%	
- Return Requirement	$ 420,771	
- Revene Gross-Up Factor	1.6514 x	
- Revenue Requirement Impact		$694,861
- Depr. Expense Increase:	$5,457,477	
- Composite Depr. Rate	2.90%	
- Revenue Requirement Impact		$158,269
- Total Revenue Requirement Impact		$853,130

The AG submits that a substantial portion of this additional revenue requirement of $853,000 included in the Company's total rate increase request in this case has been, and will be, covered by the additional revenue generated by the growth in the Company's number of customers and related total number of customer bills.

Q. COULD YOU ELABORATE ON THIS ?

A. Yes. As shown in the response to data request PSC 1-42, pages 1 and 2, the Company has experienced, and is still experiencing, significant growth in its residential customers for each of the years 1991 through the 1996 test year. In fact, the actual residential customers have grown by an average annual growth rate of 2.84% during the 6-year period 1991 - 1996, as shown in schedule RJH-11 footnote (2) and confirmed by Delta in its response to data request AG 1-75. The response to PSC 1-42, page 2 shows that the Company's actual number of residential customers as of December 31, 1996 is 31,505. One possible way to "match" the use of the test year-end plant in this case with the appropriate level of annualized residential revenues would be to re-state the actual weather normalized 1996 residential revenues based on the December 31, 1996 number of customers of 31,505. Under this approach, the difference between (1) Delta's proposed test year revenues (based on the average 1996 level of customers of 30,370) and (2) the re-stated test year revenues (based on the December 31, 1996 customers of 31,505) would represent the applicable revenue annualization adjustment. However, because the Company's actual number of customers can fluctuate from month to month due to reasons of seasonality, this particular revenue annualization approach, in my opinion, would not be appropriate and would result in an overstated revenue annualization adjustment.

TY = 1996

Q. WHAT SPECIFIC REVENUE ANNUALIZATION APPROACH AND METHODOLOGY DO YOU RECOMMEND BE USED IN THIS PROCEEDING IN ORDER TO MATCH THE PRO FORMA TEST YEAR RESIDENTIAL REVENUES WITH THE PROPOSED USE OF THE TEST YEAR-END PLANT IN SERVICE?

A. It is reasonable to assume that the Company's actual average 1996 plant in service is

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approximately equivalent to the actual plant in service level during the mid-point of the 1996 test year, i.e., as of June 30, 1996[6]. Therefore, the difference between the proposed test year-end plant level and the average test year plant level essentially represents one-half year's worth of growth in the Company's plant investment level. Since the Company's proposed test year residential revenues are based on the average number of customers (and the related total number of bills), the appropriate revenue annualization adjustment should similarly be based on one-half year's worth of growth in the number of customers (and the related total number of bills).

As shown under footnote (2) of schedule RJH-11, based on the average annual growth rate of 2.84% experienced during the period 1991 - 1996, the annual half-year growth rate would be 1.42%. Applying this half-year growth rate to the average 1996 number of residential customers of 30,370 results in an annualized level of customers of 30,801 with a corresponding total number of bills of 369,612. The second column of schedule RJH-11, under the recommended AG position, shows that the use of this annualized total customer bill level of 369,612 results in total recommended residential customer charge revenues of $2,199,191 and total recommended residential gas usage revenues of $18,689,321. Schedule RJH-11, lines 8 -10 shows that this recommended residential retail revenue annualization adjustment also results in a corresponding gas cost increase of $174,498. On schedule RJH-10, lines 1 and 5, I have summarized the impact of this recommended annualization adjustment on test year residential retail revenues and cost of gas.

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[6] In fact, the response to data request AG 2-20 shows that the average 1996 plant level (net of Canada Mountain) of $89.5 million is very close to the corresponding actual June 30, 1996 plant level of $89.2 million.

Commercial GS Retail Revenue and Cost of Gas Adjustments

Q. HOW DID THE COMPANY DETERMINE ITS PROPOSED PRO FORMA COMMERCIAL GS RETAIL REVENUE AND ASSOCIATED COST OF GAS EXPENSES FOR THE TEST YEAR IN THIS CASE?

A. As shown on FR #6-h, Schedule 2, page 1, lines 6 through 13 and as summarized under the first column of schedule RJH-12, the Company's proposed pro forma commercial GS retail revenues for the test year consist of two revenue categories: (1) customer charge revenues of $1,022,303, and (2) gas usage revenues of $11,341,578. The proposed customer charge revenues of $1,022,303, are based on the actual per books 1996 number of customer bills of 55,681[7] times the current customer charge rate per bill of $18.36. The proposed gas usage revenues of $11,341,578 are based on the actual 1996 commercial GS retail Mcf sales, adjusted for normal weather, of 1,533,074 Mcf times the current total base and GCR rate per Mcf of $7.3992. The actual weather-normalized 1996 sales of 1,533,074 was generated by the actual 1996 average number of commercial GS retail customers of 4,640.

Q. IS THERE AN ISSUE WITH REGARD TO THE COMPANY'S PROPOSAL TO BASE ITS PROPOSED TEST YEAR COMMERCIAL GS RETAIL REVENUES ON THE 1996 AVERAGE NUMBER OF COMMERCIAL GS RETAIL CUSTOMERS AND ASSOCIATED ACTUAL TOTAL NUMBER OF COMMERCIAL GS RETAIL BILLS?

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[7] Actual 1996 average number of customers of 4,640 times 12 monthly bills = actual total 1996 number of bills of 55,681.

A. Yes. The issue here is exactly the same as the previously discussed issue regarding the residential retail revenues in that the Company has not annualized its proposed test year commercial GS retail revenues for the growth in its commercial GS retail number of customers and related total number of commercial GS retail bills. Because of this, the Company's proposed test year commercial GS retail revenues are not properly "matched" with the Company's proposal to use a test year-end rate base in this proceeding.

As shown in the response to data request PSC 1-42, pages 1 and 2, the Company has experienced, and is still experiencing, significant growth in its commercial customers for each of the years 1991 through the 1996 test year. In fact, the actual commercial customers have grown by an average annual growth rate of 2.26% during the 6-year period 1991 - 1996, as shown in schedule RJH-12 footnote (2) and confirmed by Delta in its response to data request AG 1-75.

The response to PSC 1-42, page 2 shows that the Company's actual number of commercial customers as of December 31, 1996 is 4,964. As discussed in the prior testimony section regarding residential revenues, one possible way to "match" the use of the test year-end plant in this case with the appropriate level of annualized commercial revenues would be to re-state the actual weather normalized 1996 commercial GS retail revenues based on the December 31, 1996 number of customers of 4,964. However, because the Company's actual number of commercial customers can fluctuate significantly from month to month due to reasons of seasonality, this particular revenue annualization approach would not be appropriate and would result in an overstated revenue annualization adjustment.

Therefore, I recommend that the same approach and methodology used by the AG for the residential retail revenue annualization be applied here in order to match the proposed use of the test year-end plant in service level with the appropriate annualized test year commercial GS retail revenues.

As shown under footnote (2) of schedule RJH-12, based on the average annual growth rate of 2.26% experienced during the period 1991 - 1996, the annual half-year growth rate would be 1.13%. Applying this half-year growth rate to the average 1996 number of commercial customers of 4,640 results in an annualized level of customers of 4,692 with a corresponding total number of bills of 56,304. The second column of schedule RJH-12, under the recommended AG position, shows that the use of this annualized total customer bill level of 56,304 results in total recommended commercial GS customer charge revenues of $1,033,741 and total recommended commercial gas usage revenues of $11,469,689. Schedule RJH-12, lines 8 -10 shows that this recommended commercial GS retail revenue annualization adjustment also results in a corresponding gas cost increase of $85,480. On schedule RJH-10, lines 2 and 6, I have summarized the impact of this recommended annualization adjustment on test year commercial GS retail revenues and cost of gas.

Q. WHY HAVE YOU NOT PROPOSED SIMILAR REVENUE AND COST OF GAS ANNUALIZATION ADJUSTMENTS FOR THE COMPANY'S INDUSTRIAL CUSTOMERS?

A. The response to data request PSC 1-42, pages 1 and 2 shows that this customer class has not experienced the same consistent and continuous customer growth pattern as experienced by the residential and commercial customer classes. Specifically, the actual average number of industrial customers were as follows during the years 1991 - 1996:

1991	68
1992	68
1993	75
1994	76
1995	72
1996	73

For this reason, I do not believe it appropriate to make a revenue annualization adjustment for this class of customers in this proceeding.

Other Revenue Adjustment

Q. WHY HAVE YOU MADE THE REVENUE ADJUSTMENT OF $70,375 SHOWN ON SCHEDULE RJH-10, LINE 3?

A. I have incorporated this revenue adjustment in my revenue requirement analysis to reflect the recommendations made by AG witness, David Brown Kinloch.

Loan Forgiveness Expense Adjustment

Q. PLEASE EXPLAIN THE RECOMMENDED ADJUSTMENT FOR THE LOAN FORGIVENESS EXPENSE SHOWN ON SCHEDULE RJH-13, LINE 2.

A. The response to data request PSC 1-40 shows that Mr. Glennings, Delta's president and chief executive officer, received total compensation of approximately $208,000 in 1996 which represents a substantial increase over his 1995 total compensation of $161,451. The

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ADJUSTMENT OF RATES OF DELTA NATURAL GAS COMPANY, INC.	)))	Case No. 99-176

DIRECT TESTIMONY OF ROBERT J. HENKES ON BEHALF OF THE OFFICE OF RATE INTERVENTION OT THE ATTORNEY GENERAL FOR THE COMMONWEALTH OF KENTUCKY

September 23, 1999

HENKES CONSULTING
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Old Greenwich, Connecticut

C. OPERATING INCOME

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED AND YOUR RECOMMENDED PRO FORMA OPERATING INCOME FOR THE TEST YEAR IN THIS CASE.

A. The Company's proposed and my recommended pro forma operating income positions are summarized on Schedule RJH-7. The Company has proposed a total pro forma test year operating income amount of $5,564,849. I have made a large number of adjustments to the Company's proposed operating revenues, expenses and taxes which, in total, have the effect of increasing the Company's proposed operating income by $702,283 for a total recommended pro forma test year operating income amount of $6,267,132. Each of my recommended operating revenue, expense and tax adjustments will be discussed below.

- Year End Customer Revenue Adjustment

Q. PLEASE EXPLAIN YOUR RECOMMENDED ADJUSTMENT TO THE COMPANY'S PROPOSED YEAR END CUSTOMER REVENUE ADJUSTMENT, AS SHOWN ON SCHEDULE RJH-8, LINE 1.

A. In its response to AG-73, the Company agreed with the AG that it had made certain mathematical errors in its year end customer revenue adjustment calculations. As confirmed in revised Walker Exhibit 5, the correction for these errors increases the Company's proposed pro forma revenues by $119,549.

- Year End Customer Expense Adjustment

Q. PLEASE EXPLAIN YOUR RECOMMENDED ADJUSTMENT TO THE COMPANY'S PROPOSED YEAR END CUSTOMER EXPENSE ADJUSTMENT, AS DETAILED ON SCHEDULE RJH-8, LINE 3 AND SUMMARIZED ON SCHEDULE RJH-9, LINE 9.

A. The Company has proposed to calculate the incremental O&M expenses associated with the year end customer revenue annualization adjustment by applying an expense-to-revenue ratio of 17.92% to the year end customer revenue adjustment amount. As shown in footnote 3 of Schedule RJH-8, this results in a Delta-proposed incremental O&M expense adjustment of $54,498.

I do not agree with the expense-to-revenue ratio of 17.92% proposed by the Company. As shown in footnote 3, the Company determined the 17.92% ratio by taking the actual 1998 total O&M expenses net of gas supply expenses and wages and salaries as a ratio of the actual 1998 non-GCR revenues. Through this methodology, the Company takes the position that such expenses as employee pensions and benefits, regulatory commission expenses, property insurance, outside services employed and miscellaneous general expenses are directly variable with revenues from additional customers. I do not agree with that position. If the Company takes the position that the level of its current employees will not vary with the incremental sales for year end customers[4], then it would be consistent to also assume that the pension and benefit expenses associated with these same current employees

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[4] As evidenced by the removal of all salaries and wages from the expense-to-revenue ratio calculations

will not vary with the incremental sales for year end customers. I also do not believe that regulatory, property insurance, outside services and miscellaneous general expenses vary with the incremental sales recognized in this case as a result of the year end customer sales annualization adjustment.

Q. WHAT EXPENSE-TO-REVENUE RATIO DO YOU RECOMMEND BASED ON THE FOREGOING FINDINGS AND CONCLUSIONS?

A. As shown in footnote 3 on Schedule RJH-8, I recommend a ratio of 3.62%. This ratio excludes employee pension & benefit, miscellaneous general, regulatory commission, property insurance and outside services expenses.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDED POSITION ON THE COMPANY'S PROPOSED YEAR END CUSTOMER EXPENSE ADJUSTMENT?

A. Schedule RJH-8 shows that my recommendation results in a recommended O&M expense increase of $15,353, which is $39,145 lower than the Company's proposed O&M expense increase of $54,498.

- Payroll Expense Adjustment

Q. PLEASE EXPLAIN YOUR RECOMMENDED ADJUSTMENT TO THE COMPANY'S PROPOSED PAYROLL EXPENSE ADJUSTMENT.

A. The Company's proposed payroll expense adjustment of $116,199 represents a gross payroll expense adjustment amount, not an adjustment to payroll expenses charged to O&M expense. As agreed to by the Company in its response to AG-43, the Company's proposed pro forma payroll cost adjustment should be reduced to only reflect the portion of this payroll increase that will be charged to O&M expenses. As shown on Schedule RJH-10, the resultant appropriate payroll O&M expense adjustment amount should be $85,964, which is $30,235 lower than Delta's proposed payroll cost adjustment of $116,199.

- Pension Expense Adjustment

Q. PLEASE EXPLAIN YOUR RECOMMENDED PENSION EXPENSE ADJUSTMENT SHOWN ON SCHEDULE RJH-11.

A. The Company has proposed to recognize the actual 1998 test year per book pension expenses of $292,818 for rate making purposes in this case. However, as confirmed by the Company in response to Supplemental AG-23, the actual current annual pension expenses for Delta based on its most recent actuary report dated April 1, 1999 amount to $181,167. Since this cost amount is the most recent annual pension cost amount available at this time, I believe it is more representative of the annual pension expenses expected to be incurred during the rate effective period in this time than the actual 1998 test year pension cost level.

As shown on Schedule RJH-11, the difference between the actual 1998 test year and the current annualized pension cost levels is $111,651. Since I believe that this costs differential represents "gross" pension costs (i.e., pension costs prior to the allocation to construction and subsidiaries), I have applied an assumed pension cost O&M ratio of

73.98%[5] to this gross pension cost adjustment. This results in a recommended pension O&M expense adjustment of $82,599.

Q. WHY DO YOU BELIEVE THAT THE CURRENT ANNUALIZED PENSION COST LEVEL OF $181,167 IS REPRESENTATIVE OF THE COST LEVEL THAT CAN BE EXPECTED DURING THE RATE EFFECTIVE PERIOD OF THIS CASE?

A. As shown in the response to Supplemental AG-23 b, the Company's pension fund has been overfunded since 1995. While the excess of pension assets over pension liabilities was $92,989, this overfunding level grew to $490,000 in 1997 and then jumped to approximately $1.9 million in 1998. The earnings on this pension fund overfunding are used to reduce the Company's pension expense accruals and this is the reason why the Company's actual per books pension expenses has been declining during the last 3 to 4 years. Now that the current overfunding level has reached the very high level of $1.9 million, it can be expected that the Company's pension costs for the near-term future will continue to go down or, at a minimum, will stay at approximately the same level as the current annualized pension cost level of $181,000.

- <u>401 (k) Expense Adjustment</u>

Q. PLEASE EXPLAIN YOUR RECOMMENDED 401(K) ADJUSTMENT SHOWN ON

[5] This ratio is equivalent to the payroll O&M ratio for 1998 employed in the payroll adjustment on Schedule RJH-10 in this case.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ADJUSTMENT OF THE GAS RATES	)	
OF LOUISVILLE GAS AND	)	CASE NO. 2000-080
ELECTRIC COMPANY	)	

DIRECT TESTIMONY OF ROBERT J. HENKES ON BEHALF OF THE OFFICE OF RATE INTERVENTION OF THE ATTORNEY GENERAL FOR THE COMMONWEALTH OF KENTUCKY

June 21, 2000

Q. WHAT IMPACT DOES YOUR RECOMMENDATION HAVE ON THE COMPANY'S PROPOSED AMORTIZATION EXPENSES?

A. As shown on Schedule RJH-15, my recommendation reduces the Company's proposed amortization expenses by $56,000.

- Net Savings of Year 2000 Job Elimination for LG&E

Q. PLEASE DESCRIBE THE RECOMMENDED NET ANNUALIZED EXPENSE SAVINGS ADJUSTMENT RESULTING FROM THE RECENTLY COMPLETED EMPLOYEE SEPARATION PROGRAM SHOWN ON SCHEDULE RJH-16.

A. In response to PSC 1-37, the Company confirmed that LG&E Energy has announced the elimination of 250 jobs company wide, some of which would take place at LG&E, mostly in April 2000.

The Company's response to AG 2-42 provides preliminary estimates indicating the elimination of a total of 127 employees at LG&E -- consisting of 5 senior managers, 9 managers, 8 supervisors, and 105 exempt/office employees -- as a result of this LG&E Energy company wide employee separation initiative. In its response to PSC 3-25, the Company provided calculations showing estimated total annual LG&E labor, payroll tax and 401(k) expense savings of $5,623,030. The Company then used its Gas Labor Allocator of 21% to allocate $1,180,836 of these total estimated annual labor and employee benefit expense savings to its gas operations. This is shown on Schedule RJH-16, lines 6 - 10.

Q. DO YOU AGREE WITH THESE CALCULATED ANNUAL EXPENSE SAVINGS?

A. The Company's expense savings calculations presented in its response to PSC 3-25 have no workpapers showing the assumptions and calculations supporting the data on PSC 3-25. Thus, at this time, there are still many open questions, such as, for example: (1) how many employee eliminations and what type of eliminated employees are assumed in the expense savings calculations; (2) what are the specific eliminated annualized wages and salaries on an employee by employee basis; (3) how many "replacement employees" were assumed for which the added costs were included as an offset in the expense savings calculations; and (4) why did the Company not reflect other labor overhead expense savings over and above the payroll tax and 401(k) expense savings shown on PSC 3-25? These questions will have to answered during the hearing phase of this proceeding. Moreover, at that time, most or all of the Cost to Achieve and cost savings associated with this employee elimination initiative may be known and certain and, if so, this actual cost and cost savings data should be immediately made available by the Company. In the meantime, the currently estimated information in the response to PSC 3-25 is the only cost savings data from this separation program available at this time. For presentation purposes in this testimony, I have accepted this information. However, this recommendation is not final at this time. As stated before, the Company should provide workpapers showing all assumptions and calculations supporting the cost savings summary data on PSC 3-25 and should update the current estimated cost savings data with actual results as soon as this information has become available. The AG should then be afforded the opportunity to finalize its recommended cost savings position based on its review of this information.

Q. HAS THE COMPANY ALSO PROVIDED INFORMATION REGARDING THE COST TO ACHIEVE THIS EMPLOYEE SEPARATION INITIATIVE?

A. Yes, this information was provided by the Company in its response to AG 2-42. This response shows that the Company at this time has estimated total Cost to Achieve of approximately $8.1 million. Of this total estimated cost amount, approximately $6.6 million consists of employee severance payments, benefits continuations and outplacement service costs, and the remaining $1.5 million of estimated costs is for consulting fees, information technology and other miscellaneous expenses. Again, other than this summary cost data, the Company did not provide additional information showing all of the assumptions and calculations in support of this cost data. The Company then allocated this total Cost to Achieve amount of $8.1 million to its gas operations using a gas allocator of 25% for a proposed gas-allocated Cost to Achieve amount of $2,035,338. In its response to PSC 3-25, the Company additionally indicates that it would propose to amortize this cost over a three-year period for an annual amortization expense amount of $502,390 allocated to the gas operations. This Company proposal is shown on Schedule RJH-16, lines 1-5.

Q. DO YOU AGREE WITH THESE CALCULATED COST TO ACHIEVE AMORTIZATION EXPENSES?

A. No, I do not, for several reasons. First, I find it inappropriate and inequitable to the ratepayers to allocate the cost savings from this separation program to the gas operations at a gas allocator of 21% while allocating the costs associated with this very same separation program at a gas allocator of 25%. The Cost to Achieve and the cost savings come from the exact same

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program and should be allocated between electric and gas using the same allocation ratios. Another way of looking at this issue is that the total annual Cost to Achieve (amortized over an appropriate amortization period) should first be offset against the total annual cost savings in order to arrive at the total net annual savings, which should *only then* be allocated to the gas operations using the appropriate allocation ratio.[16] The Company's proposal to use different gas allocators for the cost and savings aspects of this employee separation program represents an inappropriate attempt to minimize the net savings from this program to be flowed back to its ratepayers.

Q. WHAT IS THE APPROPRIATE ALLOCATOR TO BE USED TO ALLOCATE THE NET SAVINGS FROM THIS EMPLOYEE SEPARATION PROGRAM TO THE COMPANY'S GAS OPERATIONS?

A. I believe that the Gas Labor Allocator of 21% should be used to allocate the net savings (i.e., both the Cost to Achieve and the cost savings) from this employee separation program to the Company's gas operations. The lion's share of the Cost to Achieve consists of employee

[16] Under the Company's proposed position, this would have the following results: total annual cost savings of $5,623,030, offset by annual amortized cost to achieve of $2,713,783 ($8,141,350 / 3 yrs) = total net annual cost savings of $2,909,247 x 21% = $610,942.

Under the AG's proposed position, this would have the following results: total annual cost savings of $5,623,023, offset by annual amortized cost to achieve of $1,628,270 ($8,141,350 / 5yrs) = total net annual cost savings of $2,909,247 x 21% = $838,898.

severance payments[17] and continued employee benefit provisions. For rate making purposes in this case, the Company has consistently used the Gas Labor allocator of 21% for its payroll and employee benefit expenses. In addition, as discussed before, the Company has used the Gas Labor allocator of 21% for allocating the savings from this program and it would be inconsistent and inequitable to use different gas allocators for the cost and savings aspects of this employee separation program.

Q. WHAT IS THE BASIS FOR THE COMPANY'S PROPOSED RATIO OF 25% TO ALLOCATE THE COST TO ACHIEVE TO ITS GAS OPERATIONS?

A. As stated in the footnote on page 3 of the response to AG 2-42, the basis for the 25% allocation ratio is a claimed 25/75% gas/electric split for total utility plant.[18] It should be recognized that this "total utility plant" split is not the same as the Common Utility Plant split of 25/75% proposed by the Company in this case that was updated to a 23/77% Common Utility Plant split during the course of this proceeding, as was previously discussed in the "Utility Plant"section of this testimony. Rather the claimed split of 25/75% applies to the Company's <u>total utility plant</u>. However, the Company's 12/31/99 test year-end total utility plant is <u>not split</u> 25/75% between gas and electric. In fact, the Company's Utility Plant workpaper for its 12/31/99 Utility Plant balance shows that, using a Common Utility Plant split of 25/75%, the

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[17] The AG has assumed that the severance payments would consist of such items as lump-sum wage/salary payments based on the employees' service records and/or other one-time compensation measures.

gas plant portion of the total utility plant is 14.34%[19], not 25% as claimed by the Company. Thus, if the PSC were to follow the Company's approach of allocating the Cost to Achieve to the gas operations using the total utility plant split, a gas allocator of approximately 14% should be used.

Q. IS THERE ANOTHER REASON WHY YOU DO NOT AGREE WITH THE COMPANY'S PROPOSED COST TO ACHIEVE AMORTIZATION EXPENSES?

A. Yes. I do not agree with the Company's proposed 3-year amortization period for the Cost to Achieve. The Company has not provided a specific basis for its proposed 3-year amortization period. If the basis is that the Company will file another rate case in 3 years, I have previously pointed out that this is not known and measurable at this time, that there is no evidence on the record in this case that would support the Company's claim that its next gas rate case will definitely be filed in the year 2003, and that all we know at this time is that the Company's last rate case was 10 years ago, in 1990. In addition, this employee separation program represents an extraordinary event that cannot be expected on a frequent recurring basis. Even if a similar employee separation program were to happen within the next three years, the Company will receive the benefits of all the costs savings associated with that program (which would not be reflected in its then-current rates) while, undoubtedly, deferring the Cost to Achieve for its next rate case, such as it did for its manufactured gas plant mediation expenditures since 1992.

Based on the aforementioned information, and in order to ameliorate the large rate

[19] Using the updated Common Utility Plant split of 23/77%, the gas portion of the total utility plant at 12/31/99 is 14.23%.

increase amount being requested in this case, I believe that a 5-year amortization period for the Cost to Achieve in this case is more appropriate and reasonable than the 3-year amortization period proposed by LG&E.

Q. BASED ON THE FOREGOING FINDINGS AND CONCLUSIONS, WHAT IS THE RECOMMENDED ANNUAL COST TO ACHIEVE AMORTIZATION EXPENSE?

A. As shown on Schedule RJH-16, lines 1-5, I recommend an annual amortization expense level of $341,937 at this time. Similar as for the program savings, the Company should provide workpapers showing all assumptions and calculations supporting the Cost to Achieve summary data on AG 2-42 and should update the current estimated cost data with actual results as soon as this information has become available. The AG should then be afforded the opportunity to finalize its recommended Cost to Achieve amortization expense position based on its review of this information.

Q. WHAT IS YOUR OVERALL RECOMMENDATION REGARDING THIS ISSUE?

A. As shown on Schedule RJH-16, at this time I recommend net annualized savings of $838,900 as a result of the Company's employee separation program. As previously described, the AG should be given an opportunity to finalize this recommendation based on workpapers and updates to be provided by the Company.

- Account 925 Expense Normalization Adjustment

Q. PLEASE DESCRIBE THE ACCOUNT 925 ANALYSIS SHOWN ON THE TOP OF YOUR SCHEDULE RJH-17.

A. Account 925 represents the Company's Injury and Damages expenses and consists of four subaccounts, Account 925001 covering general liability activities, Account 925002 covering workers comp and injury activities, Account 925003 covering automobile insurance related activities, and Account 925100 covering direct claim charges as well as the amortization of prepaid insurance policies. Because Injury and Damage related liabilities, claims and settlements can fluctuate significantly from year to year, the Account 925 Injury & Damage expenses will also show significant annual fluctuations. For example, one of the reasons why the 1999 test period Account 925001 expense of $520,255 is so much higher than the corresponding expense levels for the prior three years is because of a lawsuit settlement paid out by the Company in 1999.[20] As another example, the unusually high 1999 test period expense level of $402,419 (as compared to the prior three years) for Account 925100 is due to a liability claim that was incurred in 1999.[21]

In summary, due to the nature of the Injury and Damage activities in expense Account 925, the expected annual expense level for this account is difficult to predict. As shown on Schedule RJH-17, the total annual expenses for this account have fluctuated from $765,000 in 1996 down to $608,000 in 1997, back up to $758,000 in 1998 and then to $1,048,000 in the 1999 test period.

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[20] Response to AG 2-32, Item xx.

[21] Response to AG 2-32, Item yy.

Q. DO YOU HAVE A RECOMMENDATION WITH REGARD THESE ACCOUNT 925 EXPENSES?

A. Yes. Based on the previously discussed facts and the analysis shown on Schedule RJH-17, it would not be appropriate to simply assume that the actual 1999 test period expense level of $1,048,283 is representative of a normal annualized expense level that can be expected on an ongoing basis in the near-term future. I believe that a more reasonable approach to approximate the appropriate "normal" annual Account 925 expense level during the rate effective time of this case is by way of averaging the most recent actual annual expense levels. The average of the annual Account 925 expenses incurred during the 4-year period 1996 - 1999 is approximately $795,000. I recommend that this amount be used as the normalized Account 925 expense level for rate making purposes in this case.

As shown on Schedule RJH-17, lines 1 - 3, my recommendation decreases the Company's proposed expenses by $253,706.

- <u>Account 916 Expense Normalization Adjustment</u>

Q. PLEASE EXPLAIN YOUR RECOMMENDED ACCOUNT 916 EXPENSE NORMALIZATION ADJUSTMENT DETAILED ON SCHEDULE RJH-18.

A. The analysis on Schedule RJH-18 shows that the actual 1999 test period expense level of $53,482 is substantially higher than the corresponding Account 916 expenses for the prior 4 year period 1995 - 1998. The data in this analysis shows that these miscellaneous sales expenses experience very significant fluctuations from year to year. Based on this information

Q. COULD YOU NOW SUMMARIZE THE TOTAL MISCELLANEOUS EXPENSES YOU RECOMMEND BE REMOVED FROM THIS CASE?

A. Yes. As shown on Schedule RJH-20, line 8, I recommend a total miscellaneous expense disallowance of $150,673 in this case.

- Depreciation Expense Adjustment

Q. PLEASE EXPLAIN YOUR RECOMMENDED DEPRECIATION EXPENSE ADJUSTMENT SHOWN ON SCHEDULE RJH-4.

A. The first column on Schedule RJH-4 shows the Company's proposed annualized depreciation expenses of $13,682,361 (line 7), determined by applying its current depreciation rates to its depreciable plant in service balances as of 12/31/99. In determining this annualized depreciation expense amount, the Company assumed a Common Utility Plant gas ratio of 25% for its depreciable Common Utility and Miscellaneous Intangible Plant balances shown on lines 2 and 3 of Schedule RJH-4. As discussed in the previous "Utility Plant" section of this testimony, the 25% ratio was based on the Company's 1998 Common Utility Plant study which was later updated to 23% in the 1999 Common Utility Plant study. For the reasons previously described, I recommend the use of the more recent updated Common Utility Plant gas ratio of 23%. In its response to AG 2-4, the Company has confirmed that the use of this lower gas allocation ratio of 23% would decrease the Company's proposed annualized depreciation expenses for Common Utility and Miscellaneous Intangible Plant by a total amount of $247,959.

Q. DO YOU RECOMMEND ANOTHER ADJUSTMENT TO THE COMPANY'S PROPOSED ANNUALIZED DEPRECIATION EXPENSES?

A. Yes. An amount of $10,444,203 of the Company's gas utility plant balance at 12/31/99 has been funded with cost free Customer Advances for Construction. Recognizing this, the Company has appropriately removed this utility plant portion from its rate base by virtue of using its 12/31/99 Customer Advances for Construction balance of $10,444,203 as a rate base deduction in this case. However, while the Company is not asking a return <u>on</u> the plant funded by Customer Advances for Construction, it is asking a return <u>of</u> this same plant because it is requesting rate recognition for the depreciation expenses associated with the utility plant funded by the cost free Customer Advances for Construction. This is inappropriate and inconsistent. I therefore recommend the removal of the depreciation expenses associated with the utility plant funded by Customer Advances for Construction. As shown on Schedule RJH-4, line 6 and further detailed in footnote (3) of that schedule, this recommendation reduces the Company's proposed annualized depreciation expenses by $299,749.

Q. WHAT IS YOUR TOTAL DEPRECIATION EXPENSE ADJUSTMENT IN THIS CASE?

A. Schedule RJH-4, line 9 shows that the total impact of my two recommended depreciation expense adjustments is an expense reduction of $547,708.

- <u>Payroll Tax Adjustment</u>

Q. WHY HAVE YOU MADE AN ADJUSTMENT TO INCREASE THE COMPANY'S

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF GAS RATES OF THE UNION LIGHT, HEAT AND POWER COMPANY	)))	CASE NO. 2001-092

DIRECT TESTIMONY OF ROBERT J. HENKES ON BEHALF OF THE OFFICE OF RATE INTERVENTION OF THE ATTORNEY GENERAL FOR THE COMMONWEALTH OF KENTUCKY

OCTOBER 4 , 2001

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be discussed in the following sections of this testimony.

Schedule RJH-8, line 13 shows that, after considering all of the recommended pro forma operating income adjustments, the AG's recommended pro forma operating income for the test year amounts to $7,517,290.

- Revenue Adjustments for Added Customers

Q. PLEASE EXPLAIN THE RECOMMENDED REVENUE ADJUSTMENTS FOR ADDED CUSTOMERS SHOWN ON SCHEDULE RJH-9.

A. The Company has proposed significant revenue reduction adjustments for changes that took place with two of its large customers. The first change concerns the shutting down of Newport Steel in March 2001 with the result that Newport is now expected to take a significantly reduced load on a going forward basis. The Company has proposed (and I have accepted) an annual revenue reduction of approximately $433,000 to reflect this expected gas consumption reduction. The second change concerns the cessation of the manufacturing operations of Johns Manville that became final on August 27, 2001.[6] The revenue reduction that both the Company and I have recognized in this case for this event is approximately $150,000.

However, there are also two new large commercial/industrial customers that were added to ULHP's system in May 2001 and August 2001 for which the annualized sales and revenues were not reflected in the Company's proposed sales normalization and annualization adjustments in this case. The first customer addition concerns the addition in May 2001 of an

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[6] See response to AG-2-10(2).

industrial customer identified in the Company's response to AG-1-25 with anticipated annual revenues of $27,555. The second customer addition concerns the addition of a commercial customer who took over the Johns Manville building when Johns Manville ceased operations. As confirmed in the response to AG-2-10, this customer is expected to generate annual base revenues of approximately $6,000.

On Schedule RJH-9, I show that these additional revenues, net of associated expenses and taxes, would contribute $20,428 in annual net after-tax operating income.

- Weather Normalization Adjustment

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

A. Yes. The Company has proposed an adjustment to restate the pro forma test year sales levels for the weather-sensitive customer classes based on "normal" weather for the ULHP service territory.

Q. DID THE COMPANY USE A WEATHER NORMALIZATION METHODOLOGY IN THIS CASE DIFFERENT FROM THE WEATHER NORMALIZATION METHOD IT HAS TRADITIONALLY USED IN ALL OF ITS PRIOR RATE CASES?

A. Yes. As confirmed in its response to AG-1-27, prior to this rate case, the Company weather-normalized test period sales using 30-year average NOAA[7] weather data. In this case, the

[7] NOAA stands for National Oceanic and Atmospheric Administration.

Company has for the first time proposed an alternative weather normalization method. Specifically, the Company has weather normalized its test year sales based on the average of the actual weather experienced for the 10-year period 1990 through 1999. The Company has done so because it believes that this (warmer) period is more representative of the expected rate effective period of this case. As shown on Schedule RJH-10, lines 1 - 3, the Company's proposed alternative weather normalization method produces $1,041,320 less in sales revenues than if it had weather normalized its test period sales based on the traditional 30-year average NOAA method.

Q. DO YOU BELIEVE THAT THE COMPANY'S PROPOSED ALTERNATIVE WEATHER NORMALIZATION METHOD SHOULD BE USED FOR RATE MAKING PURPOSES IN THIS CASE AS OPPOSED TO THE TRADITIONAL 30-YEAR AVERAGE NOAA WEATHER NORMALIZATION METHOD THAT HAS ALWAYS BEEN USED FOR THIS COMPANY IN ITS PRIOR RATE CASES?

A. No, I do not believe so. The fact that the 10-year period from 1990 through 1999 on average has been warmer than the average weather for the prior 30 years does not mean that the rate effective period of this case is going to be warmer than what the 30-year NOAA average would indicate. This is evidenced, for example, by the severe heating season ULHP's service territory experienced this past winter. Therefore, the Company's proposed alternative normalization method would not make it a better predictor of what weather can be expected during the rate effective period of this case. The 30-year average NOAA weather normalization method has consistently been used for rate making purposes up to this point and it would be inappropriate to change this method mid-stream based on a perceived warming trend in recent years.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Company's pro forma test year sales be weather normalized based on the 30-year average NOAA method. As shown on Schedule RJH-10, this increases the Company's proposed pro forma test year revenues by $1,041,320.

Q. DOES YOUR RECOMMENDATION ALSO RESULT IN CORRESPONDING EXPENSE AND TAX INCREASES?

A. Yes, in response to AG-2-11, the Company confirms that the corresponding expense and tax increases associated with the revenue increase from this weather normalization method change would concern incremental uncollectible expenses, PSC maintenance fees, and income taxes. I have reflected these incremental expenses and taxes on Schedule RJH-10, lines 4 through 7.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S PROPOSED PRO FORMA TEST YEAR NET AFTER-TAX OPERATING INCOME?

A. As shown on Schedule RJH-10, line 8, my recommendation increases the Company's proposed pro forma test year operating income by $633,934.

- <u>Rate Case Expense Adjustment</u>

Q. WHAT IS YOUR RECOMMENDED POSITION WITH REGARD TO THE APPROPRIATE

Q. WHAT WOULD BE THE "MATHEMATICAL AVERAGE OF THE TEST YEAR AND 4 PREVIOUS CALENDAR YEARS" THAT WAS REFERENCED IN PSC-2-47 C?

A. The mathematical average of the overtime expenses in the test year and the 4 previous calendar years that can be derived from the response to PSC-2-47 B amounts to $425,636. As compared to the actual test year overtime expenses of $459,631, this approach would suggest a pro forma test year overtime expense reduction of $33,995, or even larger than my recommended overtime expense adjustment of $28,421.

- Amortization Expense Adjustment

Q. WHY HAVE YOU MADE THE INCOME ADJUSTMENT TO ELIMINATE THE COMPANY'S PROPOSED AMORTIZATION EXPENSES FOR THE PRIOR DEFERRED MERGER RELATED COSTS AND REDUCE THE COMPANY'S PROPOSED AMORTIZATION EXPENSE FOR A PRIOR EARLY RETIREMENT PROGRAM COSTS?

A. I have made these recommended amortization expense adjustments and the associated overall net operating income adjustment shown on Schedule RJH-8, line 6 for all of the reasons discussed in the prior section C entitled "Prior Early Retirement And Merger Related Cost Deferrals".

- LERP 2000 Expense Adjustment

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED RATE MAKING POSITION WITH

REGARD TO THE SO-CALLED DEFERRED LERP 2000 COSTS.

A. LERP 2000 stands for the Limited Early Retirement Program that was offered by the Company in the year 2000. The test year in this case includes all of the $362,529 one-time implementation costs associated with this downsizing program. For rate making purposes, the Company has proposed to remove this one-time cost of $362,529 from the test year and, instead, replace it with an annual expense level of $120,843 based on a proposed 3-year amortization of the total one-time cost of $362,529. The Company has also proposed an adjustment to reflect the annualized expense savings that can be expected as a result of this downsizing program. It has quantified such annual cost savings to be $85,290.

In summary, as shown in the first column of Schedule RJH-13, the net impact of the Company's proposal is a pro forma test year expense reduction of $326,976. The Company has not proposed to include the unamortized balance of the deferred cost in rate base.

Q. DO YOU GENERALLY AGREE WITH THIS RATE MAKING PROPOSAL OF THE COMPANY?

A. Yes. Similar to the 1992 downsizing program, the LERP 2000 downsizing program is taking place at the same time the Company has filed a base rate case. Therefore, the annual savings from this downsizing program, if properly quantified and reflected for rate making purposes in this case, will flow to the ratepayers on a going forward basis. It would then also be appropriate to give appropriate rate recognition to the costs incurred to implement the downsizing program.

Q. DO YOU AGREE WITH THE COMPANY'S CALCULATIONS TO DETERMINE ITS PROPOSED PRO FORMA TEST YEAR EXPENSE REDUCTION FOR THIS PROGRAM?

A. No, not entirely. First, the response to AG-2-16 confirms that while $180,792 of the total implementation cost of $362,529 represents immediate one-time cash payments, the remaining cost balance of $181,737 represents "delayed" cash payments that will be paid out over the lifetime of the retirees. The Company has proposed to use an amortization period of 3 years for both of these cost components. In accordance with the method used by the Commission with regard to the one-time costs for the 1992 downsizing program in Case No. 92-346, I recommend a 3-year amortization period for the immediate one-time cash payments and a 10-year amortization period for the "delayed" cash payments.

Second, in its responses to AG-1-56A and AG-2-17, the Company has confirmed that its initially quantified annual expense savings amount of $85,290 is incorrect and should be revised to $233,969. I have reflected this revision.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDED ADJUSTMENTS ON THE COMPANY'S PROPOSED PRO FORMA TEST YEAR EXPENSES AND NET AFTER-TAX OPERATING INCOME?

A. As shown on Schedule RJH-13, the previously discussed adjustments further decrease the Company's proposed pro forma test year expenses by $191,084 and increase the Company's proposed pro forma net after-tax income by $117,808.

- <u>Y2K Expense Adjustment</u>

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION OF UNITED WATER DELAWARE FOR AN INCREASE IN WATER RATES	)))	PSC DOCKET NO. 98-98

TESTIMONY OF STAFF WITNESS

ROBERT J. HENKES

AUGUST, 1998

which actual data are available at the time this testimony is being prepared. Considering that these balances were as high as $600,000 up until November 1997, I believe that $162,000 represents a reasonable and conservative rate base deduction balance. I have treated this recommended rate base deduction of $162,000 as a cash working capital offset in this case.

Q. HAVE THESE CONTRACTOR RETENTIONS ACCOUNTS PAYABLES NOT ALREADY BEEN ACCOUNTED FOR AS A CASH WORKING CAPITAL REDUCTION THROUGH AN EXPENSE PAYMENT LAG IN THE COMPANY'S CASH WORKING CAPITAL LEAD/LAG STUDY?

A. No. The lead/lag study only considers the payment lags of <u>operating expenses</u>. It does not consider the payment lags of capital expenditures. Since contractor retentions represent payables directly related to plant in service and do not represent payables associated with any of the Company's operating expenses, they are not already accounted for as expense payment lags in the lead/lag study.

- <u>OPEB Adjustment</u>

Q. PLEASE EXPLAIN YOUR UNDERSTANDING OF THE COMPANY'S PROPOSED OPEB-RELATED RATE BASE DEDUCTION.

A. In accordance with the proposal made by UWD and adopted by the Commission in the prior case, Docket No. 96-164, the Company in the instant rate case has proposed to reduce its rate base by the difference between (1) the total cumulative amount of FAS 106 OPEB expenses allowed in rates through the end of the pro forma test period, 9/30/98, and (2) the total cumulative amount of cash contributions made to its VEBA trust as of 9/30/98. As shown on schedule RJH-8, the Company has calculated that the total OPEB expense collected in rates through 9/30/98 amounts to $427,429 and that the total OPEB funding in its VEBA trust as of 9/30/98 amounts to $271,922, thereby resulting in a rate base deduction of $155,507 for the difference between these two amounts.

Q. DO YOU AGREE WITH THE COMPANY'S CALCULATED RATE BASE DEDUCTION AMOUNT OF $155,507?

A. No, I do not. While I agree that the actual cumulative contributions to the VEBA trust account as of 9/30/98 amount to $271,922, I do not agree with the Company's contention that the total FAS 106 OPEB expenses collected in rates through 9/30/98 amount to $427,429. The appropriate amount of FAS 106 OPEB expenses collected in rates through 9/30/98 is $679,311, not the $427,429 claimed by UWD. As shown on schedule RJH-8, substituting this OPEB rate collection amount of $679,311 for the incorrect amount of $427,429 results in the recommended OPEB Adjustment rate base deduction of $407,389.

Q. COULD YOU NOW EXPLAIN THE DIFFERENCES BETWEEN YOUR RECOMMENDED AND UWD'S PROPOSED POSITIONS REGARDING THE OPEB EXPENSES COLLECTED IN RATES THROUGH 9/30/98?

A. Yes. In Docket No. 96-164, the Company was allowed annual rate recovery of $305,546 for its ongoing FAS 106 OPEB expenses, as well as $41,336 for the amortization of its OPEB deferred debit. Thus, the total annual OPEB expense allowed in rates in the prior case was

$346,882. The rates from the prior case went into effect on October 15, 1996 in the form of an interim rate increase of $2,230,000. From 10/15/96 through 9/30/98 represents a time period of 23.5 months. Therefore, through 9/30/98 the Company has collected in rates a total OPEB expense of 23.5/12 x $346,882, or $679,311.

By contrast, in determining its proposed total OPEB rate recovery amount of $427,429, UWD made two significant conceptual errors in its calculations. First, the Company did not assume that the annual OPEB amount collected in rates since the prior case was equal to the PSC-approved OPEB expense level of $346,882; rather, it assumed that the OPEB amount collected in rates was equal to the OPEB expense level it actually recorded on its books through 9/30/98. This is an incorrect assumption that should be rejected by the Commission. Second, and more importantly, the Company assumed that it did not start receiving rate recovery for its OPEB expenses until 7/29/97, the effective date of the PSC's final Order in Docket No. 96-164.

Q. WHY IS THIS LATTER UWD ASSUMPTION INCORRECT?

A. As mentioned earlier, the rates from Docket No. 96-164 became effective on an interim basis on October 15, 1996 when the Company was allowed to increase its rates by an annualized amount of $2,230,000. On July 29, 1997, the PSC issued its final order in which it decided that the appropriate annualized rate increase was $1,550,356. Since this final rate increase amount of $1,550,356 included full recovery of the Company's annual OPEB expense and amortization level of $346,882, and since the final rate increase amount of $1,550,356 was less than the annual interim rate increase amount of $2,230,000 that became effective 10/15/96, it follows logically that the full amount of $346,882 for OPEB expense has been recovered in UWD's rates since 10/15/96.

Q. IS THE COMPANY'S POSITION THAT THE RATES FROM DOCKET NO. 96-164 BECAME EFFECTIVE ON THE FINAL ORDER DATE OF 7/29/97 RATHER THAN THE INTERIM RATE INCREASE DATE OF 10/15/96 INCONSISTENT WITH THE EFFECTIVE RATE INCREASE DATE IT HAS ASSUMED IN THE INSTANT PROCEEDING?

A. Yes. As stated on page 7, lines 16-17 of Mr. Jost's testimony, the Company has assumed that the new rates from the instant rate case became effective around May 1, 1998, the then-expected interim rate increase date for this case. The Company's argument that the rates from Docket No. 96-164 became effective at the PSC's final order date rather than the interim rate increase date is therefore entirely inconsistent with its position that the rates from the current case became effective at the date of the interim rate increase.

C. OPERATING INCOME

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED PRO FORMA OPERATING INCOME, THE METHOD EMPLOYED BY THE COMPANY TO DETERMINE ITS PRO FORMA OPERATING INCOME, AND YOUR RECOMMENDED OPERATING INCOME ADJUSTMENTS.

A. The Company's proposed pro forma operating income of $3,206,513 is summarized by specific

Q. HOW DOES THE RECOMMENDED GROSS PAYROLL COST LEVEL OF $2,898,085 COMPARE TO THE ACTUAL GROSS PAYROLL COST FOR THE MOST RECENT 12-MONTH PERIOD?

A. As confirmed in the response to PSC-A-7 (Set II), the Company's actual gross payroll costs for the 12-month period ended May 31, 1998 amounts to $2,716,100. Thus, the recommended pro forma gross payroll level of $2,898,085 is approximately $182,000 or 7% higher than the actual cost level for the year ending May 31, 1998.

(2) Retirement Benefits

Q. PLEASE EXPLAIN THE RETIREMENT BENEFITS EXPENSE ADJUSTMENT SHOWN ON SCHEDULE RJH-11, LINE 3.

A. The Company's actual FAS 106 OPEB expenses for the last 3 years have shown a decreasing trend, as shown in the table below:

	Actual OPEB Costs
1995	$ 305,546
1996	$ 295,499
1997	$ 266,790

By contrast, for pro forma purposes in this case, the Company has reflected estimated OPEB expenses of $348,351. In other words, it is the Company's estimated position that the downward trend in actual OPEB costs during the last three years will suddenly reverse to a significant extent. The requested expense level of $348,351 is not based on an official actuary study; rather, it is based on a preliminary estimate dated 1/29/98.

I do not believe that the estimated OPEB expense level of $348,351 which UWD has proposed for ratemaking purposes in this case can be considered known and measurable or reliable. I therefore recommend that the pro forma OPEB expense to be recognized in this case be set at $266,790, the Company's most recent actual OPEB expense level. As shown on schedule RJH-13, my recommendation decreases UWD's proposed net O&M expenses by $71,692.

(3) Health and Welfare Expenses

Q. PLEASE EXPLAIN THE HEALTH AND WELFARE EXPENSE ADJUSTMENT SHOWN ON SCHEDULE RJH-11, LINE 4.

A. In the Company's original filing, it reflected pro forma projected medical costs of $293,851. In the July 16 update filing, the Company changed its original pro forma medical cost amount from $293,851 to $277,485 based on more updated information. However, in the amended update filing of July 30, 1998, UWD reverted back to its original pro forma medical cost amount of $293,851. Since it is my understanding that the pro forma medical cost estimate of $277,485 incorporates the most recent updated information, I have corrected for this apparent error by reducing the Company's proposed medical costs by $16,366. Details for this recommended expense adjustment are shown on schedule RJH-14.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION	)	
OF ARTESIAN WATER COMPANY, INC.	)	
FOR AN INCREASE IN WATER RATES	)	PSC DOCKET NO. 99-197
(FILED APRIL 30, 1999)	)	

DIRECT TESTIMONY OF ROBERT J. HENKES
ON BEHALF OF
THE DELAWARE PUBLIC SERVICE COMMISSION STAFF

SEPTEMBER 22, 1999

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This conclusion is consistent with the conclusion reached by Staff in the Company's prior rate case. In that case, the Company, using the same forecasting technique, had projected industrial sales for the pro forma 1998 period of 36.552 MG. As shown in the above table, the actual 1998 industrial sales turned out to be 47.226 MG.

Q. WHAT RECOMMENDATION DO YOU HAVE REGARDING THE PROJECTED TEST PERIOD INDUSTRIAL SALES AND REVENUES?

A. Based on the foregoing analysis and conclusions, I recommend that the projected test period industrial sales and revenue level be set at levels equal to the actual experience in the test year. As shown on schedule RJH-7, page 3, this would increase Artesian's proposed test period revenues by $26,045 and consumption by 9.125 MG.

(3) **South Bethany Revenue Imputation**

Q. PLEASE EXPLAIN THE THIRD OF YOUR RECOMMENDED REVENUE ADJUSTMENTS CONCERNING THE SOUTH BETHANY REVENUE IMPUTATION.

A. In this case, the Company has proposed to reflect in rate base an investment of approximately $4 million[7] for Phase I of its expansion into the South Bethany area. In addition, the Company's filing includes annualized depreciation expenses based on this rate base investment level, as well as associated property taxes and O&M expenses. As shown on DBS Exhibit 5, this $4 million Phase I plant is designed to serve and support 705 customer equivalents without the need for additional incremental investments. This was also confirmed by the Company in

[7] The updated South Bethany Phase I plant included in the September 3, 1999 supplemental filing's rate base amounts to $3,943,050 as per the response to PSC-A-142 and Exhibit BPK-8, updated 9/99.

its responses to IDC-4 and IDC-5.

Q. WHAT IS THE ISSUE HERE?

A. The issue is that the South Bethany Phase I project revenues included in the supplemental filing are calculated by the Company based on 385 customer equivalents which were actually on line at the end of the test year, 6/30/99. Thus, while the Company is requesting rate recognition in this case for the rate base return requirement, annualized depreciation expenses, property taxes and O&M expenses associated with a $4 million investment in rate base that is designed to serve and support 705 customers without having to spend any more investment money, it is only "matching" this with revenues from 385 customers. This is inappropriate as it represents mismatched rate making. Given that this $4 million Phase I project is designed to serve and support 705 customers, it would be appropriate to offset the annualized revenue requirement associated with this investment and its related expenses with the annualized revenues from 705 customers, not with the annualized revenues from only 385 customers. This is particularly true considering that the Company's current updated expectation is that the "build-out" to 705 customers will be accomplished early on during the rate effective period of this case.[8]

Q. WHAT IS YOUR RECOMMENDATION BASED ON THE FOREGOING FINDINGS AND CONCLUSIONS?

A. I recommend that revenues from an additional 320 South Bethany Phase I customers be imputed for rate making purposes in this case. The 320 additional customers represent the

[8] See the response to PSC-A-101 as revised (increased) in the response to PSC-A-143.

difference between the total 705 customers and the 385 customers recognized by the Company in this case. As detailed in Schedule RJH-7, page 4, my recommendation increases the Company's pro forma South Bethany revenues at current rates in this case by $94,890. My recommended revenue recommendation also increases the recommended pro forma test period consumption by 20.512 MG

(4) <u>Windsong Revenue Imputation</u>

Q. PLEASE EXPLAIN THE FOURTH OF YOUR RECOMMENDED REVENUE ADJUSTMENTS CONCERNING THE WINDSONG REVENUE IMPUTATION.

A. I have made this recommended revenue imputation adjustment for the same reasons as described above for the South Bethany Phase I project. The Company is claiming a rate base investment of $237,000 for this project, as well as associated annualized depreciation expenses. In its response to PSC-A-111, the Company confirms that this investment is designed to serve and support 223 planned lots. In this same response, the Company also indicated that "the cost/benefit analysis for Windsong was calculated based upon the 223 planned lots and, therefore, the investment of $1,063 per customer ($237,087/223) compares favorably to Artesian's 5-year average investment per customer...."

The issue is that the Company has only recognized the revenues from 2 customers for rate making purposed in this case.[9] This represents a similar rate making "mismatch" issue as described above for South Bethany Phase I. To correct for this mismatch, I recommend that revenues from an additional 221 Windsong customers be imputed for rate making purposes in this case. The 221 additional customers represent the difference between the total 223 customers and the 2 customers recognized by the Company in this case.

Q. HOW DID YOU CALCULATE THE RECOMMENDED IMPUTED REVENUES FROM THESE ADDITIONAL 221 CUSTOMERS?

A. In its response to IDC-7, the Company indicates that it does not know the specific revenues from Windsong customers because "it does not project total revenues based on specific contracts. Customer growth is projected for our entire water system based on historical average increases." Given this lack of data, I have calculated the recommended revenue imputation amount by multiplying the incremental 221 customers by the average pro forma revenues per residential customers for Artesian's entire residential customer base.

As detailed in Schedule RJH-7, page 5, my recommendation increases the Company's pro forma Windsong revenues at current rates in this case by $65,589. I have also estimated that my recommended revenue recommendation increases the recommended pro forma test period consumption by 14.173 MG.

[9] Response to DPA-99.

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(5) Church Creek Revenue Imputation

Q. PLEASE EXPLAIN THE FIFTH OF YOUR RECOMMENDED REVENUE ADJUSTMENTS CONCERNING THE CHURCH CREEK REVENUE IMPUTATION.

A. The Company's proposed rate base as of 6/30/99 includes a plant investment of $314,192 for Church Creek and its pro forma test period expenses include the annualized depreciation expenses based on this plant investment. In the response to IDC-8, the Company confirms that the $314,192 Church Creek investment is designed to serve approximately 150 customers without incremental investment. However, for rate making purposes in this case, the Company has only reflected the revenues from 5 customers.[10] For the same reasons as described for the South Bethany and Windsong projects above, I recommend a revenue imputation adjustment based on an incremental 145 customers. The revenue imputation calculations are based on the same method as described for the Windsong revenue imputation adjustment above.

Schedule RJH-7, page 6 shows that my recommended revenue imputation adjustment increases the Company's pro forma test period revenues by $43,033 and consumption by 9.299 MG.

(6) Choptank Revenue Imputation

Q. PLEASE EXPLAIN THE SIXTH OF YOUR RECOMMENDED REVENUE ADJUSTMENTS CONCERNING THE CHOPTANK REVENUE IMPUTATION.

[10] Response to DPA-98.

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A. The Company's proposed rate base as of 6/30/99 includes a plant investment of $494,085[11] for the Choptank project and its pro forma test period expenses include the annualized depreciation expenses based on this plant investment. In the response to IDC-14, the Company confirms that this Choptank investment is designed to serve approximately 125 customers without incremental investment. However, for rate making purposes in this case, the Company has only reflected the revenues from 62 customers.[12] For the same reasons as described for the other plant projects above, I recommend a revenue imputation adjustment based on an incremental 63 customers. The revenue imputation calculations are based on the same method as described for the Windsong and Church Creek revenue imputation adjustments above.

Schedule RJH-7, page 7 shows that my recommended revenue imputation adjustment increases the Company's pro forma test period revenues by $18,697 and consumption by 4.04 MG.

(7) **Stonefield Iron Revenue Imputation**

Q. PLEASE EXPLAIN THE SEVENTH OF YOUR RECOMMENDED REVENUE ADJUSTMENTS CONCERNING THE STONEFIELD IRON REVENUE IMPUTATION.

A. The Company's proposed rate base as of 6/30/99 includes a plant investment of $468,519[13] for the Stonefield Iron plant project and its pro forma test period expenses include the annualized depreciation expenses based on this plant investment. In its response to Staff's Engineering

[11] Response to IDC-14.
[12] Provided by the Company during informal discovery conference of 9/15/99.
[13] Response to IDC-12.

data request No. 10, the Company confirms that the $468,519 investment is designed to serve approximately 35 customers without incremental investment. However, for rate making purposes in this case, the Company has reflected no revenues from any customers.[14] For the same reasons as described for the other plant projects above, I recommend a revenue imputation adjustment based on an incremental 35 customers. The revenue imputation calculations are based on the same method as described for the other revenue imputation adjustments above.

Schedule RJH-7, page 8 shows that my recommended revenue imputation adjustment increases the Company's pro forma test period revenues by $10,387 and consumption by 2.245 MG.

(8) Revenues from Boothhurst and Willow Grove

Q. PLEASE EXPLAIN THE EIGHTH OF YOUR RECOMMENDED REVENUE ADJUSTMENTS CONCERNING THE REFLECTION OF BOOTHHURST AND WILLOW GROVE REVENUES.

A. Staff witness Brian Kalcic has concluded that the annualized revenues for Boothhurst and Willow Grove are not included in the Company's pro forma test period operating revenues at current rates. He has therefore recommended that I increase the Company's proposed test period operating revenues at current rates by $34,594 to include the revenues from Boothhurst and Willow Grove. This revenue adjustment, with an associated consumption increase adjustment of 22.223 MG, is shown on Schedule RJH-7, page 1, line 9.

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[14] Provided by Company during informal discovery conference of 9/15/99.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S PROPOSED PRO FORMA WAGE AND SALARY EXPENSES CHARGED TO O&M?

A. As shown in Schedule RJH-10, my recommendation decreases the Company's proposed wage and salary expenses charged to O&M by $43,171.

(4) Pensions

Q. HOW DOES THE COMPANY DETERMINE ITS PRO FORMA TEST PERIOD PENSION EXPENSES?

A. The Company determines its pro forma test period pension expenses by applying the appropriate pension/payroll ratio actually experienced in its test year to its gross pro forma test period wages and salaries.

Q. WHAT IS THE APPROPRIATE 1998 TEST YEAR PENSION/PAYROLL RATIO TO BE APPLIED TO THE GROSS PRO FORMA TEST PERIOD WAGES AND SALARIES?

A. This ratio is 8.07%.

Q. HOW DID YOU DERIVE THIS RATIO?

A. The Company's actual per books pension expenses during the 1998 test year amount to $449,681. However, this "per books" pension expense number is distorted in that it was reduced by approximately $73,000 for certain "forfeiture" credits relating to prior periods but recorded as a credit to the Company's pension expenses in 1998. Thus, in order to determine the normalized 1998 test year expenses, one would have to take the actual per books pension expenses of $449,681 and then add back the $73,000 prior period "forfeiture" credits. This would result in appropriate normalized 1998 test year pension expenses of $522,581, as calculated and confirmed by the Company in its response to IDC-23. Taking this normalized test year pension expense of $522,581 as a ratio of the actual 1998 test year gross wages and salaries of $6,474,140[15] results in the appropriate test year pension/payroll ratio of 8.07%.

Q. IF ONE WERE TO APPLY THIS APPROPRIATE TEST YEAR PENSION/PAYROLL RATIO OF 8.07% TO THE COMPANY'S PROPOSED PRO FORMA TEST PERIOD GROSS WAGES AND SALARIES, WHAT WOULD BE THE RESULTING PRO FORMA TEST PERIOD GROSS PENSION EXPENSES?

A. The Company has proposed pro forma test period gross wages and salaries of $7,063,558. Applying the appropriate normalized test year pension/payroll ratio of 8.07% to this number would indicate a pro forma test period gross pension expense of approximately $570,000. Applying the Company's proposed test period pension O&M expense ratio of 80.66% to this gross pension expense amount results in a pro forma test period pension expense charged to O&M of $459,762. Comparing this pro forma test period pension expense amount of $459,762 to the actual per books 1998 pension expense amount of $449,681 indicates the need for a pro forma pension expense increase adjustment of $10,081.

Q. WHAT PRO FORMA PENSION EXPENSE INCREASE ADJUSTMENT HAS BEEN REFLECTED IN THE COMPANY'S SUPPLEMENTAL FILING?

A. In its supplemental filing the Company has proposed a pension expense adjustment of $109,279 rather than $10,081. The Company's proposed expense adjustment of $109,279 is fraught with conceptual and mathematical calculation errors and should be rejected by the

[15] *See* DBS Exhibit 1, Schedule 3-C.

Commission.

Q. HAVE YOU CALCULATED THE APPROPRIATE PENSION EXPENSE ADJUSTMENT BASED ON STAFF'S RECOMMENDED PRO FORMA TEST PERIOD GROSS WAGES AND SALARIES?

A. Yes. My calculations are detailed on Schedule RJH-11. Based on Staff's recommended pro forma test period gross wages and salaries, the recommended pension expense adjustment is $6,617. As summarized on Schedule RJH-8, line 9, Staff's recommended position reduces the Company's proposed pension expense adjustment by $102,662.

(5) <u>Normalized Rate Case Expenses</u>

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED CLAIM FOR RATE CASE EXPENSES IN THIS PROCEEDING.

A. As shown on Schedule RJH-12, page 1, the Company claims total annual rate case expenses of $312,260 in this case. This amount consists of estimated current case expenses of $592,000 normalized by using a 2-year amortization period (resulting in a normalized annual expense amount of $296,000), and $16,260 of normalized expenses related to the depreciation and compensation studies conducted in the prior case.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED CLAIM FOR RATE CASE EXPENSES?

A. I agree with the annual expense claim of $16,260 associated with the prior case's depreciation and compensation studies. However, I do not agree with the Company's proposed normalized annual expense of $296,000 for the current rate case expenses.

STAFF EXHIBIT NO. 2

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

In the Matter of:

THE JOINT APPLICATION OF TIDEWATER UTILITIES, INC. / PUBLIC WATER SUPPLY COMPANY FOR A GENERAL INCREASE IN WATER RATES AND A CONSOLIDATED TARIFF (FILED SEPTEMBER 20, 1999)	)))))	**DOCKET NO. 99-466**

DIRECT TESTIMONY OF ROBERT J. HENKES
ON BEHALF OF
THE DELAWARE PUBLIC SERVICE COMMISSION STAFF

March 8, 2000

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SUMMARIZED ON SCHEDULES RJH-7A AND 7B, LINE 5 AND FURTHER DETAILED ON SCHEDULE RJH-8.

A. My recommended 401(k) expense adjustment is a direct result of my previously discussed recommendation that 4 of the Company's proposed projected employee additions be eliminated from rate recognition in this case. Schedule RJH-8, line 8 and footnote (5) show how this employee reduction recommendation impacts the Company's proposed 401(k) expenses. As shown on line 8 of this schedule, I recommend that Tidewater's proposed 401(k) expenses be reduced by $1,126 and Public's by $1,016.

- Pension Expense

Q. PLEASE EXPLAIN THE PENSION EXPENSE ADJUSTMENTS SUMMARIZED ON SCHEDULES RJH-7A AND 7-B, LINE 3 AND FURTHER DETAILED ON SCHEDULE RJH-9.

A. In response to DPA-26, the Company provided information confirming that it had made a mistake in the determination of its proposed Tidewater and Public pension expenses and that the correction for this mistake would increase Tidewater's pension expenses by $7,339 and decrease Public's pension expenses by $100. I have accepted these corrected numbers.

- FAS 106 Expense

Q. PLEASE EXPLAIN THE FAS 106 ADJUSTMENT SHOWN ON SCHEDULE RJH-7A AND

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7B, LINE 4.

A. As confirmed in its response to PSC-A-112, the Company failed to offset its proposed FAS 106 expenses with the PAYGO expenses of $4,194 that are already separately included in the test period medical expenses for Tidewater. I have corrected for this oversight by reducing the Company's proposed FAS 106 expenses for Tidewater by $4,194.

- Rate Case Expenses

Q. PLEASE EXPLAIN THE RECOMMENDED RATE CASE EXPENSE ADJUSTMENT SUMMARIZED ON SCHEDULE RJH-7A AND 7B, LINE 10 AND FURTHER DETAILED ON SCHEDULE RJH-10.

A. As shown on Schedule RJH-10, I recommend that the Company's proposed normalized annual rate case expense level for the combined Tidewater Utilities of $70,000 be reduced by $37,000 to $33,000. The recommended annual rate case expense reduction of $37,000 results from two adjustments made by me.

Q. PLEASE EXPLAIN THE FIRST ADJUSTMENT.

A. As detailed on Schedule RJH-10, lines 1 through 5, the Company has proposed total rate case expenses of $210,000 for this case. I have accepted this total rate case expense amount with one exception. This exception concerns the approximate $14,000 of rate case expenses charged by Middlesex personnel that is included in the $210,000 total. The response to PSC-A-107D indicates that this $14,000 expense amount consists of the services rendered by

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BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION OF ARTESIAN WATER COMPANY, INC. FOR A REVISION OF RATES	)))	PSC DOCKET 00-649

DIRECT TESTIMONY OF
ROBERT J. HENKES
ON BEHALF OF
DELAWARE PUBLIC SERVICE COMMISSION

APRIL, 2001

of its proposal to add another pro forma increase of 4% to the actual year 2000 salary base that already includes the very large average year 2000 base salary increase of 16.8%.

(2) Pension Expenses

Q. WHAT METHODOLOGY HAS BEEN USED BY THE COMPANY TO DETERMINE ITS PRO FORMA TEST PERIOD PENSION EXPENSES AND PROPOSED PENSION EXPENSE ADJUSTMENT IN THIS CASE?

A. The Company determined its pro forma test period gross pension costs by applying a "gross pension/gross payroll" ratio of approximately 6.885% to its proposed pro forma test period gross payroll amount of $8,586,686. This ratio application resulted in the proposed pro forma gross pension cost amount of $591,175. The Company then applied an O&M expense ratio of approximately 78.05% to this pro forma gross pension cost in order to arrive at its proposed pro forma pension O&M expense amount of $461,451. The Company then determined its proposed pension expense adjustment of $47,609 by comparing the pro forma pension expense amount of $461,451 to the actual pension expense of $413,842 booked in the test year.

Q. WHAT HAS BEEN THE COMPANY'S ACTUAL HISTORIC "GROSS PENSION COST/GROSS PAYROLL" RATIO?

A. As shown in more detail under footnote (2) of Schedule RJH-10, the Company's actual "gross pension/gross payroll" ratios have been as follows during the last 5 years:

1996	7.99%
1997	8.55%
1998	7.64%
1999	6.43%
2000	6.38%

Q. WHAT CONCLUSION DO YOU DRAW FROM THE ABOVE TABLE?

A. Based on the data shown in the above table, I conclude that it would be appropriate to assume a "gross pension cost/gross payroll" ratio of 6.38% for rate making purposes in this case. This represents the actual ratio for the most recent calendar year 2000 which, given the consistent downward trend in this ratio in the last four years, should be considered most representative of the ratio that can be expected during the rate effective period of this case.

Q. WHAT ARE THE RECOMMENDED PRO FORMA TEST PERIOD PENSION EXPENSES AND RECOMMENDED PENSION EXPENSE ADJUSTMENT THAT YOU HAVE DETERMINED BASED ON THE AFOREMENTIONED FINDINGS AND CONCLUSIONS?

A. As shown on Schedule RJH-10, the application of the recommended "gross pension cost/gross payroll" ratio of 6.38% and the O&M ratio of 78.05% to the pro forma test period gross payroll of $8,586,686 results in a recommended pro forma test period pension O&M expense of $427,582. Comparing this recommended pro forma pension expense amount to the actual test year pension expense of $413,842 indicates the need for a recommended pension expense adjustment of $13,740.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION OF TIDEWATER UTILITIES, INC. FOR A GENERAL INCREASE IN RATES (FILED JANUARY 25, 2002)	))))	PSC DOCKET NO. 02-28

DIRECT TESTIMONY
OF
ROBERT J. HENKES
ON BEHALF OF
COMMISSION STAFF

JUNE 7, 2002

- **Employee Pension & Benefit Expense**

Q. PLEASE EXPLAIN THE RECOMMENDED ADJUSTMENT IN EMPLOYEE PENSION AND BENEFIT EXPENSES SHOWN ON SCHEDULE RJH-12, LINE 8.

A. The Company reduced its proposed Test Period employee pension & benefit expenses by $39,045 for expense allocations to Southern Shores. In its response to PSC-A-59, the Company explained that this adjustment was proposed in error and should not have been made. Based on my review of the Company's response to PSC-A-59, I have increased the Company's proposed Test Period employee pension & benefit expenses by $39,045.

- **Regulatory Commission Expense**

Q. WHAT IS THE COMPANY'S PROPOSED POSITION WITH REGARD TO REGULATORY COMMISSION EXPENSES IN THIS CASE?

A. The Company's proposed position is summarized in the first column of Schedule RJH-16. First, the Company has estimated total rate case expenses for this proceeding of $200,500 and has proposed to normalize these rate case expenses over a 3-year normalization period, thereby resulting in an annualized rate case expense level of approximately $67,000.

Second, the Company is proposing a $48,112 expense for the continued rate recognition in this case of what it calls the "unamortized" rate case expenses from the prior 1999 rate case.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION OF DELMARVA POWER & LIGHT COMPANY, D/B/A CONECTIV POWER DELIVERY, FOR A CHANGE IN ITS NATURAL GAS BASE RATES (FILED MARCH 31, 2003)	)))))	PSC DOCKET NO. 03-127

DIRECT TESTIMONY
OF
ROBERT J. HENKES
ON BEHALF OF
COMMISSION STAFF

AUGUST 15, 2003

Damage reserve balance. As indicated in its response to PSC-A-66, the Company agrees with this recommended rate base deduction.

C. OPERATING INCOME

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED PRO FORMA OPERATING INCOME AND STAFF'S RECOMMENDED OPERATING INCOME ADJUSTMENTS.

A. The Company's proposed pro forma operating income of $8,954,697 is summarized by specific operating income component on Schedule RJH-8. As shown on this schedule, Staff has recommended a number of operating income adjustments that increase the Company's proposed pro forma operating income by a total of $3,217,057 and result in Staff's recommended pro forma operating income of $12,171,754. Each of these recommended operating income adjustments will be discussed in detail below.

- <u>Unbilled Revenue Adjustment</u>

Q. WHAT PRO FORMA ADJUSTMENT HAS THE COMPANY PROPOSED WITH REGARD TO UNBILLED REVENUES?

A. The Company has removed from the test year unbilled revenues it booked in September 2002 (the last month of the test year) that relate to services rendered during the test year, but were not billed until the first month after the test year. These unbilled revenues amount to $611,997.

Q. DO YOU AGREE WITH THIS ADJUSTMENT?

A. No. The test year should include all revenues associated with actual services rendered during the test year. The unbilled revenues the Company is proposing to remove from the test year relate to services rendered during the test year and, therefore, should be reflected for ratemaking purposes in this case. On the other hand, the first month of the test year (October 2001) includes billed revenues that relate to services rendered in the month prior to the test year. The response to PSC-A-73 C indicates that the revenues included in the test year that relate to services rendered in September 2001, the month prior to the test year, amount to $84,624. It is *these* revenues that should be removed from the test year because they are not for services rendered during the test year.

Q. HOW DOES YOUR RECOMMENDED ADJUSTMENT TO THE COMPANY'S UNBILLED REVENUE APPROACH IMPACT THE COMPANY'S PROPOSED PRO FORMA TEST YEAR OPERATING INCOME?

A. As shown on Schedule RJH-9, my recommended adjustment increases the Company's proposed pro forma test year operating income by $312,970.

- **Major Customer Adjustment**

Q. PLEASE EXPLAIN THE COMPANY'S ADJUSTMENT REGARDING MAJOR CUSTOMERS.

A. The Company has adjusted its test year results by removing the Mcf sales and associated sales revenues of two large industrial customers (# 44 and #75) and one commercial customer (#83). The Company made these adjustments because these 3 customers left the DPL gas system either during the test year or after the end of the test year and the Company claims that "these customers will not be replaced by comparable new gas customers at those locations, or any other location known to the Company."[3] Filing Schedule CLD-2 shows that this proposed Major Customer Adjustment reduces the test year revenues by $537,602.

Q. TO BE CONSISTENT WITH THE PROPOSAL TO REFLECT CUSTOMERS LOST DURING AND AFTER THE TEST YEAR, DID THE COMPANY MAKE A SIMILAR ADJUSTMENT TO REFLECT CUSTOMERS ADDED DURING AND AFTER THE TEST YEAR?

A. In response to a similar question, Company witness Charles Driggs states on page 15 of his testimony: "No. The Company has only adjusted the test period for its known and measurable change."

Q. DO YOU AGREE WITH THIS PROPOSED RATEMAKING APPROACH?

A. No, I do not. The response to PSC-A-21 shows that customer #75 (the largest industrial customer proposed to be removed by DPL) was an active customer with consistent Mcf consumption during each month of the test year. The Company claims that, at some point after the test year, this customer left the system and that, therefore, all of the test year sales from this customer must be removed for ratemaking purposes. In this regard, the Company was asked the following question in PSC-A-23:

[3] Testimony of Charles Driggs, page 14, lines 8-10.

> Please provide all changes (additions and/or reductions) in the Company's test year industrial customers and commercial customers, on a customer by customer basis, during the period October 2002 through June 2003. For each customer change, provide the annualized consumption impact (Mcf or therms) and the associated impact on net operating margins (revenues net of associated gas expenses).

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

> Please see CLD-2 of Charlie Driggs' testimony for all Customer Sales and Revenue Adjustments (three customers) to the test year data. <u>The Company has not made an adjustment in the COS for any changes of any customer's sales and revenues beyond the test year</u>.[emphasis supplied]

Based on this response, the Company's proposed removal of customer #75 from the test year is both inappropriately asymmetric and contrary to its response to PSC-A-23. First of all, customer #75 was an active customer during each month of the test year and the change from being an active to a "lost" customer did not occur until some point after the test year. Therefore, the proposed removal of customer #75 from the test year is inconsistent with the Company's statement in the response to PSC-A-23 that "The Company has not made an adjustment in the COS for any change of any customer's sales and revenues beyond the test year." It is also contrary to Mr. Driggs' testimony on page 15 of his testimony that the Company has only made revenue adjustments for known and measurable changes within the test period.

Second, it is inappropriate to make this single "out-of-test year" customer change adjustment without considering all other "out-of-test year" customer changes. This represents inappropriate single-issue ratemaking and should be rejected by the Commission. Unfortunately, Staff's request in PSC-A-23 to obtain perspective and all required sales and revenue annualization details regarding the entire universe of post-test year major customer changes was dismissed by DPL through its response that it has not considered such information.

With regard to customer nos. 44 and 83, these were active customers during parts of the test year[4] and, apparently, became "lost" customers at some point within the test year. The Company, therefore, removed the sales and revenues that were booked for these customers during the test year. However, the responses to PSC-A-21 and PSC-A-70 indicate that the test year also includes a number of newly added customers for which sales consumption and revenues were only reflected during part of the test year. Even though these represent known and measurable customer changes within the test year, the Company did not propose a revenue annualization adjustment for these new customers. Again, this is "one-way street" approach is inappropriate and inconsistent with Mr. Driggs' testimony on page 15 of his testimony that the Company has only made revenue adjustments for known and measurable changes within the test period.

In summary, for the foregoing reasons, Staff recommends that the Company's proposed Major Customer adjustment be rejected for ratemaking purposes in this case.

Q. HOW DOES YOUR RECOMMENDATION IMPACT THE COMPANY'S PROPOSED TEST YEAR OPERATING INCOME?

A. As shown on Schedule RJH-10, Staff's recommendation increases the Company's proposed test year operating income by $318,402.

[4] The response to PSC-A-21 shows monthly consumption of customer # 83 for the first 5 months of the test year

Correction for Margin Sharing Error

- ~~**Flexibly Priced Revenue Adjustment**~~

Q. PLEASE EXPLAIN THE RECOMMENDED ADJUSTMENT TO THE COMPANY'S PROPOSED MARGIN SHARING REVENUE ADJUSTMENT, SHOWN ON SCHEDULE RJH-11.

A. As shown on filing workpaper 2.4, the Company has proposed to remove Interruptible Transportation ("IT") margins of $772,937 from the test year operating revenues. This is appropriate because 80% of the IT margins are flowed to the ratepayers through the GCR while the remaining 20% of the IT margins can be retained by DPL's stockholders. Therefore, 100% of these margins must be removed from the test year operating revenues for purposes of setting the Company's base rates in this case. However, as indicated in the response to DPA-25 and confirmed in a telephone conference with DPL, the total IT margins included in the test year operating revenues amount to $972,285, not $772,937. Therefore, another $199,348 of IT margins must be removed from test year operating revenues. Staff has corrected for this error on the Company's part on Schedule RJH-11.

Q. HOW DOES STAFF'S RECOMMENDED IT MARGIN SHARING ADJUSTMENT IMPACT THE COMPANY'S PROPOSED TEST YEAR OPERATING INCOME?

A. As shown on Schedule RJH-11, Staff's recommended revenue adjustment decreases the Company's proposed pro forma test year operating income by $118,303.

- **Weather Normalization Adjustment**

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nd monthly consumption of customer #44 for the first 9 months of the test year.

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Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED WEATHER NORMALIZATION ADJUSTMENT.

A. The Company has proposed an adjustment to restate the actual per books test year sales and associated revenue levels for the weather-sensitive customer classes based on "normal" weather for DPL's service territory. Company witness Charles Driggs explains on pages 16 – 17 of his testimony that the Company has used the same weather normalization method as was used in the Company's latest GCR filing of August 30, 2002, in Docket No. 02-284F, except that "the Company has utilized and proposes to formally change to a fifteen-year weather normalization rather than the thirty-year normalization approach used in the Company's latest GCR filing."

Q. WHY IS THE COMPANY PROPOSING TO CHANGE FROM A THIRTY-YEAR TO A FIFTEEN-YEAR WEATHER NORMALIZATION?

A. The Company wants to make the weather normalization used for ratemaking purposes consistent with the weather normalization used in the Company's daily operations and development of financial and business plans because it believes that the fifteen-year normalization comes up with a better answer than the thirty-year normalization. In this regard, Mr. Driggs states on page 17 of his testimony:

> Long term weather trend analysis and weather experience over the past decade resulted in a business decision several years ago to adopt a fifteen-year normalization approach for preparation of forecasts and budgets. The Company does not purport to know what is actually causing the change in weather patterns seen in recent years, and national experts are vigorously debating the cause. The Company has, however, observed that a fifteen-year normalization provided more realistic projections of future gas sales and revenue.

Mr. Driggs does not explain why the Company continued the thirty-year weather normalization approach in its GCR proceedings all the way through August 30, 2002 even though it was several years ago that the Company changed to a fifteen-year normalization approach for the preparation of its internal forecasting and budgeting. Apparently, the Company saw no harm in using this two-pronged approach during the last several years.

As shown on Schedule RJH-12, page 1, the Company's proposed alternative 15-year weather normalization approach produces almost $1 million less in weather normalized test year sales revenues than if its test period sales were weather normalized based on the traditional 30-year average method.

Q. IS THE COMPANY'S PROPOSAL TO CHANGE FROM A 30-YEAR TO A 15-YEAR WEATHER NORMALIZATION APPROACH IN VIOLATION OF THE STIPULATION REACHED AMONG THE PARTIES IN THE COMPANY'S PRIOR BASE RATE PROCEEDING, DOCKET NO. 94-22?

A. Yes. As acknowledged by Mr. Driggs on page 17 of his testimony, the Settlement Agreement reached in the Company's prior base rate case, Docket No. 94-22, states in Section II.2 paragraph (b):

> *The Company will file future gas base rate proceedings beginning with its next base rate case, using a weather normalization methodology relying upon National Oceanic and Atmospheric Administration (NOAA) data for the <u>most recent consecutive thirty year period</u>*

Thus, the Company's 15-year weather normalization approach proposal in the instant rate case - representing the Company's next base rate case after Docket No. 94-22 - clearly violates this Settlement provision and, for that reason alone, should be rejected by the Commission.

Q. ARE THERE OTHER REASONS WHY THE COMPANY'S PROPOSAL TO CHANGE FROM A 30-YEAR TO A 15-YEAR WEATHER NORMALIZATION APPROACH SHOULD BE REJECTED?

A. Yes. The fact that the 15-year period 1988 through 2002 used in the Company's proposed 15-year weather normalization approach on average has been warmer than the average weather for the prior 30 years should not mean or even imply that, therefore, the rate effective period of this case is going to be warmer than what the 30-year weather normalization average would indicate. This is evidenced, for example, by the severe heating season DPL's service territory experienced this past winter. In fact, with its 5,171 Heating Degree Days, the most recent heating season (2002/2003) goes on record as one of the coldest in the last 30 years.[5] There is therefore no evidence that the Company's proposed 15-year weather normalization approach is any better predictor of weather conditions than the traditional 30-year weather normalization approach. The 30-year weather normalization method has consistently been used for ratemaking purposes both in rate cases and GCR filings for DPL up to this point and Staff believes it would be inappropriate to now change this method based on the Company's desire to make it consistent with what it does for internal sales forecasting purposes.

Q. WHAT WEATHER NORMALIZATION PERIOD HAS STAFF USED AS THE

[5] Per the responses to DPA-23 and PSC-A-71: only the heating seasons of 1978 and 1988 had higher HDDs than

BASIS FOR ITS RECOMMENDED WEATHER NORMALIZATION ADJUSTMENT?

A. Consistent with the terms of the previously referenced Settlement Agreement in Docket No. 94-22, Staff has used the most recent consecutive 30-year period as the basis for its recommended weather normalization adjustment. This represents the 30-year period through the most recent 2002/2003 heating season. In the response to PSC-A-30, the Company provided the test year Mcf sales adjustment based on this most recent 30-year weather normalization approach, however, the Company did not calculate the corresponding sales revenue adjustment. Staff again requested this sales revenue adjustment information in PSC-A-72, however, the Company responded that it will not make these calculations because "the development of such normalized weather revenue adjustments would take extensive effort to develop, is original work, and is not normally or routinely done by the Company." Staff, therefore, has been forced to make its own estimate of the sales revenue adjustment associated with the weather normalization approach using the most recent 30-year average through the 2002/2003 heating season. This estimation methodology is shown on Schedule RJH-12, page 2. Staff believes that the method employed on this schedule has generated a reasonably accurate sales revenue adjustment number.

Q. HOW DOES STAFF'S RECOMMENDED 30-YEAR WEATHER NORMALIZATION ADJUSTMENT COMPARE TO THE COMPANY'S PROPOSED 15-YEAR WEATHER NORMALIZATION ADJUSTMENT AND HOW DOES THE DIFFERENCE IMPACT THE COMPANY'S PROPOSED PRO FORMA

2003.

TEST YEAR OPERATING INCOME?

A. As shown on Schedule RJH-12, page 1, Staff's recommended 30-year weather normalization adjustment generates $962,986 higher pro forma test year sales revenues than the Company's proposed 15-year weather normalization adjustment. This difference increases the Company's proposed pro forma test year operating income by $570,341.

- **CPD/Pepco O&M Expense Reduction Program**

Q. HAS THE COMPANY IN THIS RATE FILING REFLECTED ANY OPERATING CHANGES AND ASSOCIATED OPERATING EXPENSE CHANGES AS A RESULT OF THE MERGER WITH PEPCO THAT BECAME EFFECTIVE AUGUST 2002?

A. No. The Company has chosen a test year ending September 30, 2002 for this base rate case. Since the merger with Pepco became effective in August 2002, it is safe to assume that the actual test year results in this case do not reflect any operating expense impacts of the merger. Furthermore, the Company has not proposed any pro forma test year expense adjustments to reflect potential operating expense reductions and other synergy savings associated with the merger. It is simply the Company's position that any merger related expense impacts are not known and measurable at this time.

Q. DOES STAFF BELIEVE THAT ANY ESTIMATED SAVINGS RELATED TO THE MERGER THAT ARE AVAILABLE AT THIS TIME SHOULD BE REFLECTED FOR RATEMAKING PURPOSES AT THIS TIME?

BEFORE THE BOARD OF PUBLIC UTILITIES
STATE OF NEW JERSEY
BPU DOCKET NO. WR95070303

IN THE MATTER OF THE REVISION OF RATES
FILED BY
UNITED WATER NEW JERSEY INC.
INCREASING ITS RATES FOR WATER SERVICE

TESTIMONY OF ROBERT J. HENKES
ON BEHALF OF
THE NEW JERSEY DIVISION
OF THE RATEPAYER ADVOCATE

JANUARY, 1996

117 9255

lower than UWNJ's original "as filed" BPU/RPA assessment amount of $295,000.

10. Pensions (Schedule RJH-9, Line 20)

The Company's original "as filed" pro forma pension expense credit amount as updated by UWNJ based on the most recent actuary study changed from ($39,000) to ($795,000), resulting in my recommended expense adjustment of $756,000.

In summary, of my recommended total pro forma operating income adjustment of $5,112,000 shown on Schedule RJH-8, Line 14, a total amount of $1,633,000 is caused by the previously described non-contested adjustments to reflect updates and corrections. The remaining recommended expense and tax adjustments will be discussed in the following sections of this testimony.

- Depreciation Expense

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED POSITION IN THIS CASE CONCERNING PRO FORMA DEPRECIATION EXPENSES.

A. Company witness Earl Robinson has conducted a depreciation study for UWNJ and has concluded that the Company's depreciation rates should be increased. Mr. Robinson's proposal would increase UWNJ's currently allowed composite depreciation rate of approximately 2.25% to 2.57%. The Company is requesting that its pro forma depreciation expenses in this case be based on the application of Mr. Robinson's determined composite depreciation rate of 2.57% to the actual total depreciable plant balance as of 10/31/95.

Q. HOW DID YOU DETERMINE THE PRO FORMA DEPRECIATION EXPENSES YOU RECOMMEND BE RECOGNIZED FOR RATE MAKING PURPOSES IN THIS CASE?

A. The Ratepayer Advocate's expert depreciation witness in this case, Michael Majoros, has recommended that UWNJ's current depreciation rates be decreased to a composite rate of 2.01%. Therefore, the recommended depreciation expenses should be based on the application of Mr. Majoros' recommended composite depreciation rate of 2.01% to the Company's actual total depreciable plant balance as of 10/31/95, plus Mr. Majoros' recommended net salvage allowance of $570,000 for a total amount of $9,135,000 (Schedule RJH-4).

Q. DID YOU MAKE ANY ADJUSTMENTS TO THIS ANNUALIZED DEPRECIATION EXPENSE AMOUNT OF $9,135,000 TO ARRIVE AT YOUR RECOMMENDED DEPRECIATION EXPENSE LEVEL IN THIS CASE?

A. Yes. I have reduced the annualized depreciation expense of $9,135,000 by $43,000 to remove depreciation expenses associated with the 10/31/95 plant that has been financed by customer advances. The Company's actual plant in service balance at 10/31/95 includes plant that has been financed by contributions in aid of construction (CIAC) and customer advances. The actual 10/31/95 depreciable plant balance of $426,124,000 provided by UWNJ in response to DC-5, excludes plant financed by CIAC but does not exclude plant financed by customer advances. I do not believe it is appropriate to charge ratepayers with depreciation accruals on plant funded by ratepayer advances. The Company may argue that customer advances on its books as of 10/31/95 do not represent a known and measurable permanent funding level because a portion of customer advances is subject to refund. Such an argument, in my opinion, is improper. While certain customer advances portions may be refunded to customers on an on-going basis, at the same time new customer advances will be added on an on-going basis. The end result is that the Company will always, and at any point in time, carry a certain level of customer advances on its books. This is evidenced by the following table:

	UWNJ's Customer Advances ($000's)
1991	$ 3,767
1992	3,709
1993	3,768
1994	3,881
10/31/95	3,631

(Source: UWNJ's Annual Reports to the BPU)

The above table clearly proves that the Company's 10/31/95 customer advances level of $3.6 million represents a reasonably known and measurable permanent funding level.

Q. WHAT IS THE POSITION OF UWR, UWNJ'S PARENT COMPANY, ON THE ISSUE OF DEPRECIATING PLANT FINANCED BY CUSTOMER ADVANCES?

A. On page 30 of its 1994 annual report to the stockholders, UWR reports:

> The balances of <u>advances</u> and contributions are used to reduce utility plant in determining rate base, and plant funded by <u>advances</u> and contributions is generally not depreciated. (emphasis supplied).

Thus, it would appear that UWNJ's proposal in this case to depreciate plant financed by customer advances is inconsistent with the position on this issue expressed by its own parent company, UWR.

Q. WHERE DO YOU SHOW YOUR RECOMMENDED DEPRECIATION EXPENSES IN THE SCHEDULES ATTACHED TO THIS TESTIMONY?

A. My recommended depreciation expense amount of $9,092,000 is detailed on Schedule RJH-4.

- <u>Real Estate Taxes</u>

Q. PLEASE EXPLAIN HOW YOU DERIVED YOUR RECOMMENDED REAL ESTATE TAX AMOUNT OF $4,603,000 SHOWN ON SCHEDULE RJH-8, LINE 8.

A. As shown in footnote (5) of Schedule RJH-8, the Company's latest updated pro forma annualized real estate taxes amount to $4,856,000. This amount includes $253,000 for UWNJ's proposed amortization of the pre-test year Corwick tax appeal

UWNJ's 11/21/95 update also assumed pro forma annual life insurance costs of $209,000. I have taken no exception to this Company-calculated component of the employee welfare expenses.

Schedule RJH-14, Lines 5 through 7 show that my recommended pro forma total employee welfare expenses, after applying UWNJ's proposed updated O&M expense factor of 78.25%, amount to $2,468,000.

Schedule RJH-9, Line 5 shows that this recommended expense number is $402,000 lower than UWNJ's original "as filed" employee welfare expenses of $2,870,000.

- <u>OPEB Expense</u>

Q. COULD YOU BRIEFLY DESCRIBE THE HISTORY OF UWNJ'S ALLOWED RATEMAKING TREATMENT FOR ITS OTHER POST EMPLOYMENT BENEFIT (OPEB) EXPENSES?

A. Yes. Up to today, UWNJ has been allowed to recover its "pay-as-you-go" OPEB expense in rates. On January 1, 1993, UWNJ was required, for book accounting purposes, to change to the accrual accounting method for its OPEB expenses as a result of FASB 106. At that time, UWNJ elected to amortize the TBO (Transition Benefit Obligation) portion of its FASB 106 OPEB expense over the full twenty year period allowed by FASB 106. In Docket No. W092111054, dated February 25, 1993, the Board allowed the Company to defer as a regulatory asset the difference between the Company's "pay-as-you-go" OPEB expenses and the OPEB accrual expenses booked by the Company under FASB 106 with an effective date of January 1, 1993.

Q. COULD YOU NOW DESCRIBE THE COMPANY'S PROPOSED ORIGINAL "AS FILED" AND UPDATED POSITIONS FOR ITS OPEB EXPENSE?

A. Yes. The company's original "as filed" OPEB expense proposal was as follows:

- Total projected FASB 106 accrual	$ 3,149,000
- Less: "pay-as-you-go" amount already included in employee welfare expenses	(720,000)
- Net excess over pay-as-you-go	$ 2,429,000
- % Expensed	73.63%
- Net excess expensed	$ 1,788,000
- Plus: Proposed 10-year amortization of the deferred regulatory asset	764,000
- Total included in O&M expense	$ 2,552,000

Based on the most recent updated actuary projection which took into account all August and October 1995 employee transfers from UWNJ to UWM&S, the Company updated its OPEB expense claim in this case as follows:

- Total projected FASB 106 accrual	$ 3,165,496
- Less: "pay-as-you-go" amount already included in updated employee welfare expenses	(820,000)
- Net excess over pay-as-you-go	$ 2,345,496
- % Expensed	78.25%
- Net excess expensed	$ 1,835,351
- Plus: Proposed 10-year amortization of the deferred regulatory asset	951,939
- Total included in O&M expense	$ 2,787,290

Q. DO YOU HAVE ANY COMMENTS ON THE COMPANY'S UPDATED OPEB EXPENSE CALCULATIONS?

A. Yes. I believe there are many questions and uncertainties concerning the Company's OPEB expense calculations in this case which would make the Company's projected OPEB expense proposal unreliable at best.

For example, it appears strange and illogical that after the transfer of 63 employees, representing a ratio of approximately 14% of UWNJ January 1995 total employee level, the Company's projected updated FASB 106 accrual expenses would go up from $3,149,000to $3,165,496. With the transfer of approximately 14% of its workforce to UWM&S one would expect a significant reduction, not an increase, in UWNJ's projected FASB 106 OPEB accruals.

Another questionable area of the Company's proposed OPEB expense claim in this case concerns the assumptions regarding the size of the deferred regulatory asset. In its original filing results, the Company claimed that this deferred regulatory asset amounted to $7,640,000[8]. However, in its update this claimed balance suddenly increases to $9.5 million[9]. During the course of this proceeding I made several attempts to determine how the Company derived its numbers for the deferred regulatory asset, however, without success. Every time a new document was presented by the Company, the numbers had changed either due to the correction for errors or due to a change in the calculation methodology. Based on my review, I have therefore concluded that the Company, despite its sincere efforts, has not proven the accuracy and appropriateness of its deferred regulatory asset numbers. Moreover, it appears that the Company did not apply an O&M expense factor to its proposed 10-year amortization amount for the deferred regulatory asset.

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8 See the above "as filed position" table: 10 years x $764,000 = $7,640,000.

9 See the above "updated position" table: 10 years x $951,939 = $9,519,390.

In my opinion, the Company's proposal to receive rate recognition not only for its total projected FASB 106 accrual amount but also for a 10-year amortization of its deferred regulatory asset should be rejected for the aforementioned reasons alone.

Q. ARE THERE ANY OTHER REASONS WHY THE COMPANY'S OPEB EXPENSE PROPOSAL IN THIS CASE SHOULD BE REJECTED?

A. Yes. The Board's policy decision to include the accounting accrual in rates should not be based on the simple grounds that FASB has adopted an accounting standard. It should be based on sound policy and a showing of significant benefits to customers. Without the showing of such benefits, the requested FASB 106 accrual expense, which is approximately four times higher than the Company's current "pay-as-you-go" expense level, is not justified.

Second, the Company's FASB 106 accrual proposal should be rejected because the inclusion of the accrual in rates would charge current customers for more than one generation of costs. UWNJ's OPEB expense would increase by a factor of approximately 4.0 times, increasing from the updated "pay-as-you-go" level of $820,000 to the updated FASB 106 accrual level of $3,165,496. This increase includes a charge for the post-retirement benefits earned by current employees (the "current portion") and an additional charge for benefits for existing retirees (the TBO amortization and associated interest). The Company's proposal would charge current customers not only for today's cash expenditures but also for a 20-year amortization of amounts that, under the Company's accrual theory of expense recognition, should have been charged in the past.

Third, if the Board allows UWNJ to recover the FASB 106 accrual expense in rates, this would remove incentives for the Company to control such costs and/or to continually evaluate the need for such post-retirement benefits. In this regard, it should be noted that UWNJ has maintained its right to reduce, terminate or amend its other post employment benefits (Response to RAR-A-33).

Finally, the excess of FASB 106 accruals over "pay-as-you-go expenses" does not represent a known and certain amount. There are numerous uncertain variables that affect the computation of the accrual. At paragraph 256 of FASB 106, the FASB acknowledged that "the actuarial techniques for measuring post-retirement health benefit obligations are still developing and should become more sophisticated and reliable with time and experience". At paragraph 198, the FASB listed some of the factors affecting the determination of the accrual such as: changes in health care costs and services; changes in health care utilization; changes in health care delivery patterns; changes in medical technology; sociodemographic changes; and changes in public and private policy. Because of all of these uncertainties, it would be inappropriate to move the Company's currently projected OPEB accrual expenses into rates at this time.

Q. ARE ANY OF THE OTHER NEW JERSEY UTILITIES CURRENTLY ALLOWED RATE RECOVERY FOR THEIR FULL OPEB EXPENSES UNDER

FASB 106 AND FOR THE AMORTIZATION OF THEIR DEFERRED REGULATORY ASSETS?

A. Not that I am aware of. I understand that PSE&G and Rockland Electric, by stipulation, currently receive rate recovery for their "pay-as-you-go" expenses and are allowed to defer the difference between their "pay-as-you-go" expenses and full FASB 106 accrual expenses in a regulatory asset account. Other utilities[10], again by stipulation, are currently allowed rate recovery for their "pay-as-you-go" expenses as well as the "current portion" of their FASB 106 OPEB accrual.

Q. WHAT IS YOUR RECOMMENDATION REGARDING UWNJ'S RATEMAKING PROPOSAL IN THIS CASE FOR OPEB EXPENSE?

A. Based on all of the previously discussed findings and conclusions, I recommend that UWNJ continue to receive rate recovery for its "pay-as-you-go" OPEB expense only.

- <u>Amortizations</u>

Q. WHAT ARE THE AMORTIZATION EXPENSES PROPOSED BY UWNJ FOR RATE INCLUSION IN THIS CASE?

A. As detailed on Schedule RJH-15, the Company has proposed a total rate inclusion of $475,000 for various amortization expenses. Of this total amount, $314,000 represents the Company's proposal to amortize over a 5-year period the pre-test year

[10] Such as, for example, JCP&L and Elizabethtown Water Company.

BEFORE THE
STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF ELIZABETHTOWN WATER COMPANY FOR APPROVAL OF AN INCREASE IN RATES FOR SERVICE	))))	BPU DOCKET NO. WR95110557 OAL DOCKET NO. PUC RL12247-95N

Direct Testimony and Exhibits
of
Robert J. Henkes

On behalf of the
Division of the Ratepayer Advocate

March 19, 1996

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(1) this property has been included in rate base since the 1950's;

(2) the test year includes $5,000 of real estate taxes associated with this property which will no longer be incurred after the sale; and

(3) the Company realized a pre-tax gain of $169,000 on the sale of this property.

The ratepayers should obviously not be charged for the non-recurring property tax expense of $5,000. It is also my opinion that the ratepayers should be credited with the full amount of the $169,000 pre-tax gain. They have compensated EWC's shareholders for the return on this property for over 40 years and have always paid for the property taxes and maintenance expenses related to this property. I recommend that this pre-tax gain be credited to the ratepayers over a 2-year period, similar to the 2-year amortization period used by the Company and me to determine the "normalized" rate case expense level in this case. As shown on Schedule RJH-20, line 5 and footnote (6), my recommendation results in an annual ratepayer credit of $89,000.

- <u>Depreciation on CIAC and Customer Advances</u>

Q. WHAT IS THE ISSUE WITH REGARD TO DEPRECIATION ASSOCIATED WITH CONTRIBUTIONS IN AID OF CONSTRUCTION AND CUSTOMER ADVANCES?

A. Contributions in Aid of Construction (CIAC) represent mostly main investments that have been permanently contributed to the Company by individuals, developers, municipalities or other outside parties. Customer advances represent the exact same type of property contributions, however, portions of these customer advances are still subject to refund to the contributing outside parties. Once EWC has paid the partial refunds for its customer advances, the remaining customer advances balances will be reclassified to CIAC as permanent property contributions. While certain customer advances portions will be refunded to customers on an on-going basis, at the same time new customer advances will be added on an on-going basis. The end result is that the Company will always, and at any point in time, carry a permanent level of customer advances on its books. This is evidenced by the following table:

	EWC's Cust. Adv. Balances ($000's)
1991	$ 39,417
1992	40,553
1993	41,633
1994	41,820
1995	40,449

(Source: EWC's Annual Reports to the BPU)

The above table clearly indicates that the Company can be expected to carry on its books a permanent level of customer advances in excess of $40 million.

In summary, EWC's combined CIAC and customer advances balances are to be considered permanent non-investor supplied capital. Since the Company's investors never laid out any funds for these contributed investments, they should not be entitled to (1) earn a return <u>on</u> such investments (through rate base inclusion), or (2) receive a return <u>of</u> the investments (through depreciation). The Company has properly recognized the first of these ratemaking principles by removing the plant investments financed by CIAC and customer advances from its rate base. However, the Company has not consistently followed through on the second of these ratemaking principles, i.e., it is claiming a return <u>of</u> this contributed property by reflecting depreciation expenses on its plant financed by CIAC and customer advances. I have corrected for this inconsistency by removing these depreciation expenses from EWC's proposed pro forma year operating expenses. As shown on Schedule RJH-21, footnote (2), EWC's proposed depreciation expenses on its pro forma year plant financed by CIAC and customer advances amounts to $674,000. Thus, my recommendation reduces the Company's proposed pro forma year depreciation expenses by this same amount of $674,000. To be consistent, I have also reflected the impact of this depreciation expense adjustment on the pro forma year depreciation reserve balance, as shown on Schedule RJH-10, line 9.

Q. WHAT IS THE POSITION OF OTHER WATER UTILITY COMPANIES ON THE ISSUE OF DEPRECIATING PLANT FINANCED BY CONTRIBUTED PROPERTY?

A. The American Water Works Company, the parent company of New Jersey American Water Company, holds the following position on this subject, as stated on page 47 of its 1994 Annual Report to the Stockholders:

> Utility plant funded by advances and contributions is excluded from rate base and is generally not depreciated for ratemaking purposes.

Similarly, United Water Resources, the parent company of United Water of New Jersey, reports on page 30 of its 1994 Annual Report to the Stockholders:

> The balances of advances and contributions are used to reduce utility plant in determining rate base, and plant funded by advances and contributions is generally not depreciated.

I also understand that Middlesex Water Company has always taken the position in its base rate proceedings that plant financed by contributed property is not depreciated for rate making purposes.

Q. HAS EWC BEEN ALLOWED DEPRECIATION ON ITS CONTRIBUTED PROPERTY FOR RATE MAKING PURPOSES DURING THE LAST 10 YEARS?

A. As confirmed in the Company's response to RAR-A-28, EWC has not been allowed depreciation on its contributed property since 1986.

- <u>Federal Income Taxes</u>

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE RECOMMENDED NON-CRP FEDERAL INCOME TAXES FOR THE PRO FORMA YEAR, AS SHOWN ON SCHEDULE RJH-23.

A. In calculating the recommended pro forma year federal income taxes, I used the exact same methodology as proposed by the Company. The starting point of my calculations is the recommended non-CRP pre-tax operating income level for the pro forma year. I

BEFORE THE STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
OFFICE OF ADMINISTRATIVE LAW

IN THE MATTER OF CONSUMERS NEW JERSEY WATER COMPANY FOR APPROVAL OF AN INCREASE IN RATES FOR WATER SERVICE

BPU DOCKET NO. WR96100768
OAL DOCKET NO. PUC 10317-96

DIRECT TESTIMONY OF ROBERT J. HENKES
ON BEHALF OF
THE NEW JERSEY DIVISION
OF THE RATEPAYER ADVOCATE

MARCH 14, 1997

Federal Income Tax ("FIT") rate of 34% applicable to CNJWC.

As shown on Schedule RJH-4, I have recommended a large number of operating adjustments with the effect of increasing the Company's proposed pro forma operating income by a total amount of $470,922. Each of these recommended operating income adjustments will be discussed in detail below.

- Metered Sales Revenues

Q. WHY HAVE YOU ADJUSTED THE COMPANY'S PROPOSED PRO FORMA METERED SALES REVENUES?

A. I have adjusted the Company's proposed pro forma metered sales revenues to reflect a higher projected level of total Customer Equivalent Units ("CEU") at September 30, 1997. I have accepted all other forecasting methodology components used by the Company to forecast its pro forma metered sales revenues. In the table below, I have summarized the projected CEU levels (by Division) recommended by the RPA as compared to the levels proposed by CNJWC:

	Northern	Central	Southern	Total
RPA	9,949	11,662	14,355	35,966
CNJWC	9,889	11,679	14,020	35,588
Difference	60	(17)	335	378

The RPA-recommended projected CEU levels at September 30, 1997 were derived by taking the actual CEU levels at December 31, 1996 and then adding projected CEU growth from December 31, 1996 to September 30, 1997 based on the 3-year average historic growth numbers shown in footnote (1) on Schedule RJH-11. As stated before, I have made no other adjustments to the Company's proposed metered sales revenue projection assumptions. Schedule RJH-11 shows that the application of the recommended projected CEU levels at September 30, 1997 to all of the remaining projection assumptions used by CNJWC results in the following pro forma metered sales revenues (by Division) as compared to the pro forma metered sales revenues proposed by CNJWC:

	Northern	Central	Southern	Total
RPA	$2,922,363	$3,509,447	$4,631,844	$11,063,655
CNJWC	$2,905,669	$3,512,085	$4,519,582	$10,937,336
Difference	$ 16,694	$ (2,638)	$ 112,262	$ 126,319

In summary, I recommend that the Company's proposed pro forma metered sales revenues be increased by $126,319.

Q. COULD YOU NOW DESCRIBE THE RECOMMENDED PRO FORMA MILLION GALLON ("MG") PRODUCTION NUMBERS WHICH YOU HAVE CALCULATED BASED ON THE RECOMMENDED PRO FORMA MG SALES LEVELS?

A. As shown on Schedule RJH-11, lines 12 through 14, I derived the recommended pro forma MG production levels by dividing the recommended MG sales levels for each Division by the so-called "metered ratios" established by the Company. The Company has proposed metered ratios for the Northern, Central and Southern Divisions of 80%, 90% and 92%, respectively. While I have accepted the two latter Company-proposed metered ratios, I do not agree with the Company's proposed 80% metered ratio for the Northern Division. The Northern Division has historically experienced very high unaccounted-for water levels. In response to SRW/T-10, the Company has confirmed this and agreed that this unaccounted-for level should be reduced. In fact, the Northern Division is scheduled to start a comprehensive leak survey for its water system which survey is expected to be completed sometime in April 1997. In this regard, the Company states in response to SRW/T-10 : "The Northern Division is hopeful that the comprehensive leak survey will raise the metered ratio in 1997". Based on this information, I recommend that a metered ratio of 85% for the Northern Division be used for purposes of determining the pro forma Northern MG production level.

- Public Fire Revenues

Q. WHY HAVE YOU ADJUSTED THE COMPANY'S PROPOSED PRO FORMA PUBLIC FIRE REVENUES?

A. I have adjusted the Company's proposed pro forma public fire revenues to reflect a higher projected level of inch-feet at September 30, 1997. I have accepted all other forecasting methodology components used by the Company to forecast its pro forma public fire revenues. The recommended projected inch-feet levels at September 30, 1997 were derived by taking the actual inch-feet levels at December 31, 1996 and then adding projected inch-feet growth from December 31, 1996 to September 30, 1997, as derived in footnote (3) of Schedule RJH-12. As shown in this footnote, in order to be conservative I have based my projected growth analysis on the actual growth experienced in 1996 over 1995 rather than based on the indicated 3-year average historic growth numbers. Schedule RJH-12 shows that the application of the recommended projected inch-feet levels at September 30, 1997 to all of the remaining projection assumptions used by CNJWC results in a recommended pro forma public fire revenue level that is $10,843 higher than the pro forma revenues proposed by the Company.

- <u>Labor Expenses</u>

Q. PLEASE SUMMARIZE THE RECOMMENDED ADJUSTMENTS YOU HAVE MADE TO THE COMPANY'S PROPOSED PRO FORMA LABOR EXPENSES.

A. The Company has proposed total pro forma O&M labor expenses of $2,078,507 in this case. The first column of Schedule RJH-14 shows more details regarding some of the key components of the Company's proposed pro forma labor expense calculations. The second column of Schedule RJH-14 shows that I have adjusted the Company's proposed labor expense calculations to reflect (1) 1997 labor rate increases of 4.0% rather than the Company's proposed rate increases of 4.25%; (2) a lower level of projected wages for summer employees; (3) the removal of incentive compensation expenses; and (4) an O&M expense ratio of 82.88% rather than the ratio of 85.28% proposed by the Company.

Q. PLEASE EXPLAIN YOUR RECOMMENDED ADJUSTMENT FOR THE LOWER 1997 WAGE RATE INCREASES.

A. The Company's proposed pro forma labor expenses incorporated assumed wage increases of 4.25% for its senior management effective April 1, 1997 and for its remaining employees by Division personnel with the suppliers during the summer of 1996"[6]. Also, the Company could not specify the expected effective date of this price increase.

- Employee Benefit Expenses

Q. PLEASE DESCRIBE YOUR RECOMMENDED ADJUSTMENT TO THE COMPANY'S PROPOSED PRO FORMA EMPLOYEE BENEFIT EXPENSES.

A. As shown on Schedule RJH-16, while I have accepted the Company's proposed pro forma health, life insurance and long-term disability expenses, I recommend that the Company's proposed pro forma pension expenses be reduced by $5,647. In calculating its proposed pension expenses, the Company has applied an assumed ratio of 4% to the pro forma base wage expenses. As shown in footnote (3) of Schedule RJH-16, the Company's actual "% pension of base wages" during the years 1994 through 1996 ranged from 3.41% to 4.19% with a 3-year average of 3.75%. I recommend that the pro forma pension expenses in this case be determined by applying this 3-year historic average ratio of 3.75% to the pro forma base wages.

[6] Response to RAR-A-81

not receive rate recognition. *See* Re Atlantic City Sewerage, Docket Nos. 615-401, 618-692, May 9, 1962, Re New Jersey Water Service Company, Docket Nos. 6611-796, 672-72, April 24, 1967

In summary, as shown in the third column of Schedule RJH-18, I recommend that the appropriate rate case expense level to be recognized in this case amount to $28,163.

- <u>Other Post Retirement Employee Benefits ("OPEB") Costs</u>

Q. PLEASE DESCRIBE THE COMPANY'S ANNUAL OPEB COST LEVELS, AS DETERMINED BY ITS ACTUARY UNDER THE FINANCIAL ACCOUNTING STANDARDS ("FAS") 106 ACCRUAL METHOD, FROM 1993 THROUGH TO DATE.

A. The annual FAS 106 OPEB cost levels booked by the Company since 1993 are as follows:

1993	$46,600
1994	$50,900
1995	$47,200
1996	$39,300
1997	$31,000

Q. WHAT ANNUAL LEVEL OF OPEB COSTS HAS THE COMPANY BEEN ALLOWED TO RECOVER IN RATES?

A. Since the Company's 1994 rate case, it has been allowed to recover a total annualized amount of $22,300 in rates for its OPEB costs. Because the rates from the Company's 1994 rate case became effective in May 1994, it experienced approximately 7 months worth of

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OPEB related rate recoveries, or $13,008, in the year 1994. For the years 1995 and 1996 it recovered the full annual amounts $22,300. Assuming that the rates from the instant case will become effective August 1, 1997, the Company will experience $13,008 of OPEB related rate recoveries through the currently effective rates during the first 7 months of 1997.

Q. GIVEN THE AFOREMENTIONED INFORMATION, HAVE YOU CALCULATED THE COMPANY'S APPROPRIATE FAS 106 RELATED REGULATORY ASSET BALANCE AS OF AUGUST 1, 1997, THE EXPECTED RATE EFFECTIVE DATE OF THE CURRENT CASE?

A. Yes. The FAS 106 regulatory asset balance represents the accumulated difference between the Company's actual OPEB costs as determined under the FAS 106 accrual method and the actual OPEB costs recovered in rates by the Company. Based on the previously discussed information, I have calculated that CNJWC's appropriate FAS 106 regulatory asset balance as of August 1, 1997 amounts to $131,467. My calculations are shown in detail in footnote (2) on Schedule RJH-19.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE RATE MAKING TREATMENT TO BE ALLOWED FOR THE COMPANY'S OPEB COSTS IN THIS CASE?

A. Pursuant to the recent Board-approved stipulation in the generic FAS 106 proceeding, BPU Docket No. AX96070530, dated December 23, 1996, I am making the following recommendations with regard to the rate making treatment to be recognized in this case for the Company's OPEB costs:

1. The Company's rates should include the full annual OPEB costs as determined by its actuary on a FAS 106 accrual basis. In this regard, I recommend that the most recent actuary-determined 1997 FAS 106 cost level of $31,000 be included in rates.

2. The Company's FAS 106 regulatory asset balance at August 1, 1997 of $131,467 should be amortized over a period of approximately 15.42 years and this annual amortization amount should be recovered in rates. The recommended 15.42 amortization period is derived by taking a total amortization period of 20 years as the starting point and then subtracting the time period already expired between January 1, 1993 and July 31, 1997 (approximately 4.58 years), in accordance with the requirements of FASB's EITF 92-12.

3. The Company's regulatory expenses incurred as a result of the generic FAS 106 proceeding, BPU Docket No. AX96070530 of $3,815 should be amortized over the same 15.42 year amortization period as recommended for the regulatory asset and this amortization amount should also be recovered in rates.

4. All previous OPEB costs recovered in rates and all future OPEB cost rate recoveries should be fully funded in an external trust(s), including but not limited to a VEBA

trust, 401(k) plan or other acceptable vehicle.

In summary, as shown on Schedule RJH-19, I recommend that the Company be allowed to include in rates a total amount of $39,775 for its pro forma FAS 106 related expenses.

- Office Leases

Q. WHY HAVE YOU MADE AN ADJUSTMENT FOR THE COMPANY'S PROPOSED PRO FORMA EXPENSES FOR OFFICE LEASES?

A. The Company has projected that it will incur expenses of $8,000 for the moves of its Northern and Corporate offices to new facilities and has included these expenses in its pro forma year operating expenses. It should be noted that these expenses do not represent annual recurring operating expenses, rather, they represent one-time, non-recurring costs. When questioned about this, the Company stated in its response to RAR-A-65: "I agree that the moving expenses are one-time expenses, and the Company would not be opposed to an amortization". Based on this information, I recommend that these moving expenses be amortized over a 10-year period. As shown on Schedule RJH-13, line 10, my recommendation reduces the Company's proposed office leases expense by $7,200.

complex procedure be replaced by simply removing this "income" amount of $20,000 from the Company's pro forma cost of service. I have done so on Schedule RJH-13, line 18.

- Depreciation Expenses

Q. IS THE COMPANY CURRENTLY DEPRECIATING ITS UTILITY PLANT FUNDED BY CIAC?

A. No. CIAC represent mostly Main Plant Investments that have been permanently contributed to the Company by individuals, developers, municipalities or other outside parties. As such, plant financed with CIAC comes at no cost to the Company and requires no investor-supplied capital. For this reason, the Company does not depreciate its plant funded with CIAC because it would not be appropriate to charge the ratepayers for costs that were never incurred by the Company.

Q. IS THE COMPANY CURRENTLY DEPRECIATING ITS UTILITY PLANT FUNDED BY CUSTOMER ADVANCES?

A. Yes, it is.

Q. DO YOU AGREE WITH THIS POSITION?

A. No, I do not. Customer advances represent the exact same type of property contributions as CIAC, however, portions of these customer advances are still subject to refund to the contributing outside parties. Once CNJWC has paid the partial refunds for its customer advances, the remaining customer advances balances will be reclassified to CIAC as permanent property contributions. While certain customer advances portions will be refunded to customers on an on-going basis, at the same time new customer advances will be added on an on-going basis. The end result is that the Company will always, and at any point in time, carry a permanent level of customer advances on its books. This is evidenced by the data shown on Schedule RJH-7 which indicates that the Company's customer advances balances are always growing when viewed over the course of any particular year. Thus, CNJWC's customer advances balance, similar to its CIAC balance, is to be considered permanent non-investor supplied capital used to finance the Company's plant investment. Since the Company's investors never laid out any funds for the plant investments financed with customer advances, they should not be entitled to (1) earn a return <u>on</u> such investments (through rate base inclusion), or (2) receive a return <u>of</u> the investments (through depreciation). The Company has properly recognized the first of these rate making principles by removing the plant investments financed by customer advances from its rate base. This has been accomplished by treating the pro forma customer advances balance as a separate rate base deduction. However, the Company has not consistently followed through on the second of these rate making principles, i.e., it is claiming a return <u>of</u> this contributed property by reflecting depreciation expenses on its plant financed by customer advances. I have corrected for this inconsistency by removing these depreciation expenses from CNJWC's proposed pro forma year operating expenses. As shown on Schedule RJH-7, CNJWC's proposed depreciation expenses on its pro forma year plant financed by customer advances amounts to $103,700. Thus, I recommend that the Company's proposed pro forma year depreciation expenses be reduced by this same amount of $103,700. To be consistent, I have also reflected the impact of this depreciation expense adjustment on the pro forma year depreciation reserve balance, as shown on Schedule RJH-6.

Q. WHAT IS THE POSITION OF OTHER WATER UTILITY COMPANIES ON THE ISSUE OF DEPRECIATING PLANT FINANCED BY CONTRIBUTED PROPERTY?

A. The American Water Works Company, the parent company of New Jersey American Water Company, holds the following position on this subject, as stated on page 47 of its 1994 Annual Report to the Stockholders:

> Utility plant funded by advances and contributions is excluded from rate base and is generally not depreciated for rate making purposes.

Similarly, United Water Resources, the parent company of United Water New Jersey, reports on page 30 of its 1994 Annual Report to the Stockholders:

> The balances of advances and contributions are used to reduce utility plant in determining rate base, and plant funded by advances and contributions is generally not depreciated.

Thus, my recommendation is consistent with the depreciation accounting treatment espoused by the two largest water utility systems in New Jersey.

BEFORE THE
STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
OFFICE OF ADMINISTRATIVE LAW

IN THE MATTER OF THE PETITION OF	)	
CONSUMERS NEW JERSEY WATER	)	BPU Docket No. WR97080615
COMPANY FOR AN INCREASE IN ITS	)	OAL Docket No. PUC08464-97
RATES FOR WATER SERVICE	)	

Direct Testimony
of
ROBERT J. HENKES

On Behalf of the New Jersey
Division of the Ratepayer Advocate

January 16, 1998

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- Metered Sales Revenues

Q. PLEASE SUMMARIZE THE COMPANY'S ORIGINAL "AS-FILED" AND SUBSEQUENTLY REVISED PRO FORMA METERED SALES REVENUE PROJECTIONS.

A. As shown on Company Exhibit P-13, Sheet 1, the Company originally projected its pro forma metered sales revenues based on conditions expected as of August 31, 1998 to be $11,078,773. The Company subsequently submitted a revised study, employing a new revenue forecasting methodology, indicating that its projected pro forma metered sales revenues should be revised downward to $10,971,446, or $107,327 lower than the original projections. The results of this latest revised metered sales revenue projection are summarized on schedule RJH-8, page 2 of 2.

Q. DO YOU BELIEVE THAT THE COMPANY'S LATEST REVISED METERED SALES PROJECTION METHODOLOGY IS REASONABLE?

A. Yes. I have reviewed and analyzed the reasons why the Company has changed its sales forecasting methodology and find these reasons to be valid. Therefore, in determining the recommended metered sales revenues, I have used the same forecasting methodology as used in the Company's revised study.

Q. HAVE YOU ADJUSTED THE COMPANY'S REVISED METERED SALES REVENUE PROJECTIONS?

A. Yes. I have adjusted the Company's proposed revised pro forma metered sales revenues to

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reflect a higher projected level of total Customer Equivalent Units ("CEU") at August 31, 1998. As shown on schedule RJH-8, page 1, I have accepted all other forecasting methodology components used by the Company to forecast its revised pro forma metered sales revenues.

The Ratepayer Advocate recommended projected CEU levels at August 31, 1998 were derived by taking the actual CEU levels at December 31, 1997 and then adding projected CEU growth from December 31, 1997 to August 31, 1998 based on the 4-year average historic growth numbers shown in footnote (1) on Schedule RJH-8, page 1. As stated before, I have made no other adjustments to the Company's proposed revised metered sales revenue projection assumptions. Schedule RJH-8, page 1, line 11 shows that the application of the recommended projected CEU levels at August 31, 1998 to all of the remaining projection assumptions used by CNJWC results in total recommended pro forma metered sales revenues of $11,101,417. Schedule RJH-4, line 2 shows that this recommended pro forma metered sales revenue amount of $11,101,417 is $22,644 higher than the Company's "as filed" pro forma metered sales revenue amount of $11,078,773.

Q. COULD YOU NOW DESCRIBE THE RECOMMENDED PRO FORMA MILLION GALLON PRODUCTION NUMBERS WHICH YOU HAVE CALCULATED BASED ON THE RECOMMENDED PRO FORMA MG SALES LEVELS?

A. As shown on Schedule RJH-8, lines 12 through 14, I derived the recommended pro forma Million Gallon ("MG") production levels by dividing the recommended MG sales levels for each Division by the so-called "metered ratios", similar to the aproach used by CNJWC.

The Company has proposed metered ratios for the Northern, Central and Southern Divisions of 80%, 90% and 92%, respectively, and I have accepted these Company-proposed metered ratios. The resulting recommended total pro forma MG production level amounts to approximately 3,904 MG.

- Labor Expenses

Q. PLEASE SUMMARIZE THE RECOMMENDED ADJUSTMENTS YOU HAVE MADE TO THE COMPANY'S PROPOSED PRO FORMA LABOR EXPENSES.

A. The Company has proposed total pro forma O&M labor expenses of $2,121,380 in this case. The first column of Schedule RJH-10 shows more details regarding some of the key components of the Company's proposed pro forma labor expense calculations. The second column of Schedule RJH-10 shows that I have adjusted the Company's proposed labor expense calculations to reflect: (1) a lower level of projected wages for summer employees; (2) the removal of the entire requested amount for incentive compensation expenses; and (3) an O&M expense ratio of 83.75% rather than the ratio of 85.82% proposed by the Company.

Q. PLEASE EXPLAIN YOUR FIRST RECOMMENDED ADJUSTMENT FOR THE LOWER LEVEL OF SUMMER EMPLOYEE WAGE EXPENSES.

A. In response to RAR-A-67, the Company confirmed the following information regarding its actual total summer employee hours worked and gross wages paid during 1995, 1996 and 1997:

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Company's "Other Expenses". This recommendation is based upon information that I have obtained through my participation in other utility base rate cases filed before the BPU.

Q. BASED ON YOUR PREVIOUSLY DISCUSSED FINDINGS AND CONCLUSIONS, WHAT LEVEL OF "OTHER EXPENSES" DO YOU RECOMMEND BE USED FOR RATE MAKING PURPOSES IN THIS CASE?

A. As shown on Schedule RJH-15, I recommend that the appropriate level of "Other Expenses" to be recognized for rate making purposes in this case is $757,074.

- <u>Depreciation Expenses</u>

Q. IS THE COMPANY CURRENTLY DEPRECIATING ITS UTILITY PLANT FUNDED BY CONTRIBUTIONS IN AID OF CONSTRUCTION?

A. No. CIAC represent mostly Main plant investments that have been permanently contributed to the Company by individuals, developers, municipalities or other outside parties. As such, plant financed with CIAC comes at no cost to the Company and requires no investor-supplied capital. For this reason, the Company does not depreciate its plant funded with CIAC because it would not be appropriate to charge the ratepayers for costs that were never incurred by the Company.

Q. IS THE COMPANY CURRENTLY DEPRECIATING ITS UTILITY PLANT FUNDED BY CUSTOMER ADVANCES?

A. Yes, it is.

Q. DO YOU AGREE WITH THIS POSITION?

A. No, I do not. Customer advances represent the exact same type of property contributions as CIAC, however, portions of these customer advances are still subject to refund to the contributing outside parties. Once CNJWC has paid the partial refunds for its customer advances, the remaining customer advances balances will be reclassified to CIAC as permanent property contributions. While certain customer advances portions will be refunded to customers on an on-going basis, at the same time new customer advances will be added on an on-going basis. The end result is that the Company will always, and at any point in time, carry a permanent level of customer advances on its books. Thus, CNJWC's customer advances balance, similar to its CIAC balance, is to be considered permanent non-investor supplied capital used to finance the Company's plant investment.

Since the Company's investors never contributed any funds for the plant investments financed with customer advances, they should not be entitled to: (1) earn a return <u>on</u> such investments (through rate base inclusion), or (2) receive a return <u>of</u> the investments (through depreciation). The Company has properly recognized the first of these rate making principles by removing the plant investments financed by customer advances from its rate base. This has been accomplished by treating the pro forma customer advances balance as a separate rate base deduction. However, the Company has not consistently followed through on the second of these rate making principles, i.e., it is claiming a return <u>of</u> this contributed property by reflecting depreciation expenses on its plant financed by customer advances. I have corrected this inconsistency by removing these depreciation expenses from CNJWC's proposed pro forma year operating expenses. As shown on Schedule RJH-16, CNJWC's proposed depreciation expenses for its pro forma year plant financed by customer advances amounts to $95,970. Thus, I recommend that the Company's proposed pro forma year depreciation expenses be reduced by this same amount of $95,970. To be consistent, I have also reflected the impact of this depreciation expense adjustment on the pro forma year depreciation reserve balance, as shown on Schedule RJH-5.

- Revenue Taxes

Q. HOW DID YOU DERIVE THE RECOMMENDED PRO FORMA REVENUE TAXES TO BE USED FOR RATE MAKING PURPOSES IN THIS CASE?

A. As shown on Schedule RJH-17, I have used the exact same methodology and calculation components as those used by the Company to derive the recommended pro forma revenue taxes. The difference between the recommended and Company-proposed pro forma revenue tax levels is due to the "flow-through" impact of adjustments made to the Company's proposed positions regarding total operating revenues and bad debt expenses.

- Income Taxes

Q. HOW DID YOU DERIVE THE RECOMMENDED PRO FORMA INCOME TAXES TO BE USED FOR RATE MAKING PURPOSES IN THIS CASE?

A. As shown on Schedule RJH-18, I have used the exact same methodology and calculation components as those used by the Company to derive the recommended pro forma income

BEFORE THE
STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
OFFICE OF ADMINISTRATIVE LAW

IN THE MATTER OF THE PETITION OF NEW JERSEY - AMERICAN WATER COMPANY, INC FOR AN INCREASE IN RATES FOR WATER AND SEWER SERVICE AND OTHER MODIFICATIONS	)))))	**BPU Docket No. WR98010015** **OAL Docket No. PUC699-98S**

Direct Testimony
of
ROBERT J. HENKES

On Behalf of the New Jersey
Division of the Ratepayer Advocate

June 30 , 1998

- <u>Group Insurance, 401(k), Payroll Taxes</u>

Q. PLEASE EXPLAIN YOUR RECOMMENDED ADJUSTMENTS TO NJAWC's PROPOSED PRO FORMA GROUP INSURANCE, 401(K) EXPENSES AND PAYROLL TAXES SUMMARIZED ON SCHEDULE RJH-4, LINE 9 AND DETAILED IN SCHEDULE RJH-18.

A. I have adjusted the Company's proposed pro forma group insurance, 401(k) expenses and payroll taxes to reflect a recommended construction ratio of 11.05% rather than the Company's proposed construction ratio of 10.45%, as discussed in more detail in the previous "Salaries and Wages" section of this testimony.

This recommended adjustment reduces the Company's proposed pro forma expenses by $34,000 with a related pro forma income increase impact of $22,000.

- <u>Post -Retirement Benefits Other Than Pensions ("PBOP") Expenses</u>

Q. PLEASE EXPLAIN YOUR RECOMMENDED ADJUSTMENTS TO NJAWC'S PROPOSED PRO FORMA PBOB EXPENSES SUMMARIZED ON SCHEDULE RJH-4, LINE 10 AND DETAILED IN SCHEDULE RJH-19.

A. I have adjusted the Company's proposed PBOP expenses in two respects. First, I have replaced the Company's proposed 1997 PBOP costs of $2,264,000 with the 1998 PBOP costs of $2,200,897. In response to RAR-A-102, the Company has agreed that this most recent PBOP cost number should be used for ratemaking purposes in this case.

Second, I adjusted NJAWC's proposed amount chargeable to construction. Whereas NJAWC has proposed a construction ratio of 10.45%, I recommend a construction ratio of 11.05% as discussed in more detail in the previous "Salaries and Wages" section of this testimony.

These two recommended adjustments reduce the Company's proposed pro forma PBOP expenses by $70,000, with a related pro forma income increase impact of $46,000.

- <u>Power Expenses</u>

Q. PLEASE EXPLAIN YOUR RECOMMENDED ADJUSTMENT TO NJAWC'S PROPOSED PRO FORMA POWER EXPENSES SUMMARIZED ON SCHEDULE RJH-4, LINE 11 AND DETAILED IN SCHEDULE RJH-20.

A. The Company's proposed pro forma test year power expenses are based on the current electric rates of Atlantic Electric, Public Service Electric &Gas, and GPU Energy, the electric utilities serving NJAWC. This means that the Company has not adjusted its pro forma power expenses to reflect the impact of electric industry restructuring currently pending for all of the electric utilities in New Jersey. Pursuant to the Board's "Green Book" restructuring recommendations and the subsequent restructuring filings by the aforementioned electric utilities, it can be expected that the electric rates for these utilities will be reduced by *at least* 5% effective January 1, 1999. Since these electric rate reductions can be expected to take place during the time that the rates from this case will become effective, I recommend that the Company's proposed pro forma power expenses be reduced by a factor of 5%.

- Depreciation Expenses

Q. PLEASE EXPLAIN YOUR RECOMMENDED ADJUSTMENTS TO NJAWC'S PROPOSED PRO FORMA DEPRECIATION EXPENSES SUMMARIZED ON SCHEDULE RJH-4, LINE 26 AND DETAILED IN SCHEDULE RJH-33.

A. I have adjusted the Company's proposed depreciation expenses in two respects. First, I have removed the Company's proposed depreciation expenses associated with contributed plant. Second, I have reflected the impact on the Company's proposed depreciation expenses of the recommended plant in service adjustments. In total, these two recommended adjustments reduce NJAWC's proposed pro forma depreciation expenses by $1,460,000 and increase the Company's proposed pro forma income by $949,000.

Q. PLEASE DESCRIBE THE REASONS FOR THE FIRST RECOMMENDED DEPRECIATION ADJUSTMENT.

A. Contributions in Aid of Construction (CIAC) represent main, services, hydrants and meters investments that have been permanently contributed to the Company by individuals, developers, municipalities or other outside parties. Customer advances represent the exact same type of property contributions, however, portions of these customer advances are still subject to refund to the contributing outside parties. Once NJAWC has paid the partial refunds for its customer advances, the remaining customer advances balances will be reclassified to CIAC as permanent property contributions. Since the Company's investors never laid out any funds for these contributed investments, they should not be entitled to (1) earn a return <u>on</u> such investments (through rate base inclusion), or (2) receive a return of the investments (through depreciation). The Company has properly recognized the first of these ratemaking principles by removing the plant investments financed by CIAC and customer advances from its rate base. However, the Company has not consistently followed through on the second of these ratemaking principles, i.e., it is claiming a return of this contributed property by reflecting depreciation expenses on its plant financed by CIAC and customer advances. I have corrected for this inconsistency by removing these depreciation expenses from NJAWC's proposed pro forma year operating expenses. As shown on Schedule RJH-33, footnote (2), NJAWC's proposed depreciation expenses on its pro forma year plant financed by CIAC and customer advances amounts to approximately $726,000. Thus, my recommendation reduces the Company's proposed pro forma year depreciation expenses by this same amount of $726,000.

Q. IS THE COMPANY CURRENTLY BEING ALLOWED TO BOOK DEPRECIATION ON CONTRIBUTED PLANT FOR RATEMAKING PURPOSES?

A. No. NJAWC's most recent Annual Report states on pages 10 and 11:

> Depreciation expense on contributed property is not recognized in cost of service by the Board.
>
> Utility plant funded by advances and contributions is excluded from rate base and is not depreciated.

Also, in response to RAR-A-25, the Company has confirmed that it..."does not book depreciation on contributed property and has not booked it for at least the past five years."

In summary, my recommendation to exclude depreciation on contributed property in this case is appropriate for the reasons described earlier.

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Q. PLEASE DESCRIBE YOUR SECOND DEPRECIATION EXPENSE ADJUSTMENT.

A. This adjustment is a direct result of my recommended plant in service adjustment in this case. As shown in footnote (3) on Schedule RJH-33, my recommendation to reduce the Company's proposed projected plant in service level by $$29.2 million results in a corresponding depreciation expense adjustment of $$733,000.

- Amortization of Land Sales Gain

Q. PLEASE EXPLAIN THE INCOME ADJUSTMENT FOR THE AMORTIZATION OF LAND SALES GAINS SHOWN ON SCHEDULE RJH-4, LINE 27.

A. The reasons for this recommended income adjustment were previously discussed in the "Unamortized Gain on Land Sales" rate base section of this testimony and the calculations underlying this income adjustment are shown on Schedule RJH-11.

- Interest Synchronization

Q. PLEASE EXPLAIN YOUR RECOMMENDED INTEREST SYNCHRONIZATION ADJUSTMENT SUMMARIZED ON SCHEDULE RJH-4, LINE 28 AND DETAILED ON SCHEDULE RJH-34.

A. Both the Company and I believe it is appropriate to use "synchronized interest" as a tax deduction in calculating the appropriate pro forma income taxes in this case. The "synchronized interest" amount is determined by multiplying the rate base times the weighted cost of debt

BEFORE THE
STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
OFFICE OF ADMINISTRATIVE LAW

IN THE MATTER MIDDLESEX WATER COMPANY FOR APPROVAL OF AN INCREASE IN ITS RATES FOR WATER SERVICE AND OTHER TARIFF CHANGES	)))))	BPU Docket No. WR98090795 OAL Docket No. PUCRL 8776-98S

Direct Testimony
of
ROBERT J. HENKES

On Behalf of the New Jersey
Division of the Ratepayer Advocate

March 19, 1999

MWC's pro forma test year results amounts to $12,000, of which $7,000 is actually booked in the test year and $5,000 is reflected as a pro forma test year expense adjustment. The $5,000 pro forma adjustment was removed by me as part of the South Amboy incremental revenue requirement analysis on Schedule RJH-2 (line 10 b.). The remaining $7,000 actual test year per books expense has been removed as a separate expense adjustment on Schedule RJH-18, line 8.

- <u>Pro Forma Annualized Depreciation Expenses</u>

Q. PLEASE EXPLAIN THE DERIVATION OF THE RECOMMENDED PRO FORMA ANNUALIZED DEPRECIATION EXPENSES SHOWN ON SCHEDULE RJH-17.

A. As shown on Schedule RJH-17, page 1, I have calculated separate pro forma annualized depreciation expenses for (1) the CJO plant upgrade, and (2) all non-CJO upgrade related plant in service included in rate base.

The annualized depreciation expenses associated with the CJO upgrade were calculated by applying the CJO-specific composite depreciation rate of 2.69% to the CJO upgrade plant level of $36.420 million included in rate base in this case. This results in annualized CJO upgrade depreciation expenses of $979,334 as shown on Schedule RJH-17, page 1, line 8.

With regard to the non-CJO upgrade plant in service, the pro forma annualized depreciation expenses were determined by applying the appropriate composite depreciation rate of 2.22% to the non-CJO upgrade plant in service balance included in rate base, exclusive of non-depreciable land and land rights, and net of plant funded by CIAC and Customer Advances. This results in annualized non-CJO upgrade depreciation expenses of $2,829,338 as shown on Schedule RJH-17, page 1, line 5.

Thus, the total recommended pro forma annualized depreciation expenses to be recognized for ratemaking purposes in this case amount to $3,808,672, as shown on Schedule RJH-17, page 1, line 9.

Q. WHY IS 2.22% THE APPROPRIATE COMPOSITE DEPRECIATION RATE TO DETERMINE THE NON-CJO UPGRADE PLANT DEPRECIATION EXPENSES?

A. The recommended rate base inclusion for the non-CJO upgrade plant in service is based on the actual per books plant in service balance as of January 31, 1999. Schedule RJH-17, page 2 shows that the application of the Company's currently authorized depreciation rates to the corresponding actual plant account balances at January 31, 1999 derives the appropriate composite depreciation rate of 2.22%.

Q. IN CALCULATING ITS PROPOSED ANNUALIZED DEPRECIATION EXPENSES, HAS THE COMPANY PROPOSED TO DEPRECIATE PLANT FUNDED BY CIAC AND CUSTOMER ADVANCES?

A. While the Company does not propose to depreciate plant funded by CIAC, it does propose to depreciate plant funded by Customer Advances.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED POSITION?

A. No, I do not. CIAC represent mostly Main plant investments that have been permanently contributed to the Company by individuals, developers, municipalities or other outside parties. As such, plant financed with CIAC comes at no cost to the Company and requires no investor-supplied capital. For this reason, the Company does not depreciate its plant funded with CIAC because it would not be appropriate to charge the ratepayers for costs that were never incurred by the Company.

Customer Advances represent the exact same type of property contributions as CIAC, however, portions of these Customer Advances are still subject to refund to the contributing outside parties. Once MWC has paid the partial refunds for its Customer Advances, the remaining Customer Advances balances will be reclassified to CIAC as permanent property contributions. While certain Customer Advances portions will be refunded to customers on an on-going basis, at the same time new Customer Advances will be added on an on-going basis. The end result is that the Company will always, and at any point in time, carry a permanent level of Customer Advances on its books. Thus, MWC's Customer Advances balance, similar to its CIAC balance, is to be considered permanent non-investor supplied capital used to finance the Company's plant investment.

Since the Company's investors never laid out any funds for the plant investments financed with Customer Advances, they should not be entitled to (1) earn a return <u>on</u> such investments (through rate base inclusion), or (2) receive a return <u>of</u> the investments (through depreciation). The Company has properly recognized the first of these rate making principles by removing the plant investments financed by Customer Advances from its rate base. However, the Company has not consistently followed through on the second of these rate making principles, i.e., it is claiming a return <u>of</u> this contributed property by reflecting depreciation expenses on its plant financed by Customer Advances. I have corrected for this inconsistency by not calculating depreciation expenses on plant funded by the Company's Customer Advances balance.

- <u>GR&FT Expenses</u>

Q. WHY HAVE YOU MADE AN ADJUSTMENT TO THE COMPANY'S PROPOSED GR&FT EXPENSES, AS SHOWN ON SCHEDULE RJH-18?

A. The recommended GR&FT expense adjustment shown on Schedule RJH-18 is a direct result of my recommended revenue adjustments discussed earlier in this testimony and shown on Schedules RJH-13 and RJH-14.

- <u>Income Taxes</u>

Q. HAVE YOU CALCULATED THE RECOMMENDED PRO FORMA INCOME TAXES TO BE RECOGNIZED FOR RATEMAKING PURPOSES IN THIS CASE IN A MANNER CONSISTENT WITH THE COMPANY'S METHODOLOGY?

A. Yes, my calculations are presented on Schedule RJH-19. There are three reasons why the recommended pro forma income taxes are different from the Company's proposed pro forma income taxes. First, the recommended operating income before income taxes is higher than

BEFORE THE
STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
OFFICE OF ADMINISTRATIVE LAW

IN THE MATTER OF THE PETITION OF MOUNT HOLLY WATER COMPANY FOR APPROVAL OF AN INCREASE IN RATES FOR SERVICE	))))	BPU Docket No. WR99010032 OAL Docket No. PUCRS 00582-99S

Direct Testimony
of
ROBERT J. HENKES

On Behalf of the New Jersey
Division of the Ratepayer Advocate

July 16, 1999

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shown on Schedule RJH-16, this results in a recommended total annual normalized WRM expense level of $28,866.

- FASB 106 Expense Adjustment

Q. PLEASE EXPLAIN THE RECOMMENDED EXPENSE ADJUSTMENT TO THE COMPANY'S PROPOSED FASB 106 EXPENSES.

A. While the Company in response to RAR-A-71 indicated that its most recent actuary-prepared FASB 106 cost for 1999 would be available around June 15, 1999, this actuary valuation was still not available at the time this testimony was being prepared. In the meantime, the Company based its pro forma FASB 106 cost estimate of $48,917 in its 4/30/99 Update Filing on its actual 1998 FASB 106 costs, increased by an inflator of 5%. I disagree with this cost estimate. Instead, I recommend that as long as the actual 1999 FASB 106 cost valuation is not available, the actual 1998 FASB 106 expenses without the assumed 5% inflator be used for ratemaking purposes in this case. The Board has never allowed a cost increase based on unsubstantiated inflation estimates. As shown on Schedule RJH-17, my recommendation reduces the Company's proposed FASB 106 costs by $1,871.

- Regulatory Expense Adjustment

Q. PLEASE EXPLAIN YOUR RECOMMENDED ADJUSTMENTS TO THE COMPANY'S PROPOSED REGULATORY EXPENSES IN THIS CASE.

A. The derivation of the recommended regulatory expenses in this case are detailed on Schedule

O&M expense level to which the Company applied the estimated cost increase factor based on its 1999 operating budget represents a normalized level that can reasonably be expected on an on-going basis.

For these reasons, the Company's proposed general cost adjustment should be rejected by the Board. My recommendation is shown on Schedule RJH-19, lines 4 and 5.

- Miscellaneous Expense Adjustment

Q. PLEASE EXPLAIN THE MISCELLANEOUS EXPENSE ADJUSTMENT SHOWN ON SCHEDULE RJH-12, LINE 16.

A. As detailed in footnote 4 of Schedule RJH-12, the total recommended miscellaneous expense adjustment of $1,184 consists of the recommended removal of $684 for lobbying expenses and $500 for donation expenses. Both lobbying and donation expenses should be treated "below-the-line" for ratemaking purposes as they do not represent expenses that are necessary for the provision of adequate and reliable water service. The Ratepayer Advocate has a well-established and long-standing policy that 100% of a utility's donation expenses should be paid for by the shareholder and I agree with that policy.

- Depreciation Expense Adjustment

Q. PLEASE EXPLAIN THE DERIVATION OF THE RECOMMENDED PRO FORMA ANNUALIZED DEPRECIATION EXPENSES SHOWN ON SCHEDULE RJH-20.

A. As detailed on Schedule RJH-20, the starting point of my recommended pro forma annualized depreciation expense position is the Company's pro forma annualized depreciation expense amount reflected in its 4/30/99 Update Filing. I then decreased this Company-proposed annualized depreciation expense amount to remove the depreciation expenses associated with plant funded by customer advances and to eliminate the depreciation expenses related to the utility plant disallowances recommended by me in this case. Thus, the total recommended pro forma annualized depreciation expenses to be recognized for ratemaking purposes in this case amount to $582,898 as shown on Schedule RJH-20, line 4.

Q. IN CALCULATING ITS PROPOSED ANNUALIZED DEPRECIATION EXPENSES, HAS THE COMPANY PROPOSED TO DEPRECIATE PLANT FUNDED BY CIAC AND CUSTOMER ADVANCES?

A. While the Company does not propose to depreciate plant funded by CIAC, it does propose to depreciate plant funded by Customer Advances.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED POSITION?

A. No, I do not. CIAC represent mostly Main plant investments that have been permanently contributed to the Company by individuals, developers, municipalities or other outside parties. As such, plant financed with CIAC comes at no cost to the Company and requires no investor-supplied capital. For this reason, the Company does not depreciate its plant funded with CIAC because it would not be appropriate to charge the ratepayers for costs that were never incurred by the Company.

Customer Advances represent the exact same type of property contributions as CIAC, however, portions of these Customer Advances are still subject to refund to the contributing

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outside parties. Once MH has paid the partial refunds for its Customer Advances, the remaining Customer Advances balances will be reclassified to CIAC as permanent property contributions. While certain Customer Advances portions will be refunded to customers on an on-going basis, at the same time new Customer Advances will be added on an on-going basis. The end result is that the Company will always, and at any point in time, carry a permanent level of Customer Advances on its books. Thus, MH's Customer Advances balance, similar to its CIAC balance, is to be considered permanent non-investor supplied capital used to finance the Company's plant investment.

Since the Company's investors never laid out any funds for the plant investments financed with Customer Advances, they should not be entitled to (1) earn a return on such investments (through rate base inclusion), or (2) receive a return of the investments (through depreciation). The Company has properly recognized the first of these rate making principles by removing the plant investments financed by Customer Advances from its rate base. However, the Company has not consistently followed through on the second of these rate making principles, i.e., it is claiming a return of this contributed property by reflecting depreciation expenses on its plant financed by Customer Advances. I have corrected for this inconsistency by not calculating depreciation expenses on plant funded by the Company's Customer Advances balance.

Q. IS THE COMPANY'S POSITION REGARDING DEPRECIATION ON PLANT FUNDED BY CUSTOMER ADVANCES INCONSISTENT WITH THE POSITION REGARDING THIS SAME ITEM TAKEN BY ITS PARENT COMPANY, ELIZABETHTOWN WATER COMPANY ("EWC")?

Yes. EWC is currently not depreciating plant funded by both CIAC and customer advances. This is confirmed on page 17 of EWC's 1998 Annual Report to the Stockholders where it reports:

> A decrease of $.6 million [in depreciation expenses] resulted from Elizabethtown no longer being required by the BPU to depreciate utility plant acquired through Contributions in Aid of Construction and Customers' Advances for Construction.

Q. HAVE YOU CALCULATED THE DEPRECIATION AMOUNT ASSOCIATED WITH PLANT FUNDED WITH CUSTOMERS ADVANCES THAT SHOULD BE REMOVED FROM THIS CASE?

A. Yes. This depreciation expense amounts to $48,324. As shown on Schedule RJH-20, footnote 2, this amount is derived by applying the appropriate depreciation rate of 1.66% to the customer advances balance of $2,911,000 projected for the end of the pro forma period, 12/31/99.

Q. HOW DID YOU CALCULATE THE DISALLOWED DEPRECIATION EXPENSE AMOUNT RELATED TO UTILITY PLANT DISALLOWANCES RECOMMENDED BY YOU IN THIS PROCEEDING?

A. As detailed in footnote 3 of Schedule RJH-20, I applied an appropriate composite depreciation rate of 1.84% to the recommended utility plant adjustment amount of $348,496. The composite depreciation rate of 1.84% was calculated based on information contained in P-4-U and P-8-U, Sch. 2, page 1.

BEFORE THE
STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
OFFICE OF ADMINISTRATIVE LAW

IN THE MATTER OF THE PETITION OF	)
THE MOUNT HOLLY WATER COMPANY	) BPU Docket No. WR99010032
FOR APPROVAL OF AN INCREASE IN BASE	) OAL Docket No. PUCRS 00582-99S
RATES FOR SERVICE AND INCORPORATING	)
THEREIN THE PURCHASED WATER	)
ADJUSTMENT CLAUSE	)

Supplemental Direct Testimony
of
ROBERT J. HENKES

On Behalf of the New Jersey
Division of the Ratepayer Advocate

September 2, 1999

- Chemical Expense Adjustment

Q. PLEASE EXPLAIN THE DERIVATION OF THE RECOMMENDED PRO FORMA ANNUAL CHEMICAL EXPENSES SHOWN ON SCHEDULE RJH-13-S.

A. Similar to the recommended power expense derivation, the starting point of my calculations is the recommended pro forma MG pumpage of 1,333.51 associated with the pro forma revenue projections in this case. As discussed in the prior section of this testimony, this recommended pumpage level incorporates a UFW ratio of 8.33% as opposed to the UFW ratio of 10.72% proposed by the Company.

I then applied to this pro forma MG pumpage level the same unit chemical cost number of $58.90 MG as proposed by the Company in its supplemental filing. As shown on Schedule RJH-13-S, line 3, this results in a recommended pro forma annual chemical cost level of $78,544.

- FASB 106 Expense Adjustment

Q. PLEASE EXPLAIN THE RECOMMENDED EXPENSE ADJUSTMENT TO THE COMPANY'S PROPOSED FASB 106 EXPENSES.

A. While the Company in response to RAR-A-71 indicated that its most recent actuary-prepared FASB 106 cost for 1999 would be available around June 15, 1999, this actuary valuation was still not available at the time this supplemental testimony was being prepared. In the meantime, the Company based its pro forma FASB 106 cost estimate of $48,917 on its actual 1998 FASB 106 costs, increased by an inflator of 5%. I disagree with this cost estimate. Instead, I recommend that as long as the actual 1999 FASB 106 cost valuation is not available, the actual 1998 FASB 106 expenses without the assumed 5% inflator be used for ratemaking purposes in this case. The Board has never allowed a cost increase based on unsubstantiated inflation estimates. As shown on Schedule RJH-14-S, my recommendation reduces the Company's proposed FASB 106 costs by $1,871.

- Transportation Expense Adjustment

Q. PLEASE DESCRIBE YOUR RECOMMENDED ADJUSTMENT FOR TRANSPORTATION EXPENSES.

A. Based on my review of the data contained on P-8-U, Schedule 1-N, page 2 and the cross-examination of Company witness Stroin, I believe that the Company's proposed projected transportation expense level of $105,000 is overstated. To be able to analyze this issue in more detail, the Company was requested, through hearing transcript requests, to provide additional information regarding the derivation of its transportation expense proposal. However, the responses to these transcript requests are still outstanding at this time. Therefore, until I have had the opportunity to review the responses to these transcript requests, I recommend that the Company's actual transportation expenses for the most recent 12-month period for which actual data are available be recognized for ratemaking purposes at this time. As shown in the response to RAR-A-31, page 4, Update 7/31/99, the actual transportation expenses for the 12-month period ended 7/31/99 amount to $80,371.

On Schedule RJH-10-S, line 14, I show that the reflection of this cost number reduces the Company's proposed expenses by $24,629.

Advocate has a well-established and long-standing policy that 100% of a utility's donation expenses should be paid for by the shareholder and I agree with that policy.

- Depreciation Expense Adjustment

Q. PLEASE EXPLAIN THE DERIVATION OF THE RECOMMENDED PRO FORMA ANNUALIZED DEPRECIATION EXPENSES SHOWN ON SCHEDULE RJH-16-S.

A. As detailed on Schedule RJH-16-S, the starting point of my recommended pro forma annualized depreciation expense position is the Company's pro forma annualized depreciation expense amount reflected in its supplemental filing. I then decreased this Company-proposed annualized depreciation expense amount to remove the depreciation expenses associated with plant funded by customer advances and to eliminate the depreciation expenses related to the Mansfield II plant and other utility plant disallowances recommended by me in this case. Thus, the total recommended pro forma annualized depreciation expenses to be recognized for ratemaking purposes in this case amount to $847,992 as shown on Schedule RJH-16, line 5.

Q. WHY DID YOU REMOVE THE DEPRECIATION EXPENSES ASSOCIATED WITH PLANT FUNDED BY CUSTOMER ADVANCES?

A. This depreciation expense adjustment was agreed upon between the Ratepayer Advocate and the Company, as described on page 2 of the MOU dated 8/25/99. I derived the recommended depreciation expense removal by applying the agreed upon depreciation rate of 1.66% to the projected 12/31/99 customer advances balance recommended by me in this testimony.

Q. HOW DID YOU CALCULATE THE DISALLOWED DEPRECIATION EXPENSE AMOUNT RELATED TO THE "ROUTINE" UTILITY PLANT DISALLOWANCES RECOMMENDED BY YOU IN THIS PROCEEDING?

A. As detailed in footnote 3 of Schedule RJH-16-S, I applied the appropriate composite "routine plant" depreciation rate of 1.73% to the recommended utility plant adjustment amount. The composite depreciation rate of 1.73% was calculated based on information contained in PI-29-U-S.

Q. HOW DID YOU CALCULATE THE DISALLOWED DEPRECIATION EXPENSE AMOUNT RELATED TO THE MANSFIELD II PLANT DISALLOWANCES RECOMMENDED BY YOU IN THIS PROCEEDING?

A. As detailed in footnote 4 of Schedule RJH-16-S, I applied the appropriate composite Mansfield II plant depreciation rate of 2.25% to the recommended Mansfield II plant adjustment amount. The composite depreciation rate of 2.25% was calculated based on information contained in PI-29-U-S.

- Revenue Tax Adjustment

Q. WHY HAVE YOU MADE AN ADJUSTMENT TO THE COMPANY'S PROPOSED REVENUE TAXES, AS SHOWN ON SCHEDULE RJH-17-S?

A. The recommended revenue tax adjustment shown on Schedule RJH-17-S is a direct result

BEFORE THE
STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
OFFICE OF ADMINISTRATIVE LAW

IN THE MATTER OF THE PETITION OF	**)**
ENVIRONMENTAL DISPOSAL CORPORATION	**)BPU Docket No. WR99040249**
FOR APPROVAL OF AN INCREASE IN RATES	**)OAL Docket No. PUC5487-99**

Direct Testimony
of
ROBERT J. HENKES

On Behalf of the
New Jersey Division of the
Ratepayer Advocate

October 19, 1999

the Company's ratepayers and shareholders on a 50/50 basis.

Finally, I used a 3-year normalization period to determine the recommended normalized annual rate case expense level of $38,300. This recommended normalized rate case expense amount is $41,700 lower than the Company's proposed rate case amortization expense amount of $80,000

- Depreciation Expenses

Q. PLEASE EXPLAIN THE DERIVATION OF THE RECOMMENDED PRO FORMA ANNUALIZED DEPRECIATION EXPENSES.

A. As detailed on Schedule RJH-11, the starting point of my recommended pro forma annualized depreciation expense position is the Company's pro forma annualized depreciation expense amount for the rate year of $724,407. I then decreased this Company-proposed annualized depreciation expense amount to eliminate the depreciation expenses related to the recommended utility plant disallowances reflected on Schedule RJH-4. Thus, the total recommended pro forma annualized depreciation expenses to be recognized for ratemaking purposes in this case amount to $558,681.

Testimony 1

BEFORE THE
STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
OFFICE OF ADMINISTRATIVE LAW

IN THE MATTER OF THE PETITION OF	**)**	
SHORE WATER COMPANY FOR APPROVAL	**)**	**BPU Docket No. WR99090678**
OF AN INCREASE IN RATES FOR SERVICE	**)**	

Direct Testimony
of
ROBERT J. HENKES

On Behalf of the New Jersey
Division of the Ratepayer Advocate

May 12, 2000

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- Maintenance of Other T&D Plant

Q. WHY HAVE YOU ADJUSTED THE COMPANY'S PROPOSED EXPENSE ADJUSTMENT FOR MAINTENANCE OF OTHER T&D PLANT?

A. The derivation of my recommended expense adjustment for maintenance of other T&D plant is explained in detail in footnote (7) of Schedule RJH-7. Schedule RJH-7, line 8 shows that my recommended expense adjustment of $8,546 is $2,789 higher than the Company's proposed expense adjustment of $5,757.

- Depreciation Expenses

Q. PLEASE EXPLAIN THE DERIVATION OF THE RECOMMENDED PRO FORMA ANNUALIZED DEPRECIATION EXPENSES.

A. As detailed on Schedule RJH-10, I applied the Company's current depreciation rates to the corresponding depreciable plant in service components that make up my recommended plant in service balance as of 6/30/2000. I then decreased this recommended annualized depreciation expense amount to eliminate the depreciation expenses associated with plant funded by Customer Advances for Construction. This is consistent with current Board policy. Thus, the total recommended pro forma annualized depreciation expenses to be recognized for rate making purposes in this case amount to $30,963.

- Taxes Other Than Income Taxes

BEFORE THE
STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
OFFICE OF ADMINISTRATIVE LAW

IN THE MATTER OF THE PETITION OF CONSUMERS NEW JERSEY WATER COMPANY FOR APPROVAL OF AN INCREASE IN ITS RATES FOR WATER SERVICE AND OTHER TARIFF CHANGES	)))))	BPU Docket No. WR00030174 OAL Docket No. PUCRS 04524-00S

Direct Testimony
of
ROBERT J. HENKES

On Behalf of the New Jersey
Division of the Ratepayer Advocate

September 14, 2000

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amount of $736,008. Each of these recommended operating income adjustments will be discussed in detail below.

- Metered Sales Revenues

Q. HOW DID YOU DERIVE YOUR RECOMMENDED METERED SALES REVENUES SHOWN ON SCHEDULE RJH-11?

A. Consistent with my recommendation to reflect the rate base as of the end of the test year, September 30, 2000, I recommend that the Company's metered sales revenues be annualized based on the billing determinants in existence as of September 30, 2000. In making the calculations for these recommended annualized metered sales revenues on Schedule RJH-11, I have essentially used the same approach as used by the Company to determine its proposed annualized metered sales revenues based on projected billing determinants as of March 31, 2001.

The starting point of my calculations is the actual level of Customer Equivalent Units ("CEUs") as of July 31, 2000. I then added to these actual CEU levels projected growth for the 2-months August and September 2000 in order to arrive at the recommended projected CEUs as of September 30, 2000. Details underlying the 2-month growth projections are shown in footnote (1) of Schedule RJH-11. I then multiplied these projected CEUs times a normalized MG/CEU usage level to arrive at the annualized and normalized annual metered consumption level. The recommended normalized MG/CEU usage level was based a 5-year historic average (1995-1999) for the Central and Southern Division CEUs.

For the Northern Division I used a normalized MG/CEU usage level based on the most recent 2-year historic average (1998-1999) similar to what the Company has done. Finally, I multiplied the projected 9/30/2000 CEUs with the annual CEU charge of $79.80 and the projected annual normalized MG sales level with the annual rate per MG of $2,570 to arrive at the total recommended metered sales revenues of $12,835,662 shown on line 11 of Schedule RJH-11.

Q. COULD YOU NOW DESCRIBE THE RECOMMENDED PRO FORMA MILLION GALLON ("MG") PRODUCTION NUMBERS WHICH YOU HAVE CALCULATED BASED ON THE RECOMMENDED PRO FORMA MG SALES LEVELS?

A. As shown on Schedule RJH-11, lines 12 through 14, I derived the recommended pro forma MG production levels by dividing the recommended MG sales levels for each Division by the so-called "metered ratios" established by the Company. The Company has proposed metered ratios for the Northern, Central and Southern Divisions of 71.5%, 91.5% and 93.0%, respectively. I have accepted each of these Company-proposed metered ratios.

- <u>Fire Protection Revenues</u>

Q. WHY HAVE YOU ADJUSTED THE COMPANY'S PROPOSED PRO FORMA PUBLIC FIRE REVENUES, AS YOU SHOW ON SCHEDULE RJH-4, LINES 3 AND 4?

A. Consistent with my recommendation to reflect the rate base as of September 30, 2000, I also recommend that the Company's fire protection revenues be annualized based on the number

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of hydrants and inch-feet as of that same date. On Exhibits P-18, Sheet 1 and P-19, Sheet 1, the Company has calculated the annualized fire protection revenues based on projected billing determinants as of September 30, 2000. I have accepted these Company-calculated fire protection revenue projections. Since the Company's proposed fire protection revenues represent annualized revenues based on projected billing determinants at March 31, 2001 (thereby incorporating additional revenue growth), my recommended annualized test year fire protection revenues are $92,802 lower than the Company's proposed annualized pro forma period fire protection revenues.

- Other Miscellaneous Revenues

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED OTHER MISCELLANEOUS REVENUES CLAIMED IN THIS CASE.

A. The Company's proposed other miscellaneous revenues are based on projections extending into the year 2001 consistent with its proposed Pro forma period ended March 31, 2001. As shown on Schedule RJH-4, lines 5 and 6, the Company's proposed other miscellaneous revenues consist of projected miscellaneous revenues of $35,000 and projected golf course revenues of $12,500.

Q. WHAT OTHER MISCELLANEOUS REVENUES ARE YOU RECOMMENDING IN THIS CASE?

A. Consistent with my recommended approach to base the rate base and all revenues on stockholders. Undoubtedly, many of the ratepayers in CNJWC's service territory are already making their own individual charitable contributions to organizations of their choice. The inclusion of 100% of CNJWC's charitable contributions in rates would force these same ratepayers into making additional charitable contributions to organizations chosen by CNJWC. CNJWC's ratepayers should be made responsible for legitimate and prudent costs incurred by the Company to provide timely, safe and adequate water service. They should not be made responsible for the costs associated with CNJWC management's decisions to make charitable contributions to organizations of their choice. If CNJWC decides to go beyond the call of its utility service duty, then the costs associated with that should be picked up by the stockholder.

Q. BASED ON YOUR PREVIOUSLY DISCUSSED FINDINGS AND CONCLUSIONS, WHAT LEVEL OF OTHER EXPENSES DO YOU RECOMMEND BE USED FOR RATE MAKING PURPOSES IN THIS CASE?

A. As shown on Schedule RJH-19, I recommend that the appropriate level of Other Expenses to be recognized for rate making purposes in this case is $368,492.

- <u>Depreciation Expenses</u>

Q. PLEASE DESCRIBE THE DERIVATION OF THE DEPRECIATION EXPENSES YOU RECOMMEND FOR RATE MAKING PURPOSES IN THIS CASE.

A. I show this derivation on Schedule RJH-20. As the starting point, I used the total projected

"Company-funded" plant in service level as of the end of the test year, September 30, 2000. This plant level therefore excludes plant that has been funded with CIAC contributions and Customer Advances, consistent with the Company's current accounting policy of not depreciating plant funded with CIAC and Customer Advances. Next, from this total plant in service level I then removed non-depreciable plant in service components such as land, land rights, and intangible organization and franchise plant elements in order to arrive at the recommended net depreciable plant balance as of September 30, 2000. Finally, I applied to this depreciable plant balance the composite depreciation rate of 2.749% recommended by Ratepayer Advocate witness Mr. Majoros.

- Revenue Taxes

Q. HOW DID YOU DERIVE THE RECOMMENDED PRO FORMA REVENUE TAXES TO BE USED FOR RATE MAKING PURPOSES IN THIS CASE?

A. As shown on Schedule RJH-21, I have used the exact same methodology and calculation components as those used by the Company to derive the recommended pro forma revenue taxes. The difference between the recommended and Company-proposed pro forma revenue tax levels is caused merely due to the "flow-through" impact of recommended adjustments made by me in the areas of operating revenues and bad debt expenses.

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BEFORE THE
STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
OFFICE OF ADMINISTRATIVE LAW

IN THE MATTER MIDDLESEX WATER	)	
COMPANY FOR APPROVAL OF AN	)	
INCREASE IN ITS RATES FOR WATER	)	BPU Docket No. WR00060362
SERVICE AND OTHER TARIFF CHANGES	)	OAL Docket No. PUCRL-04879-00S
	)	

Direct Testimony
of
ROBERT J. HENKES

On Behalf of the New Jersey
Division of the Ratepayer Advocate

November 3, 2000

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Amboy and this contract was terminated. Despite this water sales contract termination, the Company in this case is proposing to amortize the $300,000 contribution over a 25-year period, thereby increasing the test year's annual operating expenses by $12,000. I do not believe that the ratepayers should be saddled with the burden to reimburse Middlesex for a contribution related to a contract that is now non-existent due to its termination in 1999. I therefore recommend that the proposed $12,000 amortization expense be removed for rate making purposes in this case.

- Pro Forma Annualized Depreciation Expenses

Q. PLEASE EXPLAIN THE DERIVATION OF THE RECOMMENDED PRO FORMA ANNUALIZED DEPRECIATION EXPENSES SHOWN ON SCHEDULE RJH-14.

A. As shown on Schedule RJH-14, I calculated the recommended pro forma annualized depreciation expenses by applying the appropriate composite depreciation rate of 2.36% to the recommended plant in service balance included in rate base, exclusive of non-depreciable land and land rights, and net of plant funded by CIAC and Customer Advances. This results in annualized depreciation expenses of $4,133,864.

Q. IN CALCULATING ITS PROPOSED ANNUALIZED DEPRECIATION EXPENSES, HAS THE COMPANY PROPOSED TO DEPRECIATE PLANT FUNDED BY CIAC AND CUSTOMER ADVANCES?

A. While the Company does not propose to depreciate plant funded by CIAC, it does propose to depreciate plant funded by Customer Advances.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED POSITION?

A. No, I do not. CIAC represent mostly Main plant investments that have been permanently contributed to the Company by individuals, developers, municipalities or other outside parties. As such, plant financed with CIAC comes at no cost to the Company and requires no investor-supplied capital. For this reason, the Company does not depreciate its plant funded with CIAC because it would not be appropriate to charge the ratepayers for costs that were never incurred by the Company.

Customer Advances represent the exact same type of property contributions as CIAC, however, portions of these Customer Advances are still subject to refund to the contributing outside parties. Once Middlesex has paid the partial refunds for its Customer Advances, the remaining Customer Advances balances will be reclassified to CIAC as permanent property contributions. While certain Customer Advances portions will be refunded to customers on an on-going basis, at the same time new Customer Advances will be added on an on-going basis. The end result is that the Company will always, and at any point in time, carry a permanent level of Customer Advances on its books. Thus, Middlesex's Customer Advances balance, similar to its CIAC balance, is to be considered permanent non-investor supplied capital used to finance the Company's plant investment.

Since the Company's investors never laid out any funds for the plant investments financed with Customer Advances, they should not be entitled to (1) earn a return <u>on</u> such investments (through rate base inclusion), or (2) receive a return <u>of</u> the investments (through depreciation). The Company has properly recognized the first of these rate making principles by removing the plant investments financed by Customer Advances from its rate base. However, the Company has not consistently followed through on the second of these rate making principles, i.e., it is claiming a return of this contributed property by reflecting depreciation expenses on its plant financed by Customer Advances. I have corrected for this inconsistency by not calculating depreciation expenses on plant funded by the Company's Customer Advances balance.

- Payroll Taxes

Q. PLEASE EXPLAIN THE PAYROLL TAX ADJUSTMENT YOU SHOW ON SCHEDULE RJH-9, LINE 4a.

A. This recommended tax adjustment is a direct result of my recommendation to reduce the Company's proposed payroll expenses for incentive compensation. The recommended payroll tax adjustment is calculated by applying the payroll tax rate of 7.65% to my recommended payroll expense adjustment.

- GR&FT Expenses

Q. WHY HAVE YOU MADE AN ADJUSTMENT TO THE COMPANY'S PROPOSED GR&FT EXPENSES, AS SHOWN ON SCHEDULE RJH-9, LINE 4b?

A. This recommended GR&FT expense adjustment is a direct result of my recommended revenue adjustment discussed earlier in this testimony and shown on Schedules RJH-9, line 1. The

BEFORE THE
STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
OFFICE OF ADMINISTRATIVE LAW

IN THE MATTER OF THE PETITION OF	)	
PINELANDS WATER COMPANY	)	
FOR APPROVAL OF AN INCREASE IN ITS	)	BPU Docket No. WR00070454
RATES FOR WATER SERVICE AND	)	OAL Docket No. PUCRS 06242-00S
OTHER TARIFF CHANGES	)	

Direct Testimony
of
ROBERT J. HENKES

On Behalf of the New Jersey
Division of the Ratepayer Advocate

December 18, 2000

- Pro Forma Annualized Depreciation Expenses

Q. PLEASE EXPLAIN THE DERIVATION OF THE RECOMMENDED PRO FORMA ANNUALIZED DEPRECIATION EXPENSES SHOWN ON SCHEDULE RJH-8.

A. As shown on Schedule RJH-8, I calculated the recommended pro forma annualized depreciation expenses by applying the appropriate composite depreciation rate of 3.13% to the recommended plant in service balance included in rate base, exclusive of non-depreciable land and land rights, and net of plant funded by CIAC and Customer Advances. This results in annualized depreciation expenses of $41,144.

Q. IN CALCULATING ITS PROPOSED ANNUALIZED DEPRECIATION EXPENSES, HAS THE COMPANY PROPOSED TO DEPRECIATE PLANT FUNDED BY CIAC AND CUSTOMER ADVANCES?

A. While the Company does not propose to depreciate plant funded by CIAC, it does propose to depreciate plant funded by Customer Advances.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED POSITION?

A. No, I do not. CIAC represent mostly Main plant investments that have been permanently contributed to the Company by individuals, developers, municipalities or other outside parties. As such, plant financed with CIAC comes at no cost to the Company and requires no investor-supplied capital. For this reason, the Company does not depreciate its plant funded with CIAC because it would not be appropriate to charge the ratepayers for costs that were never incurred by the Company.

Customer Advances represent the exact same type of property contributions as CIAC, however, portions of these Customer Advances are still subject to refund to the contributing outside parties. Once Pinelands has paid the partial refunds for its Customer Advances, the remaining Customer Advances balances will be reclassified to CIAC as permanent property contributions. While certain Customer Advances portions will be refunded to customers on an on-going basis, at the same time new Customer Advances will be added on an on-going basis. The end result is that the Company will always, and at any point in time, carry a permanent level of Customer Advances on its books. Thus, Pinelands' Customer Advances balance, similar to its CIAC balance, is to be considered permanent non-investor supplied capital used to finance the Company's plant investment.

Since the Company's investors never laid out any funds for the plant investments financed with Customer Advances, they should not be entitled to (1) earn a return <u>on</u> such investments (through rate base inclusion), or (2) receive a return <u>of</u> the investments (through depreciation). The Company has properly recognized the first of these rate making principles by removing the plant investments financed by Customer Advances from its rate base. However, the Company has not consistently followed through on the second of these rate making principles, i.e., it is claiming a return <u>of</u> this contributed property by reflecting depreciation expenses on its plant financed by Customer Advances. I have corrected for this inconsistency by not calculating depreciation expenses on plant funded by the Company's Customer Advances balance.

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BEFORE THE
STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
OFFICE OF ADMINISTRATIVE LAW

IN THE MATTER OF THE PETITION OF)	
PINELANDS WASTEWATER COMPANY)	
FOR APPROVAL OF AN INCREASE IN ITS)	**BPU Docket No. WR00070455**
RATES FOR WASTEWATER SERVICE AND)	**OAL Docket No. PUCRS 06243-00S**
OTHER TARIFF CHANGES)	

Direct Testimony
of
ROBERT J. HENKES

On Behalf of the New Jersey
Division of the Ratepayer Advocate

December 18, 2000

Q. HAVE YOU MADE AN ADJUSTMENT TO THIS "OTHER RATE CASE EXPENSE" AMOUNT OF $15,000?

A. Yes. Due to the lack of specificity and support for this rate case expense estimate, I have removed this proposed expense amount.

Q. WHAT OTHER ADJUSTMENTS DID YOU MAKE IN ORDER TO ARRIVE AT THE RECOMMENDED ANNUAL RATE CASE AMORTIZATION AMOUNT IN THIS CASE?

A. As shown on Schedule RJH-7, in accordance with long-standing and well-established BPU rate making policy, I have applied a 50/50 sharing to the recommended rate case expense level. I then used a recommended 5-year amortization period to arrive at the recommended annual rate case amortization amount of $0.

- Pro Forma Annualized Depreciation Expenses

Q. PLEASE EXPLAIN THE DERIVATION OF THE RECOMMENDED PRO FORMA ANNUALIZED DEPRECIATION EXPENSES SHOWN ON SCHEDULE RJH-8.

A. As shown on Schedule RJH-8, I calculated the recommended pro forma annualized depreciation expenses by applying the appropriate composite depreciation rate of 3.00% to the recommended plant in service balance included in rate base, exclusive of non-depreciable land and land rights, and net of plant funded by CIAC and Customer Advances. This results in annualized depreciation expenses of $81,175.

Q. IN CALCULATING ITS PROPOSED ANNUALIZED DEPRECIATION EXPENSES, HAS THE COMPANY PROPOSED TO DEPRECIATE PLANT FUNDED BY CIAC AND CUSTOMER ADVANCES?

A. While the Company does not propose to depreciate plant funded by CIAC, it does propose to depreciate plant funded by Customer Advances.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED POSITION?

A. No, I do not. CIAC represent mostly Main plant investments that have been permanently contributed to the Company by individuals, developers, municipalities or other outside parties. As such, plant financed with CIAC comes at no cost to the Company and requires no investor-supplied capital. For this reason, the Company does not depreciate its plant funded with CIAC because it would not be appropriate to charge the ratepayers for costs that were never incurred by the Company.

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Since the Company's investors never laid out any funds for the plant investments financed with Customer Advances, they should not be entitled to (1) earn a return on such investments (through rate base inclusion), or (2) receive a return of the investments (through depreciation). The Company has properly recognized the first of these rate making principles by removing the plant investments financed by Customer Advances from its rate base. However, the Company has not consistently followed through on the second of these rate making principles, i.e., it is claiming a return of this contributed property by reflecting depreciation expenses on its plant financed by Customer Advances. I have corrected for this inconsistency by not calculating depreciation expenses on plant funded by the Company's Customer Advances balance.

- Income Taxes

Q. HAVE YOU CALCULATED THE RECOMMENDED PRO FORMA INCOME TAXES TO BE RECOGNIZED FOR RATE MAKING PURPOSES IN THIS CASE IN A MANNER CONSISTENT WITH THE COMPANY'S METHODOLOGY?

A. Yes, my calculations are presented on Schedule RJH-9. There are two reasons why the recommended pro forma income taxes are different from the Company's proposed pro forma income taxes. First, the recommended operating income before income taxes is higher than the Company's proposed operating income before income taxes as a direct result of my recommended adjustments to the Company's proposed pro forma test year expenses. Second,

BEFORE THE
STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
OFFICE OF ADMINISTRATIVE LAW

IN THE MATTER OF THE PETITION OF)
PENNSGROVE WATER COMPANY FOR APPROVAL) BPU Docket No. WR00120939
OF AN INCREASE IN RATES FOR SERVICE)

Direct Testimony of ROBERT J. HENKES

On Behalf of the New Jersey
Division of the Ratepayer Advocate

JULY 16, 2001

VI. OPERATING INCOME ISSUES

- Operating Revenues

Q. HAVE YOU ADJUSTED THE COMPANY'S PROPOSED TEST PERIOD OPERATING REVENUES?

A. Yes. Schedule RJH-4, lines 1 through 6 show that the Company has proposed total *pro forma* operating revenues of $1,729,394 for its metered sales, private and public fire sales and miscellaneous service and other water revenues. I have accepted all of the Company's proposed *pro forma* revenues except those for the metered sales. As shown on line 1, I recommend that the Company's proposed metered sales revenues be increased by $30,171.

Q. WHY DO YOU PROPOSE THIS RECOMMENDED METERED SALES REVENUE ADJUSTMENT AND HOW WAS IT DERIVED?

A. The consumption charge portion of the Company's proposed metered sales revenues are based on the actual consumption in the year 2000 of 477,176 thousand gallons.[3] It is my position that this actual consumption level is abnormally low due to the extremely wet and cold weather conditions in the year 2000, particularly in the summer months of 2000. This fact is illustrated by the data in footnote 2 of Schedule RJH-5, which show substantially reduced consumption per customer levels during the two wet and cold years, 1996 and 2000.

[3] See Schedule RJH-5, line 6, first column.

A review of annual reports of water utilities in New Jersey and surrounding states for the years 1996 and 2000 will show many references to the depressed water sales levels and associated revenue reductions in these two years. Thus, it would be inappropriate to use the abnormally low sales level of the year 2000 for rate making purposes in this case. Instead, my recommended metered sales revenues are based on a normalized consumption level of 488,489 thousand gallons.[4] As detailed in footnote 2, this recommended normalized consumption level was derived by multiplying the actual 12/31/00 number of metered sales customers of 4,341 times the 5-year weighted average annual consumption per customer for the period 1996 - 2000. Schedule RJH-5, lines 7 - 11 shows that this recommended normalized sales level increases the Company's proposed consumption charge revenues by $30,171.

- <u>Removal of Inflation Adjustments</u>

Q. WHY HAVE YOU REMOVED THE COMPANY'S PROPOSED INFLATION ADJUSTMENTS TOTALING $10,357 SHOWN ON SCHEDULE RJH-7?

A. I have removed these inflation adjustments to reflect long-standing and well-established BPU rate making policy. *I/M/O Petition of New Jersey-American Water Company For An Increase In Rates For Water And Sewer Service And Other Tariff Modifications*, BPU Docket No. WR98010015.

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[4] See Schedule RJH-5, line 7, third column.

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uncollectible expenses of $14,077. This recommended expense level is $5,857 lower than the Company's proposed expense level of $19,934, as shown on Schedule RJH-11, line 5.

- Depreciation Expenses

Q. PLEASE EXPLAIN YOUR RECOMMENDED DEPRECIATION EXPENSE ADJUSTMENT OF $23,576 SHOWN ON SCHEDULE RJH-4, LINE 8.

A. As confirmed in the response to RAR-A-64, the Company's proposed *pro forma* test year depreciation expenses include $23,576 for depreciation expenses related to contributed plant. Consistent with well-established Board policy, I have removed these depreciation expenses for rate making purposes in this case. Contributed plant has not been funded by the Company, therefore, the Company should not be allowed to charge the ratepayers a return of this plant in the form of depreciation expenses. My recommendation is consistent with the Board's Decision and Order in the Company's prior rate case, Docket No. WR98030147, that depreciation on contributed property cannot be recovered from the ratepayers in the Company's rates.

- Taxes Other Than Income Taxes

Q. WHY HAVE YOU ADJUSTED THE COMPANY'S PROPOSED TAXES OTHER THAN INCOME TAXES IN THIS CASE, AS SUMMARIZED ON SCHEDULE RJH-4, LINE 9 AND DETAILED ON SCHEDULE RJH-12?

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BEFORE THE STATE OF NEW JERSEY
OFFICE OF ADMINISTRATIVE LAW

I/M/O THE PETITION OF PUBLIC SERVICE ELECTRIC & GAS COMPANY FOR APPROVAL OF AN INCREASE IN GAS RATES AND FOR CHARGES IN THE TARIFF FOR GAS SERVICE	**) BPU DOCKET NO. GR01050328** **) OAL DOCKET NO. PUC-5052-01**
I/M/O THE PETITION OF PUBLIC SERVICE ELECTRIC & GAS COMPANY FOR AUTHORITY TO REVISE ITS GAS PROPERTY DEPRECIATION RATES	**) BPU DOCKET NO. GR01050297** **) OAL DOCKET NO. PUC-5016-01**

DIRECT TESTIMONY OF ROBERT J. HENKES
ON BEHALF OF
THE NEW JERSEY DIVISION OF THE RATEPAYER ADVOCATE

BLOSSOM A. PERETZ, ESQ.
RATEPAYER ADVOCATE

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August 23, 2001

- Test Year-End Customer Revenue Annualization Adjustment

Q. WHAT REVENUE ADJUSTMENTS HAVE BEEN PROPOSED BY THE COMPANY IN THIS CASE?

A. The Company has proposed one revenue adjustment in this case, that is its proposed weather normalization adjustment which reduced the Company's per books test year revenues by almost $20 million, as shown on Schedule ANS-3, page 1. Through this adjustment, the Company has normalized the test year customer consumption levels based on 30-year average normalized weather determinants. The reason for the Company's proposed large revenue reduction adjustment is that the actual portion of the "6+6" test year filing data contains abnormally cold weather. Based on my review of the Company's proposed weather normalization methodology, I have accepted the Company's proposed revenue weather normalization adjustment.

Q. HAS THE COMPANY RESTATED ITS PROPOSED WEATHER-NORMALIZED TEST YEAR REVENUES TO REFLECT THE CUSTOMER LEVELS AS OF THE END OF THE TEST YEAR, JUNE 30, 2001?

A. No. As confirmed in its response to RAR-A-86, the Company's proposed weather-normalized test year revenues are based upon the average customer levels in the test year.

Q. DOES THIS REPRESENT AN ISSUE IN THIS CASE?

A. Yes. The issue is that the Company has not annualized its proposed test year revenues for the growth in the number of customers. Because of this, the Company's proposed test year revenues are not properly "matched" with the Company's proposal to use a test year-end rate base in this proceeding.

Q. COULD YOU EXPLAIN THIS IN MORE DETAIL?

A. Yes. As discussed before, the Company's proposed test year revenues are based on the test year's average number of customers. In this regard, it is important to recognize that the plant investment that has supported the Company's average test year number of customers is the Company's average test year plant, not the (higher) June 30, 2001 test year-end plant investment level. Since the Company has proposed the use of the higher test year-end plant in service balance, it would be appropriate and consistent to then annualize the revenues for the growth in customers up to the end of the test year.

Q. WHAT SPECIFIC REVENUE ANNUALIZATION APPROACH AND METHODOLOGY DO YOU RECOMMEND BE USED IN THIS PROCEEDING IN ORDER TO ACCOMPLISH THIS YEAR-END RATE BASE VERSUS YEAR-END CUSTOMER GROWTH MATCHING?

A. It is reasonable to assume that the Company's actual average test year plant in service is approximately equivalent to the actual plant in service level during the mid-point of the test year. Therefore, the difference between the proposed test year-end plant level and the average test year plant level essentially represents one-half year's worth of growth in the Company's plant investment level. Since the Company's proposed test year residential

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revenues are based on the average number of customers, the appropriate revenue annualization adjustment should similarly be based on one-half year's worth of growth in the number of customers. Since I do not have the Company's detailed revenue model available, I requested the Company to perform this test year-end customer growth analysis and provide the resulting increase in margins (revenues net of the associated impact on gas costs and taxes) when compared to the Company's proposed test year "6+6" margins. My detailed request to the Company and the results of the Company's calculated revenue annualization for test year-end customer growth are contained in the response to RAR-IDR-2.

Q. WHAT WAS THE RESULT OF THIS REVENUE ANNUALIZATION ANALYSIS FOR TEST YEAR-END CUSTOMER GROWTH AND HOW DOES THE REFLECTION OF SUCH ANNUALIZED REVENUES IMPACT THE COMPANY'S PROPOSED PRO FORMA TEST YEAR OPERATING INCOME IN THIS CASE?

A. The response to RAR-IDR-2 shows that my recommended revenue annualization adjustment for customer growth up to the end of the test year increases the Company's proposed "6+6" test year revenue margins by $819,000. As shown on Schedule RJH-11, this increases the Company's proposed pro forma test year operating income by $484,000.

those levels for some time to come.

Q. DID THE BOARD REITERATE THIS INCENTIVE COMPENSATION RATE MAKING POLICY IN A MORE RECENT LITIGATED BASE RATE CASE?

A. Yes. In the recently completed fully-litigated 2001 Middlesex Water Company base rate case, the BPU Staff stated on page 37 of its Initial Brief with regard to Middlesex's incentive compensation expenses:

> Staff is persuaded by the arguments of the RPA that, at this time, the incentive compensation expenses should not be recovered from ratepayers. According to the record, incentive compensation expenses have tripled since 1995. In addition, the record also indicated that the bonuses are significantly impacted by the Company achieving financial performance goals. These facts lend strength to the RPA's position that it is inappropriate for the Company to request recovery of bonuses in rates at this time.

While the ALJ in that case ruled that 50% of Middlesex's incentive compensation expenses could be recovered in rates, the Board overruled the ALJ and ordered that 100% of these incentive compensation expenses be removed from Middlesex's rates.[13]

- <u>Pension and FAS 106 Expenses</u>

Q. PLEASE DESCRIBE THE COMPANY'S TEST YEAR PENSION AND FAS 106 EXPENSES AS COMPARED TO THE BUDGETED PENSION AND FAS 106 EXPENSES FOR THE YEAR 2001.

A. As shown on Schedule RCK-14R these expense levels are as follows:

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[13] See transcript pages 10 through 13 of the April 25, 2001 Board Meeting.

	($Millions)	
	Test Year	Year 2001
Pension expenses	$ 8.4	$11.8
FAS 106 expenses	$19.2	$17.4

Q. WHAT ARE THE COMPANY'S PROPOSED POSITIONS REGARDING THE PRO FORMA PENSION AND FAS 106 EXPENSES TO BE RECOGNIZED FOR RATE MAKING PURPOSES IN THIS CASE?

A. With regard to pension expenses, the Company has reflected the higher expense amount budgeted for the year 2001. As stated on page 11 of Mr. Stellwag's testimony, "This adjustment in the amount of $3.4 million operating expense increase reflects the increase in pension expenses for 2001 over our test period amount."

By contrast, for the FAS 106 expenses, the Company has not proposed the budgeted lower FAS 106 expenses for the year 2001. Instead, the Company reflected the test year FAS 106 expenses which are $1.8 million higher than the budgeted 2001 FAS 106 expenses.

Q. DO YOU AGREE WITH THESE PROPOSED POSITIONS?

A. No. I believe it is unreasonable and inappropriate to reflect the budgeted 2001 expense for the pension expenses (resulting in a $3.4 million expense increase) while not giving similar recognition to the budgeted 2001 FAS 106 expenses (which would have resulted in $1.8 million expense reduction).

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THESE TWO EXPENSE ITEMS?

A. While I have accepted the Company's proposed 2001 budgeted pension expense level of $11.8 million, I recommend for consistency purposes that the Company's 2001 budgeted FAS 106 expense level similarly be reflected for rate making purposes in this case. As shown on Schedule RJH-15, this recommendation decreases the Company's pro forma operating expenses by $1,762,000, with a resulting operating income increase impact of $1,042,000.

Q. HAS THE COMPANY PROVIDED ANY REASONS FOR THE PROJECTED DECREASE IN ITS FAS 106 EXPENSES IN THE YEAR 2001 AS COMPARED TO THE TEST YEAR?

A. Yes. In its response to RAR-A-67e, the Company states that, "....Decreases in the estimated 2001 expense is due to the lower than expected increases in medical and prescription drug costs to Enterprise for 2001. Also, effective 2001, PSEG Company employee co-payment premiums have increased for medical and prescription drug plans...."

- <u>Gas Supply and Storage Transfer Income Adjustment</u>

Q. PLEASE EXPLAIN THE PRO FORMA INCOME ADJUSTMENT OF $17,519,000 SHOWN ON SCHEDULE RJH-4, LINE 8.

A. For the reasons explained earlier in this testimony, I have reversed all of the pro forma adjustments proposed by the Company in this case to reflect its proposed transfer of its gas supply, storage and capacity contracts from the regulated PSE&G gas utility to an unregulated during the test year should be assigned 100% to PSE&G's electric operations.

Finally, the ninth adjustment concerns the removal of certain expenses that were allocated by PSEG to PSE&G's gas operations. As shown in footnote (2) to Schedule RJH-22, these expenses include charitable contribution expenses and contributions to the Liberty Science Center and New Jersey Aquarium.

- Pro Forma Depreciation Expense Adjustment

Q. IS THE COMPANY PROPOSING BASE RATE RECOGNITION OF NEW DEPRECIATION RATES IN THIS CASE?

A. Yes. In the parallel depreciaton case, Docket No. GR01050297, that was filed by the Company on May 4, 2001, the Company is requesting Board approval for new depreciation rates. In the instant base rate proceeding, the Company is proposing base rates to recover the depreciation expenses resulting from BPU approval of the Company's proposed new depreciation rates.

The Company's proposed pro forma annualized depreciation expenses that are based on these proposed new depreciation rates amount to $154.5 million.[21] This proposed annual depreciation expense level is approximately $56 million higher than the "6+6" test year per books depreciation expense level of $98.7 million.

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[21] The detailed derivation of this PSE&G-proposed pro forma annualized depreciation expense amount, showing the Company's proposed 6/30/01 depreciable plant balances and the proposed new depreciation rates applicable to these plant balances, is contained in the reponse to RAR-A-16 C, page 8 of 8.

Q. DOES THE RATEPAYER ADVOCATE'S DEPRECIATION EXPERT, MICHAEL MAJOROS, AGREE WITH THE COMPANY'S PROPOSED NEW DEPRECIATION RATES?

A. No. Mr. Majoros does not agree with the Company's proposed new depreciation rates and has recommended appropriate alternative depreciation rates that should be approved by the BPU for rate making purposes in this case. Mr. Majoros has supplied me with his recommended depreciation rates and I have used these depreciation rates in the calculation of the recommended pro forma annualized depreciation expenses in this case.

Q. WHERE DO YOU SHOW THESE RECOMMENDED PRO FORMA ANNUALIZED DEPRECIATION EXPENSE CALCULATIONS?

A. These calculations are shown on Schedule RJH-23. As shown on line 20 of this schedule, Mr. Majoros' recommended depreciation rates produce a recommended level of pro forma annualized depreciation expenses of $65,526,000 based on the same level of test-year end depreciable plant as was used by the Company in its proposed pro forma depreciation expense adjustment calculations.

Q. WHAT IS THE IMPACT OF THE DIFFERENCE BETWEEN THE RATEPAYER ADVOCATE'S RECOMMENDED AND THE COMPANY'S PROPOSED PRO FORMA ANNUALIZED DEPRECIATION EXPENSE LEVELS?

A. As shown on Schedule RJH-23, lines20 - 24, the Ratepayer Advocate's recommended pro forma annualized depreciation expense level of $65,526,000 is $89,014,000 lower than the

Company's proposed pro forma annualized depreciation expense level of $154,540,000. This recommended expense reduction has the effect of increasing the Company's proposed pro forma test year after-tax operating income by $63,404,000.

- Income Tax Error Correction

Q. PLEASE EXPLAIN THE INCOME TAX ERROR CORRECTION SHOWN ON SCHEDULE RJH-4, LINE 18.

A. As explained in its response to RAR-A-69, the Company overstated the income tax benefits associated with its proposed pro forma depreciation expense increase adjustment on Schedule ANS-4. As shown in more detail on Schedule RJH-24, the correction for this error would increase the Company's income tax liability, and decrease the Company's operating income, by $376,000.

- Interest Synchronization Adjustment

Q. WHAT IS THE ISSUE WITH REGARD TO THE INTEREST SYNCHRONIZATION ADJUSTMENT SHOWN ON SCHEDULE RJH-4, LINE19?

A. There is no issue per se. As shown in more detail on Schedule RJH-25, the only reason why the recommended interest synchronization income tax impact is different from the Company's proposed interest synchronization income tax impact is because of the differences in the Company's proposed and Ratepayer Advocate's recommended rate base and weighted cost of

BEFORE THE
STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
OFFICE OF ADMINISTRATIVE LAW

IN THE MATTER OF THE PETITION OF ELIZABETHTOWN WATER COMPANY FOR APPROVAL OF AN INCREASE IN RATES FOR WATER SERVICE	))))	BPU Docket No. WR01040205 OAL Docket No. PUC 342701

Direct Testimony
of
ROBERT J. HENKES

On Behalf of the New Jersey
Division of the Ratepayer Advocate

October 1, 2001

$500,000 gain on the sale of the Watchung property be shared between ratepayers and the Company's stockholders on a 50/50 basis. Since this sale has not yet closed and may not close until the rate effective date of this case, I do not recommend that accrued interest be added to the ratepayer share of this gain. As shown on the bottom part of Schedule RJH-27, 50% of the gain of $500,000, amortized over the same 3-year amortization period as used for the Bridgewater Township gain amortization, results in an annual gain amortization of $83,333 that should be used as an expense credit for rate making purposes in this case. However, if the sale closes (and the associated gain is received by EWC) prior to the rate effective date in this case, I recommend that interest[26] be calculated on the 50% ratepayer gain share from the time of the sale closing until the rate effective date of this case; and this accrued interest should be added to the gain portion to be returned to the ratepayers.

- <u>Depreciation Expenses</u>

Q. PLEASE DESCRIBE HOW THE COMPANY CALCULATED ITS PROPOSED PRO FORMA ANNUALIZED DEPRECIATION EXPENSES IN THIS CASE.

A. The Company's proposed pro forma annualized depreciation expenses of $15,538,683 are based on the application of its current depreciation rates to the proposed depreciable plant balances as of February 28, 2002 that were not funded by Contributions in Aid of Construction and Customer Advances. The calculations underlying these proposed

[26] At the Company's currently authorized rate of return.

depreciation expenses of $15,538,683 are shown on filing exhibit P-2, Schedule 23 and are summarized in the first column of Schedule RJH-28 attached to this testimony. As shown on Schedule RJH-28, lines 1-3, the Company's proposed depreciation for all depreciable plant other than the Customer Care System amounts to $15,759,697 based on a composite depreciation rate of 1.8923%. The proposed pro forma depreciation expense for the Customer Care System is $641,344 based on a depreciation rate of 6.60% (lines 4-6) and for the acquired Manville plant in service is $48,750 based on a depreciation rate of 1.95% (lines 7-9). Finally, the Company then removed the depreciation associated with plant funded by Contributions in Aid of Construction and Customer Advances amounting to $911,108 based on a depreciation rate of 0.99% (lines 13-15). The resulting net total pro forma annualized depreciation expense proposed by the Company amounts to $15,538,683 (line 16).

Q. HOW DID YOU DETERMINE THE RECOMMENDED PRO FORMA ANNUALIZED DEPRECIATION EXPENSE ADJUSTMENTS IN THIS CASE?

A. I determined the recommended pro forma depreciation expenses using the same approach as used by the Company, i.e., I applied the current depreciation rates to the Ratepayer Advocate's recommended depreciable plant balances as of February 28, 2002 that were not funded by Contributions in Aid of Construction and Customer Advances. My calculations are shown in the third column of Schedule RJH-28.

Schedule RJH-4 shows that the recommended plant in service balance at February 28, 2002 in this case is $16,410,010 lower than the Company's proposed plant in service balance projected for that same date. This recommended $16,410,010 plant adjustment consist of (1) the removal of the Company's proposed CCS investment of $9,717,333, and (2) a total recommended reduction of $6,692,677 for non-CCS plant investments. Schedule RJH-28, lines 1-3 show that the recommended reduction of $6,692,677 for non-CCS plant investments results in a depreciation expense reduction of $126,669. Schedule RJH-28, lines 4-6 show that the removal of the CCS investment reduces the Company's proposed pro forma depreciation expenses by $641,344. Finally, my recommended reduction in the Company's proposed Contributions in Aid of Construction and Customer Advances balances as of February 28, 2002 increases the Company's proposed pro forma depreciation expenses by $26,275 (lines 13-15).

The resulting net total pro forma annualized depreciation expense adjustment recommended by me amounts to an expense reduction of $741,739 (line 16).

- <u>Amortization Expenses</u>

Q. WHAT IS THE REASON FOR THE RECOMMENDED AMORTIZATION EXPENSE ADJUSTMENT SHOWN ON SCHEDULE RJH-29?

A. As shown on the Company's filing exhibit P-2, Schedule 24, EWC has proposed to amortize the Manville Acquisition Adjustment balance of $2,410,000 over a 20-year period, resulting in the Company's proposed pro forma amortization expense of $120,500 for this item. Based on the reasons described in the prior "Manville Acquisition Adjustment" rate base section of this testimony, I recommend the removal of these proposed amortization expenses

BEFORE THE STATE OF NEW JERSEY
OFFICE OF ADMINISTRATIVE LAW

I/M/O THE PETITION OF PUBLIC SERVICE	)	
ELECTRIC AND GAS COMPANY FOR	)	DOCKET NO. ER02050303
APPROVAL OF CHANGES IN ELECTRIC	)	OAL DOCKET NO. PUC 5744-02
RATES, FOR CHANGES IN THE TARIFF FOR	)	
ELECTRIC SERVICE, CHANGES IN ITS	)	
ELECTRIC DEPRECIATION RATES AND FOR	)	
OTHER RELIEF	)	

DIRECT TESTIMONY OF ROBERT J. HENKES
ON BEHALF OF THE
NEW JERSEY DIVISION OF THE RATEPAYER ADVOCATE

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ALL OF THE REMAINING OTHER OPERATING REVENUES FOR THE 6+6 TEST YEAR?

A. The Company has projected 6+6 test year revenues of $3,802,532 for all of the remaining Other Operating Revenue components. These remaining Other Operating Revenue components consist of TPS revenues, EDHI Affiliation fees, PJM NF PTP Credits, DSM Liquidated Damages revenues and STC Servicing fees. While the Company is not able to separate the revenues for each individual revenue component, it states that the revenues from each of these revenue components "are embedded in the $3,802,532.[5]"

Q. HAVE YOU MADE AN ADJUSTMENT TO THE COMPANY'S PROPOSED REMAINING OTHER OPERATING REVENUE TOTAL OF $3,802,532?

A. Yes. As shown on line 8 of Schedule RJH-8, and supported by the calculations in footnotes (6) through (10) of Schedule RJH-8, I have made separate test year revenue projections for each of the Remaining Other Operating Revenue components included in the Company's proposed total of $3,802,532. The sum of these separate revenue projections adds to $4,418,798. Thus, I recommend that the Company's proposed 6+6 test year Remaining Other Operating Revenues of $3,802,532 be increased by $616,266.

- <u>Test Year-End Customer Revenue Annualization Adjustment</u>

[5] Response to RAR-A-137 C&D.

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

A. Yes. The Company's proposed weather normalization adjustment is described on pages 15-16 of Mr. Stellwag's 6+6 testimony. Schedule ANS-14 (6+6) shows that the proposed weather normalization adjustment increases the Company's 6+6 revenue margin by approximately $2 million and net after-tax income by approximately $1.2 million. Through this adjustment, the Company has normalized the 6+6 test year customer consumption levels based on 30-year average normalized weather determinants. The apparent reason for the Company's proposed revenue increase adjustment is that the actual portion of the 6+6 test year filing data contains weather that is colder than normal, thereby resulting in somewhat reduced levels of electric consumption. Based on my review of the Company's proposed weather normalization methodology, I have accepted the Company's proposed revenue weather normalization adjustment.

Q. HAS THE COMPANY RESTATED ITS PROPOSED WEATHER-NORMALIZED TEST YEAR REVENUES TO REFLECT THE CUSTOMER LEVELS AS OF THE END OF THE TEST YEAR, DECEMBER 31, 2002?

A. No. The Company's proposed weather-normalized test year revenues are based upon the average customer level for the test year. In this regard, the Company states in its response to RAR-A-87 E:

> The Company does not plan to propose a customer growth component to its weather normalization adjustment in the 6&6 update as we do not believe that such an adjustment is appropriate.

Q. DOES THIS REPRESENT AN ISSUE IN THIS CASE?

A. Yes. The issue is that the Company has not annualized its proposed test year revenues for the growth in the number of customers. Because of this, the Company's proposed test year revenues are not properly "matched" with the Company's proposal to use a test year-end rate base in this proceeding.

Q. COULD YOU EXPLAIN THIS IN MORE DETAIL?

A. Yes. As discussed before, the Company's proposed test year revenues are based on the test year's average number of customers. In this regard, it is important to recognize that the plant investment that has supported the Company's average test year number of customers is the Company's average test year plant, not the (higher) December 31, 2002 test year-end plant investment level. Since the Company has proposed the use of the higher test year-end plant in service balance and has annualized its depreciation expenses based on test year-end plant, it would be appropriate and consistent to then annualize the revenues for the growth in customers up to the end of the test year.

Q. IS YOUR RECOMMENDATION TO REFLECT A REVENUE ANNUALIZATION ADJUSTMENT FOR CUSTOMER GROWTH UP TO THE END OF THE TEST YEAR IN ACCORDANCE WITH BPU POLICY?

A. Yes. The BPU has a long-standing and well-established policy that the ratemaking use of test year-end rate base and annualized depreciation expenses based on test year-end plant be appropriately "matched" with the ratemaking use of annualized test year revenues based on customer growth up to the end of the test year. For example, in an earlier PSE&G base rate case, Docket No. 837-620, the Company proposed a test year-end rate base and depreciation annualization adjustment, but did not propose an offsetting and matching revenue annualization adjustment for customer growth up to the end of the test year. In that proceeding, the Board agreed with the ALJ's conclusion that

> ...a normalization adjustment should be made for test year-end customers. It is a proper adjustment because it matches the (test) year-end plant with the (test) year-end level of customers, and thus is consistent with the Board's clearly enunciated "matching" principle.

In PSE&G's next base rate case, BPU Docket No. ER85121163, the Company again proposed a test year-end rate base and depreciation annualization adjustment, and again did not propose an offsetting and matching revenue annualization adjustment for customer growth. In that proceeding, the Ratepayer Advocate (then Rate Counsel) and the BPU Staff proposed such a revenue annualization adjustment. On page 119 of his Initial Decision in that case, the ALJ stated:

> I agree with Staff and Rate Counsel that the Board has consistently recognized the appropriateness of this adjustment.

The BPU adopted the ALJ's reasoning and conclusions with regard to this revenue annualization adjustment. In that case, PSE&G also argued that a matching revenue annualization adjustment should not be made so as to afford the Company an attrition allowance. That argument was also rejected by the Board when it adopted the ALJ's findings and conclusions:

> ...petitioner's attrition argument has been expressly addressed by the Board in Atlantic City Electric's most recent rate case, BPU Docket ER8504434, Decision and Order of the Board dated April 3, 1986 at p.3. After considering petitioner's earnings attrition argument I noted that the Board obviously considered same in the Atlantic City Electric case and that there is no just reason presented in this case to depart from Board policy...
> [ALJ Initial Decision, pp.119-120, OAL Docket No. PUC 231-86]

Q. WHAT SPECIFIC REVENUE ANNUALIZATION APPROACH AND METHODOLOGY DO YOU RECOMMEND BE USED IN THIS PROCEEDING IN ORDER TO ACCOMPLISH THIS YEAR-END RATE BASE VERSUS YEAR-END CUSTOMER GROWTH MATCHING?

A. A review of PSE&G's actual monthly electric distribution customers throughout any particular year clearly shows that, while there is a general upward trend in number of customers, there are also significant customer fluctuations from month to month during the year. For example, original filing workpaper page 110 shows the following level of actual number of customers during various months in 2001:

1/01	2,023,482
4/01	2,004,613
5/01	2,038,384
6/01	2,010,795
7/01	2,048,315
8/01	2,016,107
11/01	2,037,709
12/01	2,029,000

Filing workpaper page 27 (6+6) shows monthly customer fluctuations of a similar magnitude for the 6+6 2002 test year. In its response to RAR-A-87 B, the Company explains that

> Seasonal influences, monthly billing irregularities as well as additions and deletions of customers can cause fluctuations in the customer bills reported each month.

With monthly customer fluctuations as obvious as this, it would not be appropriate to then compare an actual "point in time" monthly customer level (such as the test year-end December 31, 2002) to the average test year customer level and then expect to draw the right customer growth and associated revenue annualization conclusions. For that reason, the revenue annualization for customer growth up to the end of the test year must be determined through a methodology different from merely a comparison of the December 31, 2002 number of customers to the average 2002 test year customers. This methodology is explained as follows.

It is reasonable to assume that the Company's actual average test year plant in service is approximately equivalent to the actual plant in service level during the mid-point of the test year. Therefore, the difference between the proposed test year-end plant level and the average test year plant level essentially represents one-half year's worth of growth in the Company's plant investment level. Since the Company's proposed test year revenues are based on the average number of customers, the appropriate revenue annualization adjustment should similarly be based on one-half year's worth of growth in the number of customers of the Company. From the response to RAR-A-87, original filing workpaper 110 and 6+6 filing workpaper page 27, one can calculate that the 3-year average annual compound growth rate for the Company's average number of customers during the most recent period 1999 - 2002 (6+6) has been as follows:

Residential:	0.8%
Commercial	1.3%
Industrial	(0.9)%
Street Lighting	0.8%

I recommend that the revenue annualization adjustment for customer growth up to the end of the test year be calculated by (1) taking one-half of the above-referenced annual growth rates; (2) applying this half-year growth rate to the average number of customers for the 6+6 test year to determine the test year "annualized" number of customers, consisting of the average test year number of customers plus one-half year's worth of customer growth; (3) determine the margin revenues by applying the weather-normalized test year consumption per customer to the "annualized" number of customers determined in step 2 and pricing the resulting kwh consumption out at current tariffs; and finally (4) comparing these annualized margin revenues determined in step 3 to the margin revenues reflected in the 6+6 test year filing, in total and by customer category.

Q. **HAVE YOU MADE THE CALCULATIONS DESCRIBED IN THE PREVIOUSLY DISCUSSED CUSTOMER GROWTH REVENUE ANNUALIZATION APPROACH?**

A. Since I do not have the Company's detailed revenue model available, I requested the Company to perform this test year-end customer growth revenue annualization analysis and provide the resulting increase in margins (revenues net of the associated impact on costs) when compared to the Company's proposed test year 6+6 margins. My detailed request to the Company and the results of the Company's calculated revenue annualization for test year-end customer growth are contained in the response to RAR-A-138.

Q. WHAT WAS THE RESULT OF THIS REVENUE ANNUALIZATION ANALYSIS FOR TEST YEAR-END CUSTOMER GROWTH AND HOW DOES THE REFLECTION OF SUCH ANNUALIZED REVENUES IMPACT THE COMPANY'S PROPOSED PRO FORMA TEST YEAR OPERATING INCOME IN THIS CASE?

A. The response to RAR-A-138 shows that my recommended revenue annualization adjustment for customer growth up to the end of the test year increases the Company's proposed 6+6 test year revenue margins by approximately $8.5 million. As shown on Schedule RJH-9, this increases the Company's proposed pro forma test year operating income by approximately $5 million.

- Reversal of Labor O&M Ratio Normalization Adjustment

Q. WHAT REPRESENTS A "LABOR O&M RATIO"?

A. A portion of a utility's total payroll cost is charged to operation and maintenance ("O&M") expenses and the remainder of the total payroll cost is either capitalized to plant or charged to accounts other than O&M expenses. The labor dollars charged to O&M expense as compared to the total labor cost is referred to as the

- Pension and Fringe Benefit Expense Adjustments

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED POSITION WITH REGARD TO PENSION AND FRINGE BENEFIT EXPENSES.

A. The Company has taken the position that the pension and fringe benefit expenses it has projected for 2003 should be used as the pro forma adjusted test year pension and benefit expenses in this case. As shown in the first column of Schedule RJH-11, the Company has calculated a total expense adjustment of $9.673 million by comparing the projected 2003 pension and fringe benefit expenses to the corresponding expenses in the 6+6 test year.

Q. DO YOU RECOMMEND THAT ADJUSTMENTS BE MADE TO THE COMPANY'S PROPOSED PRO FORMA PENSION AND FRINGE BENEFIT EXPENSES?

A. Yes. First, while I have no specific objection to the reflection of the projected 2003 expense levels for the Company's pension and fringe benefit expenses, I do object to the fact that the Company only used this approach for certain selected employee benefit expense components such as pension, OPEB, medical, dental and thrift plan expenses.[10] Consistent with its approach, the Company's proposed employee benefit expense adjustment should also have included the effect of comparing projected 2003 expenses to actual 6+6 test year expenses for the remaining employee benefit expense components, including group life insurance, death benefits and other miscellaneous employee benefits. As shown on Schedule RJH-11, the combined projected 2003 expense level for these remaining employee benefit expenses is lower than the corresponding actual 6+6 test year expenses.

Second, I have increased the Company's projected 2003 pension expenses by $455,000 to reflect a recent update for the 2003 pension costs as determined by the Company's actuary, Hewitt Associates.

Third, I have decreased the Company's projected 2003 OPEB expenses by $5,833,000 to reflect recent OPEB cost changes, as reported by the Company in its response to RAR-A-148.

[10] For all of these Company-selected employee benefit components, the projected expenses for 2003 were higher than the actual 6+6 test year expenses.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDED PENSION AND FRINGE BENEFIT EXPENSE ADJUSTMENTS ON THE COMPANY'S PROPOSED PRO FORMA TEST YEAR EXPENSES AND NET OPERATING INCOME?

A. As shown on Schedule RJH-11, lines 19 - 21, my recommended adjustments decrease the Company's proposed pro forma test year pension and fringe benefit expenses by $5,947,000 which, in turn, increases the Company's proposed pro forma test year net operating income by $3,518,000.

- <u>Reversal of Deferred Restructuring Cost Amortization</u>

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSAL WITH REGARD TO DEFERRED RESTRUCTURING COSTS.

A. Mr. Stellwag's 6+6 testimony pages 12 and 13 state the following regarding the Company's deferred restructuring cost proposal:

> Restructuring costs incurred by the Company for activities that were necessarily undertaken to date to implement the Electric Deregulation and Energy Competition Act (EDECA) and the various Board Orders issued pursuant to that Act have been deferred... Interest was calculated on these deferred amounts at the rate of seven-year constant maturity treasuries as shown in the Federal Reserve Statistical Release on, or close to, August 1 of each year plus sixty basis points. The current annual rate used is 5.5%, which was set on August 1, 2001. Deferred restructuring costs and interest estimated at the end of the transition period totals approximately $49.4 million.... We are proposing an annual amortization amount of $12.3 million ($7.3 million net of tax) based on a four-year amortization period equivalent to the electric transition period authorized by the Board.

associated with the provision of certain financial services to PSE&G's top officers. As described in the response to RAR-A-46, these financial services include personal financial counseling and estate planning for PSE&G officers and other selected senior management personnel. I do not believe that the Company's ratepayers should be required to fund these types of top officers' compensation "perks". This should be the responsibility of the Company's shareholders.

- <u>Pro Forma Annualized Depreciation Expense Adjustment</u>

Q. IS THE COMPANY PROPOSING BASE RATE RECOGNITION OF NEW DEPRECIATION RATES FOR ITS ELECTRIC DISTRIBUTION IN THIS CASE?

A. Yes. As described on page 6 of Mr. Stellwag's direct testimony, the Company is seeking approval from the Board to implement new depreciation rates for electric and common plant that are "consistent with the rates recently approved by the Board for gas common and general plant (GR01050297, GR0105328, January 9, 2002)." The Company is proposing that these new depreciation rates become effective for book purposes simultaneously with the August 1, 2003 proposed effective date of electric rates set in this proceeding. The Company's proposed pro forma annualized depreciation expenses that are based on these proposed new depreciation rates amount to approximately $180.5 million. This proposed annual depreciation expense level is approximately $19.1 million higher than the 6+6 test year per books depreciation expense level of $161.4 million.

Q. DOES THE RATEPAYER ADVOCATE'S DEPRECIATION EXPERT, MICHAEL MAJOROS, AGREE WITH THE COMPANY'S PROPOSED ELECTRIC DEPRECIATION RATES?

A. No. Mr. Majoros does not agree with the Company's proposed depreciation rates and has recommended appropriate alternative depreciation rates that should be approved by the BPU for rate making purposes in this case. Mr. Majoros has supplied me with his recommended depreciation rates and I have used these depreciation rates in the calculation of the recommended pro forma annualized depreciation expenses in this case.

Q. WHERE DO YOU SHOW THESE RECOMMENDED PRO FORMA ANNUALIZED DEPRECIATION EXPENSE CALCULATIONS?

A. These calculations are shown on Schedule RJH-18. As shown on line 10 of this schedule, Mr. Majoros' recommended depreciation rates produce a recommended level of pro forma annualized depreciation expenses of approximately $80.3 million based on the same level of test-year end depreciable plant as was used by the Company in its proposed pro forma depreciation expense adjustment calculations.

Q. WHAT IS THE IMPACT OF THE DIFFERENCE BETWEEN THE RATEPAYER ADVOCATE'S RECOMMENDED AND THE COMPANY'S PROPOSED PRO FORMA ANNUALIZED DEPRECIATION EXPENSE LEVELS?

A. As shown on Schedule RJH-18, lines 10-12, the Ratepayer Advocate's recommended pro forma annualized depreciation expense level of $80.3 million is $100.1 million lower than the Company's proposed pro forma annualized depreciation expense level of $180.4 million. This recommended expense reduction has the effect of increasing the Company's proposed pro forma test year after-tax operating income by approximately $59.2 million.

BEFORE THE
STATE OF NEW JERSEY
OFFICE OF ADMINISTRATIVE LAW

I/M/O of the Verified Petition of: Rockland Electric Company for Approval: of Changes in Electric Rates, Its Tariff for: Electric Service, Its Depreciation Rates,: and for Other Relief : ("Base Rate Filing") :	**BPU Docket No. ER02100724** **OAL Docket No. PUCRL 09366-02N**
I/M/O of the Verified Petition of: Rockland Electric Company for the: Recovery of its Deferred Balances and the: Establishment of Non-Delivery Rates: Effective August 1, 2003 : ("Deferral Filing") :	**BPU Docket No. ER02080614** **OAL Docket No. PUCOT 07892-02**

DIRECT TESTIMONY OF ROBERT J. HENKES
ON BEHALF OF THE
NEW JERSEY DIVISION OF THE RATEPAYER ADVOCATE

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policies are renewed with carriers in January of each year, and the Company will update the budget when the final premium rates for 2003 are known."

Q. DO YOU BELIEVE THE COMPANY'S PROPOSED POSITION TO BE REASONABLE?

A. Once the final insurance premiums for 2003 have become known in January 2003 and have been reflected as updates to the Company's original projections, I have no objection to the Company's proposal to reflect its 2003 employee health and benefit expenses for ratemaking purposes in this case. However, a number of questions remain regarding the employee health and benefit insurance numbers on Exhibit P-2, Schedule 7 (7+5). These questions are contained in data request RAR-A-105 for which the response has not been received at this time. I therefore reserve the right to re-address this issue in a supplemental testimony, if needed, once the response to RAR-A-105 has been received.

- <u>Pension Expense Adjustment</u>

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED POSITION REGARDING PENSION EXPENSES IN THIS CASE.

A. As shown in the first column of Schedule RJH-11, the Company's proposed pension expenses in this case are based on projected Statement of Financial Accounting Standards ("SFAS") 87 pension accruals of approximately $4 million for the 12-month period ended 7/31/04. The Company then removed the capitalized portion of this projected pension expense at a capitalization ratio of 17.4%. Comparing the resulting net pro forma pension

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expense to the pension expenses of approximately $587,000 included in the unadjusted test year operating expenses results in RECO's proposed pension expense increase of $2,783,000.

The Settlement Agreement in RECO's prior rate case, BPU Docket No. ER91030356J, dated January 10, 1992, allowed the Company to defer the difference between the pension allowance provided for in current rates and the corresponding book expense recorded under SFAS 87. As a result of this Settlement provision, RECO will have a projected pension expense over-recovery balance of $1,370,000 as of April 30, 2003. The Company is proposing to amortize this over-recovery balance as a pension expense credit over a 3-year period. The Company then netted this proposed pension expense credit of $456,000 ($1,370,000 / 3) against its proposed pension expense increase of $2,783,000 in order to arrive at its proposed net expense increase amount of $2,327,000

Q. **DO YOU RECOMMEND THAT ADJUSTMENTS BE MADE TO THE COMPANY'S PROPOSED PRO FORMA NET PENSION EXPENSE OF $2,327,000?**

A. Yes. I do not agree with the Company's proposal to reflect for ratemaking purposes in this case the projected SFAS 87 pension expenses for the 12-month period ended July 31, 2004. Allowing expense projections that extend 15 months beyond the end of the test year would bring the ratemaking formula "out of whack" and violate the integrity of the test year concept. In addition, the Company confirms in its response to RAR-A-38 E that the final actuary calculations of the Company's SFAS 87 pension expenses for 2004 will not be available until sometime during the 2nd quarter of 2004. Therefore, the accuracy of the

Company's proposed SFAS 87 pension expenses in this case cannot be verified with actual calculations from a final actuary report during this proceeding.

For the previously discussed reasons, I recommend that the pro forma pension expenses in this case be based on the projected SFAS 87 pension expenses for calendar year 2003. While this recommendation still involves an expense projection that extends 8 months beyond the end of the test year in this case, the final actuary calculations for this pension expense estimate will become available in the 2nd quarter of 2003,[16] thereby allowing the parties and the Board to update the current expense estimate for actual actuary results prior to the close of record in this case. The projected SFAS 87 pension expense for 2003 amounts to $3,464,000. In the third column of Schedule RJH-11, I show that, using the same approach as was used by RECO, this indicates the need for a recommended net pension expense increase amount of $2,274,000.

The next recommended adjustment to RECO's proposed pension expense increase in this case concerns the amortization of the projected April 30, 2003 pension expense over-recovery balance of $1,370,000. Rather than using the 3-year amortization period proposed by RECO, I recommend the use of a 5-year amortization period. This would be consistent with the 5-year amortization that I have used for other issues in this testimony, *e.g.* the amortization of rate case expenses, the build-up period for the storm damage reserve, etc..

[16] See response to RAR-A-38 D.

Q. WHAT IS THE IMPACT OF THE PREVIOUSLY DISCUSSED RECOMMENDED PENSION EXPENSE ADJUSTMENTS ON RECO'S PROPOSED TEST YEAR OPERATING INCOME?

A. As shown on Schedule RJH-11, lines 8 – 10, the recommended pension expense adjustments decrease RECO's proposed pro forma test year pension expenses by $327,000 which, in turn, increases the Company's test year after-tax operating income by $193,000.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THE COMPANY'S PENSION EXPENSES?

A. Yes. As I discussed before, the Settlement Agreement in RECO's prior rate case, BPU Docket No. ER91030356J, dated January 10, 1992, allowed the Company to defer the difference between the pension allowance provided for in current rates and the corresponding book expense recorded under SFAS 87. I see no compelling reasons why this mechanism should continue. Pension expenses should be treated the same as any other expenses, such as wages, salaries, medical and dental expenses, outside consultants and so on. In other words, You Honor and the Board should determine an appropriate annual level of rate recovery for any expense (including pension expense) based on the best information available during a rate case. After that, a utility should not be allowed to then compare the actual expenses incurred to the expense allowances built into its rates and defer the difference for reconciliation (amortization) in the next base rate case. That would not be proper rate making practice.

In summary, I recommend that the Board order the Company to cease its current Regulatory Asset treatment for pension expenses under which it is allowed to defer the difference between the pension allowance provided for in rates, and the corresponding book expense recorded under SFAS 87. This Board order should become effective with the rate effective date of this case.

- SFAS 106 OPEB Expense Adjustment

Q. **WHAT IS THE COMPANY'S PROPOSED POSITION IN THIS CASE WITH REGARD TO THE PRO FORMA SFAS 106 OPEB EXPENSES TO BE REFLECTED FOR RATE MAKING PURPOSES?**

A. The Company's proposed Other Post-Employment Benefit ("OPEB") expenses in this case are based on projected SFAS 106 OPEB accruals of approximately $2,064,000 for the 12-month period ended 7/31/04.

Q. **DO YOU AGREE WITH THE COMPANY'S PROPOSED POSITION?**

A. No. The Company's proposal to reflect for ratemaking purposes in this case the projected SFAS 106 OPEB expenses for the 12-month period ended July 31, 2004 is inappropriate and should be rejected for the same reasons discussed in the prior section of this testimony concerning pension expenses. Allowing expense projections that extend 15 months beyond the end of the test year violates the integrity of the test year concept. Moreover, the Company confirms in its response to RAR-A-44 E that the final actuary calculations of the Company's OPEB expenses for 2004 will not be available until sometime during the 2nd quarter of 2004. Therefore, the accuracy of the Company's proposed SFAS 106 OPEB expenses in this case cannot be verified with actual calculations from a final actuary report during this proceeding.

Instead, I recommend that the pro forma OPEB expenses in this case be based on the projected SFAS 106 OPEB expenses for calendar year 2003. While this recommendation still involves an expense projection that extends 8 months beyond the end of the test year in this case, the final actuary calculations for this OPEB expense estimate will become available in the 2nd quarter of 2003,[17] thereby allowing the parties and the Board to update the current expense estimate for actual actuary results prior to the close of the record in this case. The projected OPEB expense for 2003 amounts to approximately $2,028,000. As shown on Schedule RJH-12, my recommended OPEB expense adjustment decreases RECO's proposed pro forma test year OPEB expenses by $36,000. Taking into consideration the capitalization ratio of 17.4%, my recommendation increases RECO's proposed test year after-tax operating income by $18,000.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THE COMPANY'S SFAS OPEB EXPENSES?

A. Yes. The Company currently defers the difference between the OPEB expense allowance provided for in current rates and the corresponding book expense recorded under SFAS 106. For the same reasons discussed in the prior section of this testimony regarding pension expenses, I recommend that the Board order the Company to cease its current Regulatory Asset treatment for OPEB expenses under which RECO defers the difference between the OPEB expense allowance provided for in rates and the corresponding book

[17] See response to RAR-A-44 D.

expense recorded under SFAS 106. This Board order should become effective with the rate effective date of this case.

- Enhanced Service Reliability Expense

Q. WHAT IS THE REASON FOR THE ENHANCED SERVICE RELIABILITY PROGRAM EXPENSE ADJUSTMENT SHOWN ON LINE 6 OF SCHEDULE RJH-4?

A. This adjustment is a direct result of the recommendations regarding the Enhanced Service Reliability Program that were previously discussed in the Rate Base section of this testimony. RECO has proposed to include estimated operation and maintenance expenses of $1,141,000 associated with the Enhanced Service Reliability Program. As shown in footnote (2) of Schedule RJH-4, the reversal of this pro forma O&M expense entry increases the Company's proposed after-tax test year operating income by approximately $675,000.

- Rate Case Expense Adjustment

Q. PLEASE EXPLAIN THE RATE CASE EXPENSE ADJUSTMENT YOU SHOW ON SCHEDULE RJH-13.

A. The Company is claiming estimated rate case expenses of $450,000 for this case, consisting of $400,000 for legal expenses, $40,000 for consulting fees and $10,000 for miscellaneous expenses. The Company incurred actual rate case expenses of $342,000 for

- Pro Forma Annualized Depreciation Expense Adjustment

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED PRO FORMA ANNUALIZED DEPRECIATION EXPENSE POSITION IN THIS CASE.

A. The Company's proposed pro forma annualized depreciation expense positions are shown on Exhibit P-2, Summary, page 1 (7+5), and Exhibit P-2, Schedules 10, 13, 14 and 20 (7+5), and have been presented in a somewhat confusing way. What is clear from Exhibit P-2, Summary, page 1 is that the total pro forma annualized depreciation expense amount claimed by RECO in this case is $5,200,000.[20] In the first column of my Schedule RJH-17, I have presented what I believe to be the correct breakdown of the component parts making up RECO's claimed total pro forma annualized depreciation expense amount of $5,200,000. RECO's reflected annualized depreciation expenses based on the application of its proposed new depreciation rates to the test year-end depreciable plant balances amount to $4,847,000 (see line 1). The next component of RECO's overall pro forma depreciation expense position of $5,200,000 is a negative expense of $588,000 for the proposed 20-year amortization of the Company's identified "Book versus Theoretical Reserve Difference" (line 2). The next three components -- shown on lines 3, 4 and 5 – represent RECO's proposed annual depreciation/amortization expenses associated with the Enhanced Service Reliability Program, Hourly Energy Pricing Billing project, and post-test year plant additions.

[20] Consisting of the sum of $4,697,000, $200,000, ($398,000) and $701,000.

Q. DO YOU RECOMMEND THAT ADJUSTMENTS BE MADE TO THE COMPANY'S PROPOSED PRO FORMA ANNUALIZED DEPRECIATION EXPENSES?

A. Yes. Mr. Majoros, the Ratepayer Advocate depreciation expert, has recommended appropriate depreciation rates for the Company that are different from the new depreciation rates proposed by RECO in this case. As shown on Schedule RJH-17, line 1, Mr. Majoros' depreciation rate recommendations result in a recommended annualized depreciation expense level of $3.864 million. Mr. Majoros has also recommended that the amortization of the Theoretical Reserve Difference should be $1.103 million rather than RECO's proposed amortization amount of $.588 million (see line 2).

Next, consistent with my previously discussed recommendation that the costs associated with the Company's proposed Enhanced Service Reliability Program not be included for ratemaking purposes in this case, I have reversed RECO's proposed Enhanced Service Reliability Program depreciation expense (see line 3). Finally, I have reversed the Company's proposed depreciation expenses associated with the projected post-test year plant in service, consistent with my previously discussed recommendation that such plant should not receive rate consideration in this case.

Q. WHAT IS THE IMPACT OF THE DIFFERENCE BETWEEN THE RATEPAYER ADVOCATE'S RECOMMENDED AND THE COMPANY'S PROPOSED PRO FORMA ANNUALIZED DEPRECIATION EXPENSE LEVELS?

A. As shown on Schedule RJH-17, lines 6 - 8, the Ratepayer Advocate's recommended pro forma annualized depreciation expense level is $2.239 million lower than the Company's proposed pro forma annualized depreciation expense level of $5.200 million. This recommended expense reduction has the effect of increasing the Company's proposed pro forma test year after-tax operating income by $1.324 million.

- Interest Synchronization Expense Adjustment

Q. WHAT IS THE ISSUE WITH REGARD TO THE INTEREST SYNCHRONIZATION ADJUSTMENT SHOWN ON SCHEDULE RJH-4, LINE 13?

A. There is no issue per se. As shown in more detail on Schedule RJH-18, the only reason the recommended interest synchronization income tax impact is different from the Company's proposed interest synchronization income tax impact is because of the differences in the Company's proposed and Ratepayer Advocate's recommended rate base and weighted cost of debt positions. Because of these differences, the Ratepayer Advocate's pro forma interest deduction for income tax purposes is smaller than the Company's. As can be seen from Schedule RJH-18, line 5, this results in a decrease of $.335 million in the Company's proposed pro forma test year operating income.

Q. MR. HENKES DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

BEFORE THE STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
OFFICE OF ADMINISTRATIVE LAW

IN THE MATTER OF THE PETITION)	
OF ELIZABETHTOWN WATER)	BPU Docket No. WR03070510
COMPANY FOR AN INCREASE IN)	OAL Docket No. PUCRL 07281-2003N
RATES FOR WATER SERVICE AND)	
OTHER TARIFF MODIFICATIONS)	

DIRECT TESTIMONY AND EXHIBITS OF ROBERT J. HENKES
ON BEHALF OF THE
NEW JERSEY DIVISION OF THE RATEPAYER ADVOCATE

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Filed: December 1, 2003

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Q. **DO YOU AGREE WITH THIS PROPOSED RATEMAKING TREATMENT?**

A. No. The Company's proposal is not only unreasonable and inequitable to the ratepayers, it is also contrary to Board ratemaking policy.

Q. **WHAT IS YOUR RECOMMENDATION WITH REGARD TO THIS ISSUE?**

A. In accordance with Board ratemaking policy, I recommend that 50% of the gain associated with these two property sales accrue to the Company's stockholders while the remaining 50% be flowed to the ratepayers through an appropriate amortization of this gain portion. I recommend an amortization period of three years. As shown on Schedule RJH-18, lines 3 through 6, my recommendation results in an annual pre-tax gain amortization amount of approximately $74,000 which should be used as an operating expense credit in this case.

- **Annualized Depreciation Expense**

Q. **PLEASE EXPLAIN THE COMPANY'S PROPOSED AND YOUR RECOMMENDED ANNUALIZED DEPRECIATION EXPENSE LEVELS.**

A. The Company has proposed a total annualized depreciation expense of $17.467 million. As shown in detail on filing Exhibit P-2, Schedule 24, EWC generally determined this proposed annualized depreciation expenses by applying its currently authorized depreciation rates to its proposed projected depreciable plant balances as of June 30, 2004. This produced annualized deprecation expenses of $18.503 million. The Company then

[19] Now referred to as Washington Valley land

reduced this annualized depreciation expense by the depreciation associated with plant funded by Customer Advances and Contributions in Aid of Construction. The net result is the Company's proposed pro forma annualized depreciation expense of $17.467 million. This is summarized in the first column on Schedule RJH-19.

Schedule RJH-19 shows that when the Company's proposed annualized gross depreciation expense of $18.503 million is divided into the Company's projected 6/30/04 depreciable plant in service balance, this results in an overall composite depreciation rate of 1.973%. In determining the recommended annualized depreciation expense level, I have applied this same overall composite depreciation rate of 1.973% to the preliminary recommended depreciable plant in service balance of $875.649 million. As shown on Schedule RJH-19, line 5, this produces a preliminary recommended annualized depreciation expense of $17.281 million. I then reduced this annualized depreciation expense by the depreciation expense associated with plant funded by Customer Advances and Contributions in Aid of Construction. This produces the currently recommended annualized net depreciation expense level of $16.273 million. This annualized depreciation expense number must eventually be updated by re-calculating it based on the actual plant in service and actual Customer Advances and Contributions in Aid of Construction levels as of December 31, 2003.

BEFORE THE STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
OFFICE OF ADMINISTRATIVE LAW

IN THE MATTER OF THE PETITION	)
OF NEW JERSEY-AMERICAN WATER	) BPU Docket No. WR03070511
COMPANY FOR AN INCREASE IN RATES	) OAL Docket No. PUCRL 07279-2003N
FOR WATER AND SEWER SERVICE	)
AND OTHER TARIFF MODIFICATIONS	)

**DIRECT TESTIMONY AND EXHIBITS OF ROBERT J. HENKES
ON BEHALF OF THE
NEW JERSEY DIVISION OF THE RATEPAYER ADVOCATE**

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Filed: December 1, 2003

- **Pension Expenses**

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED POSITION WITH REGARD TO PENSION EXPENSES.

A. As shown on Schedule RJH-15, line 1, the Company has proposed to include pension costs of $4.635 million in this case. After removing the capitalized portion, the proposed pro forma pension cost charged to O&M expense amounts to $4.048 million.

Q. WHAT IS THE BASIS FOR THE COMPANY'S PROPOSED PENSION EXPENSES IN THIS CASE?

A. The Company's proposed pension expense in this case is based on its pro forma 2004 FASB 87 pension liability. In its response to RAR-A-152, the Company acknowledges that the proposed pension cost of $4.635 million represents an estimate and that the actual FASB 87 pension expense will not be available until March 2004.

Q. WHAT IS THE MOST RECENT ACTUAL FASB 87 PENSION COST AVAILABLE AT THIS TIME?

A. This is the Company's FASB 87 cost for 2003. As shown in the response to RAR-A-105 C, the Company's actual actuary-determined FASB 87 pension cost for 2003 amounts to $3,641,333.

Q. WHAT PENSION COST DO YOU RECOMMEND BE USED FOR RATEMAKING PURPOSES AT THIS TIME?

A. Since the Company's proposed estimated 2004 pension cost number is not currently known and measurable, I recommend the use of the most recent actual 2003 FASB 87 pension cost for ratemaking purposes at this time. If the actual actuary-determined 2004 pension cost becomes available prior to the close of record in this case, this more updated cost number could be considered for rate recognition, after review for appropriateness.

Q. HAS THE COMPANY MADE ANOTHER PROPOSAL WITH REGARD TO ITS PENSION COSTS?

A. Yes. The Company has been deferring the difference between the annual FASB 87 pension cost liabilities and the corresponding annual ERISA contributions to the pension fund. As shown in the response to SIR-29, the actual cumulative balance in this pension deferral balance was approximately $6.6 million as of 12/31/2002. The Company then estimated that this actual $6.6 million deferral balance would approximately double to $12 million from 12/31/02 to 6/30/04, the assumed rate effective date of this case. In this case, the Company is proposing to amortize this estimated pension cost deferral balance of $12 million over 10 years for a requested annual amortization expense of $1.2 million (see Schedule RJH-15, line 4).

Q. DO YOU AGREE WITH THE COMPANY'S CALCULATION OF THE ESTIMATED GROWTH IN THIS PENSION DEFERRAL BALANCE FROM 12/31/02 TO 6/30/04?

A. No. The Company made incorrect assumptions in its calculation of the estimated growth in this deferral account from $6.6 million at 12/31/02 to $12 million at 6/30/04. For example, the response to SIR-29 shows that the Company assumed that its annual FASB 87 pension expenses are $4,635,359 from 1/1/03 going forward. This is incorrect. As previously discussed, the $4,635,359 number represents the Company's estimated FASB 87 pension costs for 2004. Even if this estimated number were to be accurate on an actual basis, it obviously would not be effective starting on 1/1/03. Thus, the Company's proposed estimated pension deferral balance of $12 million as of 6/30/04 is incorrectly calculated, inaccurate and unreliable.

Q. DOES THE PENSION DEFERRAL BALANCE AT ISSUE HERE IMPACT THE COMPANY'S BALANCE SHEET FOR FINANCIAL REPORTING PURPOSES?

A. No. As confirmed by the Company in its response to RAR-A-197 B, the pension deferral balance recorded in Other Deferred Debits account 186 is exactly offset by a corresponding pension accrual balance in the Other Deferred Credits account on the liability side of the Company's balance sheet. Therefore, the impact on the Company's balance sheet is $0 because these two asset and liability accounts are exactly offsetting.

Q. CAN THIS DEFERRED PENSION BALANCE BE AUTOMATICALLY EXTINGUISHED IN THE FUTURE WHEN FUTURE ERISA PENSION FUND CONTRIBUTIONS EXCEED FASB 87 PENSION COST BOOKINGS?

A. Yes. As confirmed in the response to RAR-A-107, the current pension deferral balance which the Company proposes to amortize over an accelerated 10-year period has been built up because in the recent past the Company's cumulative FASB 87 pension bookings have exceeded the cumulative ERISA contributions to the pension trust. This was likely caused by the fact that the Company's trust fund was over funded during the recent past. As acknowledged by the Company in this same response, the current pension deferral balance will be *decreased*, and possibly completely extinguished, if and when future ERISA contributions exceed FASB 87 pension bookings. In response to RAR-A-107 D, the Company states that "This situation[16] has not existed since 1995." However, given the current under funding of many pension funds, it would not be unrealistic to expect the Company's future ERISA contributions to exceed the FASB 87 liabilities.

In summary, I believe there should be no compelling reasons for the Company to remove this deferral balance from its books over an accelerated 10-year period given that it is likely that this balance will automatically be reduced – and possibly completely extinguished – through traditional book keeping entries in the future when ERISA contributions exceed FASB 87 pension costs. This is exactly the same situation as exists with accelerated deferred income taxes. These deferred taxes build up when accelerated depreciation exceeds book depreciation in the early life of the associated assets, however, eventually, the deferred tax balance gets reduced when the reverse situation occurs, i.e., when book depreciation starts exceeding accelerated tax depreciation. Nobody in this case is proposing to amortize the Company's accumulated deferred income taxes over an accelerated 10-year period.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THIS ISSUE?

A. Based on the foregoing findings and conclusions, I recommend that the Company's

[16] This situation refers to the excess of ERISA contributions over FASB 87 pension cost bookings.

proposal to amortize over 10 years the previously discussed pension deferral be rejected by Your Honor and the Board.

Q. **WHAT IMPACT DO YOUR RECOMMENDED PENSION COST ADJUSTMENTS HAVE ON THE COMPANY'S PROPOSED PRO FORMA NET OPERATING INCOME?**

A. As shown on Schedule RJH-15, my two recommended pension cost adjustments decrease the Company's proposed pro forma expenses by $2.071 million which, in turn, increases the Company's proposed net operating income by $1.346 million.

- **Electric Power Expenses**

Q. **PLEASE EXPLAIN THE RECOMMENDED ELECTRIC POWER EXPENSE ADJUSTMENT SHOWN ON SCHEDULE RJH-16.**

A. In the determination of its proposed pro forma electric power expenses, the Company assumed projected rate increases effective August 1, 2003 of 12.8% for PSE&G, 12.4% for JCP&L and 8.4% for Conectiv. The actual rate increases for these three power suppliers turned out to be 13.6% for PSE&G, 3.3% for JCP&L and 8.1% for Conectiv. As confirmed in its response to RAR-A-93, the Company has calculated that the update for these actual rate increases reduces its originally proposed electric power expenses from $8.374 million to $7.982 million. As shown on Schedule RJH-16, this recommended expense adjustment increases the Company's proposed pro forma net operating income by $255,000.

to give rate consideration to gains accrued by NJAWC on the sales of various utility properties. This recommendation was discussed in detail earlier in this testimony.

- **Annualized Depreciation Expense**

Q. **PLEASE EXPLAIN THE COMPANY'S PROPOSED AND YOUR RECOMMENDED ANNUALIZED DEPRECIATION EXPENSE LEVELS.**

A. The Company has proposed a total annualized depreciation expense of $31.471 million. As shown in detail on filing Exhibit P-2, Schedule 42, NJAWC generally determined this proposed annualized depreciation expenses by applying its currently authorized depreciation rates to its proposed projected depreciable plant balances as of June 30, 2004 that were not funded by Customer Advances and Contributions in Aid of Construction.

Schedule RJH-23 shows that when this proposed annualized depreciation expense of $31.471 million is divided into the Company's projected 6/30/04 plant in service balance of $1,306.827 million, this results in an overall composite depreciation rate of 2.408%. In determining the recommended annualized depreciation expense level, I have applied this same overall composite depreciation rate of 2.408% to the preliminary recommended plant in service balance of $1,254.068 million. As shown on Schedule RJH-23, this results in a preliminary recommended annualized depreciation expense of $30.198 million. This annualized depreciation expense number must eventually be re-calculated based on the actual depreciable plant in service level as of December 31, 2003.

BEFORE THE STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
OFFICE OF ADMINISTRATIVE LAW

IN THE MATTER OF THE PETITION	)	
OF THE MOUNT HOLLY WATER	)	**BPU Docket No. WR03070509**
COMPANY FOR APPROVAL OF AN	)	**OAL Docket No. PUCRL 07280-2003N**
INCREASE IN RATES FOR WATER	)	
SERVICE AND OTHER TARIFF	)	
MODIFICATIONS	)	

DIRECT TESTIMONY AND EXHIBITS OF ROBERT J. HENKES ON BEHALF OF THE NEW JERSEY DIVISION OF THE RATEPAYER ADVOCATE

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Filed: December 1, 2003

inappropriate and contrary to established BPU policy.[12] I therefore recommend the removal of the Company's proposed 3% inflation adjustment of $12,000.

I have also removed the lobbying expense portion of the Company's test year NAWC dues, amounting to approximately $2,000, as confirmed by the Company in its response to RAR-A-30.

Finally, I have removed from the test year operating expenses an amount of $50,000 the Company has proposed to include for so-called Thames Overhead charges. The inclusion of these Thames Overhead charges in the 2002 base year is shown in the responses to RAR-A-32 (account 930-517968). I understand that MHWC is no longer charged with this Thames Overhead cost allocation of $50,000. This is also evidenced by the fact that these costs are no longer booked by MHWC in the 2003 Pro Forma Year.

As shown on line 5 of Schedule RJH-16, the combined impact of these Other O&M expense adjustments is a decrease of $64,000 in the Company's proposed pro forma Other O&M expenses.

- **Annualized Depreciation Expense**

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED AND YOUR

[12] *I/M/O the Petition of New Jersey-American Water Company for an Increase in Rates for Water and Sewer Service and Other Tariff Modifications*, BPU Docket No. WR98010015, Order Adopting in Part and Rejecting in Part Initial Decision at 33 (April 6, 1999).

RECOMMENDED ANNUALIZED DEPRECIATION EXPENSE LEVELS.

A. The Company has proposed a total annualized depreciation expense of $1.275 million. As shown in detail on filing Exhibit P-2, Schedule 21, MHWC generally determined this proposed annualized depreciation expenses by applying its currently authorized depreciation rates to its proposed projected depreciable plant balances as of June 30, 2004. This produced annualized deprecation expenses of $1.430 million. The Company then reduced this annualized depreciation expense by the depreciation associated with plant funded by Customer Advances and Contributions in Aid of Construction. The net result is the Company's proposed pro forma annualized depreciation expense of $1.275 million. This is summarized in the first column on Schedule RJH-18.

Schedule RJH-18 shows that when the Company's proposed annualized gross depreciation expense of $1.430 million is divided into the Company's projected 6/30/04 depreciable plant in service balance, this results in an overall composite depreciation rate of 2.153%. In determining the recommended annualized depreciation expense level, I have applied this same overall composite depreciation rate of 2.153% to the preliminary recommended depreciable plant in service balance of $53.604 million. As shown on Schedule RJH-18, line 5, this produces a preliminary recommended annualized depreciation expense of $1.162 million. I then reduced this annualized depreciation expense by the depreciation expense associated with plant funded by Customer Advances and Contributions in Aid of Construction. This produces the currently recommended annualized net depreciation expense level of $1.009 million. This annualized depreciation expense number must eventually be updated by re-calculating it based on the actual plant in service and actual

Customer Advances and Contributions in Aid of Construction levels as of December 31, 2003.

- **Amortization Expenses**

Q. **WHY DID YOU ADJUST THE COMPANY'S AMORTIZATION EXPENSES, AS SHOWN ON SCHEDULE RJH-7, LINE 12?**

A. As discussed earlier in this testimony, I have reduced the Company's proposed Pro Forma Year amortization expenses by approximately $52,000 to reflect my recommendation that all aspects of the Homestead Water Acquisition Adjustment, including the Company's proposed 10-year amortization of this acquisition adjustment, be removed for ratemaking purposes from this case.

- **Payroll Taxes**

Q. **WHY HAVE YOU ADJUSTED THE COMPANY'S PROPOSED PRO FORMA PAYROLL TAXES, AS SHOWN ON SCHEDULE RJH-7, LINE 14?**

A. The recommended payroll tax adjustment is a direct result of the recommended payroll expense adjustment. The calculations underlying this recommended payroll tax adjustment are shown on Schedule RJH-10.

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BEFORE THE STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
OFFICE OF ADMINISTRATIVE LAW

IN THE MATTER OF THE PETITION OF	**)**
APPLIED WASTEWATER MANAGEMENT,	**) BPU Docket No. WR03030222**
INC. FOR APPROVAL OF AN INCREASE	**) OAL Docket No. PUCRS 02351-03S**
IN RATES FOR SERVICE	**)**

DIRECT TESTIMONY AND EXHIBITS OF ROBERT J. HENKES
ON BEHALF OF THE
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- **Depreciation Expenses**

Q. PLEASE DESCRIBE THE DERIVATION OF THE ANNUALIZED DEPRECIATION EXPENSES YOU RECOMMEND FOR RATE MAKING PURPOSES IN THIS CASE.

A. I show this derivation on Schedule RJH-11. The composite depreciation rate proposed by the Company in this case is 2.69%, as shown on filing Exhibit P-2, Schedule 19. I applied this same composite depreciation rate to the recommended actual depreciable plant in service balance as of June 30, 2003, resulting in recommended annualized depreciation expenses of $431,197. Next, I reduced this depreciation expense by the depreciation associated with plant funded by Customer Advances and CIAC. The resulting recommended net annualized depreciation expense amounts to $218,130.

Q. WHY IS THE RECOMMENDED ANNUALIZED DEPRECIATION EXPENSE LOWER THAN THE COMPANY'S PROPOSED ANNUALIZED DEPRECIATION EXPENSE?

A. There are two reasons for this. First, the recommended actual depreciable plant in service balance as of June 30, 2003 is approximately $2.1 million lower than the projected depreciable plant in service balance as of June 30, 2003 that was proposed by the Company. Second, the Company only removed the depreciation related to plant funded by CIAC. In its response to RAR-A-48, the Company conceded that this was an error in that it should have removed the depreciation related to plant funded by both CIAC and Customer Advances. Since I have correctly removed the depreciation related to both CIAC and

Customer Advances, this is the second reason for the difference between the Company's proposed and my recommended depreciation expenses.

- **Amortization Expenses**

Q. WHY HAVE YOU REMOVED THE COMPANY'S PROPOSED AMORTIZATION EXPENSES FOR RATEMAKING PURPOSES, AS SHOWN ON SCHEDULE RJH-6, LINE 12?

A. The amortization expense of $31,186 represents the 10-year amortization of the Homestead Acquisition Adjustment that was discussed in the "Acquisition Adjustment" section of this testimony. For the reasons described there, I have removed these amortization expenses for ratemaking purposes in this case.

- **Revenue Taxes**

Q. WHY HAVE YOU ADJUSTED THE COMPANY'S PROPOSED REVENUE TAXES, AS SHOWN ON SCHEDULE RJH-6, LINE 13?

A. The recommended revenue tax adjustment is a direct result of the recommended revenue adjustment on Schedule RJH-6, line 8. I calculated the revenue tax adjustment by applying the Gross Receipts and Franchise Tax rate of 12.61% to the revenue adjustment on line 8.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS AND CONDITIONS OF LOUISVILLE GAS AND ELECTRIC COMPANY	)))	**CASE NO. 2003-00433**

DIRECT TESTIMONY

AND EXHIBITS

OF

ROBERT J. HENKES

PERTAINING TO THE GAS RATE CASE

On Behalf of the Office Of Rate Intervention Of The Attorney General Of The Commonwealth Of Kentucky

March 23, 2004

purposes in this case.

Second, I recommend the removal from test year gas operating expenses portions of the Company's American Gas Association (AGA) dues that are associated with legislative and regulatory advocacy, legislative and regulatory policy research, advertising, marketing and public relations. I do not believe that these expenses should be charged to the ratepayers as they produce no material benefit to the ratepayers. In PSC-3-48, the Company was requested to provide the total test year AGA expense level, as well as a breakdown of this test year AGA expense level by the categories that I just listed, in the same detail as shown for the Company's electric EEI expenses in the response to AG-1-85. While the Company, in its response to PSC-3-48, provided the total test year AGA expense level, it did not provide the requested breakdown on this total expense level. Absent this AGA expense breakdown, I have conservatively assumed that 25% of AGA's test year expenses are associated with the type of activities referenced earlier. The total AGA dues included in LG&E's test year gas operating expenses amount to $103,752. Applying the 25% disallowance rate to these test year AGA dues results in the recommended AGA expense disallowance of approximately $26,000. If the Company is able to provide the AGA expense breakdown requested in PSC-3-48, the currently recommended AGA expense disallowance could be updated based on this information.

Q. WHAT IS THE IMPACT OF YOUR MISCELLANEOUS EXPENSE ADJUSTMENT RECOMMENDATIONS ON THE COMPANY'S PROPOSED TEST YEAR GAS AFTER-TAX OPERATING INCOME ?

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ADJUSTMENT OF RATES OF	)	
JACKSON ENERGY	)	Case No. 2000-373
COOPERATIVE CORPORATION	)	

DIRECT TESTIMONY OF ROBERT J. HENKES ON BEHALF OF THE OFFICE OF RATE INTERVENTION OT THE ATTORNEY GENERAL FOR THE COMMONWEALTH OF KENTUCKY

February 13, 2001

1-56, pages 7-8 and involve awards and prizes, tuition reimbursements, gifts and donations, NRECA meeting fees and Christmas hams and turkeys. The total of these expenses removed by me amounts to $9,816, as shown in footnote 1 of this Schedule RJH-6, page 1. I have removed these expenses in accordance with PSC rate making principles.

- A&G - Institutional Advertising Expenses

Q. PLEASE EXPLAIN YOUR RECOMMENDED A&G EXPENSE ADJUSTMENT FOR INSTITUTIONAL ADVERTISING EXPENSES, AS SHOWN ON SCHEDULE RJH-6, PAGE 1, LINE 3.

A. Filing exhibit 11 shows that Jackson's proposed pro forma test year expenses includes $4,643 worth of expenses classified on its books as institutional advertising expenses. Institutional advertising expenses have traditionally been disallowed for rate making purposes by the PSC. In its response to data request AG 2-25, Jackson states that a portion of this total expense amount of $4,643 is associated with safety displays and that it is estimated that approximately 2/3rds of the $4,643, or $3,095, represents institutional advertising. I have accepted this representation and have therefore removed only $3,095 from test year expenses.

- A&G - Directors Fees and Expenses

Q. PLEASE EXPLAIN YOUR RECOMMENDED A&G EXPENSE ADJUSTMENTS FOR

DIRECTORS FEES AND EXPENSES, AS SUMMARIZED ON SCHEDULE RJH-6, PAGE 1, LINE 4 AND DETAILED ON SCHEDULE RJH-6, PAGE 3.

A. The first adjustment is that I have removed $4,800 from test year expenses for extra per diem fees paid to the Chairman and Secretary/Treasurer of the Board in accordance with rate making principles applied by the PSC in previous electric cooperative rate cases.

Second, I have removed $4,469 for test year expenses related to two directors who retired during the test year. These represent non-recurring test year expenses that should be disallowed for rate making purposes. Jackson has agreed with this position in its response to data request AG 2-30.

Third, I have removed all the directors' VISA charges that are included in Jackson's proposed pro forma adjusted test year expenses. As shown in the response to data request AG 2-27, these VISA charges relate to NRECA Regional meetings and Congressional Breakfasts. These type of directors' expenses have been specifically disallowed by the PSC in previous electric cooperative rate proceedings.

Fourth, Jackson's proposed pro forma adjusted test year directors' expenses still include insurance policy expenses of $10,425, as shown in filing Exhibit 6, page 13, line 15. I do not know at this time what directors' insurance this involves. However, since it has been established PSC rate making policy to exclude from rates such expenses as the directors' health insurance and postretirement benefit insurance, I have also removed these insurance policy expenses.

Finally, I have removed a range of additional directors' expenses that were still included in Jackson's proposed pro forma adjusted test year directors expenses. These additional expense removals are listed by director and by expense type in footnote 5 of Schedule RJH-6, page 3. I have removed these expenses based on my understanding that similar type directors' expenses have been consistently disallowed by the PSC in prior electric cooperative rate proceedings.

- A&G - Annual Meeting Expenses

q PLEASE EXPLAIN YOUR RECOMMENDED A&G EXPENSE ADJUSTMENT FOR ANNUAL MEETING EXPENSES, AS SHOWN ON SCHEDULE RJH-6, PAGE 1, LINE 5.

A. Pursuant to PSC rate making policy, I have removed from Jackson's proposed pro forma A & G expenses $2,307 worth of expenses related to prizes and giveaway items during the annual meeting in the test year. Footnote 3 of Schedule RJH-6, page 1, provides the relevant source reference for this recommended expense disallowance.

- A&G - Manager Search Expenses

Q. PLEASE EXPLAIN YOUR RECOMMENDED A&G EXPENSE ADJUSTMENT FOR EXPENSES ASSOCIATED WITH THE MANAGER SEARCH, AS SHOWN ON SCHEDULE RJH-6, PAGE 1, LINE 6 AND FOOTNOTE 4.

A. As conceded by Jackson in this case, all expenses associated with the manager's search that are included in the test year operating expenses represent non-recurring expenses that should

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE	)	
RATES OF DELTA NATURAL	)	Case No. 2004-00067
GAS COMPANY, INC.	)	

Attorney General's Response to Delta Natural Gas Company Inc.
Data Request #12

Response of the Attorney General
To Delta Natural Gas Company
Case No. 2004-00067

Responding Witness:
Charles King

12. Please provide a copy of all written testimony submitted by Mr. King in the following proceedings:

g. District of Columbia; Docket No. 989; Washington Gas Light Company;

h. District of Columbia; Docket No. 1016; Washington Gas Light Company;

i. Georgia; Docket No. 14311-U; Atlanta Gas Light Company;

j. Georgia; Docket No. 17066-U; Georgia Power Company;

k. Illinois; Docket No. 02-0690; Illinois-American Water Company;

l. Kentucky; Docket No. 2002-00145; Columbia Gas Company of Kentucky;

m. Kentucky; Docket No. 2003-00252; The Union Light, Heat and Power Company;

n. Maryland; Docket No. 8855; Baltimore Gas & Electric Company;

o. Michigan; Docket No. U-13808; Detroit Edison Company.

Response

Mr. King's testimony in Maryland P.S.C. Docket No. 8855 cannot be provided because it was file under seal. Copies of the all other requested testimonies are provided in: the Original of the Responses filed with the Public Service Commission; the Copy of the Response filed with John Hall of Delta Natural Gas: the Copy of the Response filed with Robert M. Watt III, Counsel for Delta Natural Gas. The copies are voluminous and will otherwise be provided only request.

BEFORE THE

ILLINOIS COMMERCE COMMISSION

ILLINOIS-AMERICAN WATER COMPANY	)	
	)	Docket No. 02-0690
Proposed General Increase in Water	)	
And sewer Rates (Tariffs Filed	)	
September 20, 2002)	)	

TESTIMONY OF

CHARLES W. KING

On behalf of

THE CITY OF O'FALLON

O'Fallon Exhibit No. 1.0

February 5, 2003

CONTENTS

DIRECT TESTIMONY OF CHARLES W. KING

INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Charles W. King. I am President of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. PLEASE DESCRIBE SNAVELY KING.

A. Snavely King, formerly Snavely, King & Associates, Inc., was founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. The firm has a professional staff of 15 economists, accountants, engineers and cost analysts. Much of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 33-year history, members of the firm have participated in over 600 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. O'Fallon Exhibit No. 1.1 is a summary of my qualifications and experience.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. O'Fallon Exhibit 1.2 is 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 City of O'Fallon, Illinois.

Q. WHAT ISSUES WILL YOU ADDRESS IN YOUR TESTIMONY?

A. My testimony addresses three issues. In Part I, I address the appropriate rate of return to be applied to the rate base of the Illinois-American Water Company ("IAWC" or "the Company"). In Part II, I address the treatment of retirement costs for purposes of calculating depreciation rates. In Part III, I address the propriety of establishing wholesale rates for water that is sold to customers, such as the City of O'Fallon, that in turn resell water to their own retail customers. In an exhibit (O'Fallon Exhibit 1.6) to that section, I present a cost of service study that quantifies the revenue/cost relationships for the respective customer classes when the functions assumed by such wholesale customers are appropriately recognized.

Q. WHAT INFORMATION DID YOU REVIEW IN PREPARING YOUR TESTIMONY?

A. I have obtained the Company's testimony and exhibits. I propounded data requests and interrogatories, to which the Company replied. I also obtained the responses that the Company provided to other parties in this proceeding. I requested and obtained from the Commission Staff the cost of service study that they prepared from Company data in the last IAWC case, Docket No. 00-0340. I have also reviewed the Commission decisions in previous IAWC rate cases.

PART I – RATE OF RETURN

Q. WHAT HAVE YOU FOUND TO BE THE APPROPRIATE RATE OF RETURN FOR THE COMPANY'S RATE BASE?

A. I find that the appropriate rate of return on the Company's rate base is **7.14 percent,** inclusive of a return to equity of **9.1 percent.**

Q. HOW WILL YOU STRUCTURE THIS PART OF YOUR TESTIMONY?

A. I will first discuss the capital structure of the Company, that is, the mix of debt and common equity, and the cost of the Company's debt. I will then discuss the return to equity, and principally the testimony and exhibits of the Company's rate-of-return witness, Paul Moul. I will demonstrate that Mr. Moul's own Discounted Cash Flow ("DCF") analysis finds the market-determined rate of return for his proxy water companies to be 9.22 percent. However, his further rate-of-return analyses are conceptually so flawed as to be virtually worthless. I will conclude that the lower risk of IAWC and Mr. Moul's inappropriate adjustments to the dividend yield calculation justifies a reduction in Mr. Moul's proxy group return to 9.1 percent when applied to IAWC. I will conclude by applying the respective cost rates to the components of the capital structure to develop the appropriate return to total capital.

A. CAPITAL STRUCTURE AND COST OF DEBT

Q. WHAT IS THE COMPANY'S CLAIMED CAPITAL STRUCTURE?

A. The Company's claimed capital structure is 54.85 percent debt and 45.15 percent equity, reflective of the average mix of debt and equity during the year 2003.

Q. DO YOU AGREE WITH THIS CAPITAL STRUCTURE?

A. No, I do not. The Company's capital structure includes retained earnings reflecting an assumption that the full amount of its requested rate increase is granted. As I shall discuss in more detail later, the Company's claimed cost of capital and depreciation allowances are excessive. I also suspect that the Commission Staff and other parties will find that there are other downward adjustments to be made in the Company's claimed revenue requirement. For this reason, I do not believe that the Company will have the retained earnings that it assumes.

Furthermore, the assumption that increased earnings from the proposed rate increase will alter the capital structure makes the revenue requirement calculation circular to some extent. The greater the revenue requirement, the greater the rate increase. The greater the rate increase, the greater the increment to the equity proportion of the capital structure. The higher equity proportion in the capital structure, the greater the revenue requirement.

For these reasons, I recommend that the equity increment that reflects the increase in revenues and income from this rate case be excluded from the capital structure.

Q. WHAT CAPITAL STRUCTURE DO YOU RECOMMEND?

A. I recommend the following capital structure:

Table 1
Capital Structure, Year Average 2003
(Dollars in Millions)

	Amount	Proportion
Long Term Debt	$296,005,645	55.04%
Common Equity	241,836,431	44.96%
Total Capital	$537,842,076	100.00%

Source: IAWC Exhibit No. 13.0, Schedule D.1, page 1.

Q. WHAT IS THE COMPANY'S COST OF DEBT?

A. The Company computes that the composite cost of its long-term debt is 5.537 percent.[1] The Company asserts that it will have no short-term debt during the year 2003. This statement is not altogether accurate. Schedule D-2 shows that the Company expects to maintain an average of $1,642,000 during the year 2003. This number is so small relative to total capital that it does not warrant inclusion in the capital structure.

B. THE COST OF EQUITY

Q. WHAT IS THE BASIS FOR FINDING A RATE OF RETURN TO THE EQUITY COMPONENT OF THE IAWC'S CAPITAL?

A. In its landmark Hope Natural Gas decision, the United States Supreme Court established the following standards for the return to equity that must be allowed a regulated public utility:

> ..the return to the equity owner should be commensurate with the returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[2]

It can be seen from this excerpt that there are essentially three standards for determining an appropriate return to equity. The first is the "comparable earnings" standard, that the earnings must be "commensurate with the returns on investments in other enterprises having corresponding risks." The second is that they must be sufficient to assure "confidence in the financial integrity of the enterprise," and the third is that they must allow the utility to be able to attract capital.

Q. HOW CAN THE COMPARABLE EARNINGS STANDARD BE APPLIED IN ESTIMATING THE RATE OF RETURN TO EQUITY CAPITAL?

[1] IAWC Exhibit No. 13.0, Schedule D-1, page 1.
[2] Federal Power Commission et. al. vs. Hope Natural Gas Company, 320 U.S. 592, at 603.

A. There is a certain circularity to the comparable earnings standard because the competitive nature of the capital markets virtually ensures that the returns to all enterprises having corresponding risks are comparable with each other. Investors establish the price of each traded stock based on that stock's present and prospective earnings in comparison with the present and prospective earnings of all other stocks and other investments available to them. If the earnings of a firm are depressed, then investors will pay only a low price for that firm's stock. As a result, their return on the market value of that stock will be comparable to the return on the market value of the stock of other highly profitable companies which, as a consequence of their profitability, have been bid up to a very high price. Thus, if "return" is defined as the earnings of an equity investment relative to its current market price, then the comparable earnings test becomes a cipher. All returns are comparable with all other returns.

In public utility regulation the conventional procedure for resolving this circularity is to identify the required equity return based on the market value of a utility's stock. That return is combined with the cost of debt and preferred stock, using either the actual or a hypothetical minimum-cost capital structure. The blended return to total capital is then applied to a rate base calculated from the original "book" cost of the utility's assets, less accrued depreciation, and adjusted for ratepayer contributions such as deposits and deferred taxes. Under this procedure, the market price of a stock is used only to determine the return that investors expect from that stock. That expectation is then applied to the book value of the utility's investment to identify the level of earnings which regulation will allow the utility's common shareholders to recover.

Q. HOW CAN THE FINANCIAL INTEGRITY AND CAPITAL ATTRACTION STANDARDS BE APPLIED IN ESTIMATING THE RATE OF RETURN TO EQUITY CAPITAL?

A. If the utility can earn a return on its investment comparable to that required by enterprises of comparable risk, then it should have no difficulty in attracting capital and maintaining credit. Investors would have no reason to shun such a utility in favor of other investment opportunities. Thus, if the comparable earnings test is met, then the financial integrity and capital attraction standards are met as well.

Q. FOR PURPOSES OF THIS INQUIRY, WHAT TYPES OF ENTERPRISES HAVE COMPARABLE RISK TO IAWC?

A. The enterprises likely to have business risks most comparable to IAWC are those engaged in the same business, that is, the collection, treatment and distribution of water to retail and wholesale customers under rate base/rate-of-return regulation.

Q. HAS THE COMPANY'S RATE-OF-RETURN WITNESS, PAUL MOUL IDENTIFIED SPECIFIC COMPANIES THAT ARE IN THE SAME BUSINES AS IAWC?

A. Yes. Mr Moul has identified six water companies that he has used as proxies for IAWC:

American States Water
California Water Service Group
Connecticut Water Service Co.
Middlesex Water Co.
Philadelphia Suburban Corp.
SJW Corp.

Q. WHY HAS MR. MOUL NOT INCLUDED IAWC'S PARENT COMPANY, AMERICAN WATER WORKS, IN HIS LIST?

A. Mr. Moul reports that on September 16, 2001, American Water Works ("AWW"), IAWC's parent company, entered into an agreement to merge with Thames Water, the UK subsidiary of RWE Aktiengesellchaft at a premium of 36.5 percent over the AWW's price for the 30 trading days prior to the announcement. This merger is about to be consummated, so that the current price of the stock is driven entirely by its prospective buyout value. It does not reflect investors' expectations as to future dividends and earnings of AWW.

Q. WHAT RISK FACTORS DO THE COMPANY'S WITNESSES CITE WITH RESPECT TO WATER COMPANIES?

A. Two of IAWC's witnesses, Fredrick Ruckman and Paul Moul, discuss the risks confronting the water and wastewater industry. They argue that this industry faces considerable risk owing to the following factors:

- The Safe Drinking Water Act, the Federal Clean Water Act, and the Resource Conservation and Recovery Act impose millions of dollars of new construction obligations, monitoring obligations, operating expenses, and violations liability on the water and wastewater utilities.

- The aging of the water system infrastructure is imposing additional replacement and reconstruction requirements on the industry.

- Undetected contaminants may present exposure to claims for injury.

- Competition from customer bypass, condemnation by municipalities and municipal systems threaten the investor owned water utilities.

- Population and economic growth threaten the availability of supply for some utilities.

- Water utilities face security risks.

- Water utilities are capital intensive, and expansion of plant usually requires external financing.

- Most of water utilities' costs are fixed and do not contract if usage contracts.

- Residential water usage per household is declining.

Q. DO YOU AGREE THAT THESE FACTORS IMPOSE RISK ON THE WATER UTILITIES?

A. Many of them do not. First of all, it is important to define "risk" in the context in which investors view it. Investment risk is a function of <u>uncertainty</u>, that is, the inability to foresee the likely pattern of earnings into the future. Risk does not increase in proportion to the cost increases in an industry if there is a high likelihood that those costs will be recovered. Nor is it related to the amount of capital investment or the rate at which that investment must be generated – provided that the investment can be recovered and that it earns a adequate and reasonably reliable return.

Consider the Federal laws governing drinking water and wastewater treatment. The requirements have been written into law. The regulations by which they are implemented are established through rulemaking procedures that take years to complete. These regulations may involve capital expenditures, but the need to raise capital does not, by itself, increase risk, particularly in a regulated industry. To the contrary, it has been argued that regulation encourages capital expenditures because capital is the only source of profit for a company subject to rate base/rate-of-return regulation.

This same observation applies to the contention that much of the infrastructure may have to be replaced and that the industry is capital intensive. These facts alone do not increase risk.

Nonetheless, it must be conceded that the water utility industry does involve some risk. That risk, however, is reflected in the prices investors are willing to pay for the common stock of water companies relative to current and future earnings. If water utilities are as risky as Messrs. Ruckman and Moul contend, their stocks will trade at high prices, and their rate of return indicators, discussed later in this testimony, will increase accordingly.

Q. HOW DOES RISK OF IAWC COMPARE WITH THAT OF MR. MOUL'S PROXY WATER GROUP?

A. None of the risk factors cited by Messrs. Ruckman and Moul applies with greater force to IAWC than to the companies in Mr. Moul's proxy water group. Indeed, some of them probably apply much less. For example, I am not aware that IAWC is facing supply shortages, as are some of the water companies operating in the western states, e.g. California Water Services. Nor am I aware that IAWC's water systems are so old and in such poor repair that they require unusually large amounts of replacement capital. As regards the remaining factors, I know of no evidence that IAWC faces any greater risks than the other six companies in Mr. Moul's group.

In one important respect, IAWC faces considerably <u>less</u> risk. Unlike the six companies in Mr. Moul's group, IAWC is part of a much larger enterprise, AWW. It is AWW, not IAWC, that raises the equity capital for the Company. AWW operates in 28 states and three Canadian provinces. This geographic diversification protects AWW and IAWC from the risk that localized economic and weather conditions can threaten the profitability of the overall enterprise. It allows AWW to raise equity capital in large volumes and in very liquid markets, enjoying minimal flotation costs and market acceptance risks. The difference in size between AWW and Mr. Moul's six proxy companies can be demonstrated by their market capitalization:

Table 2
Market Capitalization, Water Companies

Company	Shares (Mil.) Outstanding	50-Day Price	Market Capital (Mil)
American States	16.80	$24.05	$404.04
California Water Svs	15.20	24.93	378.94
Connecticut Water	7.66	26.12	200.08
Middlesex Water	7.86	21.82	171.51
Philadelphia Suburban	69.00	20.58	1,420.02
SJW Corp.	3.05	80.79	246.41
Average			$470.17
American Water Works	100.06	$44.92	$4,494.70

AWW is over three times the size of the largest of the companies in Mr. Moul's proxy group. It is almost ten times the average size of his comparison companies.

Q WHAT OTHER PROXIES DOES MR. MOUL USE TO DEVELOP HIS RETURN TO EQUITY?

A. In addition to his proxy water companies, Mr. Moul uses a proxy group of four gas distribution companies which he regards as of comparable risk to his water companies.

Q. DO YOU AGREE THAT MR. MOUL'S GAS DISTRIBUTION UTILITIES HAVE COMPARABLE RISKS TO THE WATER COMPANIES?

A. No. Gas distribution companies face substantially greater business risk than do water companies, for the following reasons:

- Gas distribution companies face the direct competition of other heating fuels such as electricity and fuel oil. There is no substitute for water.

- Gas is used primarily for heating and its demand is therefore extraordinarily susceptible to the vagaries of winter weather. Water consumption is not nearly as weather sensitive.

- Gas distribution companies do not produce the product that they sell. It is purchased in highly volatile commodity markets. Most water companies draw their supply directly from rivers, streams, lakes or wells.

- Many gas distribution companies do not even own the gas they distribute. Much of it is purchased by customers and gas marketers over whom the distribution companies can exert only a limited degree of control. Most water companies do not have to deal with intermediaries.

- Gas distribution companies are entirely dependent on gas pipelines for their gas supply. The capacity of these pipelines is limited and can be severely constrained on peak days of the year. Except in the western states, most water companies take their supply directly from natural sources.

Mr. Moul's own data demonstrate that investors, for whatever reasons, find that gas distribution companies are considerably more risky than water utilities. Mr. Moul's adjusted Discounted Cash Flow ("DCF") return of his water group is 9.68 percent and his gas distribution group is 11.97 percent, for a difference of 229 basis points.[3] This difference is too great to be considered as a chance "blip" in the data. Clearly, investors require a higher return from gas distribution companies than from water companies. They are not "enterprises having corresponding risks." For this reason, I shall ignore Mr. Moul's gas distribution proxy group and concentrate on his analysis of the water utilities.

Q. HOW DOES MR. MOUL IDENTIFY THE RATE OF RETURN TO THE EQUITY INVESTMENT IN HIS PROXY WATER COMPANIES?

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[3] IAWC Exhibit 7.0, page 44.

A. Mr. Moul first applies the Discounted Cash Flow ("DCF") procedure, which he claims produces an equity return indication of 9.68 percent. Next, he then employs an interest rate risk premium approach that he claims indicates an equity return of 12.00 percent. Finally, he applies the Capital Asset Pricing Model ("CAPM") to generate a claimed return of 13.13 percent. His ultimate recommendation is 11.015 percent.

I can find to objective basis for Mr. Moul's 11.015 percent recommendation. It does not reconcile with any of Mr. Moul's various analyses. It appears that Mr. Moul is not so confident in his own results as to adopt any of them either directly or through some sort of weighting or reconciliation process.

1. DISCOUNTED CASH FLOW PROCEDURE

Q. PLEASE DESCRIBE THE DISCOUNTED CASH FLOW PROCEDURE.

A. The basic premise of the Discounted Cash Flow (" DCF") procedure is that the market values each stock at the discounted present value of all future flows of cash that investors expect from purchasing that stock. The discount rate that equates those future cash flows with the market value of the stock is the investors' required rate of return.

The DCF approach is usually represented by the following formula:

$$k = {}^{d}/_{P} + g$$

where k = required rate of return
d = dividend in the immediate period
P = market price
g = expected growth rate in dividends

While the DCF method is usually presented in mathematical notation format (as above), it can also be described in narrative fashion. The formula says that the return that any investor expects from the purchase of a stock consists of two components. The first is the immediate cash flow in the form of a dividend. The second is the prospect for future growth in dividends. The sum of the rates of these two flows, present and future, equals the return that investors require. Investors adjust the price they are willing to pay for the stock until the sum of the dividend yield and the annual rate of expected future growth in dividends equals the rate of return they expect from other investments of comparable risk. The DCF test thus determines what the investing community requires from the company in terms of present and future dividends relative to the current market price.

Q. DON'T MOST INVESTORS REGARD CAPITAL APPRECIATION AS A PORTION OF THEIR EXPECTED RETURN?

A. Yes. The expectation of capital appreciation is captured in the "g" or growth portion of the DCF formula. If dividends grow, then it follows that the market price of the stock will grow as well. It is this growth that most equity investors seek, at least in part, in purchasing shares in a traded company.

Q. IS THERE A CONVENTIONAL PROCEDURE FOR CALCULATING DCF RETURNS?

A. Yes There is a conventional procedure for calculating equity return under the DCF formula that is often referred to as the "classic" DCF calculation. The Federal Communications Commission ("FCC") has concluded that this method should be given the greatest weight in determining the rate of return to equity.[4] I agree with this conclusion.

Q. HAS MR. MOUL EMPLOYED THE "CLASSIC" DCF CALCULATION IN HIS ANALYSIS OF WATER COMPANIES?

A. Yes, he has, although he has added inappropriate embellishments to it, as I will discuss.

[4] *Notice Initiating a Prescription Proceeding and Notice of Proposed Rulemaking*, CC Docket No. 98-166, October 5, 1998.

Q. HOW DOES THE CLASSIC DCF CALCULATION DERIVE THE DIVIDEND YIELD PORTION OF THE DCF FORMULA?

A. Under the classic calculation, the dividend yield is calculated as the next year's dividend divided by an average of recent prices of the stock. The resultant yield should reasonably match the dividend yields shown by the financial reporting services.

There are several ways to predict next year's dividend. Several investors' services provide forecasts of dividends. Another, somewhat more mechanical approach is to compute the next year's dividend as the most recent dividend annualized and then increased by one half of the analysts' prediction of long-term annual growth rate in earnings per share.

Q. HOW HAS MR. MOUL DERIVED THE DIVIDEND YIELDS OF THE WATER COMPANIES?

A. Mr. Moul first followed the mechanical procedure described above for increasing the current dividend yield to next year's level. He then applied two inappropriate adjustments that have the effect of increasing the dividend yield. His derived dividend yield is 3.47 percent.[5]

Q. WHAT ARE THE TWO INAPPROPRIATE ADJUSTMENTS THAT MR. MOUL APPLIED IN THE DIVIDEND YIELD CALCULATION?

A Mr. Moul's first adjustment is to reduce the month-end prices by the fraction of the quarterly dividend since the time of the last ex-dividend date. If the ex-dividend dates for a $1.00 dividend are, say, December 31 and March 31, Mr. Moul subtracts $0.33 from the January 31 price of the stock and $.66 from the February 28 price. He believes these amounts reflect the dividend value that the market has imputed into the price of the stock and therefore should be removed to yield the "true" value of the stock.

[5] IAWC Exhibit 7.0, page 30.

Mr. Moul's other adjustment is to compound the quarterly dividends throughout the year on the theory that the investor reinvests the dividend and earns further return. A $1.00 dividend on April 1 has a value of $1.025 on July 1 if the average return is 10 percent. That dividend is worth $1.075 by year-end. The June 30 dividend is worth $1.050 by year-end, and so on.

Q. IS MR. MOUL'S EX-DIVIDEND PRICE ADJUSTMENT APPROPRIATE?

A. No. First of all, Mr. Moul presents no empirical evidence that demonstrates a decline in the market price of the typical stock on the ex-dividend date by the amount of the dividend. While there may be investors who calculate their expected returns with this degree of precision, it would take practically simultaneous action by almost all investors to achieve a predictable drop in every stock's value on its ex-dividend date. Moreover, if there were such a predictable drop in every stock's price, speculators would soon put an end to it by selling stocks short on their ex-dividend dates in anticipation of the drop in price.

But even if Mr. Moul's highly questionable assumptions as to stock price were true, his procedure of reducing the stock's price by the anticipated amount of the dividend effectively double-counts the same dividend in the dividend yield calculation. The dividend itself makes up the numerator, but it is again subtracted from the denominator to inflate further the level of the yield.

Q. IS MR. MOUL'S COMPOUNDING OF QUARTERLY DIVIDENDS APPROPRIATE?

A. No. It is true that investors can reinvest their dividends and earn a return on them throughout the rest of the year, but that investment is made outside of the enterprise being studied. That is, the Company issuing the dividend does not have to generate the compounded returns; investors do it on their own. Therefore it is no part of the required return from the dividend-issuing company.

Q. HOW IS THE "g" OR GROWTH FACTOR IN THE DCF FORMULA IDENTIFIED UNDER THE CLASSIC DCF CALCULATION?

A According to the DCF theory, the relevant measure of "g" should be the growth in dividends. Dividends, however, are largely a function of management discretion, and they do not necessarily reflect the underlying driver of earnings. Simply by changing the dividend payout ratio, a company's management can create a rate of dividend growth that is unsustainable. For this reason, I believe that earnings per share ("EPS") is the most reliable indicator of the "g" factor.

The classic DCF calculation employs predictions of EPS growth, usually in the three to five year time horizon. Investment analysts routinely attempt to forecast future earnings of traded companies. No one forecast can be considered reliable, but presumably a consensus of forecasts might be a good indication of investors' collective expectations as regards the company's future prospects.

Q. HAS MR. MOUL FOLLOWED THIS PROCEDURE?

A Yes. Mr. Moul has used the earnings forecasts of the following analysts:

- Institutional Brokers' Estimation Service, or I/B/E/S
- Zacks Investment Services
- Thompson FN – First Call
- MarketGuide – Multex Investor
- Value Line

These sources provide Mr. Moul with a growth indication of 5.75 percent.[6]

[6] IAWC Exhibit 7.0, page 37.

Q. WHAT ARE THE RESULTS OF MR. MOUL'S CLASSIC DCF FORMULATION?

Adding his dividend yield of 3.47 percent to his forecast growth rate of 5.75 percent generates a rate of return of 9.22 percent. Mr. Moul describes this return as the "market determined cost of equity."[7]

Q. DOES MR. MOUL ADOPT THIS RETURN AS HIS DCF INDICATION?

A. No. Mr. Moul makes an upward adjustment to the straightforward results of the DCF model to reflect what he perceives to be the greater risk of a capital structure based on book equity relative to the capital structure derived from the market's capitalization of equity.

Q. IS THE CAPITAL STRUCTURE ADJUSTMENT APPROPRIATE?

A. No. The purported logic underlying Mr. Moul's adjustment is that investors set their return requirements based on the market value of each company's equity, which in almost every case is considerably higher than the book equity amount. This higher market equity value implies a much lower level of financial risk than the book equity value. Therefore, when the DCF return is applied to book equity, its must be adjusted upward to reflect that greater risk.

I have confirmed that with the exception of the Middlesex Water Company, each of Mr. Moul's proxy water companies has a per-share market value greater than its book value. I would agree with Mr. Moul that a company having a capital structure that reflects the average market valuation of the equity of his proxy companies would have lower financial risk than a company having a capital structure based on those companies' book equity.

[7] See page 42 of IAWC Exhibit 7.0, definition of *ke*.

But this is not the comparison we are making in this study. There are not two companies having different capital structures, but a single company in every case. While investors are aware that the market valuation might provide a cushion of equity value over book value that reduces the risk of the company, their assessment of the company's equity risk does not change when applied to the book equity value. They know that the company's regulated earnings are applied to a book value rate base, and that knowledge is factored into the price they are willing to pay for the stock. Mr. Moul double counts whatever effect there is to the regulatory practice of using a book value rate base when he adds an further adjustment to market determined return to reflect that practice.

2. INTEREST RATE RISK PREMIUM APPROACH

Q. WHAT IS THE INTEREST RATE RISK PREMIUM APPROACH?

A. While equity return requirements are difficult to estimate, bond yields and interest rates can be measured with precision and currency. Indeed, they are reported daily in business publications and weekly by the Federal Reserve Board. The interest rate risk premium approach attempts to analyze the relationship between measurable interest rates and bond yields and immeasurable equity returns.

Q. HOW HAS MR. MOUL APPLIED THE INTEREST RATE RISK PREMIUM APPROACH?

A Mr. Moul has sought to use this approach to develop point estimates of the cost of his water and gas utility proxy groups' equity. Those point estimates are 12.00 percent for the water utilities and 12.25 percent for his gas distribution utilities.[8]

In developing these estimates, Mr. Moul started with the Blue-Chip Financial Forecast for Aaa and Baa rated 2002 and 2003 adjusted to reflect the premium appropriate for A-

[8] IAWC Exhibit 7.0, page 49.

rated public utility bonds. His selected bond yield was 7.25 percent. Mr. Moul then examined the differentials between the earned returns to public utility stocks and utility bonds over a series of time periods ranging from 1928-2001 to 1979-2001. He selected a risk premium of 5.32 percent, based principally on the experienced bond vs. stock return differentials during the periods 1974-2001 and 1979-2001. Taking into account the differences in relative risk, Mr. Moul adopted a 4.75 risk premium for water utilities and 5.0 percent risk premium for gas distribution companies. The sum of the A-rated bond yields and Mr. Moul's selected risk premiums gave him his risk premium returns to equity.

Q. WHAT IS YOUR RESPONSE TO THIS CALCULATION?

A. I have encountered this same historical risk premium approach in a number of rate-of-return proceedings and have always found it so flawed, both conceptually and statistically, as to be virtually worthless.

At the conceptual level, the historical risk premium approach is based on two utterly unsupportable assumptions. The first is that the experienced differences in return between stocks and bonds represent the expected differences in return. The theory is that over a long enough period, actual return differentials between stocks and bonds will equate to required or expected return differentials.

This is a statement of faith, not experience, and it defies logic. If investors' short-term expectations are continually being frustrated (as they certainly have been during the last three years) or exceeded (as they were in the late '90s), what possible logic supports the proposition that the sum of those mistaken short-term expectations represents a valid long-term representation of their expectations?

The second unsupportable assumption is that the spread between the required returns of bonds and stocks is fixed and unchanging over extended periods of time. This presumption is flatly untrue. The perceived safety/risk relationship of bonds differs from stocks, and their relative desirability as investment vehicles changes continually depending on such factors as inflation, economic growth, and the capital structures of the enterprises issuing the securities.

Bonds, particularly long-term bonds, suffer severe inflation risk because their returns are fixed in nominal dollar terms. On the other hand, they are much better protected from the business cycle than are stocks. Stocks are regarded as a hedge against inflation, but their prices are highly susceptible to investors' expectations regarding business, economic, monetary and geo-political conditions. The risk premium in returns to stocks over bonds is continually changing, contrary to the underlying assumption of Mr. Moul's historical risk premium approach.

Quite apart from this conceptual failing, the theory fails statistically, as demonstrated on page 22 of IAWC Exhibit 8.0. For all four series, the standard deviations exceed the means, in one case (public utility stock index) by a factor of two. When the variance of the observations around the mean exceeds the value of the mean, the mean is said to lack "statistical significance," particularly as a predictive value. If the means lack statistical significance, the differentials between those means are statistically useless as a predictive tool.

3. <u>CAPITAL ASSET PRICING MODEL</u>

Q. WHAT IS THE CAPITAL ASSET PRICING MODEL?

A. The Capital Asset Pricing Model ("CAPM") is described on pages 49 through 55 of Mr. Moul's testimony (IAWC Exhibit 7.0) and in more detail in IAWC Exhibit 7.8. As described by Mr. Moul, CAPM employs a measure called "beta," which tests the covariance of the stock at issue with that of the overall market, to assess the relative risk of the stock against the market. As conventionally used by rate-of-return analysts, the beta is assumed to measure the cost of the company's equity on a continuum between the average required return of the equity market overall and a risk-free return.

Q. WHAT IS YOUR ASSESSMENT OF THE CAPM?

A. I believe that CAPM's beta has value in assessing the relative risk of different stocks and portfolios of stocks. It can therefore be useful in checking the results of other, more reliable, methods of measuring equity return, such as the DCF procedure. However, I question whether it has much value in directly estimating the required return to the equity of a specific company owing to the following problems:

- The measurement of beta. As noted, beta measures the degree of covariance of the stock with that of the market overall. But neither the fluctuations of the stock nor those of the market are constant, or even consistent with each other over any extended period of time. As a result, there are as many estimates of beta for a given company as there are analysts making the measurement.

- The risk-free rate. Usually, the yields of U.S. Treasury securities are assumed to be risk-free, but there are quite a number of Treasury securities that have different yields. Which one to pick depends on the context.

- The return to the overall market. The complexities and uncertainties associated with measuring the return to equity of an individual company are not reduced when the object of the analysis is expanded to the entire market for equities. Generally, CAPM analysts use one of two procedures. Either they perform simplistic DCFs for a wide variety of stocks, in which case why not use the same DCF for the stock under study? Or they use the historical return to market equities, which assumes, totally unrealistically, that the investors in the equity markets during the period under study actually realized the return that they were expecting. This historical approach tells us nothing about investors' present expectations as to future earnings. It is these expectations that drive the current price of the stock.

- The assumption of linearity. CAPM assumes that there is a linear relationship between beta and the difference between the market's return and a risk-free return. A stock with a .5 beta, for example, is assumed to have an equity return requirement mid-way between these two measures. Carried to its logical extremes, this assumption is absurd. A stock that does not vary at all with the market, and therefore has a beta of 0, is assumed to have the same risk as a U.S. Treasury bond. More absurd yet, stocks that vary inversely with the market – and they certainly exist – would have equity return requirements lower than the yield on a Treasury bond.

Q. HOW HAS MR. MOUL APPLIED THE CAPM ?

A. Mr. Moul has applied the CAPM in the conventional fashion, but with some embellishments of his own. He has adopted Value Line's betas for his proxy groups of companies, .55 for his water utilities and .59 for his gas distribution companies, but he then decided that these betas must be adjusted for the difference in the market vs. the book capital structures. In this manner, he inflates the betas to .71 and .69 for the water and gas utilities, respectively. As his risk-free rate, Mr. Moul adopts the yields on long-term government bonds, which he finds to be 5.5 percent.

To derive his market risk premium, Mr. Moul uses two approaches. His forecast approach adds the dividend yield predicted by Value Line for 1700 stocks to an annualized expression of the median appreciation potential forecast to the period 2004-2006 by Value Line for these same 1700 stocks. This yields an estimate of the total expected market return of 10.49 percent.

Separately, Mr. Moul develops an historical risk premium based on the difference between the earned returns to stocks and yields to government bonds over the 76 year period 1926-2001. This differential is 7.0 percent. Mr. Moul then averages his forecast 10.49 percent and historical 7.0 percent to create a risk premium of 8.75 percent.[9]

[9] IAWC Exhibit 7.0, page 53.

When he adds his risk free rate of 5.50 percent to the product of his betas and his market risk premium of 8.75 percent, he generates a CAPM return of 11.71 percent for his water proxy group and 11.54 percent for his gas distribution group.[10]

Mr. Moul further inflates these returns by allowances for the purported risk effect of the size differential between the water and gas companies in his groups in the spectrum of companies traded on the three major stock exchanges, NYSE, AMEX and NASDAQ. These adders are 1.42 percent for the water group and .72 percent for the gas distribution group. Mr. Moul's final CAPM results are 13.13 percent for the water group and 12.26 percent for the gas distribution group.[11]

Q. DOES MR. MOUL'S CAPM SUFFER FROM THE FOUR PROBLEM AREAS YOU HAVE IDENTIFIED?

A. Yes. It does.

Q. WHAT ARE THE BETA MEASUREMENT PROBLEMS IN MR. MOUL'S CAPM ANALYSIS?

A. Mr. Moul has used Value Line's betas, which differ quite dramatically from those of other analysts. For example Zacks Investor Services has a very different view of what the betas for these companies should be:

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[10] Id.
[11] Id., page 55.

Table 3
Water Company betas

Company	Value Line	Zacks
American States	.65	.00
California Water Svs	.60	.04
Connecticut Water	.45	-.07
Middlesex Water	.45	.24
Philadelphia Suburban	.60	-.31
SJW Corp	.55	.56
Average	.55	.08

Clearly, these two analyst organizations have very different ways of measuring betas. My experience is that there are as many betas as there are analysts attempting to measure them, and that most of them are lower than Value Line's beta.

Mr. Moul's capital structure adjustment to his Value Line beta has no conceptual justification whatever. Whatever the appropriate beta, it measures the movement of the specific stock relative to the movement of the market. To the extent that financial risk (caused by capital structure effects) is reflected in this covariance, it does not change because of the difference in the market relative to the book valuation. Indeed, beta has nothing to do with market-to-book ratios. It is purely a measure of market price fluctuations.

Q. WHAT PROBLEMS DOES MR. MOUL'S ANALYSIS ENCOUNTER WITH RESPECT TO THE MEASUREMENT OF THE RISK FREE RATE?

A. Mr. Moul uses as his risk-free return the yield on long-term Treasury bonds. This at first seems like a risk-free return, but the yields on shorter term Treasury instruments are lower, as is clearly demonstrated by the chart that Mr. Moul provides on page 25 of IAWC Exhibit 8.0. In June 2002, long-term Treasury bonds were yielding 5.66 percent, but one-year bonds were yielding only 2.20 percent. This pattern is consistent: the shorter the term of the bond, the lower the yield.

It is logically impossible for long-term Treasury bonds that have a yield of 5.45 percent to be totally risk free when there are other Treasury securities with dramatically lower yields. In reality, long-term Treasury bonds are not risk free. They face the very substantial risk that an acceleration in inflation sometime in the future could erode their value and diminish their real return. That is why one-year bonds are much less risky than long-term bonds.

Q. WHAT PROBLEMS DOES MR. MOUL'S ANALYSIS ENCOUNTER WITH RESPECT TO THE MEASUREMENT OF THE RETURN TO THE OVERALL MARKET?

A. As noted, Mr. Moul uses two sources for his estimate of the return to the overall market. His forecast return is based on a quasi-DCF application of Value Line data for the period 2004-2006. The predicted dividend yields are arguably acceptable. For his growth factor, however, Mr. Moul uses Value Line's estimates of capital appreciation, not its forecasts of earnings per share, which is the indicator he uses in his DCF analysis. Mr. Moul provides no explanation for this inconsistency in his methodology.

Mr. Moul's historical market return suffers from all of the problems that I have discussed with respect to his interest rate risk premium application.

Q. WHAT PROBLEMS DOES MR. MOUL'S ANALYSIS ENCOUNTER WITH RESPECT TO THE ASSUMPTION OF LINEARITY BETWEEN THE MARKET RETURN AND THE RISK-FREE RETURN?

A. Arguably, Mr. Moul does not encounter these problems because he uses Value Line's betas and not those of other analysts. Had he used Zacks' betas, he would have had to deal with a zero beta for American States Water and a negative beta for Philadelphia Suburban. These betas reflect Zacks' apparent finding that there is no correlation whatever between the variation in American States' stock prices and those of the market, and that Philadelphia Suburban's stock varies inversely with the market. Neither of these stocks is risk free, as postulated by the CAPM theory. If the CAPM results for these companies are non-sensical, then there is no reason to suppose that the CAPM results for companies with higher betas make any more sense.

Q. IS THERE ANY JUSTIFICATION FOR THE SMALL COMPANY ADJUSTMENT THAT MR. MOUL MAKES TO HIS CAPM RESULTS?

A. No. While it is true that the proxy water companies, with on average of $470 million in market capitalization, are much smaller than the average company traded on the stock exchange, the company at issue here, American Water Works, has a market capitalization of $4,495 million. Mr. Moul does not disclose the average market capitalization, but he claims that his gas distribution companies, with an average capitalization of $1,148 million, are in the fifth decile. It would appear that AWW approaches, and maybe exceeds the size of the larger companies in the fourth decile, which would be above the median for the series.

Q. OVERLOOKING ALL OF THE CONCEPTUAL PROBLEMS WITH THE CAPM, CAN YOU PROVIDE AN ESTIMATE OF YOUR COMPARISON GROUP'S EQUITY COST USING THIS APPROACH?

A. Yes, although I cannot attach much significance to the result.

If we average Value Line's betas of .55 and Zacks' average beta of .08 for the proxy water companies, we arrive at a beta of .32. If we then substitute the one-year Treasury bond yield for Mr. Moul's long-term Treasury bond yield, we have a risk free rate of 2.20 percent.[12] Then, for purposes of this exercise, I will accept Mr. Moul's Value Line based market return of 10.49 percent, which yields an equity risk premium of 8.29 percent. (10.49%-2.20%). Applying the .32 beta to this risk premium generates a premium for his water companies of 2.65 percent (8.29 x .32). When this premium is added to the risk-free rate of 2.20 percent, the resultant CAPM return is only 4.85 percent. This is an

[12] IAWC Exhibit 8.0, page 25.

unacceptable result because it is no higher than the current yield on long-term Treasury bonds, clearly a lower-risk investment instrument than utility stocks.

If anything, this exercise proves the uselessness of the CAPM approach.

4. RECOMMENDED RETURN TO EQUITY

Q. HAS MR. MOUL PROVIDED ANY REASONABLY RELIABLE ESTIMATES OF THE EQUITY RETURN OF HIS WATER COMPANY PROXY GROUP?

A. The only reasonably reliable estimate of the equity return of his water company proxy group that Mr. Moul has provided is his "market-determined rate of return" of 9.22 percent. All of the other estimates are so flawed conceptually as to be virtually worthless.

Q. IS MR. MOUL'S 9.22 PERCENT REASONABLE AS A COST OF EQUITY CAPITAL FOR IAWC?

A. No. As I have discussed, this return contains two inappropriate adjustments to the dividend yield. Mr. Moul quantifies the value of his dividend compounding adjustment as 10 basis points (.1 percent).[13] He does not quantify the effect of his presumed ex-dividend stock price decline, so I will conservatively assume it is no more than 2 basis points (.02 percent).

Q. WHAT RETURN TO EQUITY CAPITAL DO YOU RECOMMEND?

A. By reducing Mr. Moul's market determined rate of return for the proxy water companies by 12 basis points, I arrive at a recommended rate of return to equity of **9.1 percent.**

[13] The difference between 3.37% and 3.47% on lines 665 and 676 on page 30 of IAWC Exhibit 7.0. page 30.

Q. IS THERE ANY REASON TO BELIEVE THAT THIS RETURN MIGHT BE TOO LOW OR TOO HIGH WHEN APPLIED TO IAWC?

A. There is reason to believe that this rate of return might be too high. As I discussed earlier in this testimony, AWW, IAWC's parent company and the entity that raises its equity capital, has almost 10 times the average market capitalization of the six companies in Mr. Moul's proxy water company group. As Mr. Moul himself argues, large companies have less business risk than smaller companies, all other things being equal.[14] For this reason, I believe that a good case could be made for a lower rate of return than 9.1 percent when applied to IAWC.

Q. IS THERE ANY WAY TO CHECK THE REASONABLENESS OF YOUR RECOMMENDATION?

A. Yes. In order to test whether my 9.1 percent equity return recommendation is reasonable, it is appropriate to compare the then prevailing bond yields and interest rates with the Commission's allowed returns to IAWC's equity in earlier cases. If it appears that bond yields have increased, but I am recommending a reduced return to equity, then there may be reason to question my recommendation. On the other hand, if my proposed equity return tracks with the changes in bond yields, then there is at least a "sanity check" on the propriety of my finding.

Q. WHAT IS THE RELATIONSHIP BETWEEN EQUITY RETURN ALLOWANCES AND BOND YIELDS IN PAST CASES?

A.. The specific relationship between the equity return findings in the last four ICC rate cases involving IAWC or its predecessors and the then-current yields on 10-year Treasury bonds and Aaa corporate bonds is as follows:

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[14] See IAWC Exhibit 7.0, page 54.

Table 4
IAWC Equity Return Allowances and Contemporaneous Bond Yields

Docket	Utility	Date	ROE Allowed	10-Yr Treas.	Aaa Corporate
94-0183	Lincoln Water	Jan 5, '95	11.9%	7.78%	8.49%
94-0481	Citizens Utilities	Sep13, '95	11.6%	6.20%	7.33%
97-0081	IAWC	Dec 22, '97	10.6%	5.81%	6.74%
00-0340	IAWC	Feb 15, '01	10.2%	5.10%	6.98%
02-0690	**IAWC**	**(Feb, 03)**	**9.1%**	**4.10%**	**6.24%**

Source: ICC Records and Federal Reserve Statistical Releases.

Q. WHAT DO YOU CONCLUDE FROM THIS COMPARISON?

A. I conclude that while my recommended equity return allowance is lower than any that have been approved for IAWC or its predecessor companies since 1995, this result is justified by the evidence of lower overall capital costs as evidenced by Treasury and corporate bond yields. For this reason, I conclude that my recommended equity return of 9.1 percent is reasonable.

C. <u>RETURN TO TOTAL CAPITAL</u>

Q. WHAT IS YOUR RECOMMENDED RETURN TO TOTAL CAPITAL?

A. My recommended return to total capital is **7.14 percent**, calculated as follows:

Table 11
Return to Total Capital

Item	Proportion	Cost	Weighted Cost
Long-term Debt	55.04%	5.537%	3.05%
Equity	44.96%	9.10%	4.09%
Total	100.00%		**7.14%**

PART II

RETIREMENT COSTS

Q. WHAT IS THE OBJECTIVE OF THIS PART OF YOUR TESTIMONY?

A The objective of this part of my testimony is to describe and discuss Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, ("SFAS 143"), which the Company has stated it will adopt. I calculate the effect of applying the SFAS 143 procedures to all of the Company's retirement costs in the Southern/Peoria/Streator/Pontiac Districts. I will also suggest the appropriate treatment of the retirement costs that do not qualify for this standard, once they have been identified.

Q. WHAT ARE THE CONCLUSIONS AND RECOMMENDATIONS OF THIS PART OF YOUR TESTIMONY?

A. I conclude that SFAS 143 will require the Company to change the manner in which it recovers the retirement costs for assets that it is legally obliged to retire. This change will reduce dramatically the annual recovery of the retirement costs of most of these assets. To date, the Company has not determined which assets are covered by this accounting standard. I therefore recommend that in this proceeding the SFAS 143 procedure be applied to the retirement costs of all assets. The effect is to reduce test year depreciation for the Southern/Peoria/Streator/Pontiac Districts by 29 percent.

Once IAWC has determined which assets are subject to SFAS 143, I recommend that the retirement costs of all assets not covered by this standard either be added to the capital cost of the replacement asset or, if the asset is not being replaced, that those costs be expensed on a normalized basis. These changes will eliminate a timing difference in retirement cost recognition that I believe is highly unfair to ratepayers.

Q. WHAT ARE "RETIREMENT COSTS?"

A. Retirement costs refer principally to the costs of removal, dismantlement or conversion to an alternative use. In the case of reservoirs and storage tanks, they cover the cost of removing the facilities and returning the sites to their original condition. In the case of mains and services, they usually involve capping the retired pipe and leaving it in place. In some instances these costs are offset partially, but rarely completely, by the scrap value of the material removed.

Q PLEASE DESCRIBE SFAS 143.

A. O'Fallon Exhibit 1.3 is the Financial Accounting Standards Board's summary of Statement No. 143. The Statement addresses long-lived assets for which there are legal obligations to incur retirement costs. A legal obligation is defined as "an obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel."

When a company finds that it has a legal obligation that fits this description, it must declare the retirement cost as a liability on its balance sheet. That liability is not the ultimate cost of the retirement, but the present value of that cost, using as the discount factor the risk-free interest rate when the liability was recognized.

The annual expense associated with this liability consists of two parts. One is the amortization of the liability, which is the present value of the liability divided by the life of the asset – comparable to depreciation. The second expense is the annual accretion in the present value of the liability.

Q. CAN YOU ILLUSTRATE HOW THIS PROCEDURE WORKS?

A. Assume that IAWC builds a storage tower that it expects to last for 40 years. It is obligated to dismantle that tower when it retires at an estimated cost of $1 million.

IAWC would book a liability for this retirement cost, not at $1 million, but at $1 million discounted at the risk-free interest rate. The risk free interest rate over 40 years is that of a long-term Government bond, currently 5.01 percent.[15] The liability would therefore be booked as $148,595 ($1 mil/1.0501^{40})

Each year, IAWC would show two items of expense. The first would be the amortization of the liability. In the first year after installation that would be $148,595 / 40 years = $3,714. This item would increase each year as the present value of the liability increases. The second expense would be the annual accretion in the liability itself. In this instance, it would be $1 million times 1.0505^{39} - 1.0505^{40}. This is $1 million x (0.15604 - 0.148595 = .007445) or $7,445. As the present value factors increase, that is, as they approach 1.0, this annual amount would also increase. Total expense in the first year of operation would be $3,714 + $7,445 = $11,159.

Q. WILL IAWC ADOPT SFAS 143?

A. Yes. The Company has stated that it will adopt this standard.[16]

Q. HAS THE COMPANY IDENTIFIED THE RETIREMENT COSTS THAT WOULD BE SUBJECT TO THIS STANDARD?

A. No. In response to O'Fallon Data Request no. 2.1, the Company states as follows:

> The Company is currently in the process of evaluating the effect that the adoption of the provisions of SFAS 143 will have on its results of operations and financial position.

Q. HOW DOES THE COMPANY CURRENTLY ACCOUNT FOR RETIREMENT COSTS?

[15] Federalreserve.gov/releases/H15 20 year Treasury bonds, Dec 2002.
[16] IAWC Response to O'Fallon Data Request no. 2.1.

A. Currently, the Company recovers retirement costs through its depreciation charges. It periodically studies recent retirement costs and salvage recovery to derive the average amount of "net salvage" -- salvage value less retirement costs – for each plant account. For most of the Company's accounts the net salvage is negative, that is, the removal costs exceed the value of the salvaged materials. For each plant account, this net salvage amount is compared with the value of the plant that has recently been retired to develop a "net salvage ratio." The numerator of the ratio is the recent net salvage costs and the denominator is the original cost of the plant retired. The net salvage ratio is then applied to the original cost of all of the plant in the account to derive an estimate of the retirement cost that has to be recovered. The sum of the original cost and the retirement cost is the amount that is depreciated over the life of the plant account.

Q. HOW LARGE ARE THESE RETIREMENT COSTS FOR IAWC?

A. They are enormous. For IAWC's largest single plant account, Transmission and Distribution Mains (#331.11), retirement costs amount to 150 percent of the original cost. The test year amount in this account for the Southern/Peoria/Streator/Pontiac Districts is $145.6 million. The retirement cost that is being depreciated is therefore $218.4 million.

The third largest account is Customer Services (#333.0) which is currently assigned a 300 percent negative salvage ratio. This assumes that retirement costs are three times the initial cost of the services. For the Southern/Peoria/Streator/Pontiac Districts, the test year original cost of this account was $43.4 million. Retirement costs depreciated in this account are $130.2 million.

Two other accounts have very high negative salvage ratios: Meter Installations (#334.41) at $11.7 million in original cost has a 150 percent negative salvage ratio, and Hydrants (#355.0) has a 100 percent negative salvage ratio.

Q. HOW DOES THE CURRENT METHOD OF RECOVERING RETIREMENT COSTS DIFFER FROM THE PROCEDURE PRESCRIBED IN SFAS 143?

A. Unlike the SFAS 143 procedure, the current method of recovering retirement costs fails to recognize the discounted present value of costs that will not be incurred until many years into the future. To the contrary, the present method charges ratepayers in present, more valuable dollars for the effect of future inflation in retirement costs that has not yet occurred.

Q. HOW DOES THE PRESENT METHOD CHARGE CURRENT RATEPAYERS FOR FUTURE INFLATION?

A. As discussed earlier, the current method develops a ratio of recent retirement costs to the original cost of the plant retired. For Account No. 333, for example, the Company purports to have found a 300 percent negative salvage ratio. This extraordinary number resulted from comparing the cost of retirements each year with the original cost of the plant retired in that year. In 1998, for example, service retirement costs came to $380,278, and positive salvage was $1,035, for a net negative salvage of $379,243. The original cost of the services retired was $93,954, so the negative salvage ratio for that year was -403.65 percent ($93,954/$379,243).[17] Other years showed similar results, so the Company proposed a –300 percent net salvage ratio for this account.

The Company estimates the average life of the Services account to be 75 years, which means that the installation year of the average service removed in 1998 would have been 1923. The Bureau of Labor Statistics' Consumer Price Index for mid-year (June) 1923 is 17.0 (1983 = 100). The mid-year CPI for 1998 was 163.0. The $93,954 in original cost for services retired in 1998 would have been worth $900,853 expressed in 1998 dollars ($93,954 x (163/17)). Were the net salvage ratio expressed in dollars of comparable value, it would have been –42.10 percent ($379,244/$900,853) rather than –403.65 percent.

[17] AUS Consultants: *Illinois-American Water Company, Depreciation Study as of December 31, 1998*, submitted in Docket 00-0390, page 7-15.

The Company does not apply its –300 percent negative salvage ratio just to retired plant. Instead, it applies it to all plant in the Services account, including that placed just last year. A dollar of plant placed in 2000 generates a removal cost allowance that reflects the difference in the value of the dollar from 1923 to 1998, a multiple of about nine times. Ratepayers now pay for the projection of past inflation 75 years into the future.

Q. IS THIS FAIR TO RATEPAYERS?

A. No. It is unfair to require ratepayers to pay now – in 2003 dollars – for a cost that will not be incurred until 2078 when the dollar will no doubt be worth much less than it is now.

Q. BUT DON'T RATEPAYERS RECEIVE THE BENEFIT OF THE RATE BASE DEDUCTION REPRESENTED BY THE ACCRUAL OF THESE RETIREMENT COST ALLOWANCES?

A. No. An argument might be made that inflated depreciation charges build up the depreciation reserve, which in turn reduces the net investment rate base. The reduced rate base lowers the requirement for return and income taxes. Over time, one might think this reduction should cancel out the increase in revenue requirement represented by the excessive depreciation expenses.

Only it doesn't. That is because the dollar value of the Company's plant is always expanding. The Company is growing, but even if it were not, inflation causes the dollars added each year to exceed the dollars retired. There is always more new plant generating higher depreciation charges than old plant that has accumulated depreciation reserve. Ratepayers never catch up.

Q. DOES THE SFAS 143 TREATMENT RESOLVE THIS UNFAIRNESS?

A. Yes. It does by recognizing the present value of future retirement costs.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO SFAS 143?

A. The Company has stated that it will adopt SFAS 143, but it apparently has not yet determined which retirement costs qualify as legal obligations and therefore are subject to the terms of SFAS 143. When the Company does identify its legal retirement cost obligations, it should not be permitted to maintain the current procedure for recovering retirement costs for which it has no such obligations. If it did, then ratepayers would receive the benefit of present value recognition of retirement costs for which the Company has a legal obligation to incur, but not for retirement costs for which the Company has no such obligation. This would be a truly anomalous result.

Since the Company cannot now identify which retirement costs qualify for SFAS 143 treatment, I recommend that in this proceeding <u>all</u> retirement costs be treated as though they were legal obligations. Later, when the Company has implemented SFAS 143, alternative treatment might be adopted for those retirement costs which do not fall under the purview of SFAS 143. I will suggest the treatment that the Commission might consider for these costs later in my testimony.

Q. HAVE YOU DEVELOPED REMOVAL COST FACTORS THAT CONFORM TO SFAS 143?

A. Yes. O'Fallon Exhibit 1.4 converts the currently effective negative net salvage percentages into factors that reflect the methodology of SFAS 143. Columns A and C present the remaining lives and net salvage ratios that were prescribed in Docket No. 00-0340. Column B presents the factors that reduce the negative salvage ratios to present value from the end of their remaining live using the current 5.01 percent interest rate on a long-term (20-year) Treasury bond. Column D shows the negative salvage percentages corrected for present value.

Column F presents the increment portion of the retirement cost expense, which is the unadjusted negative salvage ratio times the difference between the discount factor in column B and the following year's discount factor.[18] To illustrate, the -.18 percent in column F for Supply Structures and Improvements is the –25 percent in Column B times $1/1.0501^{39}$-$1/1.0501^{40}$. The calculation is 25% x (0.15232 - 0.14505 = 0.00727) = 0.18%.

Q. HAVE YOU APPLIED THESE FACTORS TO THE TEST YEAR PLANT DATA TO DETERMINE THE ACCRUAL RATES THAT CONFORM WITH SFAS 143?

A. Yes. That calculation for the Southern/Peoria/Streator/Pontiac Districts is presented in O'Fallon Exhibit 1.5. Columns A and B show the test year plant balances and depreciation reserves as presented in the Company's filing. Column C shows the net plant. Column D copies the negative salvage ratios from O'Fallon Exhibit 1.4, and Column E presents the retirement cost that must be recovered. The sum of these costs and the net plant is the amount that must be recovered over the remaining life of each plant account. Column G shows the remaining life of each account as approved by the Commission in Docket No. 00-0340. Column H shows the annual depreciation accrual amounts, and Column I the annual depreciation rates, inclusive of salvage allowances.

Column J replicates the retirement cost accretion factors developed on page 1 and Column K adds those values to the depreciation rates. The final column shows the total accrual for both depreciation and retirement cost accretion. I have combined these factors for purposes of presentation, but the Company may wish to show them separately in its income statement. Combined or separate, the results would be the same.

The total accrual for the Southern/Peoria/Streator/Pontiac Districts is $10,287,795. This amount is 29.2 percent, or $4,251,640 less than the depreciation the Company is proposing in this proceeding for these districts.

[18] The discount factors employ a half-year convention, that is, it is assumed that the plant was installed in mid-year.

Q. ON A LONG-TERM BASIS, DO YOU RECOMMEND RETENTION OF SFAS PROCEDURE FOR RETIREMENT COSTS THAT DO NOT QUALIFY AS LEGAL OBLIGATIONS?

A. Certainly, retaining the SFAS 143 procedure for all accounts would be preferable to retaining the present procedure. However, even the SFAS procedure that I have described is rooted in the practice of comparing recent retirement costs with the original cost of the plant being retired, a practice that I believe is fundamentally flawed.

For this reason, I recommend that once the Company has identified the assets that are not subject to SFAS 143, it use two procedures for recovering retirement costs. For any assets that are being replaced, the cost of retirement should be added to the cost of the replacement plant. This procedure would probably apply to most of the Company's transmission and distribution plant. For plant that is not being replaced, the retirement costs should be expensed on a normalized basis. By "normalized," I mean that an average of actual retirement costs over a period of years should be used to identify the retirement cost allowance. These allowances should be separately reported in the income statement and not hidden in the depreciation rates as they are now.

Q ARE THERE ANY REGULATORY PRECEDENTS FOR THE PROCEDURES YOU ARE PROPOSING?

A. Yes. The Federal Energy Regulatory Commission ("FERC") has issued a Notice of Proposed Rulemaking in which it proposes to establish the accounts that would implement SFAS 143. Even for assets not subject to SFAS 143, the FERC proposes that retirement cost allowances be accounted for separately from depreciation.[19]

The practice of incorporating retirement costs into the capital cost of the replacement plant is explicitly recognized in FERC's Uniform System of Accounts ("USOA").

[19] Docket No. RM02-7-000, *Accounting, Financial Reporting And Rate Filing Requirements For Asset Retirement Obligations*, Notice of Proposed Rulemaking, October 30, 2002.

Paragraph 31 of the Electric USOA (Subchapter C) and paragraph 32 of the gas USOA (Subchapter F) contain the following definition:

> *Replacing or replacement*, when not otherwise indicated in the context, means the construction or installation of electric (gas) plant in place of property retired, <u>together with the removal of the property retired.</u> [Emphasis supplied]

Paragraph 10 of both the electric and gas plant instructions covers additions and retirements of plant. It refers to "...additions to and retirements <u>and replacements</u> of electric (gas) plant..." It goes on to provide instructions for the recording of retirement unit additions and retirements. If the definition of replacements provided above applies, then the addition of a replacement unit should include the cost of removing the property retired.

PART III

WHOLESALE RATE PROPOSAL

Q. WHAT IS THE OBJECTIVE OF THIS PORTION OF YOUR TESTIMONY?

A. The objective of this portion of my testimony is to recommend a rate schedule to apply to customers who resell water through their own storage and distribution systems to retail customers for whom they assume all metering, billing and collection functions. I refer to these customers as "wholesale customers."

Q. WHAT IS YOUR CONCLUSION IN THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I will demonstrate that the particular low-cost characteristics of large wholesale customers justify a special tariff schedule. The schedule I recommend would contain applicability provisions to ensure that the proposed wholesale rate applies only to customers that display these low-cost characteristics. The schedule incorporates all of the customer charges in the Metered General Water Service rate schedule. I do not recommend declining block rates. Instead, I recommend a single volumetric rate which is set at a discount of 22.7 percent from the rate shown in the fourth block of the General Service rate schedule.

Q. WOULD YOUR PROPOSED WHOLESALE RATE SCHEDULE APPLY TO ALL CUSTOMERS WITHIN THE "SALES FOR RESALES" CLASS, ALSO REFERRED TO AS "OTHER WATER UTILITIES?"

A. I cannot say because I do not know the characteristics of all of the other customers in this class. I can say that this proposed rate schedule would apply to the City of O'Fallon.

Q. WHAT SPECIFIC CHARACTERISTICS OF O'FALLON WOULD QUALIFY IT FOR THE RATE SCHEDULE THAT YOU ARE PROPOSING?

A. As discussed in the accompanying testimony of Dean Rich, O'Fallon's Director of Finance (O'Fallon Exhibit 2.0), the City of O'Fallon receives its water from IAWC through a 30 inch main, backed up by a 24 inch main that directly connects to IAWC's treatment facility. O'Fallon then distributes the water through its own system of mains and customer services to the residents of O'Fallon, its retail customers. O'Fallon also has about three million gallons of storage on its own system, sufficient to meet any sudden "surge" in water demand. O'Fallon meters, bills, and collects from its own customers, which means that it takes full responsibility for uncollectible accounts.

Q. WHAT ARE THE COST CHARACTERISTICS OF THE WHOLESALE CUSTOMER CLASS?

A. Wholesale customers use only the very largest mains on the IAWC system, in O'Fallon's case, mains over 24 inches in diameter. Wholesale customers use none of IAWC's smaller mains, none of its services, and in O'Fallon's case, only four meters. Wholesale customers require only one bill per month, but they perform all metering, meter-reading, billing and collection functions for their own customers. They assume all risk of uncollectible accounts. From IAWC's standpoint, wholesale customers incur negligible metering and billing costs, no uncollectible expenses, no billing inquiries, and no customer service. Moreover, since some wholesale customers, such as O'Fallon, maintain storage equivalent to at least a half a day's average consumption, IAWC incurs no added costs associated with intra-day peak hour water demands.

Q. HAVE YOU ATTEMPTED TO MEASURE THE EFFECT OF THESE COST CHARACTERISTICS ON IAWC?

A. Yes. O'Fallon Exhibit 1.6 presents a cost of service study that measures the cost effect of wholesale service relative to other, retail customer classes. I have used the cost of service model from IAWC's last rate case, Docket 00-0340, that was provided to me by the Commission Staff. I then input the test year data for the Southern Division that IAWC provided to the Staff in this docket. This permitted me to replicate a Staff cost of service study applicable to the Southern Division in which O'Fallon is located. The first 16 pages of Exhibit 1.6 match, in format, those of the Staff's cost of service studies in Docket No. 00-0340 and presumably in this case, unless the Staff changes that format.

The final three pages of Exhibit 1.6 present the reallocation of costs between the wholesale class, referred to in the study as "sales for resale" or "other water utilities," and the remaining, retail classes. The following costs were reallocated:

- Transmission and distribution costs exclusive of mains and valves 18" or greater,
- All customer accounts expenses,
- All peak hour costs,
- Overheads for General and Administrative expense on the reallocated direct expenses, and
- Overheads for General Plant on the reallocated direct net plant.

Q. **WHAT WAS THE RESULT OF YOUR ANALYSIS?**

A. I set the overall revenue requirement equal to the revenue that the Company seeks to recover in this case. I did this for display purposes, not because I endorse this revenue requirement. Using this format, the composite revenue from all classes at the Company's proposed rates exactly matches the revenue requirement. Classes whose revenue under proposed rates recovers more than 100 percent of allocated costs can be described as being overcharged; classes with revenue recovery less than 100 percent are being undercharged. The results are found in the bottom line on page 2 of the exhibit, as follows:

- Residential 113%
- Commercial 100%
- Industrial 67%
- Large Industrial 57%
- Public Authority 84%
- Fire Protection 65%
- **Sales for Resale 131%**

Q. HAVE YOU CALCULATED THE RATES THAT WOULD CAUSE THE REVENUE FROM THE WHOLESALE CLASS TO MATCH ITS REVENUE REQUIREMENT?

A. Yes. This calculation is presented on O'Fallon Exhibit 1.7. My proposed wholesale rate schedule retains the Company's customer charges for the Southern Division. For wholesale customers, these charges represent a small portion of the total bill relative to the volumetric charges.

I have eliminated the declining block structure of the conventional rate schedule on the grounds that the wholesale customers qualifying for this rate incur none of the higher costs of small volume delivery. I have used the revenue requirement developed in O'Fallon Exhibit 1.6, less the customer charge revenue, to calculate a single volumetric rate per 100 cubic feet. That rate is 22.7 percent lower than the proposed fourth block rate of the conventional general service rate schedule applicable to the Southern Division.

The volumetric rate I calculate is $1.0826 per 100 cubic feet. I do not recommend this rate, because it reflects the Company's proposed revenue requirement which is substantially overstated by reason of an inflated rate of return and excessive depreciation charges, as discussed earlier in this testimony. Whatever the appropriate rate for the fourth block in the general service rate schedule, it should be reduced by 22.7 percent for large wholesale customers.

Q. HAVE YOU DEVELOPED A LARGE WHOLESALE TARIFF SCHEDULE?

A. Yes. O'Fallon Exhibit 1.8 is my recommended "Large Wholesale Water Service" rate schedule. The schedule applies to water utilities that sell IAWC's water to their own retail customers. I have not established a minimum volume for qualification, but rather a minimum size of connecting main, 18 inches. This will ensure that customers on this schedule do not use the Company's smaller transmission and distribution mains. I have also established a requirement that qualifying customers must have storage equivalent to one half day's average consumption. This protects IAWC from having to respond to severe peak hour demands from these customers.

I retain the customer charges from the Metered General Water Service rate schedule, and I apply only one volumetric charge, expressed as both per-100 cubic feet and per- 1000 gallons, using the Company's 1.333 equivalency factor.

Again, I emphasize that I am not recommending the numerical value of these rates, but rather their form and their relationship to the general service rates. Whatever the final determination of rate levels, the Wholesale Service volumetric rate should be discounted by 22.7 percent from the fourth block rate in the Metered General Water Service rate schedule

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. It does.

Charles W. King
City of O'Fallon

Summary of Statement No. 143
Financial Accounting Standards Board

Summary of Statement No. 143

Accounting for Asset Retirement Obligations (Issued 6/01)

Summary

This Statement addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. This Statement applies to all entities. It applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and (or) the normal operation of a long-lived asset, except for certain obligations of lessees. As used in this Statement, a legal obligation is an obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel. This Statement amends FASB Statement No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies.*

Reasons for Issuing This Statement

The Board decided to address the accounting and reporting for asset retirement obligations because:

- Users of financial statements indicated that the diverse accounting practices that have developed for obligations associated with the retirement of tangible long-lived assets make it difficult to compare the financial position and results of operations of companies that have similar obligations but account for them differently.

- Obligations that meet the definition of a liability were not being recognized when those liabilities were incurred or the recognized liability was not consistently measured or presented.

Differences between This Statement, Statement 19, and Existing Practice

This Statement requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. This Statement differs from Statement 19 and current practice in several significant respects.

- Under Statement 19 and most current practice, an amount for an asset retirement obligation was recognized using a cost-accumulation measurement approach. Under this Statement, the amount initially recognized is measured at fair value.

- Under Statement 19 and most current practice, amounts for retirement obligations were not discounted and therefore no accretion expense was recorded in subsequent periods. Under this Statement, the liability is discounted and accretion expense is recognized using the credit-adjusted risk-free interest rate in effect when the liability was initially recognized.

- Under Statement 19, dismantlement and restoration costs were taken into account in determining amortization and depreciation rates. Consequently, many entities recognized asset retirement obligations as a contra-asset. Under this Statement, those obligations are recognized as a liability. Also, under Statement 19 the obligation was recognized over the useful life of the related asset. Under this Statement, the obligation is recognized when the liability is incurred.

Some current practice views a retirement obligation as a contingent liability and applies FASB Statement No. 5, *Accounting for Contingencies,* in determining when to recognize a liability. The measurement objective in this Statement is fair value, which is not compatible with a Statement 5 approach. A fair value measurement accommodates uncertainty in the amount and timing of settlement of the liability, whereas under Statement 5 the recognition decision is based on the level of uncertainty.

This Statement contains disclosure requirements that provide descriptions of asset retirement obligations and reconciliations of changes in the components of those obligations.

How the Changes in This Statement Improve Financial Reporting

Because all asset retirement obligations that fall within the scope of this Statement and their related asset retirement cost will be accounted for consistently, financial statements of different entities will be more comparable. Also,

- Retirement obligations will be recognized when they are incurred and displayed as liabilities. Thus, more information about future cash outflows, leverage, and liquidity will be provided. Also, an initial measurement at fair value will provide relevant information about the liability.

- Because the asset retirement cost is capitalized as part of the asset's carrying amount and subsequently allocated to expense over the asset's useful life, information about the gross investment in long-lived assets will be provided.

- Disclosure requirements contained in this Statement will provide more information about asset retirement obligations.

How the Statement Generally Changes Financial Statements

Because of diverse practice in current accounting for asset retirement obligations, various industries and entities will be affected differently. This Statement will likely have the following effects on current accounting practice:

- Total liabilities generally will increase because more retirement obligations will be recognized. For some entities, obligations will be recognized earlier, and they will be displayed as liabilities rather than as contra-assets. In certain cases, the amount of a recognized liability may be lower than that recognized in current practice because a fair value measurement entails discounting.

- The recognized cost of assets will increase because asset retirement costs will be added to the carrying amount of the long-lived asset. Assets also will increase because assets acquired with an existing retirement obligation will be displayed on a gross rather than on a net basis.

- The amount of expense (accretion expense plus depreciation expense) will be higher in the later years of an asset's life than in earlier years.

How the Conclusions in the Statement Relate to the Conceptual Framework

The Board concluded that all retirement obligations within the scope of this Statement that meet the definition of a liability in FASB Concepts Statement No. 6, *Elements of Financial Statements*, should be recognized as a liability when the recognition criteria in FASB Concepts Statement No. 5, *Recognition and Measurement in Financial Statements of Business Enterprises*, are met.

The Board also decided that the liability for an asset retirement obligation should be initially recognized at its estimated fair value as discussed in FASB Concepts Statement No. 7, *Using Cash Flow Information and Present Value in Accounting Measurements.*

Effective Date

This Statement is effective for financial statements issued for fiscal years beginning after June 15, 2002. Earlier application is encouraged.

Charles W. King
City of O'Fallon

Docket No. 02-0690
Exhibit 1.4

Illinois-American Water Company
Retirement Cost Allowances

Account No.	Account Title	A Remaining Life	B Discount @2.2%	C Negative Salvage	D Discounted Negative Salvage	E Increment in Present Value
Source of Supply						
304.00	Structures & Improvements	40	0.14505	-25%	-3.63%	-0.18%
305.00	Collecting & Impounding Reservoirs	36	0.176377	-10%	-1.76%	-0.09%
307.00	Lake, River and Other Intakes	44	0.119288	-15%	-1.79%	-0.09%
307.00	Wells & Springs	45	0.113597	-30%	-3.41%	-0.17%
309.00	Supply Mains	54	0.073163	-15%	-1.10%	-0.05%
Pumping Plant						
304.00	Structures & Improvements	23	0.332997	-25%	-8.32%	-0.42%
310.00	Power Generation Equipment	30	0.236497	-25%	-5.91%	-0.30%
311.20	Electric Pumping Equipment	30	0.236497	-20%	-4.73%	-0.24%
311.30	Diesel Pumping Equipment	26	0.287573	-10%	-2.88%	-0.14%
311.50	Other Pumping Equipment	10	0.628693	-10%	-6.29%	-0.31%
Water Treatment Plant						
304.00	Structures & Improvements	37	0.167962	-10%	-1.68%	-0.08%
320.10	Water Treatment Equipment	16	0.468872	-30%	-14.07%	-0.70%
320.00	Chemical Equipment	11	0.598698	-10%	-5.99%	-0.30%
Transmission & Distribution Plant						
330.00	Reservoirs & Standpipes	34	0.194492	-15%	-2.92%	-0.15%
331.00	Mains	80	0.020525	-70%	-1.44%	-0.07%
333.00	Services	58	0.060168	-300%	-18.05%	-0.90%
334.21	Installation	59	0.057298	-150%	-8.59%	-0.43%
334.23	Vaults	84	0.01688	-150%	-2.53%	-0.13%
335.00	Hydrants	41	0.13813	-100%	-13.81%	-0.69%
General Plant						
304.70	Stores, Shops & Garage Structures	23	0.332997	-15%	-4.99%	-0.25%
304.80	Miscellaneous Structures	33	0.204236	-10%	-2.04%	-0.10%

Illinois American Water Company
Southern/Peoria/Streator/Pontiac
Test Year Depreciation

Account No.	Account Title	A Plant in Service	B Depreciation Reserve	C Net Plant	D Salvage Ratio	E Retirement Cost (Salvage)	F Total To Be Recovered	G Remaining Life	H Annual Accrual	I Depreciation Rate	J Retirement Cost Accretion	K Total Accrual Rate	L Total Accrual
	Source	Schedule B-4	Schedule B-6	Col A - Col B	p.1, col. D	Col A*Col D	Col C + Col E	O'Fallon D.R.# 1.52	Col F/Col G	Col H/Col A	p.1, col.F	Col I + ColJ	Col K * Col A
Intangible Plant													
301.00	Organization	78,840		78,840			78,840						
302.00	Franchises	769		769			769						
339.60	Other P/E Comp Planing	148,400	811,478	(663,078)			(663,078)						
Source of Supply													
303.20	Land and Land Rights	818,294		818,294			818,294						
304.10	Structures & Improvements	7,155,969	912,611	6,243,358	-3.63%	259,494	6,502,852	39.6	164,213	2.29%	0.18%	2.48%	177,214
305.00	Collecting & Impounding Reservoirs	1,714,723	393,950	1,320,773	-1.76%	30,244	1,351,017	36.1	37,424	2.18%	0.09%	2.27%	38,939
306.00	Lake, River and Other Intakes	2,694,587	758,906	1,935,681	-1.79%	48,215	1,983,896	43.9	45,191	1.68%	0.09%	1.77%	47,607
307.00	Wells & Springs	412,664	107,516	305,148	-3.41%	14,063	319,211	44.6	7,157	1.73%	0.17%	1.91%	7,862
309.00	Supply Mains	4,654,108	1,637,931	3,016,177	-1.10%	51,076	3,067,253	54.3	56,487	1.21%	0.05%	1.27%	59,046
Pumping Plant													
303.30	Land and Land Rights	647,472	(5,520)	652,992		-	652,992						
304.20	Structures & Improvements	10,526,306	2,619,534	7,906,772	-8.32%	876,306	8,783,078	22.6	388,632	3.69%	0.42%	4.11%	432,535
310.10	Power Generation Equipment	2,229,176	639,060	1,590,116	-5.91%	131,798	1,721,914	30.4	56,642	2.54%	0.30%	2.84%	63,245
311.20	Electric Pumping Equipment	24,896,053	6,733,268	18,162,785	-4.73%	1,177,567	19,340,352	29.6	653,390	2.62%	0.24%	2.86%	712,386
311.30	Diesel Pumping Equipment	950,807	460,763	490,044	-2.88%	27,343	517,387	25.7	20,132	2.12%	0.14%	2.26%	21,502
311.50	Other Pumping Equipment	53,342	16,329	37,013	-6.29%	3,354	40,367	10.4	3,881	7.28%	0.31%	7.59%	4,049
Water Treatment Plant													
303.40	Land and Land Rights	1,371,706	(21,885)	1,393,591		-	1,393,591						
304.30	Structures & Improvements	40,610,892	7,460,513	33,150,379	-1.68%	682,108	33,832,487	37.4	904,612	2.23%	0.08%	2.31%	938,786
320.10	Water Treatment Equipment	49,674,618	16,926,309	32,748,309	-14.07%	6,987,315	39,735,624	15.9	2,499,096	5.03%	0.70%	5.74%	2,849,160
Transmission & Distribution Plant													
303.50	Land and Land Rights	1,598,982		1,598,982		-	1,598,982						-
304.40	Structures and Improvements	102,997	5,548	97,449	0.00%	-	97,449	25.0	3,898	3.78%		3.78%	3,898
330.00	Reservoirs & Standpipes	6,910,576	2,497,372	4,413,204	-2.92%	201,608	4,614,812	33.6	137,346	1.99%	0.15%	2.13%	147,446
331.00	Mains	145,883,650	37,637,394	108,246,256	-1.44%	2,096,028	110,342,284	79.57	1,386,732	0.95%	0.07%	1.02%	1,491,743
333.00	Services	43,346,924	18,407,934	24,938,990	-18.05%	7,824,316	32,763,306	58.0	564,885	1.30%	0.90%	2.21%	956,883
334.11	Meters - Bronze Case	9,881,300	2,268,338	7,612,962	5.00%	(494,065)	7,118,897	6.9	1,031,724	10.44%		10.44%	1,031,724
334.12	Meters - Plastic Case	286,114	331,106	(44,992)	1.00%	(2,861)	(47,853)	6.9		0.00%		0.00%	-
334.20	Meter Installation	14,935,354	7,879,219	7,056,135	-8.59%	1,283,639	8,339,774	58.6	142,317	0.95%	0.43%	1.38%	206,627
335.00	Hydrants	14,174,511	6,476,314	7,698,197	-13.81%	1,957,925	9,656,122	41.1	234,942	1.66%	0.69%	2.35%	333,034

Account No.	Account Title	A Plant in Service	B Depreciation Reserve	C Net Plant	D Salvage Ratio	E Retirement Cost (Salvage)	F Total To Be Recovered	G Remaining Life	H Annual Accrual	I Depreciation Rate	J Retirement Cost Accretion	K Total Accrual Rate	L Total Accrual
General Plant													
303.60	Land and Land Rights	469,365		469,365		-	469,365			0.00%		0.00%	-
304.50	Structures and Improvements	370,862	104,367	266,495		-	266,495	25.0	10,660	2.87%		2.87%	10,660
304.60	Office Structures	3,377,201	1,467,488	1,909,713	5.00%	(168,860)	1,740,853	23.8	73,145	2.17%		2.17%	73,145
304.70	Stores, Shops & Garage Structures	2,925,710	1,663,544	1,262,166	-4.99%	146,138	1,408,304	22.5	62,591	2.14%	0.25%	2.39%	69,913
304.80	Miscellaneous Structures	302,794	154,215	148,579	-2.04%	6,184	154,763	32.6	4,747	1.57%	0.10%	1.67%	5,057
340.10	Office Furniture	763,334	419,685	343,649		-	343,649	16.1	21,345	2.80%		2.80%	21,345
340.20	Computers and Peripherals	719,637	2,320,066	(1,600,429)	5.00%	(35,982)	(1,636,411)	4.8		0.00%		0.00%	-
340.30	Computer Software	11,258	1,223,088	(1,211,830)		-	(1,211,830)	4.8		0.00%		0.00%	-
340.30	Personal Computer Software	116,035	227,182	(111,147)		-	(111,147)	2.6		0.00%		0.00%	-
340.50	Other Office Equipment	94,543	68,645	25,898		-	25,898	5.8	4,465	4.72%		4.72%	4,465
341.10	Light Duty Trucks	3,624,693	1,639,380	1,985,313	30.00%	(1,087,408)	897,905	2.7	332,557	9.17%		9.17%	332,557
341.20	Heavy Duty Trucks	509,703	362,090	147,613	25.00%	(127,426)	20,187	4.2	4,806	0.94%		0.94%	4,806
341.30	Automobiles	190,856	815,422	(624,566)	25.00%	(47,714)	(672,280)	2.2		0.00%		0.00%	-
341.40	Transportation Eqpt. Other	35,542	(91,617)	127,159		-	127,159	21.2	5,998	16.88%		16.88%	5,998
342.00	Stores Equipment	126,820	66,438	60,382		-	60,382	13.7	4,407	3.48%		3.48%	4,407
343.00	Tools/Shop/Garage Equipment	2,725,613	1,595,761	1,129,852	2.00%	(54,512)	1,075,340	17.8	60,412	2.22%		2.22%	60,412
344.00	Laboratory Equipment	1,091,681	271,419	820,262		-	820,262	16.1	50,948	4.67%		4.67%	50,948
345.00	Power Operating Equipment	1,872,432	581,036	1,291,396	35.00%	(655,351)	636,045	6.1	104,270	5.57%		5.57%	104,270
346.00	Communications Eqpt Conversion	946,035	1,017,162	(71,127)		-	(71,127)	7.2		0.00%		0.00%	-
346.10	Communications Eqpt Non-telephone	29,139	2,477	26,662		-	26,662	7.2	3,703	12.71%		12.71%	3,703
346.20	Communications Eqpt Telephone	13,663	1,509	12,154		-	12,154	7.2	1,688	12.35%		12.35%	1,688
347.00	Miscellaneous Equipment	582,889	307,058	275,831		-	275,831	25.7	10,733	1.84%		1.84%	10,733
													-
	Total	406,658,939	129,170,403	277,488,536					9,095,179	2.24%			10,287,795
	IAWC's Proposed Depreciation												14,539,435
	Difference												4,251,640

Southern Division
Docket No 02-0690
O'Fallon Exhibit 1.6

Cost of Service Study
"Revenues at Present and Proposed Rates"

ITEM	PRESENT RATES	PROPOSED RATES	STAFF RATES	RESIDENTIAL BILL ANA.	RESIDENTIAL ADJUST.	COMMERCIAL BILL ANA.	COMMERCIAL ADJUST.	INDUSTRIAL BILL ANA.	INDUSTRIAL ADJUST.	CLASS 4 BILL ANA.	CLASS 4 ADJUST.	LARGE IND. BILL ANA.	LARGE IND. ADJUST.	CLASS 6 BILL ANA.	CLASS 6 ADJUST.	PUB. AUTH. BILL ANA.	PUB. AUTH. ADJUST.	SALES FOR RES. BILL ANA.	SALES FOR RES. ADJUST.	TOTAL
CUS CHARGES, MONTHLY																				
5/8" disk	11.52	14.15		902,540	0	81,459	0	823	0	0	0	0	0	0	0	3,408	0	0	0	988,230
3/4" disk	14.65	17.99		8,713	0	2,986	0	92	0	0	0	0	0	0	0	165	0	0	0	11,956
1" disk	21.38	26.26		2,947	0	9,083	0	544	0	0	0	0	0	0	0	1,155	0	0	0	13,729
1 1/2" disk	47.46	58.29		92	0	1,814	0	84	0	0	0	0	0	0	0	341	0	0	0	2,331
2" disk	73.53	90.31		178	0	7,206	0	1,318	0	0	0	24	0	0	0	2,572	0	120	0	11,416
3" disk	141.33	173.58		0	0	63	0	47	0	0	0	0	0	0	0	42	0	0	0	152
4" disk	235.20	288.87		0	0	343	0	402	0	0	0	72	0	0	0	74	0	216	0	1,107
6" disk	464.66	570.70		0	0	24	0	75	0	0	0	36	0	0	0	60	0	144	0	339
8" disk	741.05	910.16		0	0	0	0	0	0	0	0	0	0	0	0	0	0	24	0	24
10" disk	0.00	0.00		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12" disk	0.00	0.00		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3" turbine	0.00	0.00		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4" turbine	0.00	0.00		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6" turbine	0.00	0.00		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8" turbine	0.00	0.00		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10" turbine	0.00	0.00		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Remove Parallel Meters	0.00	0.00		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Bills				914,470	0	102,978	0	3,383	0	0	0	132	0	0	0	7,817	0	504	0	1,029,284
TOTAL CUS CHARGE REVENUES Present				10,605,368	0	1,693,026	0	259,254	0	0	0	35,427	0	0	0	322,895	0	144,323	0	13,260,292
Proposed				13,026,514	0	2,325,109	0	318,417	0	0	0	43,511	0	0	0	396,585	0	177,258	0	16,287,394
Staff				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
USAGE CHARGES (100 cubic feet)				(100 cubic feet)		(100 cubic feet)		(100 cubic feet)		(100 cubic feet)		(100 cubic feet)		(100 cubic feet)		(100 cubic feet)		(100 cubic feet)		(100 cubic feet)
First Block	2.1870	2.6860		5,598,081		1,007,168		36,857								111,482		4,680		6,758,268
Second Block	1.5880	1.9504		197,909		1,292,231		255,651								414,278		88,920		2,248,989
Third Block	1.1870	1.4579		0		557,270		1,085,915								417,043		1,685,813		3,746,041
Fourth Block	1.1410	1.4014		0		0		703,851								0		3,505,066		4,208,917
Third Block-Peoria																				0
Fourth Block-Peoria																				0
Competitive.rate																				0
Large user rate	0.9572	1.1734										1,754,342								1,754,342
Inside Shiloh																				0
Outside Shiloh																				0
OWU Competitive rate																				0
Block																				0
ADJUSTMENTS																				
First Block	2.1870	2.6860	0.0000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Second Block	1.5880	1.9504	0.0000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Third Block	1.1870	1.4579	0.0000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fourth Block	1.1410	1.4014	0.0000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Third Block-Peoria	0.0000	0.0000	0.0000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fourth Block-Peoria	0.0000	0.0000	0.0000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Competitive.rate	0.0000	0.0000	0.0000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Large user rate	0.9572	1.1734	0.0000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Inside Shiloh	0.0000	0.0000	0.0000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Outside Shiloh	0.0000	0.0000	0.0000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OWU Competitive rate	0.0000	0.0000	0.0000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Block	0.0000	0.0000	0.0000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Usage				5,795,990	0	2,856,669	0	2,082,274	0	0	0	1,754,342	0	0	0	942,803	0	5,284,479	0	18,716,557

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Cost of Service Study
"Revenues at Present and Proposed Rates"

ITEM		RESIDENTIAL BILL ANA.	RESIDENTIAL ADJUST.	COMMERCIAL BILL ANA.	COMMERCIAL ADJUST.	INDUSTRIAL BILL ANA.	INDUSTRIAL ADJUST.	CLASS 4 BILL ANA.	CLASS 4 ADJUST.	LARGE IND. BILL ANA.	LARGE IND. ADJUST.	CLASS 6 BILL ANA.	CLASS 6 ADJUST.	PUB. AUTH. BILL ANA.	PUB. AUTH. ADJUST.	SALES FOR RES. BILL ANA.	SALES FOR RES. ADJUST.	TOTAL
USAGE CHARGE REVENUES	Present	12,557,283	0	4,916,219	0	2,578,655	0	0	0	1,679,256	0	0	0	1,396,715	0	6,151,780	0	29,279,908
	Proposed	15,422,447	0	6,038,065	0	3,167,152	0	0	0	2,058,545	0	0	0	1,715,455	0	7,555,746	0	35,957,410
	Staff																	
OTHER ADJUSTMENTS Reconciliation	Present																	
	Proposed																	
	Staff																	
TOTAL METERED REVENUES	Present	23,162,650	0	6,809,245	0	2,837,909	0	0	0	1,714,683	0	0	0	1,719,609	0	6,296,103	0	42,540,200
	Proposed	28,448,961	0	8,363,174	0	3,485,569	0	0	0	2,102,056	0	0	0	2,112,040	0	7,733,004	0	52,244,804
	Staff																	

PVT. FIRE PROT RATES, MONTHLY	Less than 2"	3"	4"	6"	8"	10"	12"	16"		PRIVATE HYDRANTS
Size Connection										
Present	5.00	6.00	8.00	14.00	25.00	41.00	64.00	130.00	14.00	0.00
Proposed	6.14	7.37	9.83	17.19	30.71	50.36	78.60	159.67	17.16	0.00
Per Cost of Service Study	5.00	9.00	16.00	42.00	86.00	153.00	246.00	521.00		N/A
Staff										0.00
Units (ANNUAL)	204	12	852	3,395	1,584	132	144	12	24	0

NON-METERED REVENUES	PVT. FIRE	PUBLIC FIRE MUNICIPAL	PUBLIC FIRE SURCHARGE	PUBLIC FIRE TOTAL	OTHER OPERATING	VARIABLE REVENUES	TOTAL NON-METERED
Present	111,226			1,796,589	402,998	0	2,310,813
Proposed	136,603			2,176,306	402,998	0	2,715,907
Staff	0			0	402,998	0	402,998

TOTAL REVENUES	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	CLASS 4	LARGE IND	CLASS 6	PUB AUTH	SALES FOR RESALE	NON-METERED	TOTAL
Present	23,162,650	6,809,245	2,837,909	0	1,714,683	0	1,719,609	6,296,103	2,310,813	44,851,013
Proposed	28,448,961	8,363,174	3,485,569	0	2,102,056	0	2,112,040	7,733,004	2,715,907	54,960,711
Cost of Service -Proposed Rates	25,168,355	8,322,417	5,166,760		3,686,027		2,520,454	5,898,137	4,198,559	54,960,710
Percent Cost of Service - Proposed	113%	100%	67%		57%		84%	131%	65%	100%

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Cost of Service Study
"Demand Factors"

DEMAND FACTORS

Customer Class	Max Day	Max Hour
Residential	2.10	3.00
Commercial	1.75	2.10
Industrial	1.65	2.00
Class 4	0.00	0.00
Large Ind.	1.33	1.48
Class 6	0.00	0.00
Public Authority	1.75	2.10
Resale	1.65	1.65
Fire Protection	1.98	15.84
Gallons Per Minute	11,000	
Hours of Protection	3	

MGD PUMPAGE

Average Daily Rate	54.104
Max. Daily Rate	69.581
Max. Hourly Pumpage Rate	82.259
Max. Hourly Consumption Rate	82.258

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Cost of Service Study
"Allocation to Cost Functions"

Description	Alloc. Code	Base Cost Percent	Extra Capacity Max Day Percent	Extra Capacity Max Hour Percent	Customer Costs Billing Percent	Customer Costs Meter Percent	Customer Costs Services Percent	Fire Service Percent
Base Cost	1	100.00%						
Base-Max Day	2	77.76%	22.24%					
Base-Max Hr.	3	65.77%		34.23%				
Max Hour	4			100.00%				
Commercial	5				100.00%			
Meters	6					100.00%		
Services	7						100.00%	
Hydrants	8							100.00%
Plant	9	59.12%	16.90%	9.06%	0.00%	5.28%	7.43%	2.21%
Adm. and Gen	10	43.37%	12.41%	26.73%	12.65%	1.69%	1.90%	1.25%
Labor B'fits	11	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Base/Max Day/ Max Hour	12	65.77%	18.82%	15.41%				

Refer to last page for brief allocation code explanations

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Cost of Service Study
"Plant in Service Allocation"

Act. No.	Account		Utility Cost	Depreciation Reserve	Net Cost	Base Cost	Extra Capacity Max Day	Extra Capacity Max Hour	Customer Costs Billing	Customer Costs Meter	Customer Costs Services	Fire Service	Alloc. Code
	INTANGIBLE PLANT	1,613,163											
301	Organization		56,313	0	56,313	56,313							1
302	Franchises		769	0	769	769							1
339	Miscellaneous		1,556,081	514,400	1,041,681	1,041,681							1
	SOURCE OF SUPPLY PLANT	10,993,618	0										
303	Land and land rights		11,807	0	11,807	9,200	2,607	0	0	0	0	0	13
304	Structures and improvements		5,262,299	492,843	4,769,456	3,716,171	1,053,285	0	0	0	0	0	13
305	Collecting reservoirs		39,034	12,193	26,841	26,841							1
306	Intakes		2,061,407	545,295	1,516,112	1,178,881	337,231						2
307	Wells		0	0	0	0	0						2
308	Infiltration Galleries		0	0	0	0	0						2
309	Supply mains		3,619,071	1,411,504	2,207,567	1,716,535	491,032						2
339	Other plant		0	0	0	0	0						2
	PUMPING PLANT	29,537,350	0										
303	Land and land rights		296,691	(5,520)	302,211	198,775	56,862	46,575	0	0	0	0	13
304	Structures and improvements		9,058,202	1,882,631	7,175,571	4,719,627	1,350,097	1,105,846	0	0	0	0	13
310	Power Generation Equip.		1,352,651	622,676	729,975	480,130	137,346	112,498					12
310	Other power production		0	0	0	0	0	0					12
311	Other Pumping		48,128	(276)	48,404	31,837	9,107	7,460					12
311	Electrical Pumping		18,022,897	4,261,460	13,761,437	9,051,385	2,589,241	2,120,812					12
311	Diesel Pumping		758,781	396,490	362,291	238,292	68,166	55,834					12
339	OtherPlant & Misc. Equip.		0	0	0	0	0	0					12
	WATER TREATMENT PLANT	62,705,017	0										
303	Land and land rights		1,335,743	(21,885)	1,357,628	1,055,649	301,979	0	0	0	0	0	13
304	Structures and improvements		27,684,434	4,289,324	23,395,110	18,191,303	5,203,807	0	0	0	0	0	13
320	Water treatment		33,684,840	10,181,896	23,502,944	18,275,151	5,227,793						2
339	OtherPlant & Misc. Equip.		0	0	0	0	0						2
	TRANSMISSION/DISTRIBUTION	141,315,623	0										
303	Land and land rights		1,075,180	0	1,075,180	497,443	142,298	139,906	0	104,593	147,076	43,864	13
304	Structures and improvements		0	0	0	0	0	0	0	0	0	0	13
330	Dist. reservoirs and standpipes		3,230,345	1,211,494	2,018,851			2,018,851					4
331	Mains		89,216,819	23,829,617	65,387,202	43,007,479	12,302,727	10,076,996					12
333	Services		24,806,017	12,090,213	12,715,804						12,715,804		7
334	Meters		5,263,830	1,334,874	3,928,956					3,928,956			6
334	Meter installations		10,394,444	5,280,591	5,113,853					5,113,853			6
335	Hydrants		7,328,988	3,536,619	3,792,369							3,792,369	8
336	Backflow Prevention Devices		0	0	0						0		7
339	OtherPlant & Misc. Equip.		0	0	0	0	0	0	0	0	0	0	13

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ILLINOIS COMMERCE COMMISSION
Cost of Service Study
"Plant in Service Allocation"

Act. No.	Account		Utility Cost	Depreciation Reserve	Net Cost	Base Cost	Extra Capacity Max Day	Extra Capacity Max Hour	Customer Costs Billing	Customer Costs Meter	Customer Costs Services	Fire Service	Alloc. Code
	GENERAL PLANT	16,931,688											
303	Land and land rights		361,645	0	361,645	213,803	61,124	32,750	0	19,100	26,858	8,010	9
304	Structures and improvements		5,267,972	2,177,296	3,090,676	1,827,192	522,375	279,888	0	163,232	229,533	68,456	9
340	Office furniture		4,021,604	2,528,029	1,493,575	882,994	252,439	135,257	0	78,882	110,922	33,082	9
341	Transportation		2,518,188	1,523,151	995,037	588,261	168,178	90,110	0	52,552	73,898	22,039	9
342	Stores		112,683	60,520	52,163	30,838	8,816	4,724	0	2,755	3,874	1,155	9
343	Tools etc		1,782,458	985,298	797,160	471,277	134,733	72,190	0	42,101	59,202	17,656	9
344	Laboratory		670,925	202,694	468,231	276,816	79,139	42,403	0	24,729	34,774	10,371	9
345	Power operated		1,074,187	400,563	673,624	398,243	113,854	61,003	0	35,577	50,028	14,920	9
346	Communications		620,098	586,174	33,924	20,056	5,734	3,072	0	1,792	2,519	751	9
347	Miscellaneous		501,928	245,916	256,012	151,353	43,270	23,184	0	13,521	19,013	5,670	9
348	FAS 109-AFUDC Debt		474,753	0	474,753	280,672	80,241	42,993	0	25,074	35,258	10,515	9
399	RECONCILIATION		0	0	0	0	0	0	0	0	0	0	9
	TOTAL PLANT IN SERVICE		263,571,212	80,576,080	182,995,132	108,634,964	30,743,482	16,472,351	0	9,606,717	13,508,759	4,028,860	
	Allocation Code 9		Cross check =		182,995,132	59.12%	16.90%	9.06%	0.00%	5.28%	7.43%	2.21%	
	Calculation												
	General Plant		17,406,441	8,709,641	8,696,800	5,141,504	1,469,902	787,573	-	459,315	645,879	192,627	
	Ratio General/Direct Plant		7.07%	12.12%	4.99%	4.97%	5.02%	5.02%	0.00%	5.02%	5.02%	5.02%	

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Cost of Service Study
"Revenue Requirement Allocation"

Act. No.	Account		Utility Cost	Staff Adjust.	Net Cost	Base Cost	Extra Capacity Max Day	Extra Capacity Max Hour	Customer Costs Billing	Customer Costs Meter	Customer Costs Services	Fire Service	Alloc. Code
	SOURCE OF SUPPLY	3,667,950											2
601	Salaries and Wages		2,223,111	0	2,223,111	1,728,621	494,490						1
610	Purchased water		0	0	0	0							1
615	Purchased Power		1,444,839	0	1,444,839	1,444,839							1
616	Fuel for Power Prod.		0	0	0	0							1
618	Chemicals		0	0	0	0							
	SOURCE OF SUPPLY	994,119											2
620	Materials and Supplies		212,264	0	212,264	165,050	47,214						2
631	Contractual Serv.		0	0	0	0	0						2
635	Contractual Serv. - Testing		0	0	0	0	0						2
636	Contractual Serv. - Other		0	0	0	0	0						2
641	Rental of Property		260	0	260	202	58						2
642	Rental of Equipment		8,758	0	8,758	6,810	1,948						2
650	Transportation Exp.		0	0	0	0	0						2
658	Insurance		0	0	0	0	0						2
668	Water Res. Consv. Exp.		0	0	0	0	0						2
675	Misc. Expenses		772,837	0	772,837	600,934	171,903						
	PUMPING EXPENSES	182,645											12
601	Salaries and Wages		182,645	0	182,645	120,132	34,365	28,148					1
615	Purchased Power		0	0	0	0							1
616	Fuel for power production		0	0	0	0							12
620	Materials and Supplies		0	0	0	0	0	0					12
631	Contractual Serv.		0	0	0	0	0	0					12
635	Contractual Serv. - Testing		0	0	0	0	0	0					12
636	Contractual Serv. - Other		0	0	0	0	0	0					12
641	Rental of Property		0	0	0	0	0	0					
	PUMPING EXPENSES	25,720											12
642	Rental of Equipment		0	0	0	0	0	0					12
650	Tansportation Expenses		0	0	0	0	0	0					12
658	Insurance		0	0	0	0	0	0					12
675	Misc. Expenses		25,720	0	25,720	16,917	4,839	3,964					
	WATER TREATMENT EXPENSE	2,439,803											2
601	Salaries and Wages		181,935	0	181,935	141,467	40,468						2
615	Puchased Power		0	0	0	0	0						2
616	Fuel for power production		0	0	0	0	0						1
618	Chemicals		2,172,083	0	2,172,083	2,172,083							2
620	Materials and Supplies		85,785	0	85,785	66,704	19,081						

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Cost of Service Study
"Revenue Requirement Allocation"

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Act. No.	Account		Utility Cost	Staff Adjust.	Net Cost	Base Cost	Extra Capacity Max Day	Extra Capacity Max Hour	Customer Costs Billing	Customer Costs Meter	Customer Costs Services	Fire Service	Alloc. Code
	WATER TREATMENT EXPENSE	1,067,557											
631	Contractual Serv.		679,579	0	679,579	528,419	151,160						2
635	Contractual Serv. - Testing		163,611	0	163,611	127,219	36,392						2
636	Contractual Serv. - Other		0	0	0	0	0						2
641	Rental of Property		0	0	0	0	0						2
642	Rental of Equipment		9,512	0	9,512	7,396	2,116						2
650	Transportation Exp.		0	0	0	0	0						2
658	Insurance		0	0	0	0	0						2
675	Misc. Expenses		214,855	0	214,855	167,064	47,791						2
	TRANSMISSION/DISTRIBUTION	4,074,186											
601	Salaries and Wages		3,474,324	0	3,474,324	844,022	241,441	2,019,039	0	129,332	145,141	95,350	13
661	Storage Facilities		0	0	0			0					4
662	Mains		494,164	0	494,164	325,029	92,978	76,157					12
663	Meters		49,805	0	49,805					49,805			6
664	Services		55,893	0	55,893						55,893		7
615	Purchased Power		0	0	0	0							1
616	Fuel for Power Prod.		0	0	0	0							1
	TRANSMISSION/DISTRIBUTION	1,105,505											
618	Chemicals		0	0	0	0							1
620	Materials and Supplies		59,312	0	59,312	14,409	4,122	34,468	0	2,208	2,478	1,628	13
672	Dist. reservoirs and standpipes		701,366	0	701,366			701,366					4
631	Contractual Serv.		0	0	0	0	0	0	0	0	0	0	13
635	Contractual Serv. - Testing		0	0	0	0							1
636	Contractual Serv. - Other		0	0	0	0	0	0	0	0	0	0	13
641	Rental of Property		20,137	0	20,137	4,892	1,399	11,702	0	750	841	553	13
677	Hydrants		36,719	0	36,719							36,719	8
642	Rental of Equipment		17,520	0	17,520	4,256	1,218	10,181	0	652	732	481	13
650	Transportation Exp.		0	0	0	0	0	0					12
658	Insurance		0	0	0	0	0	0					12
675	Misc. Expenses		270,451	0	270,451	65,701	18,794	157,168	0	10,068	11,298	7,422	13
	CUSTOMER ACCOUNTS EXPENSE	947,993											
601	Salaries and Wages		169,924	0	169,924				169,924				5
615	Purchased Power		0	0	0				0				5
616	Fuel for Power Prod.		0	0	0				0				5
670	Bad Debt Expense		325,029	0	325,029	140,956	40,322	86,888	41,116	5,507	6,180	4,060	10
620	Materials and Supplies		453,040	0	453,040				453,040				5
	CUSTOMER ACCOUNTS EXPENSE	816,609											
631	Contractual Serv.		816,609	0	816,609				816,609				5
635	Contractual Serv. - Testing		0	0	0				0				5
636	Contractual Serv. - Other		0	0	0				0				5
641	Meter Reading		0	0	0				0				5
642	Rental of Equipment		0	0	0				0				5
650	Transportation Exp.		0	0	0				0				5
658	Insurance		0	0	0				0				5
675	Misc. Expenses		0	0	0				0				5

Cost of Service Study
"Revenue Requirement Allocation"

0

Act. No.	Account		Utility Cost	Staff Adjust.	Net Cost	Base Cost	Extra Capacity Max Day	Extra Capacity Max Hour	Customer Costs Billing	Customer Costs Meter	Customer Costs Services	Fire Service	Alloc. Code
	ADMINISTRATIVE AND GENERAL	11,072,797											
601	Salaries and Wages-employees		1,108,911	0	1,108,911	480,903	137,567	296,439	140,276	18,788	21,085	13,852	10
603	Salaries and Wages-officers		169,942	0	169,942	73,699	21,082	45,430	21,497	2,879	3,231	2,123	10
604	Pensions and benefits *		3,403,625	0	3,403,625	1,476,056	422,241	909,873	430,554	57,668	64,717	42,516	10
631-636	Outside services		1,459,491	0	1,459,491	632,940	181,059	390,158	184,624	24,728	27,751	18,231	10
615	Purchased Power		0	0	0	0	0	0	0	0	0	0	10
616	Fuel for Power Prod.		0	0	0	0	0	0	0	0	0	0	10
656-659	Insurance		910,986	0	910,986	395,069	113,013	243,529	115,239	15,435	17,322	11,379	10
641-642	Rents		33,425	0	33,425	14,495	4,147	8,935	4,228	566	636	418	10
650	Transportation Exp.		298,127	0	298,127	129,289	36,985	79,697	37,713	5,051	5,669	3,724	10
620	Materials and Supplies		83,704	0	83,704	36,300	10,384	22,376	10,588	1,418	1,592	1,046	10
660	Advertising		24,020	0	24,020	10,417	2,980	6,421	3,039	407	457	300	10
666-667	Regulatory Expense		41,522	0	41,522	18,007	5,151	11,100	5,252	704	790	519	10
675	Misc. Expenses		3,539,044	0	3,539,044	1,534,784	439,040	946,074	447,685	59,962	67,292	44,207	10
	PRO FORMA ADJUSTMENTS												
	Labor *		0	0	0	0	0	0	0	0	0	0	10
	Fuel and Power		0	0	0	0							1
	Chemicals		0	0	0	0							1
	Waste Disposal		0	0	0	0	0						2
	Management Fees		0	0	0	0	0	0					12
	Group Insurance *		0	0	0	0	0	0	0	0	0	0	10
	Pensions *		0	0	0	0	0	0	0	0	0	0	10
	Regulatory Expenses		0	0	0	0	0	0	0	0	0	0	10
	Insurance other *		0	0	0	0	0	0	0	0	0	0	10
	Customer Accounting		0	0	0				0				5
	Rents		0	0	0	0	0	0	0	0	0	0	10
	General Office Exp		0	0	0	0	0	0	0	0	0	0	10
	Maint-other		0	0	0	0	0	0	0	0	0	0	10
	Miscellaneous		0	0	0	0	0	0	0	0	0	0	10
	SUBTOTAL OPER. & MAIN.		26,394,884	0	26,394,884	13,495,082	2,825,748	6,089,114	2,881,384	385,927	433,102	284,527	
	RECONCILIATION				0	0	0	0	0	0	0	0	
	TOTAL OPERATION & MAINTENANCE		26,394,884		26,394,884	13,495,082	2,825,748	6,089,114	2,881,384	385,927	433,102	284,527	
	Depreciation		9,596,553		9,596,553	4,446,409	1,271,263	511,792	0	1,208,143	1,829,980	328,966	Dep Sch
	Other Taxes		3,448,841		3,448,841	2,038,937	582,911	312,324	0	182,148	256,132	76,389	9
	Pre-Tax Operating Income - Proposed Rates				15,520,433								
	Income Taxes, Proposed Rates		4,192,355		4,192,355	2,478,499	708,577	379,655	0	221,416	311,350	92,857	9
	Utility Operating Income - Present Rates		11,328,078		11,328,078	6,697,102	1,914,632	1,025,859	0	598,284	841,294	250,908	9
	TOTAL REVENUE REQUIREMENT- PROPOSED RATES		54,960,711		54,960,711	29,156,029	7,303,131	8,318,744	2,881,384	2,595,917	3,671,858	1,033,647	
	A&G Markup												
	Cross check =		54,960,711		0.72	0.55	0.95	0.95	0.95	0.95	0.95	0.95	
	If available insert												
	Labor Percentages (Code 11) from utility					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	will affect items followed by *												

Southern Division
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ILLINOIS COMMERCE COMMISSION
Cost of Service Study
"Customer Group Allocation Factors"

Customer Class	Annual Consumption Usage	Annual Consumption MGD	Annual Consumption %	Max Day % of Ave.	Max Day Amt. MGD	Max Day Excess MGD	Max Day %	Max Hour % of Ave.	Max Hour Amt. MGD	Max Hour Excess MGD	Max Hour %	Commercial Monthly Bills	Commercial %	Equivalent Meters Monthly No.	Equivalent Meters %	Equivalent Services Monthly No.	Equivalent Services %
Residential	5,795,990	11.878	30.66%	210%	24.943	13.066	41.48%	300%	35.633	23.756	44.18%	914,470	77.53%	924,861	77.57%	916,861	86.66%
Commercial	2,856,669	5.854	15.11%	175%	10.245	4.391	13.94%	210%	12.294	6.440	11.98%	102,978	8.73%	186,084	15.61%	120,421	11.38%
Industrial	2,082,274	4.267	11.02%	165%	7.041	2.774	8.81%	200%	8.534	4.267	7.94%	3,383	0.29%	27,774	2.33%	7,251	0.69%
Class 4	0	0.000	0.00%	0%	0.000	0.000	0.00%	0%	0.000	0.000	0.00%	0	0.00%	0	0.00%	0	0.00%
Large Ind.	1,754,342	3.595	9.28%	133%	4.782	1.186	3.77%	148%	5.321	1.726	3.21%	132	0.01%	3,792	0.32%	528	0.05%
Class 6	0	0.000	0.00%	0%	0.000	0.000	0.00%	0%	0.000	0.000	0.00%	0	0.00%	0	0.00%	0	0.00%
Pub. Authority	942,803	1.932	4.99%	175%	3.381	1.449	4.60%	210%	4.057	2.125	3.95%	7,817	0.66%	34,304	2.88%	12,972	1.23%
Sales for Resale	5,284,479	10.830	27.95%	165%	17.869	7.039	22.35%	0%	0.000	0.000	0.00%	144,323	12.24%	15,480	1.30%	2,028	0.19%
SUBTOTAL	18,716,557	38.356	99.01%		68.261	29.905	94.93%		65.840	38.313	71.25%	1,173,103	99.46%	1,192,295	100.00%	1,058,033	100.19%
Fire Prot.	187,166	0.384	0.99%		1.980	1.596	5.07%		15.840	15.456	28.75%	6,335	0.54%	—	—	—	—
TOTAL	18,903,723	38.740	100.00%		70.241	31.501	100.00%		81.680	53.770	100.00%	1,179,438	100.00%	1,192,295	100.00%	1,058,033	100.19%

Number of public fire protection bills ignored as immaterial

No services assigned to public fire protection; services considered to be part of hydrants.

No services assigned to private fire protection since customer generally pays for service line.

Fire Protection Consumption set at 1% of other consumption.

ithern Division
_ocket No 02-0690
O'Fallon Exhibit 1.6

Cost of Service Study
"Percent Allocation to Customer Groups"

DESCRIPTION	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	CLASS 4	LARGE IND	CLASS 6	PUBLIC AUTHORITY	SALES FOR RESALE	FIRE PROTECTION	TOTAL
Base	30.66%	15.11%	11.02%	0.00%	9.28%	0.00%	4.99%	27.95%	0.99%	100.00%
Maximum Day	41.48%	13.94%	8.81%	0.00%	3.77%	0.00%	4.60%	22.35%	5.07%	100.00%
Maximum Hour	44.18%	11.98%	7.94%	0.00%	3.21%	0.00%	3.95%	0.00%	28.75%	100.00%
Commercial	77.53%	8.73%	0.29%	0.00%	0.01%	0.00%	0.66%	12.24%	0.54%	100.00%
Meters	77.57%	15.61%	2.33%	0.00%	0.32%	0.00%	2.88%	1.30%	0.00%	100.00%
Services	86.66%	11.38%	0.69%	0.00%	0.05%	0.00%	1.23%	0.00%	0.00%	100.00%
Fire Service-Hyd	—	—	—	—	—	—	—	—	100.00%	100.00%

At Proposed Rates

	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	CLASS 4	LARGE IND	CLASS 6	PUBLIC AUTHORITY	SALES FOR RESALE	FIRE PROTECTION	TOTAL
Base	8,939,406	4,405,964	3,211,581	0	2,705,797	0	1,454,126	8,150,480	288,674	29,156,028
Maximum Day	3,029,092	1,017,919	643,048	0	275,055	0	335,950	1,631,953	370,114	7,303,131
Maximum Hour	3,675,231	996,276	660,184	0	266,982	0	328,807	0	2,391,265	8,318,744
ımerciai	2,234,063	251,577	8,265	0	322	0	19,097	352,583	15,476	2,881,384
Meters	2,013,649	405,149	60,471	0	8,256	0	74,688	33,704	0	2,595,917
Services	3,181,926	417,916	25,164	0	1,832	0	45,020	0	0	3,671,858
Fire Service-Hyd	—	—	—	—	—	—	—	—	1,033,647	1,033,647
Reallocation of Retail Costs	2,094,989	827,616	558,047	0	427,781	0	262,767	(4,270,583)	99,383	(0)
Total Costs @ Proposed Rates	25,168,355	8,322,417	5,166,760	0	3,686,027	0	2,520,454	5,898,137	4,198,559	54,960,710
Percent of COSS	45.73%	15.14%	9.40%	0.00%	6.71%	0.00%	4.59%	10.73%	7.64%	100.00%

Special Tariff Revenues	0
Other Operating Revenues	402,998
Unbilled Revenues	0
Total Revenues	55,363,708

* for Other and for Unbilled

Southern Division
Docket No 02-0690
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Cost of Service Study
"Public Fire Protection Surcharge"
"Single - Tier Method"

Per Hydrant Cost	$645.58				MONTHLY BILLS					Equiv.	Monthly Rates				Actual	
Customer	Hydrants	Total Cost	Municipal Paid	Customer Surcharge	5/8"	3/4"	1"	1 1/2"	Fire Prot Bills	Fire Prot Bills	5/8"	3/4"	1"	1 1/2"	Surcharge Revenues	Connections Per Hydrant
Total	5,954	3,843,557	102,187	3,741,370	993,015	11,880	13,541	11,393	1,029,829	1,101,653					3,740,179	
Outside		0		0					0	0	0.00	0.00	0.00	0.00	0	
City of Alton	861	555,843	0	555,843	136,876	888	1,840	1,526	141,130	150,438	3.69	5.54	9.23	18.45	555,130	13.66
Godfrey	338	218,205	0	218,205	65,913	747	1,181	676	68,517	73,366	2.97	4.46	7.43	14.85	217,907	16.89
Quarry Elsah	37	23,886	0	23,886	3,940	60	108	120	4,228	4,900	4.87	7.31	12.18	24.35	23,864	9.52
Fosterburg	5	3,228	0	3,228	873	12	48	0	933	1,011	3.19	4.79	7.98	15.95	3,225	15.55
City of Cairo	305	196,901	0	196,901	15,451	0	259	131	15,841	16,754	11.75	17.63	29.38	58.75	196,855	4.33
East St. Louis	898	578,438	0	578,438	118,558	229	1,402	1,874	122,063	131,777	4.39	6.59	10.98	21.95	578,507	11.35
Brooklyn	35	22,595	0	22,595	3,585	12	72	144	3,813	4,503	5.02	7.53	12.55	25.10	22,605	9.08
French Village	59	38,089	5,013	33,076	3,799	12	60	36	3,907	4,147	7.98	11.97	19.95	39.90	33,093	5.52
Sauget	45	29,051	0	29,051	982	12	72	84	1,150	1,600	18.16	27.24	45.40	90.80	29,056	2.13
Cahokia-Maplewood	72	46,482	510	45,972	3,777	24	72	48	3,921	4,233	10.86	16.29	27.15	54.30	45,970	4.54
Alorton	31	20,013	2,634	17,379	8,032	12	109	128	8,281	8,963	1.94	2.91	4.85	9.70	17,387	22.26
Midway	48	30,988	0	30,988	9,512	0	24	36	9,572	9,752	3.18	4.77	7.95	15.90	31,011	16.62
Washington Park	85	54,874	0	54,874	21,878	12	169	110	22,169	22,869	2.40	3.60	6.00	12.00	54,884	21.73
Church Road	25	16,139	0	16,139	3,994	0	144	24	4,182	4,474	3.61	5.42	9.03	18.05	16,152	13.87
Fairmont City	90	58,102	0	58,102	9,113	12	120	132	9,377	10,091	5.76	8.64	14.40	28.80	58,124	8.68
Canteen Twnshp	3	1,937	255	1,682	1,320	0	12	0	1,332	1,350	1.25	1.88	3.13	6.25	1,688	37.00
Granite City	644	415,752	0	415,752	133,420	922	1,481	1,466	137,289	145,836	2.85	4.28	7.13	14.25	415,643	17.77
City of Venice	73	47,127	0	47,127	8,590	24	96	166	8,876	9,696	4.86	7.29	12.15	24.30	47,123	10.13
Madison	123	79,408	10,450	68,956	19,376	89	265	348	20,078	21,912	3.15	4.73	7.88	15.75	69,025	13.60
Eagle Park	7	4,519	0	4,519	2,323	0	36	0	2,359	2,413	1.87	2.81	4.68	9.35	4,512	28.08
Long Lake	82	52,937	0	52,937	22,769	267	149	108	23,293	24,082	2.20	3.30	5.50	11.00	52,980	23.67
Venice Twnshp	5	3,228	0	3,228	1,272	0	0	24	1,296	1,392	2.32	3.48	5.80	11.60	3,229	21.60
Tri-City Reional	4	2,582	340	2,242	60	0	24	36	120	300	7.47	11.21	18.68	37.35	2,241	2.50
Cloverleaf	3	1,937	255	1,682	2,701	0	24	60	2,785	3,061	0.55	0.83	1.38	2.75	1,684	77.36
Belleville	915	590,704	77,738	512,966	199,425	3,448	2,959	1,994	207,826	221,965	2.31	3.47	5.78	11.55	512,770	18.93
Swansea	269	173,660	0	173,660	40,983	700	614	671	42,948	46,903	3.70	5.55	9.25	18.50	173,541	13.30
Signal Hill	150	96,837	0	96,837	26,244	664	571	192	27,671	29,628	3.27	4.91	8.18	16.35	96,888	15.37
East Side	312	201,420	0	201,420	64,285	1,616	1,089	714	67,704	73,002	2.76	4.14	6.90	13.80	201,484	18.08
Villa Hills	49	31,633	0	31,633	9,618	338	77	36	10,069	10,498	3.01	4.52	7.53	15.05	31,800	17.12
Millstadt Rural	38	24,532	3,228	21,304	4,737	157	65	57	5,016	5,420	3.93	5.90	9.83	19.65	21,302	11.00
Northwest	188	121,369	0	121,369	36,410	486	221	288	37,405	39,132	3.10	4.65	7.75	15.50	121,308	16.58
Fairview-Caseyv	19	12,266	1,614	10,652	3,908	115	36	100	4,159	4,671	2.28	3.42	5.70	11.40	10,649	18.24
Smithton	3	1,937	150	1,787	348	19	0	0	367	377	4.75	7.13	11.88	23.75	1,788	10.19
Mitchell	4	2,582	0	2,582	348	0	0	0	348	348	7.42	11.13	18.55	37.10	2,582	7.25
Columbia	26	16,785	0	16,785	2,110	36	81	0	2,227	2,367	7.09	10.64	17.73	35.45	16,779	7.14
Ofallen, Shiloh, Casey	105	67,571	0	67,571	6,505	967	61	64	7,597	8,428	8.02	12.03	20.05	40.10	67,593	6.05
City of Peoria		0		0					0	0	0.00	0.00	0.00	0.00	0	
Bartonville		0		0					0	0	0.00	0.00	0.00	0.00	0	
Limestone		0		0					0	0	0.00	0.00	0.00	0.00	0	

Tuscarora	0	0	0	0	0.00	0.00	0.00	0.00	0
West Peoria	0	0	0	0	0.00	0.00	0.00	0.00	0
Dunlap	0	0	0	0	0.00	0.00	0.00	0.00	0
Chillicothe	0	0	0	0	0.00	0.00	0.00	0.00	0
Logan-Trivoli	0	0	0	0	0.00	0.00	0.00	0.00	0

Total cost per fire protection customer based on number of Hydrants

Southern Division
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ILLINOIS COMMERCE COMMISSION
Cost of Service Study
"Fire Protection Allocation"

	Equiv. Conn.
FIRE PROTECTION	
Public, monthly	71,444
Private, monthly	8,633
Total Equiv. Connections	80,077
Total Fire Protection per Cost of Service Study	4,198,559
Less Billing Costs	15,476
Less Hydrant Costs	1,033,647
Total Non-hydrant Fire Protection Costs	3,149,435
Total Non-hydrant Fire Protection Costs Per Equiv. Connection, monthly	39.33
Public Fire Protection Connection Costs	2,809,909
Plus Hydrant Costs	1,033,647
Total Public Fire Protection Costs	3,843,557
Total Private Fire Protection Connection Costs	339,526
Plus Billing Costs	15,476
Plus Hydrant Costs	0
Total Private Fire Protection Costs	355,003

ILLINOIS COMMERCE COMMISSION
Cost of Service Study
"Private Fire Protection Rates"

Private Fire Prot.	Ratio #	Monthly COSS Rates	Monthly Staff Rates
less than 3"	0.056	4.63	5.00
3	0.162	8.80	9.00
4	0.344	15.98	16.00
6	1.000	41.77	42.00
8	2.131	86.26	86.00
10	3.832	153.17	153.00
12	6.190	245.91	246.00
16	13.192	521.27	521.00

- ratio based on capacity

Southern Division
Docket No 02-0690
O'Fallon Exhibit 1.6

Cost of Service Study
"Equiv. Meters and Services"

ITEM	METER RATIO	SERVICE RATIO	RESIDENTAL	COMMERCIAL	INDUSTRIAL	CLASS 4	LARGE IND	CLASS 6	PUB AUTH.	SALES FOR RESALE	TOTAL
METER SIZE											
5/8" disk	1.0	1.0	902,540	81,459	823	0	0	0	3,408	0	988230
3/4" disk	1.5	1.1	8,713	2,986	92	0	0	0	165	0	11956
1" disk	2.5	1.4	2,947	9,083	544	0	0	0	1,155	0	13729
1 1/2" disk	5.0	1.8	92	1,814	84	0	0	0	341	0	2331
2" disk	8.0	2.5	178	7,206	1,316	0	24	0	2,572	120	11416
3" disk	15.0	3.0	0	63	47	0	0	0	42	0	152
4" disk	25.0	4.0	0	343	402	0	72	0	74	216	1107
6" disk	50.0	5.0	0	24	75	0	36	0	60	144	339
8" disk	80.0	6.0	0	0	0	0	0	0	0	24	24
10" disk	115.0	6.5	0	0	0	0	0	0	0	0	0
12" disk	168.0	7.0	0	0	0	0	0	0	0	0	0
3" turbine	17.5	3.0	0	0	0	0	0	0	0	0	0
4" turbine	30.0	4.0	0	0	0	0	0	0	0	0	0
6" turbine	62.5	5.0	0	0	0	0	0	0	0	0	0
8" turbine	90.0	6.0	0	0	0	0	0	0	0	0	0
10" turbine	145.0	6.5	0	0	0	0	0	0	0	0	0
Parallel	?	?	0	0	0	0	0	0	0	0	0
Equiv Meters			924861	186084	27774	0	3792	0	34304	15480	1192295
Equiv Services			916861	120421	7251	0	528	0	12972	2028	1060061

JUL 2 2 2004

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In the Matter of :

EARNINGS REVIEW TO ESTABLISH)
JUST AND REASONABLE RATES FOR)
ATLANTA GAS LIGHT COMPANY)

DOCKET No. 14311-U

DIRECT TESTIMONY AND EXHIBITS

OF

CHARLES W. KING

ON BEHALF OF

THE COMMISSION ADVERSARY STAFF

CONCERNING DEPRECIATION

MARCH 28, 2002

Contents

DIRECT TESTIMONY OF
CHARLES W. KING

Introduction

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

A. My name is Charles W. King. I am President of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. Please describe Snavely King.

A. Snavely King, formerly Snavely, King & Associates, Inc., was founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. The firm has a professional staff of 12 economists, accountants, engineers and cost analysts. Most of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 32-year history, members of the firm have participated in over 500 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Georgia Public Service Commission Adversary Staff ("Adversary Staff").

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

A. Yes. Attachment 1 is a summary of my qualifications and experience.

Q. Have you previously submitted testimony in regulatory proceedings?

A. Yes. Attachment 2 is a tabulation of my appearances as an expert witness before state and federal regulatory agencies.

Q. What is the objective of your testimony?

A. The objective of my testimony is to recommend depreciation rates for other Commission Adversary Staff consultants to employ in calculating the revenue requirement of the Atlanta Gas Light Company ("AGLC" or "the Company"). In the process of developing these rates, I will comment on the depreciation study that was prepared by Deloitte and Touche and submitted into the record of this docket by AGLC witness Donald Roff.

Q. Have you previously submitted testimony to this Commission on the subject of electric plant depreciation?

A. Yes. I have testified on behalf of the Adversary Staff in the three most recent Georgia Power rate cases: Docket No. 4007-U, testimony submitted August 21, 1991; Docket No. 9355-U, testimony submitted October 2, 1998; and Docket No. 14000-U, testimony submitted October 23, 2001. On March 15, 2002, I submitted testimony in the current Savannah Electric and Power Company rate case, Docket No. 14618-U.

Q. Did the Commission accept your recommendations in the dockets in which you testified?

A. Yes. In Docket No. 4007-U, the Commission accepted all of my recommendations and adopted my proposed depreciation rates. Docket No. 9355-U was settled by stipulation, which included an agreement to continue the depreciation rates adopted in Docket No. 4007-U. In Docket No. 14000-U, the

Commission adopted all of my depreciation rates except those for Plant Votgle. The Commission set Plant Votgle's life span at 50 years, rather than the 60 years I had proposed or the 40 years proposed by Georgia Power. The Savannah Electric case has not yet been decided.

Q. Are the positions you are adopting in this testimony consistent with your previous recommendations to this Commission?

A. Yes, they are.

Q. Have you prepared an exhibit to accompany your testimony?

A. Yes. Throughout my testimony I will refer to the material in the exhibit by schedule number.

Q. Please describe the process you used in preparing this testimony?

A. I began by examining the depreciation study and supporting workpapers submitted by Mr.Roff on behalf of the Company. I prepared a number of data requests and carefully read the Company's responses. I then prepared the schedules found in my exhibit. The calculations underlying these schedules are found in my workpapers. The workpapers were prepared and the calculations were conducted either by myself or under my supervision.

<u>Summary of Recommendations</u>

Q. What depreciation rates do you recommend for AGLC?

A. My recommended depreciation rates and their effect on depreciation expense, based on year-end 2000 plant investments, are set forth in the final columns of Schedule 1 of my exhibit. That schedule also presents both the existing depreciation rates and accruals. The following table compares the existing composite functional category depreciation rates with those recommended by the Company and by myself on behalf of the Adversary Staff:

Table 1
Functional Category Depreciation Rates

Functional Category	Existing	Company Proposed	Staff Recommended
Production	2.98%	1.02%	0.69%
Storage	2.91%	2.57%	2.57%
Transmission	1.64%	1.30%	1.21%
Distribution	2.97%	3.18%	2.23%
General Plant	11.08%	10.66%	10.63%
All Depreciable Plant	3.44%	3.55%	2.76%

The changes from present accruals that the Company proposes and that I recommend can be summarized as follows:

Table 2
Changes in Functional Category Depreciation Accruals
Based on Plant Balances on September 30, 2000

Functional Category	Company Proposed	Staff Recommended
Production	($7,608)	(8,875)
Storage	(393,673)	(393,503)
Transmission	(408,469)	(505,391)
Distribution	3,742,227	(12,861,303)
General Plant	(595,622)	(636,689)
All Depreciable Plant	$2,336,855	($14,405,761)

The difference between the Company's proposed depreciation accruals and my recommended accruals is $16,742,616, based on September 30, 2000 plant.

Schedule 2 matches in format Schedule 2 in Exhibit_____(DSR-3) to Company witness Roff's testimony. It shows the present depreciation parameters being used by AGLC and those that I recommend on behalf of Adversary Staff. As I shall discuss, the differences between my parameters and those proposed by Mr.Roff relate to the net removal cost ratios that are used to compute depreciation rates for six specific accounts. For ease of reference, I have displayed the six removal cost ratios that I have changed from those recommended by the Company in **boldface**.

Depreciation – General

Q. What is depreciation?

A. In 1958, the National Association of Railroad and Utility Commissioners sanctioned the following definition of depreciation:

> "Depreciation," as applied to depreciable utility plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of elements, inadequacy, obsolescence, changes in the art, changes in demand, and requirements of public authorities.[1]

The second commonly cited definition of depreciation is that of the American Institute of Certified Public Accountants:

> Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any) over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation. Depreciation for the year is the portion of the total charge under such a system that is allocated to the year. Although the allocation may properly take into account occurrences during the year, it is not intended to be a measurement of the effect of all such occurrences.[2]

[1] *Uniform System of Accounts for Class A and Class B Electric Utilities,* 1958, rev. 1962.
[2] American Institute of Certified Public Accountants, *Accounting Research and Terminology Bulletin #1.*

If depreciation can be defined in a single sentence, I would say that it is the process of recovering the initial investment in tangible capital assets, adjusted for salvage and cost of removal, in a systematic fashion over the useful service life of the plant, recognizing that utility plant is typically a group of investments.

Q. Can depreciation be calculated with precision?

A. No. Depreciation can no more be calculated with precision than can the required rate of return to equity investors. Both are developed from analyses that, while based on quantitative values, require considerable application of judgment. In the case of rate of return, that judgment pertains to the earnings expectation of investors as indicated by the stock market and corporate financial data. In the case of depreciation, the judgment pertains to the estimation of the future surviving life of plant as indicated by past patterns of retirements, industry trends, and corporate investment plans.

Q. How does this judgmental characteristic of depreciation influence the Commission's approach to the subject?

A. The Commission must recognize that the development of depreciation rates is not a refined science subject to mathematical precision. Because depreciation analysts use judgement in their estimation of depreciation, the Commission must necessarily exercise its own judgment in assessing the rationale and data that underlie alternative depreciation rates. This is why, in this proceeding, the Commission must choose among depreciation rates that yield widely differing annual depreciation accruals.

Q. What are the basic parameters required to develop a depreciation rate?

A. At its simplest level, the only parameter that is absolutely required is an estimate of the service life of the asset being retired. The reciprocal of that number can be used as the depreciation rate.

However, because most utility depreciation is applied to accounts that are groups of assets, it is usually necessary to estimate the dispersion of retirements around an average service life. In the electric utility industry, this dispersion is usually described in terms of 18 "Iowa Curves," so named because they were developed at Iowa State University. These curves describe how closely the retirements are grouped around the average service life and whether they tend to occur more rapidly before, after or coincident with the average service life.[3]

Another parameter that is typically included in the calculation of a depreciation rate is net salvage. Net salvage is the difference between the positive scrap value of the asset's material and the cost of dismantling and removing the asset when it is retired. It is expressed as a ratio to the cost of the asset and included as a subtraction (when salvage value exceeds removal cost) or an addition (when removal cost exceeds salvage) to the amount to be recovered in depreciation charges. With a few exceptions (e.g. vehicles) most electric utility plant has a higher removal cost than its salvage value, so that the inclusion of net salvage in depreciation adds to the amount to be recovered.

Finally, virtually all major utilities, including those in Georgia, employ what is known as "remaining life depreciation." This procedure computes the depreciation rate by dividing the unrecovered net investment, adjusted for net salvage, by the estimated remaining years of the asset (or group of assets). It effectively ensures that any past under- or over-accruals of depreciation are recovered during the remaining life of the asset.

[3] For a complete discussion of Iowa Curves, see Appendix A, part 3 of *Public Utility Depreciation Practices*, National Association of Regulatory Utility Commissioners, August 1996.

Q. Can you illustrate how the parameters you have just described are used to develop depreciation rates?

A. Yes. Beginning with the simplest example, assume a single asset with a 20 year life. Its depreciation rate is the reciprocal of 20:

$$1/20 = 5\%$$

Now, let us assume that the asset is expected to have salvage value equivalent to 5 percent of its investment value. The depreciation rate declines:

$$\frac{1-.05}{20} = \frac{.95}{20} = 4.75\%$$

Assume next that the cost of removing this asset amounts to 15 percent of its value. The depreciation rate increases:

$$\frac{1-.05+.15}{20} = \frac{1.10}{20} = 5.55\%$$

This is called a "whole life" rate because it is based on the whole life of 20 years. To develop the remaining life rate, we must identify some additional items of data: the original investment, the depreciation reserve (the amount of depreciation that has already been recovered), and the remaining life of the asset.

In this illustration, let us assume that the asset originally cost $1 million and that past depreciation charges have recovered $400,000. This means that we have yet to recover $600,000 in original cost, plus a negative net salvage (i.e. net cost of removal) amounting to 10% of the original cost, or $100,000. The total amount yet to be recovered is thus $700,000. Let us further assume that the asset is 10 years old, leaving 10 years of remaining life. In remaining life depreciation, the unrecovered amount is divided by the remaining life years:

$$\frac{\$700{,}000}{10\text{ years}} = \$70{,}000 \text{ required annual accrual}$$

The depreciation rate is then calculated by dividing the annual amount to be recovered by the gross investment, in this case:

$$\frac{\$70{,}000}{\$1{,}000{,}000} = 7.0\%$$

<u>Differences between AGLC and Adversary Staff Recommended Depreciation</u>

Q. What accounts for the differences between your recommended depreciation rates and accruals and those proposed by the Company?

A. My depreciation rates differ from those of the Company because I have reduced the net removal cost ratios for six accounts. In order of their impact on total depreciation, the ratios at issue are as follows:

Net Removal Cost Ratios

Acct	Description	AGLC Ratio	Staff Ratio
380	Services	(60)	(11)
376	Distribution Mains	(40)	(8)
367	Transmission Mains	(5)	(1)
390	General Plant Structures and Improvements	(5)	0
386	Other Property on Customers' Premises	(10)	0
311	LPG Equipment	(5)	0

Q. What is a "net removal cost ratio"?

A. A net removal cost ratio reflects the difference between the cost of removing or dismantling property and the proceeds from salvaging the removed materials as scrap. When the cost of removal exceeds the revenues from salvage, as it does for most gas utility plant, the term applied is either "negative net salvage" or "net removal." Net removal ratios are conventionally shown as negatives; net salvage ratios as positive. Net removal costs are recovered by applying the ratio to the amount of total plant that must be recovered over the service life of the plant removed. For example, if removal cost is five percent of the value of the plant to be removed, then the amount to be recovered is increased by five percent. That five percent factor is referred to as the "net removal cost ratio."

<u>**Account 380 – Services**</u>

Q. **How did Company Witness Donald Roff develop his 60 percent net removal cost ratio for Account 380 - Services?**

A. Schedule 3 is a copy of the source data from which Mr. Roff presumably developed his 60 percent removal cost ratio for Account 380. The top of this two-page schedule shows the annual retirements, salvage and cost of removal. The right-hand columns show the ratios of experienced net removal cost each year to the value of the Services retired during that year. The next table shows three year "bands" starting with 1986-1988 and running through 1990-2000. The final table that runs over to the second page shows the "shrinking bands" starting in 1986 and subsequent years, and all ending in 2000.

Presumably, Mr. Roff observed that during recent years, the ratios of Services retired to removal cost has clustered around –60%, and this was the basis for his selection.

Q. **Is this procedure for selecting a removal cost ratio consistent with the procedure approved by the Commission for other utilities in Georgia?**

A. No. The Commission-approved procedure for the Georgia Power Company is to develop, wherever possible, an estimate of the total current cost of removing all existing plant in each account. This estimate is then ratioed to the current investment in the existing plant to derive the net removal ratio.

For its "mass property" transmission and distribution accounts, Georgia Power develops an estimate of the annualized amount of net removal cost based on recent experience. This annualized amount is then multiplied by the average service life to produce an estimate of the lifetime cost of removing all of the plant in the category. That lifetime removal cost is then ratioed to the plant balance and is used to adjust the amount to be recovered in each account.

Q. Is the Georgia Power procedure appropriate for AGLC's Services account?

A. Yes. The life and retirement characteristics of electric Services and gas Services are quite similar. In both cases, the plant consists of a large number of small plant units that are fairly homogenous. In both cases, much of the new investment involves replacing old plant that incurs a cost to remove. As a result, removal costs loom fairly important in the calculation of depreciation rates for both types of plant.

Q. Have you developed a removal cost ratio for AGLC's Services account that conforms to the Commission-approved procedure for Georgia Power's Services account?

A. Yes. Schedule 4 develops the removal ratio for AGLC's Services account based on the procedure that the Commission has approved for Georgia Power's Services account. The salvage and removal cost data in Columns A and B are taken directly from Schedule 3. The annual net removal costs (Col. C) are adjusted to current values using the Handy-Whitman price indices for Plastic Services (Col. D). These price-adjusted annual net removal costs (Col E) are then averaged for the most recent 10 years, 5 years and 3 years (Col G), and then the three averages are themselves averaged. This procedure captures a number of years' activity but gives the greatest weight to the most recent experience. The annual removal cost average is then multiplied by the Company's estimate of the average service life of this account, 38 years, to develop an estimate of the lifetime cost of removal of the plant in the account. When this amount is ratioed to the total balance as of September 30, 2000, the resultant removal cost ratio is 11 percent.

Q. Why is this ratio so much lower than the ratio developed by Mr. Roff?

A. The reason for Mr. Roff's much higher removal cost ratio lies in his apples-to-oranges comparison of dollars of very different value. Mr. Roff compares recent removal costs, expressed in dollars of recent value, with the original cost of the Services recently removed. Assuming that recently retired Services had experienced the account average service life, they were on average 38 years old when they were retired. The original cost of those retired Services was expressed in 1962 dollars. In 1962, the dollar was worth almost six times its present value.[4] With the denominator expressed in very old dollars of much higher value, the resultant fraction is very large, 60 percent, according to Mr. Roff.

The effect of applying this very large fraction to current plant balances, as Mr. Roff does, is to inflate enormously the accrual for removal cost. Mr. Roff's assumption that removal costs amount to 60 percent of original plant investment in Services suggests that it would cost $361 million (60% of $601.9 million) to remove all of AGLC's Services. This is an absurd number. The total cost to remove all Services since 1986 has been only $19.2 million. My calculations indicate that the lifetime cost to remove every Service on the system, expressed in current dollars, would be $65.9 million, a considerable sum, but less than a fifth of that implicitly assumed by Mr. Roff.

[4] Based on the Consumer Price Index. Source: Bureau of Labor Statistics, Department of Labor. data.bls.gov

Account 376- Distribution Mains

Q. How did Mr. Roff develop his 40 percent removal cost ratio for Account 376 - Distribution Mains?

A. Mr. Roff apparently followed the same procedure he used for the Services account. Schedule 5 presents the relevant data in identical format as Schedule 3. Mr. Roff apparently observed that the recent ratios of net removal cost to the original cost of the retired investment cluster in the general range of 40 percent, and on that basis, he selected that ratio.

Q. Do the same objections you have noted regarding Mr. Roff's procedure for selecting the removal cost ratio for Service apply as well to his Distribution Mains removal cost ratio?

A. Yes, they do.

Q. Can the Commission-approved method for developing removal cost ratios be applied to the Distribution Mains account?

A. The same concept can be applied, but not mechanistically. Observing the "Cost of Removal" column, note the discontinuity in the data beginning in 1997. Annual costs had ranged in the $400,000 to $800,000 range before that year. Suddenly, they jumped to over $2.8 million and remained well above $2 million each year thereafter.

The reason for this sudden jump in removal costs, as well as the six-fold increase in retirements in 2000, was the discovery of leaks in the Company's cast iron and steel mains. This discovery led to an agreement in June 1998 between the Company and the Commission's Pipeline Safety Staff that AGLC would pursue an aggressive program to identify leaks in its pipeline system, replace all pipeline sections with a history of leaks during the next four years, and replace all remaining steel and cast iron pipe within 10 years.

The Pipeline Safety Replacement Program increases the complexity of estimating the lifetime cost of replacing AGLC's distribution mains. The expanded replacement activity since 1997 reflects a one-time program, for which the Company has been granted a special surcharge. Once that program has been completed, and all steel and cast iron mains replaced, it is reasonable to expect that replacement activity will fall back to its pre-1997 levels.

Q. Have you implemented the Commission-approved removal cost ratio procedure taking into account the Pipeline Safety Replacement Program?

A. Yes. This program is reflected in the calculations presented on Schedule 6. The lifetime removal costs estimate assumes two blocks of years: the 11-year duration of the Pipeline Safety Replacement Program, and the remaining 44 years of the Company's assumed 55 year service life. The 11-year block of intensive replacements is assigned the average annual cost of removal during the years 1997-2000. The remaining 44 years are assigned the average annual cost during the pre-replacement period, 1991-1996. All costs are adjusted to reflect 2000 price levels using the Handy-Whitman index for plastic gas mains construction.

When these two blocks of costs are composited and then divided by the September 30, 2000 balance in the account, the resultant net removal cost ratio is 8 percent.

<u>Account 367 – Transmission Mains</u>

Q. How did Mr. Roff develop his 5 percent removal cost ratio for Account 367-Transmission Mains?

A. Exhibit 7 presents the data available to Mr. Roff concerning removal costs for transmission mains. I can only surmise that Mr. Roff based his 5 percent ratio on a single year, 2000, when there was a 6 percent ratio between plant retired and removal costs incurred.

Q. Is this an adequate justification for a 5 percent removal ratio?

A. No. The Company retired almost $1 million in transmission mains between 1987 and 1999 without incurring a penny of removal cost. Apparently the cost of removing transmission mains for AGLC is negligible.

Q. What is the basis for your 1 percent removal cost ratio for this account?

A. While AGLC has experienced negligible removal costs for its transmission mains, I know that other gas utilities do incur some cost when they remove these facilities. Accordingly, some recognition of removal costs should be allowed. One percent seems like a very small number, but it amounts to $10.8 million over the life of this account. In the 15 years between 1985 and 2000, the Company spent only $12,895 for this purpose.

<u>Account 390 – General Plant Structures and Improvements</u>

Q. Is there any justification for Mr. Roff's proposed 5 percent removal cost ratio for Account 390- General Plant Structures and Improvements?

A. Absolutely none. Schedule 8 presents the Company's retirements, salvage and removal cost data since 1986. There have been considerable retirements, some of which have incurred removal cost, others have resulted in salvage proceeds. Over the 15 year period, salvage has amounted to $5.6 million, while removal cost has come to only $496,748. On this basis, a sizable positive salvage ratio could be justified.

Q. What is your recommendation for this account?

A. This account consists principally of structures, many of which may be marketable, others must be torn down. There is no way of knowing in advance which of these two dispositions applies in what degree to the remaining plant in this account. For this reason, I recommend that there be no salvage or cost of removal ratio assigned to this account.

<u>Account 386 – Other Property on Customers' Premises</u>

Q. What does the property in Account 386 consist of?

A. According to Mr. Roff's report (Appendix B, page 13), this property is Natural Gas Refueling Stations.

Q. Is there any basis for the 10 percent removal cost ratio assumed by Mr. Roff?

A. No. The Company's data are presented on Schedule 9. The information presented is totally counter-intuitive. There were no recorded retirements between 1985 and 1997, yet the Company shows both positive salvage or removal costs during six of those years. In 2000, when some retirements were finally recorded, there were no removal costs, but there were salvage proceeds of $15,000.

Q. What is your recommendation with respect to this account?

A. An arguable case could be made for a positive salvage ratio. However, in view of the ambiguity of the data, I recommend that no salvage or removal cost ratio be assigned to this account.

Account 311 – LPG Equipment

Q. Is there any justification of the 5 percent removal cost ratio for this account?

A. No. Schedule 10 presents the Company's data on this account. This exhibit does not show possibly the most important number, which is the surviving balance of $279,310. Since 1987, $14.4 million in investment has been retired from this account, which means that it is virtually depleted. During this time, there has been no recorded cost of removal.

Q. What is your recommendation with respect to this account?

A. It is fairly obvious that there is no removal cost associated with this equipment. While a small positive allowance might be rationalized, I recommend that a zero net salvage/removal cost ratio be assigned to this account.

Development of Depreciation Rates

Q. How have you converted these revised salvage parameters into depreciation rates?

A. The procedure for converting my proposed net removal cost parameters into depreciation rates is set forth in Schedule 11. For ease of reference, I have **boldfaced** the six accounts where I have altered the net salvage ratios

Schedule 11 displays the development of all production, storage, transmission and distribution rates because a parameter change in one account affects the rates for all other accounts within the functional group. Column A presents the balance in each account as of September 30, 2000. Column B is the "theoretical depreciation reserve," which is the reserve that should now exist if the current estimates of life and survivor curve persist through the remainder of each account's service life. This reserve is adjusted by the net salvage (net removal, if negative) ratios in Column C to derive a theoretical reserve after net salvage in Column D.

The Company does not maintain depreciation reserves by account, but only by functional category. The distribution of these salvage-adjusted theoretical reserves among the respective accounts is used to allocate the category book reserves to the individual accounts. This allocation is performed in Columns E and F. Column G presents the amount of investment in each account that must be recovered over the remaining life of that account. For accounts with no net salvage, this amount is simply the account balance less the allocated book reserve. For accounts with salvage ratios, it is the account balance adjusted upward (if salvage is negative) or downward (if salvage is positive) by the amount of the ratio, less the book reserve.

Column H shows the average remaining life of each account. These values are derived by identifying the expected remaining life of each "vintage" of plant according to the average service life and survivor curve assumed for the account. The vintage remaining lives are applied to the investment surviving in each vintage and then dollar-averaged to arrive at the remaining life years shown in Column H.

The average remaining lives in Column H are divided into the amounts to be recovered in Column G to arrive at the annual accruals in column I. Those accruals are then divided by the plant balances in Column A to derive the depreciation rates in the final column, Column J.

I have shown the development of depreciation rates for each plant account in the production, storage, transmission and distribution functional categories. I am unable to reconstruct the Company's procedure for allocating book reserve in the General plant category. However, since I am changing the parameters of only one plant account, (Account 390), I have used the Company's book reserve allocation for this account and have accepted the accrual rates calculated by the Company for all of the other General Plant accounts.

Q. Why does the change of just six removal cost ratios result in a 20 percent reduction in depreciation expense?

A. There are two reasons. The first is that the two largest removal cost changes affect the two largest accounts. Combined, Account 376 – Distribution Mains and Account 380 – Services represent 66 percent of the Company's depreciable investment. I have recommended reductions in the removal cost ratios for Account 376 from 20 percent to 8 percent, and for the Account 380 from 50 percent to 11 percent. These are very significant parameter changes.

Additionally, the remaining life method of depreciation exaggerates the effect of such parameter changes. When the Services net removal cost ratio is reduced from 50 to 11 percent, the amount to be recovered over the total life of that account contracts about 25 percent.[5] However, since the Company has been accruing depreciation on the assumption of a 50 percent removal obligation, it has now greatly overaccrued its depreciation reserve. This is evident from the Services line on Schedule 11. The theoretical reserve for this account is $173.9 million (Column D), but the book reserve allocated to that account is $224.7 million (Column F). When that very large accrued reserve is subtracted from the salvage-adjusted book value of the plant, the amount remaining to recover is greatly reduced and the depreciation rate is correspondingly quite low.

Q. Does this conclude your testimony?

A. Yes. It does.

[5] 1.11/1.50 = .74

Attachment 1

Resume of Charles W. King

Attachment 2

Expert Witness Appearances of

Charles W. King

ATLANTA GAS LIGHT COMPANY

Comparison of Existing with Staff Depreciation Rates
Depreciation Study as of September 30, 2000

[1] Account Number	[2] Description	[3] 9/30/00 Balance $	[4] Existing Rate %	[5] Annual Accrual $	[6] Staff Rate %	[7] Annual Accrual $	[8] Increase/ Decrease $
PRODUCTION PLANT							
304.1	Land Rights	9,428	1.38	130	0.45%	43	(87)
305.0	Structures and Improvements	32,901	1.90	625	-0.24%	(79)	(704)
311.0	LPG Equipment	287,544	2.82	8,109	0.36%	1,029	(7,079)
320.0	Other Equipment	57,108	4.70	2,684	2.94%	1,680	(1,004)
	Total Production Plant	386,981	2.98	11,548	0.69%	2,673	(8,875)
STORAGE PLANT							
361.0	Structures and Improvements	23,582	2.51	592	2.91%	687	95
361.1	Structures and Improvements - LNG	18,656,263	2.27	423,497	2.11%	393,381	(30,116)
362.1	Storage Tanks - LNG	26,011,485	2.44	634,680	2.24%	581,659	(53,021)
363.0	Purification Equipment	6,587,513	2.43	160,077	2.28%	150,513	(9,564)
363.1	Liquefaction Equipment	13,573,958	3.79	514,453	3.30%	448,522	(65,931)
363.2	Vaporizing Equipment	17,400,571	3.79	659,482	2.94%	511,886	(147,595)
363.3	Compressor Equipment	5,388,369	2.14	115,311	2.00%	107,911	(7,400)
363.4	M & R Equipment	2,297,886	2.17	49,864	2.21%	50,727	863
363.5	Other Equipment	23,815,908	3.17	754,964	2.83%	674,131	(80,834)
	Total Storage Plant	113,755,535	2.91	3,312,920	2.57%	2,919,417	(393,503)
TRANSMISSION PLANT							
365.1	Land Rights	1,521,634	1.31	19,933	1.18%	17,920	(2,014)
365.2	Rights-of-Way	6,540,804	1.30	85,030	1.10%	71,777	(13,253)
366.0	M & R Structures	40,208	2.03	816	1.21%	488	(328)
367.0	Mains	107,584,559	1.65	1,775,145	1.21%	1,305,326	(469,819)
369.0	M & R Equipment	2,542,238	2.39	60,759	1.60%	40,782	(19,977)
	Total Transmission Plant	118,229,443	1.64	1,941,685	1.21%	1,436,294	(505,391)
DISTRIBUTION PLANT							
374.1	Land Rights	5,436,655	1.40	76,113	1.42%	77,204	1,091
375.0	Structures and Improvements	763,222	1.99	15,188	1.66%	12,653	(2,535)
376.0	Mains	799,188,639	1.96	15,664,097	1.82%	14,571,105	(1,092,992)
378.0	M & R Equipment	20,130,534	2.45	493,198	2.15%	432,132	(61,066)
379.0	City Gate Equipment	6,346,571	2.45	155,491	2.15%	136,608	(18,883)
380.0	Services	601,870,814	4.40	26,482,316	2.62%	15,773,504	(10,708,812)
381.1	Meters	97,412,500	2.76	2,688,585	2.46%	2,397,682	(290,903)
381.2	Automated Meters (ERTS)	41,036,334	4.68	1,920,500	5.62%	2,306,970	386,470
381.3	Metreteks	2,991,282	2.84	84,952	4.23%	126,508	41,555
382.0	Meter Installations	90,670,247	2.06	1,867,807	1.59%	1,442,718	(425,089)
383.0	House Regulators	32,996,240	2.16	712,719	1.81%	595,967	(116,752)
384.0	House Regulator Installations	34,852,630	1.54	536,731	1.34%	466,181	(70,549)
385.0	Industrial M & R Equipment	1,221,740	2.47	30,177	2.19%	26,803	(3,373)
386.0	Other Property on Customers' Premises	3,977,304	20.00	795,461	8.31%	330,500	(464,961)
387.0	Other Equipment	4,314,055	3.98	171,699	3.18%	137,195	(34,505)
	Total Distribution Plant	1,743,208,767	2.97	51,695,035	2.23%	38,833,732	(12,861,303)
GENERAL PLANT							
390.0	Structures and Improvements	28,529,154	1.97	562,024	0.90%	255,637	(306,387)
391.1	Office Furniture and Equipment						
	Amortized Equipment	1,713,936	8.33	142,771	9.57%	164,024	21,253
	Amortized Furniture	2,002,551	8.33	166,812	9.57%	191,644	24,832
	Total Account 391.1	3,716,487	8.33	309,583	9.57%	355,668	46,084
391.2	Data Processing Equipment						
	Amortized Hardware	3,579,268	18.18	650,711	20.52%	734,466	83,755
	Amortized Software	1,030,963	18.18	187,429	20.52%	211,554	24,125
	Depreciable Data Processing Eqpt.	83,027,352	15.29	12,694,882	14.93%	12,395,984	(298,898)
	Total Account 391.2	87,637,583	15.44	13,533,022	15.22%	13,342,003	(191,019)
393.0	Stores Equipment	454,581	2.86	13,001	1.94%	8,819	(4,182)
394.0	Tools, Shop and Garage Equipment						
	Amortized Tools	7,791,034	6.25	486,940	6.29%	490,056	3,116
	Depreciable Tools	2,633,611	5.47	144,059	4.35%	114,562	(29,496)
	Total Account 394	10,424,645	6.05	630,998	5.80%	604,618	(26,380)
395.0	Laboratory Equipment	80,842	4.00	3,234	3.41%	2,757	(477)
396.0	Power Operated Equipment	2,867,577	8.54	244,891	9.88%	283,317	38,426
397.0	Communication Equipment	7,718,606	5.89	454,626	3.18%	245,452	(209,174)
398.0	Miscellaneous Equipment						
	Amortized Miscellaneous	1,755,851	7.14	125,368	8.13%	142,751	17,383
	Depreciable Miscellaneous	384,703	6.86	26,391	6.61%	25,429	(962)
	Total Account 398	2,140,554	7.09	151,758	7.86%	168,180	16,421
	Total General Plant	143,570,029	11.08	15,903,138	10.63%	15,266,449	(636,689)
	Sub-Total Depreciable Plant	2,119,150,755	3.44	72,864,326	2.76%	58,458,565	(14,405,761)
	Acct. 362 - Fully Depreciated	238,090					
	Total Depreciable Plant	2,119,388,845					

Schedule 2
Exhibit of Charles W. King

ATLANTA GAS LIGHT COMPANY

Comparison of Existing with Staff Mortality Characteristics
Depreciation Study as of September 30, 2000

[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
		Existing			Staff Recommended		
Account Number	Description	Average Service Life	Iowa Curve	Net Salvage	Average Service Life	Iowa Curve	Net Salvage
		yrs.		%	yrs.		%
PRODUCTION PLANT							
304.1	Land Rights	58	SQ	0	69	SQ	0
305.0	Structures and Improvements	50	R3	0	50	R3	0
311.0	LPG Equipment	35	R3	(5)	35	R3	(1)
320.0	Other Equipment	20	L1.5	0	20	L1.5	0
STORAGE PLANT							
361.0	Structures and Improvements	40	S4	(5)	30	S4	0
361.1	Structures and Improvements - LNG	45	R3	(5)	45	R3	0
362.1	Storage Tanks - LNG	45	R4	(15)	45	R4	(15)
363.0	Purification Equipment	40	R4	0	40	R4	0
363.1	Liquefaction Equipment	25	R4	0	25	R4	0
363.2	Vaporizing Equipment	25	R4	0	30	R4	0
363.3	Compressor Equipment	45	R4	0	45	R4	0
363.4	M & R Equipment	45	R4	0	43	R1	0
363.5	Other Equipment	30	R3	0	30	R3	0
TRANSMISSION PLANT							
365.1	Land Rights	75	R5	0	75	R5	0
365.2	Rights-of-Way	75	R5	0	75	R5	0
366.0	M & R Structures	50	R5	(5)	40	R5	0
367.0	Mains	65	R5	(10)	65	R5	0
369.0	M & R Equipment	40	R1	0	43	R1	0
DISTRIBUTION PLANT							
374.1	Land Rights	70	R5	0	65	R5	0
375.0	Structures and Improvements	50	R2	(5)	40	R3	(15)
376.0	Mains	60	R2	(20)	55	R2.5	(8)
378.0	M & R Equipment	40	R1	0	43	R1	0
379.0	City Gate Equipment	40	R1	0	43	R1	0
380.0	Services	33	R2.5	(50)	38	R2.5	(11)
381.1	Meters	33	R3	5	35	R2.5	0
381.2	Automated Meters (ERTS)	20	R1.5	5	15	R1.5	1
381.3	Metreteks	33	R3	0	20	R1.5	0
382.0	Meter Installations	50	S0.5	(5)	60	S-.5	0
383.0	House Regulators	45	R2.5	0	50	R3	0
384.0	House Regulator Installations	67	S0.5	(5)	70	R2	0
385.0	Industrial M & R Equipment	40	R1.5	0	43	R1	0
386.0	Other Property on Customers' Premises	5	SQ	0	10	R4	0
387.0	Other Equipment	25	S2	0	30	L1	0
GENERAL PLANT							
390.0	Structures and Improvements	50	R2	(5)	45	R2	0
391.2	Data Processing Equipment	5.5	L1	10	8	R2	5
394.0	Tools, Shop and Garage Equipment	16	L0.5	10	16	R2	5
396.0	Power Operated Equipment	10	S3	20	8	S1.5	20
397.0	Communication Equipment	16	R4	0	20	R2	0
398.0	Miscellaneous Equipment	14	S1	0	14	S1	0

Schedule 3
Exhibit of Charles W. King

ATLANTA GAS LIGHT COMPANY
ACCOUNT NO.: 380 Services

YEAR	ADDITIONS	RETIREMENTS	REIMBURSEMENTS AMOUNT	REIMBURSEMENTS RATIO	SALVAGE AMOUNT	SALVAGE RATIO	COST OF REMOVAL AMOUNT	COST OF REMOVAL RATIO	NET SALVAGE W/REIMB.	NET SALVAGE W/O REIMB.
1986	0.	1709443.	0.	0.%	1569.	0.%	543297.	32.%	-32.%	-32.%
1987	0.	2076392.	0.	0.%	2721.	0.%	558774.	27.%	-27.%	-27.%
1988	0.	2072034.	0.	0.%	6985.	0.%	592554.	29.%	-28.%	-28.%
1989	0.	2113231.	0.	0.%	1587.	0.%	739289.	35.%	-35.%	-35.%
1990	0.	2570444.	0.	0.%	35.	0.%	896690.	35.%	-35.%	-35.%
1991	0.	3188433.	0.	0.%	81.	0.%	1163113.	36.%	-36.%	-36.%
1992	0.	3559094.	0.	0.%	117.	0.%	1387266.	39.%	-39.%	-39.%
1993	0.	3801163.	0.	0.%	-447.	0.%	1576739.	41.%	-41.%	-41.%
1994	0.	3232602.	0.	0.%	0.	0.%	1626826.	50.%	-50.%	-50.%
1995	0.	2335222.	0.	0.%	3207.	0.%	1490878.	64.%	-64.%	-64.%
1996	0.	3139072.	0.	0.%	0.	0.%	2609230.	83.%	-83.%	-83.%
1997	0.	3037935.	0.	0.%	0.	0.%	1547791.	51.%	-51.%	-51.%
1998	0.	3444485.	0.	0.%	0.	0.%	1435945.	42.%	-42.%	-42.%
1999	0.	2440561.	0.	0.%	0.	0.%	1243680.	51.%	-51.%	-51.%
2000	0.	1853076.	0.	0.%	0.	0.%	1862610.	101.%	-101.%	-101.%
	0.	40573187.	0.	0.%	15855.	0.%	19274682.	48.%	-47.%	-47.%
3YR-BANDS										
1986-1988	0.	5857869.	0.	0.%	11275.	0.%	1694625.	29.%	-29.%	-29.%
1987-1989	0.	6261657.	0.	0.%	11293.	0.%	1890617.	30.%	-30.%	-30.%
1988-1990	0.	6755709.	0.	0.%	8607.	0.%	2228533.	33.%	-33.%	-33.%
1989-1991	0.	7872108.	0.	0.%	1703.	0.%	2799092.	36.%	-36.%	-36.%
1990-1992	0.	9317971.	0.	0.%	233.	0.%	3447069.	37.%	-37.%	-37.%
1991-1993	0.	10548690.	0.	0.%	-249.	0.%	4127119.	39.%	-39.%	-39.%
1992-1994	0.	10592859.	0.	0.%	-330.	0.%	4590832.	43.%	-43.%	-43.%
1993-1995	0.	9368987.	0.	0.%	2761.	0.%	4694443.	50.%	-50.%	-50.%
1994-1996	0.	8706896.	0.	0.%	3207.	0.%	5726934.	66.%	-66.%	-66.%
1995-1997	0.	8512229.	0.	0.%	3207.	0.%	5647898.	66.%	-66.%	-66.%
1996-1998	0.	9621492.	0.	0.%	0.	0.%	5592965.	58.%	-58.%	-58.%
1997-1999	0.	8922981.	0.	0.%	0.	0.%	4227416.	47.%	-47.%	-47.%
1998-2000	0.	7738122.	0.	0.%	0.	0.%	4542235.	59.%	-59.%	-59.%
SHRINKING BAND										
1986-2000	0.	40573187.	0.	0.%	15855.	0.%	19274682.	48.%	-47.%	-47.%
1987-2000	0.	38863744.	0.	0.%	14286.	0.%	18731385.	48.%	-48.%	-48.%
1988-2000	0.	36787352.	0.	0.%	11565.	0.%	18172611.	49.%	-49.%	-49.%

DELOITTE & TOUCHE LLP

DEPRECIATION SYSTEM - DSALVG01 RELEASE 7.0

STUDY AS OF SEPTEMBER 30, 2000

ATLANTA GAS LIGHT COMPANY

11-21-2001

ACCOUNT NO.: 38000000
Services

YEAR	ADDITIONS	RETIREMENTS	REIMBURSEMENTS AMOUNT	REIMBURSEMENTS RATIO	SALVAGE AMOUNT	SALVAGE RATIO	COST OF REMOVAL AMOUNT	COST OF REMOVAL RATIO	NET SALVAGE W/REIMB.	NET SALVAGE W/O REIMB.
1989-2000	0.	34715318.	0.	0.%	4580.	0.%	17580057.	51.%	-51.%	-51.%
1990-2000	0.	32602087.	0.	0.%	2993.	0.%	16840768.	52.%	-52.%	-52.%
1991-2000	0.	30031643.	0.	0.%	2958.	0.%	15944078.	53.%	-53.%	-53.%
1992-2000	0.	26843210.	0.	0.%	2878.	0.%	14780965.	55.%	-55.%	-55.%
1993-2000	0.	23284116.	0.	0.%	2761.	0.%	13393699.	58.%	-58.%	-58.%
1994-2000	0.	19482953.	0.	0.%	3207.	0.%	11816960.	61.%	-61.%	-61.%
1995-2000	0.	16250351.	0.	0.%	3207.	0.%	10190134.	63.%	-63.%	-63.%
1996-2000	0.	13915129.	0.	0.%	0.	0.%	8699256.	63.%	-63.%	-63.%
1997-2000	0.	10776057.	0.	0.%	0.	0.%	6090026.	57.%	-57.%	-57.%
1998-2000	0.	7738122.	0.	0.%	0.	0.%	4542235.	59.%	-59.%	-59.%
1999-2000	0.	4293637.	0.	0.%	0.	0.%	3106290.	72.%	-72.%	-72.%
2000	0.	1853076.	0.	0.%	0.	0.%	1862610.	101.%	-101.%	-101.%

Schedule 4
Exhibit of Charles W. King

Atlanta Gas Light Company
Net Removal Cost Ratio
Account No. 380 Services

	A Cost of Removal	B Salvage	C Net Removal Cost	D Handy-Whitman Indices	E Removal Cost @ 2000 Prices	F Year Blocks	G Year Block Averages
1991	1,163,113	81	1,163,032	244	1,410,891	1991-2000	1,775,224
1992	1,387,266	117	1,387,149	245	1,675,902		
1993	1,576,739	(447)	1,577,186	254	1,837,981		
1994	1,626,826	-	1,626,826	260	1,852,079		
1995	1,490,878	3,207	1,487,671	260	1,693,656		
1996	2,609,230	-	2,609,230	266	2,903,504	1996-2000	1,856,347
1997	1,547,791	-	1,547,791	268	1,709,501		
1998	1,435,945	-	1,435,945	279	1,523,440	1998-2000	1,556,243
1999	1,243,680	-	1,243,680	287	1,282,680		
2000	1,862,610	-	1,862,610	296	1,862,610		
Average							1,729,272
Average Service Life							38
Lifetime Net Removal Cost							65,712,321
Plant Balance, September 30, 2000							601,870,814
Net Removal Cost Ratio							**11%**

ATLANTA GAS LIGHT COMPANY
ACCOUNT NO.: 376 Distribution Mains

YEAR	ADDITIONS	RETIREMENTS	REIMBURSEMENTS AMOUNT	REIMBURSEMENTS RATIO	SALVAGE AMOUNT	SALVAGE RATIO	COST OF REMOVAL AMOUNT	COST OF REMOVAL RATIO	NET SALVAGE W/REIMB.	NET SALVAGE W/O REIMB.
1986	0.	1589347.	0.	0.%	17002.	1.%	186720.	12.%	-11.%	-11.%
1987	0.	975625.	0.	0.%	30930.	3.%	222059.	23.%	-20.%	-20.%
1988	0.	1711825.	0.	0.%	300.	0.%	242692.	14.%	-14.%	-14.%
1989	0.	1785914.	0.	0.%	-417.	0.%	354707.	20.%	-20.%	-20.%
1990	0.	2142998.	0.	0.%	200.	0.%	273884.	13.%	-13.%	-13.%
1991	0.	2723791.	0.	0.%	22020.	1.%	580636.	21.%	-21.%	-21.%
1992	0.	2721992.	0.	0.%	24220.	1.%	788560.	29.%	-28.%	-28.%
1993	0.	2377263.	0.	0.%	21424.	1.%	843753.	35.%	-35.%	-35.%
1994	0.	2979007.	0.	0.%	20834.	1.%	642624.	22.%	-21.%	-21.%
1995	0.	2547272.	0.	0.%	0.	0.%	432964.	17.%	-17.%	-17.%
1996	0.	1951799.	0.	0.%	0.	0.%	378298.	19.%	-19.%	-19.%
1997	0.	2767314.	0.	0.%	0.	0.%	2889746.	104.%	-104.%	-104.%
1998	0.	2807421.	0.	0.%	0.	0.%	2680929.	95.%	-95.%	-95.%
1999	0.	2989921.	0.	0.%	0.	0.%	2321969.	78.%	-78.%	-78.%
2000	0.	12657418.	0.	0.%	0.	0.%	3477519.	27.%	-27.%	-27.%
	0.	44728907.	0.	0.%	136513.	0.%	16317060.	36.%	-36.%	-36.%
3YR-BANDS										
1986-1988	0.	4276797.	0.	0.%	48232.	1.%	651471.	15.%	-14.%	-14.%
1987-1989	0.	4473364.	0.	0.%	30813.	1.%	819458.	18.%	-18.%	-18.%
1988-1990	0.	5640737.	0.	0.%	83.	0.%	871283.	15.%	-15.%	-15.%
1989-1991	0.	6652703.	0.	0.%	21803.	0.%	1209227.	18.%	-18.%	-18.%
1990-1992	0.	7588781.	0.	0.%	46440.	1.%	1643080.	22.%	-21.%	-21.%
1991-1993	0.	7823046.	0.	0.%	67664.	1.%	2212949.	28.%	-27.%	-27.%
1992-1994	0.	8078262.	0.	0.%	66478.	1.%	2274937.	28.%	-27.%	-27.%
1993-1995	0.	7903542.	0.	0.%	42258.	1.%	1919341.	24.%	-24.%	-24.%
1994-1996	0.	7478078.	0.	0.%	20834.	0.%	1453887.	19.%	-19.%	-19.%
1995-1997	0.	7266385.	0.	0.%	0.	0.%	3701009.	51.%	-51.%	-51.%
1996-1998	0.	7526534.	0.	0.%	0.	0.%	5948974.	79.%	-79.%	-79.%
1997-1999	0.	8564656.	0.	0.%	0.	0.%	7892644.	92.%	-92.%	-92.%
1998-2000	0.	18454760.	0.	0.%	0.	0.%	8480416.	46.%	-46.%	-46.%
SHRINKING BAND										
1986-2000	0.	44728907.	0.	0.%	136513.	0.%	16317060.	36.%	-36.%	-36.%
1987-2000	0.	43139560.	0.	0.%	119511.	0.%	16130340.	37.%	-37.%	-37.%
1988-2000	0.	42163935.	0.	0.%	88581.	0.%	15908281.	38.%	-38.%	-38.%

ATLANTA GAS LIGHT COMPANY
ACCOUNT NO.: 376 Distribution Mains

			REIMBURSEMENTS		SALVAGE		COST OF REMOVAL		NET SALVAGE	
YEAR	ADDITIONS	RETIREMENTS	AMOUNT	RATIO	AMOUNT	RATIO	AMOUNT	RATIO	W/REIMB.	W/O REIMB.
1989-2000	0.	40452110.	0.	0.%	88281.	0.%	15665589.	39.%	-39.%	-39.%
1990-2000	0.	38666196.	0.	0.%	88698.	0.%	15310882.	40.%	-39.%	-39.%
1991-2000	0.	36523198.	0.	0.%	88498.	0.%	15036998.	41.%	-41.%	-41.%
1992-2000	0.	33799407.	0.	0.%	66478.	0.%	14456362.	43.%	-43.%	-43.%
1993-2000	0.	31077415.	0.	0.%	42258.	0.%	13667803.	44.%	-44.%	-44.%
1994-2000	0.	28700152.	0.	0.%	20834.	0.%	12824049.	45.%	-45.%	-45.%
1995-2000	0.	25721145.	0.	0.%	0.	0.%	12181425.	47.%	-47.%	-47.%
1996-2000	0.	23173873.	0.	0.%	0.	0.%	11748461.	51.%	-51.%	-51.%
1997-2000	0.	21222074.	0.	0.%	0.	0.%	11370163.	54.%	-54.%	-54.%
1998-2000	0.	18454760.	0.	0.%	0.	0.%	8480416.	46.%	-46.%	-46.%
1999-2000	0.	15647339.	0.	0.%	0.	0.%	5799487.	37.%	-37.%	-37.%
2000	0.	12657418.	0.	0.%	0.	0.%	3477519.	27.%	-27.%	-27.%

Schedule 6
Exhibit of Charles W. King

Atlanta Gas Light Company
Net Removal Cost Ratio
Account No. 376 Distribution Mains

	A Cost of Removal	B Salvage	C Net Removal Cost	D Handy-Whitman Indices	E Removal Cost @ 2000 Prices	F Year Blocks	G Year Block Averages	H Applicable Years	I Lifetime Removal Cost
1991	580,636	22,020	558,616	277	659,449	1991-1996	678,385	44	29,848,925
1992	788,560	24,220	764,340	280	892,640				
1993	843,753	21,424	822,329	287	936,939				
1994	642,624	20,834	621,790	292	696,320				
1995	432,964		432,964	297	476,698				
1996	378,298		378,298	303	408,262				
1997	2,889,746		2,889,746	308	3,068,010	1997-2000	2,919,451	11	32,113,965
1998	2,680,929		2,680,929	316	2,774,252				
1999	2,321,969		2,321,969	322	2,358,024				
2000	3,477,519		3,477,519	327	3,477,519				
Total									61,962,890
Plant Balance, September 30, 2000									799,188,639
Net Removal Cost Ratio									**8%**

ATLANTA GAS LIGHT COMPANY
ACCOUNT NO.: 367 Transmission Mains

			REIMBURSEMENTS		SALVAGE		COST OF REMOVAL		NET SALVAGE	
YEAR	ADDITIONS	RETIREMENTS	AMOUNT	RATIO	AMOUNT	RATIO	AMOUNT	RATIO	W/REIMB.	W/O REIMB.
1987	0.	123479.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1988	0.	417484.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1989	0.	37978.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1990	0.	17363.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1992	0.	184597.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1993	0.	105614.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1994	0.	91095.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
2000	0.	199122.	0.	0.%	0.	0.%	12895.	6.%	-6.%	-6.%
	0.	1176732.	0.	0.%	0.	0.%	12895.	1.%	-1.%	-1.%
3YR-BANDS										
1986-1988	0.	540963.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1987-1989	0.	578941.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1988-1990	0.	472825.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1989-1991	0.	55341.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1990-1992	0.	201960.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1991-1993	0.	290211.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1992-1994	0.	381306.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1993-1995	0.	196709.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1994-1996	0.	91095.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1995-1997	0.	0.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1996-1998	0.	0.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1997-1999	0.	0.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1998-2000	0.	199122.	0.	0.%	0.	0.%	12895.	6.%	-6.%	-6.%
SHRINKING BAND										
1986-2000	0.	1176732.	0.	0.%	0.	0.%	12895.	1.%	-1.%	-1.%
1987-2000	0.	1176732.	0.	0.%	0.	0.%	12895.	1.%	-1.%	-1.%
1988-2000	0.	1053253.	0.	0.%	0.	0.%	12895.	1.%	-1.%	-1.%
1989-2000	0.	635769.	0.	0.%	0.	0.%	12895.	2.%	-2.%	-2.%
1990-2000	0.	597791.	0.	0.%	0.	0.%	12895.	2.%	-2.%	-2.%
1991-2000	0.	580428.	0.	0.%	0.	0.%	12895.	2.%	-2.%	-2.%
1992-2000	0.	580428.	0.	0.%	0.	0.%	12895.	2.%	-2.%	-2.%
1993-2000	0.	395831.	0.	0.%	0.	0.%	12895.	3.%	-3.%	-3.%
1994-2000	0.	290217.	0.	0.%	0.	0.%	12895.	4.%	-4.%	-4.%
1995-2000	0.	199122.	0.	0.%	0.	0.%	12895.	6.%	-6.%	-6.%

ATLANTA GAS LIGHT COMPANY
ACCOUNT NO.: 367 Transmission Mains

			REIMBURSEMENTS		SALVAGE		COST OF REMOVAL		NET SALVAGE	
YEAR	ADDITIONS	RETIREMENTS	AMOUNT	RATIO	AMOUNT	RATIO	AMOUNT	RATIO	W/REIMB.	W/O REIMB.
1996-2000	0.	199122.	0.	0.%	0.	0.%	12895.	6.%	-6.%	-6.%
1997-2000	0.	199122.	0.	0.%	0.	0.%	12895.	6.%	-6.%	-6.%
1998-2000	0.	199122.	0.	0.%	0.	0.%	12895.	6.%	-6.%	-6.%
1999-2000	0.	199122.	0.	0.%	0.	0.%	12895.	6.%	-6.%	-6.%
2000	0.	199122.	0.	0.%	0.	0.%	12895.	6.%	-6.%	-6.%

ATLANTA GAS LIGHT COMPANY
ACCOUNT NO.: 390 General Plant Structures and Improvements

YEAR	ADDITIONS	RETIREMENTS	REIMBURSEMENTS		SALVAGE		COST OF REMOVAL		NET SALVAGE	
			AMOUNT	RATIO	AMOUNT	RATIO	AMOUNT	RATIO	W/REIMB.	W/O REIMB.
1989-2000	0.	17021437.	0.	0.%	5566338.	33.%	495508.	3.%	30.%	30.%
1990-2000	0.	17001016.	0.	0.%	5566338.	33.%	495508.	3.%	30.%	30.%
1991-2000	0.	16942082.	0.	0.%	5566338.	33.%	495508.	3.%	30.%	30.%
1992-2000	0.	16929221.	0.	0.%	5556338.	33.%	493508.	3.%	30.%	30.%
1993-2000	0.	16866633.	0.	0.%	5556338.	33.%	403456.	2.%	31.%	31.%
1994-2000	0.	16848553.	0.	0.%	5553838.	33.%	403456.	2.%	31.%	31.%
1995-2000	0.	16670810.	0.	0.%	5553538.	33.%	390363.	2.%	31.%	31.%
1996-2000	0.	14276451.	0.	0.%	4296520.	30.%	319061.	2.%	28.%	28.%
1997-2000	0.	13289186.	0.	0.%	4222656.	32.%	12550.	0.%	32.%	32.%
1998-2000	0.	8161620.	0.	0.%	2951373.	36.%	12550.	0.%	36.%	36.%
1999-2000	0.	7825152.	0.	0.%	2951373.	38.%	12550.	0.%	38.%	38.%
2000	0.	7551786.	0.	0.%	2951373.	39.%	12550.	0.%	39.%	39.%

ATLANTA GAS LIGHT COMPANY
ACCOUNT NO.: 386 Other Property on Customers' Premises

YEAR	ADDITIONS	RETIREMENTS	REIMBURSEMENTS AMOUNT	REIMBURSEMENTS RATIO	SALVAGE AMOUNT	SALVAGE RATIO	COST OF REMOVAL AMOUNT	COST OF REMOVAL RATIO	NET SALVAGE W/REIMB.	NET SALVAGE W/O REIMB.
1991	0.	0.	0.	0.%	17095.	0.%	12497.	0.%	0.%	0.%
1992	0.	0.	0.	0.%	14935.	0.%	57518.	0.%	0.%	0.%
1993	0.	0.	0.	0.%	3534.	0.%	0.	0.%	0.%	0.%
1994	0.	0.	0.	0.%	1781.	0.%	0.	0.%	0.%	0.%
1995	0.	0.	0.	0.%	10909.	0.%	9490.	0.%	0.%	0.%
1996	0.	0.	0.	0.%	656.	0.%	7700.	0.%	0.%	0.%
1997	0.	2302.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
2000	0.	19427.	0.	0.%	15000.	77.%	0.	0.%	77.%	77.%
	0.	21729.	0.	0.%	63909.	294.%	87205.	401.%	-107.%	-107.%
3YR-BANDS										
1986-1988	0.	0.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1987-1989	0.	0.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1988-1990	0.	0.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1989-1991	0.	0.	0.	0.%	17095.	0.%	12497.	0.%	0.%	0.%
1990-1992	0.	0.	0.	0.%	32030.	0.%	70015.	0.%	0.%	0.%
1991-1993	0.	0.	0.	0.%	35564.	0.%	70015.	0.%	0.%	0.%
1992-1994	0.	0.	0.	0.%	20250.	0.%	57518.	0.%	0.%	0.%
1993-1995	0.	0.	0.	0.%	16224.	0.%	9490.	0.%	0.%	0.%
1994-1996	0.	0.	0.	0.%	13346.	0.%	17190.	0.%	0.%	0.%
1995-1997	0.	2302.	0.	0.%	11565.	502.%	17190.	747.%	-244.%	-244.%
1996-1998	0.	2302.	0.	0.%	656.	28.%	7700.	334.%	-306.%	-306.%
1997-1999	0.	2302.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1998-2000	0.	19427.	0.	0.%	15000.	77.%	0.	0.%	77.%	77.%
SHRINKING BAND										
1986-2000	0.	21729.	0.	0.%	63909.	294.%	87205.	401.%	-107.%	-107.%
1987-2000	0.	21729.	0.	0.%	63909.	294.%	87205.	401.%	-107.%	-107.%
1988-2000	0.	21729.	0.	0.%	63909.	294.%	87205.	401.%	-107.%	-107.%
1989-2000	0.	21729.	0.	0.%	63909.	294.%	87205.	401.%	-107.%	-107.%
1990-2000	0.	21729.	0.	0.%	63909.	294.%	87205.	401.%	-107.%	-107.%
1991-2000	0.	21729.	0.	0.%	63909.	294.%	87205.	401.%	-107.%	-107.%
1992-2000	0.	21729.	0.	0.%	46815.	215.%	74708.	344.%	-128.%	-128.%
1993-2000	0.	21729.	0.	0.%	31880.	147.%	17190.	79.%	68.%	68.%
1994-2000	0.	21729.	0.	0.%	28346.	130.%	17190.	79.%	51.%	51.%
1995-2000	0.	21729.	0.	0.%	26565.	122.%	17190.	79.%	43.%	43.%

ATLANTA GAS LIGHT COMPANY
ACCOUNT NO.: 386 Other Property on Customers' Premises

YEAR	ADDITIONS	RETIREMENTS	REIMBURSEMENTS		SALVAGE		COST OF REMOVAL		NET SALVAGE	
			AMOUNT	RATIO	AMOUNT	RATIO	AMOUNT	RATIO	W/REIMB.	W/O REIMB.
1996-2000	0.	21729.	0.	0.%	15656.	72.%	7700.	35.%	37.%	37.%
1997-2000	0.	21729.	0.	0.%	15000.	69.%	0.	0.%	69.%	69.%
1998-2000	0.	19427.	0.	0.%	15000.	77.%	0.	0.%	77.%	77.%
1999-2000	0.	19427.	0.	0.%	15000.	77.%	0.	0.%	77.%	77.%
2000	0.	19427.	0.	0.%	15000.	77.%	0.	0.%	77.%	77.%

Schedule 10
Exhibit of Charles W. King

ATLANTA GAS LIGHT COMPANY
ACCOUNT NO.: 311 LPG Equipment

YEAR	ADDITIONS	RETIREMENTS	REIMBURSEMENTS AMOUNT	REIMBURSEMENTS RATIO	SALVAGE AMOUNT	SALVAGE RATIO	COST OF REMOVAL AMOUNT	COST OF REMOVAL RATIO	NET SALVAGE W/REIMB.	NET SALVAGE W/O REIMB.
1987	0.	7212.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1989	0.	4185.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1990	0.	804210.	0.	0.%	75000.	9.%	0.	0.%	0.%	0.%
1991	0.	469816.	0.	0.%	0.	0.%	0.	0.%	9.%	9.%
1994	0.	535748.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1995	0.	12028278.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1996	0.	52871.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1997	0.	101756.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
2000	0.	410138.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
									0.%	0.%
	0.	14414214.	0.	0.%	75000.	1.%	0.	0.%	1.%	1.%
3YR-BANDS										
1986-1988	0.	7212.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1987-1989	0.	11397.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1988-1990	0.	808395.	0.	0.%	75000.	9.%	0.	0.%	9.%	9.%
1989-1991	0.	1278211.	0.	0.%	75000.	6.%	0.	0.%	6.%	6.%
1990-1992	0.	1274026.	0.	0.%	75000.	6.%	0.	0.%	6.%	6.%
1991-1993	0.	469816.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1992-1994	0.	535748.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1993-1995	0.	12564026.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1994-1996	0.	12616897.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1995-1997	0.	12182905.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1996-1998	0.	154627.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1997-1999	0.	101756.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1998-2000	0.	410138.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
SHRINKING BAND										
1986-2000	0.	14414214.	0.	0.%	75000.	1.%	0.	0.%	1.%	1.%
1987-2000	0.	14414214.	0.	0.%	75000.	1.%	0.	0.%	1.%	1.%
1988-2000	0.	14407002.	0.	0.%	75000.	1.%	0.	0.%	1.%	1.%
1989-2000	0.	14407002.	0.	0.%	75000.	1.%	0.	0.%	1.%	1.%
1990-2000	0.	14402817.	0.	0.%	75000.	1.%	0.	0.%	1.%	1.%
1991-2000	0.	13598607.	0.	0.%	0.	0.%	0.	0.%	1.%	1.%
1992-2000	0.	13128791.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1993-2000	0.	13128791.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1994-2000		13128791.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%

ATLANTA GAS LIGHT COMPANY
ACCOUNT NO.311: 311 LPG Equipment

YEAR	ADDITIONS	RETIREMENTS	REIMBURSEMENTS		SALVAGE		COST OF REMOVAL		NET SALVAGE	
			AMOUNT	RATIO	AMOUNT	RATIO	AMOUNT	RATIO	W/REIMB.	W/O REIMB.
1995-2000	0.	12593043.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1996-2000	0.	564765.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1997-2000	0.	511894.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1998-2000	0.	410138.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1999-2000	0.	410138.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
2000	0.	410138.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%

Schedule 11
Exhibit of Charles W. King

Atlanta Gas Light Company
Average Life Group Remaining Life Rate

	Descripton	A 9/30/00 Balance	B Theoretical Reserve w/o Removal	C Net Salvage (Removal) Percent	D Theoretical Reserve w Removal	E Theoretical Reserve Distribution	F Book Reserve Allocated	G Remaining to Accrue	H Average Remaining Life	I Annual Accrual	J Accrual Rate
PRODUCTION PLANT											
304.1	Land Rights	9,428	5,915	0%	5,915	0.0232	8,332	1,096	25.71	43	0.45%
305.0	Structures and Improvements	32,901	24,107	0%	24,107	0.0947	33,960	(1,059)	13.36	(79)	-0.24%
311.0	**LPG Equipment**	**287,544**	**195,973**	**0%**	**195,973**	**0.7696**	**276,067**	**11,477**	**11.15**	**1,029**	**0.36%**
320.0	Other Equipment	57,108	28,661	0%	28,661	0.1125	40,375	16,733	9.96	1,680	2.94%
	Total Production Plant	386,981	254,656		254,656	1.0000	358,734	28,247		2,673	0.69%
STORAGE PLANT											
361.0	Structures and Improvements	23,582	9,963	0%	9,963	0.0002	11,672	11,910	17.33	687	2.91%
361.1	Structures and Improvements - LNG	18,656,263	4,293,087	0%	4,293,087	0.0920	5,029,529	13,626,734	34.64	393,381	2.11%
362.1	Storage Tanks - LNG	26,011,485	10,960,516	-15%	12,604,594	0.2701	14,766,805	15,146,403	26.04	581,659	2.24%
363.0	Purification Equipment	6,587,513	2,202,957	0%	2,202,957	0.0472	2,580,855	4,006,658	26.62	150,513	2.28%
363.1	Liquefaction Equipment	13,573,958	6,835,273	0%	6,835,273	0.1465	8,007,806	5,566,152	12.41	448,522	3.30%
363.2	Vaporizing Equipment	17,400,571	7,070,917	0%	7,070,917	0.1515	8,283,872	9,116,699	17.81	511,886	2.94%
363.3	Compressor Equipment	5,388,369	1,967,796	0%	1,967,796	0.0422	2,305,355	3,083,014	28.57	107,911	2.00%
363.4	M & R Equipment	2,297,886	524,321	0%	524,321	0.0112	614,264	1,683,622	33.19	50,727	2.21%
363.5	Other Equipment	23,815,908	11,150,714	0%	11,150,714	0.2390	13,063,524	10,752,384	15.95	674,131	2.83%
	Total Storage Plant	113,755,535	45,015,544		46,659,622	1.0000	54,663,682	62,993,576		2,919,417	2.57%
TRANSMISSION PLANT											
365.1	Land Rights	1,521,634	278,936	0%	278,936	0.0079	424,044	1,097,590	61.25	17,920	1.18%
365.2	Rights-of-Way	6,540,804	1,660,378	0%	1,660,378	0.0473	2,524,139	4,016,665	55.96	71,777	1.10%
366.0	M & R Structures	40,208	19,991	0%	19,991	0.0006	30,391	9,817	20.11	488	1.21%
367.0	**Mains**	**107,584,559**	**31,892,110**	**-1%**	**32,211,031**	**0.9172**	**48,967,839**	**59,692,566**	**45.73**	**1,305,326**	**1.21%**
369.0	M & R Equipment	2,542,238	949,844	0%	949,844	0.0270	1,443,971	1,098,267	26.93	40,782	1.60%
	Total Transmission Plant	118,229,443	34,801,259		35,120,180	1.0000	53,390,384	65,914,905		1,436,294	1.21%
DISTRIBUTION PLANT											
374.1	Land Rights	5,436,655	1,134,700	0%	1,134,700	0.0027	1,466,054	3,970,601	51.43	77,204	1.42%
375.0	Structures and Improvements	763,222	451,743	-15%	519,504	0.0012	671,210	206,496	16.32	12,653	1.66%
376.0	**Mains**	**799,188,639**	**157,213,234**	**-8%**	**169,790,293**	**0.3988**	**219,372,302**	**643,751,429**	**44.18**	**14,571,105**	**1.82%**
378.0	M & R Equipment	20,130,534	4,195,563	0%	4,195,563	0.0099	5,420,748	14,709,786	34.04	432,132	2.15%
379.0	City Gate Equipment	6,346,571	1,288,697	0%	1,288,697	0.0030	1,665,021	4,681,550	34.27	136,608	2.15%
380.0	**Services**	**601,870,814**	**156,667,562**	**-11%**	**173,900,994**	**0.4085**	**224,683,406**	**443,393,198**	**28.11**	**15,773,504**	**2.62%**
381.1	Meters	97,412,500	31,321,170	0%	31,321,170	0.0736	40,467,550	56,944,950	23.75	2,397,682	2.46%
381.2	Automated Meters (ERTS)	41,036,334	13,833,711	1%	13,695,374	0.0322	17,694,685	22,931,286	9.94	2,306,970	5.62%
381.3	Metreteks	2,991,282	1,032,516	0%	1,032,516	0.0024	1,334,030	1,657,252	13.10	126,508	4.23%
382.0	Meter Installations	90,670,247	12,178,971	0%	12,178,971	0.0286	15,735,463	74,934,784	51.94	1,442,718	1.59%
383.0	House Regulators	32,996,240	8,217,895	0%	8,217,895	0.0193	10,617,677	22,378,563	37.55	595,967	1.81%
384.0	House Regulator Installations	34,852,630	6,239,212	0%	6,239,212	0.0147	8,061,181	26,791,449	57.47	466,181	1.34%
385.0	Industrial M & R Equipment	1,221,740	198,770	0%	198,770	0.0005	256,815	964,925	36.00	26,803	2.19%
386.0	**Other Property on Customers' Premis**	**3,977,304**	**1,454,025**	**0%**	**1,454,025**	**0.0034**	**1,878,628**	**2,098,676**	**6.35**	**330,500**	**8.31%**
387.0	Other Equipment	4,314,055	584,529	0%	584,529	0.0014	755,223	3,558,832	25.94	137,195	3.18%
	Total Distribution Plant	1,743,208,767			425,752,213	1.0000	550,079,992	1,322,973,776		38,833,732	2.23%
GENERAL PLANT											
390.0	**Structures and Improvements**	**28,529,154**		**0%**			**19,771,032**	**8,758,122**	**34.26**	**255,637**	**0.90%**
391.1	Office Furniture and Equipment	3,716,487		0%						355,668	9.57%
391.2	Data Processing Equipment										
	Ammortized	4,610,231		0%						946,020	20.52%
	Depreciable	83,027,352		5%						12,395,984	14.93%
	Total Account 391.2	87,637,583									
393.0	Stores Equipment	454,581		0%						8,819	1.94%
394.0	Tools, Shop and Garage Equipment										
	Amortized	7,791,034		0%						490,056	6.29%
	Depreciable	2,633,611		5%						114,562	4.35%
	Total Account 394	10,424,645									
395.0	Laboratory Equipment	80,842		0%						2,757	3.41%
396.0	Power Operated Equipment	2,867,577		20%						283,317	9.88%
397.0	Communication Equipment	7,718,606		0%						245,452	3.18%
398.0	Miscellaneous Equipment										
	Amortized	1,755,851		0%						142,751	8.13%
	Depreciable	384,703		0%						25,429	6.61%
	Total Account 398	2,140,554									
	Total General Plant	143,570,029								15,266,452	10.63%
	Sub-Total Depreciable Plant	2,119,150,755								58,458,568	2.76%
	Acct. 362 - Fully Depreciated	238,090									
	Total Depreciable Plant	2,119,388,845									

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

JUL 22 2004

In the matter of the application of THE DETROIT EDISON COMPANY to increase rates, amend its rate schedules governing the distribution and supply of electric energy, implement Power Supply Cost Recovery plans, factors and reconciliations in its rate schedules for jurisdictional sales of electricity and for miscellaneous accounting authority and regulatory asset recovery.

MPSC Case No. U-13808

Rebuttal and Supplemental Testimony and Exhibit of Charles W. King

March 26, 2004

INTRODUCTION

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

A. My name is Charles W. King. I am President of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. For whom are you testifying in this proceeding?

A. I am testifying on behalf of the Attorney General of Michigan.

Q. Are you the same Charles W. King who submitted prefiled testimony concerning interim rate relief on December 12, 2003 and final rates on March 5, 2004?

A. Yes. I am.

Q. Did your initial testimony on interim rates have attachments that described your qualifications and prior appearances before regulatory bodies?

A. Yes. Attachment A to that testimony is a resume of my experience and education. Attachment B is a list of my appearances before regulatory agencies as an expert witness.

REBUTTAL TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the testimony submitted by the Michigan Public Service Commission Staff ("Staff") and by Energy

Michigan. First, I will point out several instances where Staff has adopted positions consistent with those taken by The Detroit Edison Company ("Edison" or "the Company") to which the Attorney General has already objected. Second, I will address Staff's approach to the definition, measurement and recovery of stranded costs. Third, I will discuss Staff's proposed treatment of customers leaving to and returning from customer choice service. Finally, I will comment on Staff's proposed acceptance of the 11.0 percent return to equity capital that was prescribed by the Commission in Edison's last rate case, Case No. U-10102.

Staff's Adoption of Objectionable Edison Positions

Q. Which of Edison's positions has Staff adopted to which you have already objected?

A. Staff has adopted four of Edison's positions to which I have already objected in previous testimony.

First, Staff has adopted Edison's proposal to establish rate increases in this proceeding that will apply to small commercial customers when their rates are uncapped on January 1, 2005 and to residential customers when their rates re uncapped on January 1, 2006.[1] In my testimony in both the interim phase and the final rates phase, I have emphasized the impropriety of increasing rates for the years 2005 and 2006 based on projected.2004 costs. This point is particularly relevant because some cost elements, notably pensions and OPEBs, will likely decline during the years 2005 and 2006 relative to 2004.[2]

Second, Staff has adopted Edison's proposal to apply any increase in revenue authorized in this case across the board to all uncapped customers and to the

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[1] March 5, 2004 Testimony of Staff witness Collins, pages 3-4.
[2] 10 T 1780, 1781 and March 5, 2004 Testimony of AG witness King, pages 5-7.

capped customers when their price caps expire.[3] As I have previously pointed out, this proposal ignores the prohibition in Section 10d(2) against cost shifting. Section 10d(2) explicitly prohibits shifting costs from capped to uncapped customers. Both Edison's class cost of service study and my modifications to that study reveal that rates to uncapped secondary service customers cannot be increased without shifting costs to those customers from other classes, particularly capped customer classes. My modification of Edison's study indicates that only a modest increase could be applied to primary service customers without cost shifting.

Third, although Staff has considerably reduced the amount of that charge, Staff has still accepted Edison's proposal to charge ratepayers for the "Control Premium" that Edison paid to acquire MCN Energy.[4] As I pointed out in my March 5, 2004 testimony, any charge to recover the merger premium has nothing to do with the provision of electric service to Edison's customers; it represents a double-recovery of the premium by previous MCN shareholders and, to some extent, Edison shareholders as well; and it sets a very undesirable precedent for future utility mergers. Furthermore, the premium cost was paid by DTE, not Edison, and the Commission must base rates on Edison's costs of service, not on Edison's hypothetical avoided costs.[5]

Finally, Staff has adopted Edison's proposal to recover transmission costs in the Power Supply Cost Recovery ("PSCR") factor. Transmission costs do not fit into the statutory definition of PSCR costs. They are not variable and unpredictable, and they are based on maximum demand, not on energy consumption, which is the measure by which PSCR costs are recovered.

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Staff's Treatment of Stranded Costs

Q. What does Staff propose with respect to stranded costs?

A. Staff witness George Stojic proposes: (1) to terminate the rate equalization and securitization offset credits, (2) to include net stranded costs for 2002, 2003, and two months of 2004 as a transition charge in Edison's RAST tariff, (3) to terminate and replace the current stranded cost methodology, (4) to modify the choice program's return to service provisions, and (5) to allocate production plant fixed cost recovery associated with customer choice migration.[6]

Q. How does Staff define stranded costs?

A. Staff has two somewhat contradictory definitions of stranded costs, both of which are articulated by Staff witness George Stojic. The first harkens back to Case No. U-11290 when the Commission first defined stranded costs and identified the various categories of those costs. The Commission defined stranded costs as "costs incurred during the regulated era that will be above market prices and those costs necessary to facilitate the transition to competitive markets."[7] It listed five categories of stranded costs: (1) regulatory assets, (2) capital costs of nuclear plant, (3) capacity costs in power purchase agreements, (4) employee retraining costs, and (5) specific costs of implementing the direct access system.[8]

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- Results are highly sensitive to sales volumes.
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- The method creates much uncertainty as to the course of future stranded cost calculations, which can undermine the customer choice program.
- After rate freezes expire the current method implies that customers going to choice have an indefinite obligation to pay fixed generating costs for generating plant they do not use or intend to use because the Commission's current method does not have an obvious termination point for stranded cost calculations.[9]

Q. Has Staff used the Case No. U-12639 methodology to calculate stranded costs in this case?

A. Yes. Notwithstanding the infirmities of the Case No. U-12639 stranded cost methodology, Staff has adopted it to calculate Edison's net stranded costs for 2002, 2003, and for that portion of 2004 for which rates have been frozen. Mr. Stojic recommends a transition charge to recover these "historical production fixed costs." based on this methodology. In doing so, he goes beyond the definition of stranded costs in Case No. U-11290 by examining whether the revenue requirements of non-securitized production assets have been covered by production-related revenue during the years since the "regulated era."

Q. What has Staff calculated with respect to historical production fixed costs?

A. Staff purports to have found the following stranded costs: [10]

[9] March 5, 2004 Testimony of Staff witness Stojic, page 6.
[10] Id., page 15.

•	2002	$3,518,000
•	2003	52,150,000
•	January, February 2004	<u>8,690,000</u>
	Total	$64,358,000

Q. How does Staff propose to recover these stranded costs?

A. Mr. Stojic proposes either of two methods. One would be to maintain the 4-mill transition charge adopted by the Commission in the interim phase of this proceeding. This charge would recover Staff's $64.36 million in 24 to 28 months, depending on the assumed level of choice customer migration. The second proposal is to amortize the stranded costs over five years through a transition charge beginning at 2 mills, but trued up as the volume of choice consumption changes over time. [11]

Q. Is Staff's position on stranded cost definition, measurement and recovery consistent?

A. No. Staff begins by proposing to return to the concept of stranded costs as they were defined in Case No. U-11290. As Mr. Stojic has noted, all stranded costs incurred during the regulated era under this definition have been securitized, and the remaining transition costs, those relating to employee retraining and choice implementation, are (or will be) recovered through charges to choice customers. Going forward, there should be no further stranded costs because current and future costs are not incurred "during the regulated era."

Having adopted the original Case No. U-11290 definition of stranded costs, Staff then superimposes further stranded costs based on the methodology of Case No. U-12639. But Staff is unwilling to have stranded costs go on forever, which would be the result of the indefinite application of the U-12639 methodology. Instead, Staff proposes to cut off all further U-12639–based stranded costs at the

[11] Id., page 15.

end of February 2004. Staff apparently adopts this proposal simply to provide closure to the issue of stranded costs.[12]

Q. What do you recommend with respect to the treatment of stranded costs?

A. I agree with Staff that some closure must be brought to this issue. This closure requires resolving the question posed by the Commission in Case No. U-12639 and the other stranded cost cases. In each of those cases, the Commission inquired whether there were any further stranded production costs beyond those identified in Case No. U-11290. It did so by comparing the fixed costs of production plant and purchased power with the revenue that can be related to those costs. In every case to date, the Commission found that there were no stranded costs.

As I have demonstrated in earlier testimony – and will further demonstrate in this testimony -- a proper application of the Commission's test reveals that there continue to be no further stranded production plant costs beyond those identified in Case No. U-11290 and subsequently securitized. I therefore recommend closing the issue of stranded costs with a finding that all such costs have been captured in securitization bond and tax charges.

Q. Why has the Staff found $64.36 million in stranded costs when you have recommended none?

A. Pursuant to the Case No. U-12639 methodology, Staff witness William Kusiak has calculated the revenue requirement applicable to the fixed components of

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[12] Implementation costs have been separated from the first three categories of stranded costs identified in U-11290. See pages 2-3 in the MPSC's Opinion and Order for Case Nos. U-11955 and U-11956 dated October 24, 2000. Staff proposes a separate component of its stranded cost charge for customer choice implementation costs and a third component for a low income and energy efficiency charge. I am not addressing those components in this testimony.

Edison's non-nuclear generating facilities and purchased power contracts for the years 2002, 2003, and he has projected the 2003 costs into the first two months of 2004.

The weakness in Staff's analysis lies in the development of fixed production-related revenue, sponsored by Staff witness Daniel Blair. According to Mr. Stojic's testimony, Staff followed a three-step procedure:

- Use the Company's last cost of service study considered by the Commission in setting rates prior to the rate freeze to estimate the percentage of revenue in the cost of service attributable to production fixed costs;
- Multiply that percentage times current revenue to estimate the amount of revenue in current rates allocable to production fixed costs;
- Add net revenue from third party sales. [13]

Mr. Blair has based production-related revenue on production-related costs. This procedure virtually guarantees that whenever there is an overall revenue shortfall, some of that shortfall will be allocated to the production function. The shortfall may have nothing whatever to do with the implementation of customer choice. Indeed, the shortfall would appear even if there were no choice customers at all.

Q. **Is there an alternative method for determining production-related revenue?**

A. Yes. It is fairly simple matter to determine the revenue allocable to the distribution function and thereby, through subtraction, the revenue relevant to the production and transmission functions. Edison purports to have identified the unit revenue requirements of each of the functions that it continues to provide to choice customers through its Retail Access Service Tariff ("RAST"). On page 2 of my Exhibit I-56, I have applied the RAST rates to the corresponding billing determinants for the entirety of Edison's 2002 customer base. From this procedure I derive the revenue that can be ascribed to the distribution and sub-transmission functions. All remaining revenue must relate to transmission and production functions.

Q. Have you applied your estimate of production and transmission-related revenue to the costs developed by Staff witness Kusiak?

A. Yes. Exhibit I-____(CWK-7) compares my estimate of production and transmission-related revenue with production and transmission-related revenue requirement using Mr. Kusiak's fixed production costs, all for the year 2002. I begin with total revenue for the year (line 1) and subtract distribution revenue, developed in Exhibit I-56 (line 2) to derive total generation and transmission revenue (line 3). I then subtract fuel and purchased power (lines 4 and 5) on the grounds that, absent the rate freeze, these will be recovered dollar-for-dollar through the PSCR mechanism. After applying a jurisdictional factor (line 8), I further subtract revenue generated by the Securitization Bond, Securitization Tax, and Nuclear Decommissioning Surcharges (lines 9-11) to derive the jurisdictional base rate generating and transmission revenues (line 12).

I then compare these revenues with the fixed production-related revenue requirement developed by Mr. Kusiak, the MISO and ITC charges identified in Exhibit A-16, Schedule F7-4, and the revenue requirement pertaining to Edison's remaining transmission facilities, developed on page 2 of my exhibit.. I find that the revenues exceed the revenue requirements by $384 million.

Q. What is your conclusion with respect to stranded costs?

A. I conclude that there are no stranded production costs outside of those already securitized, nor have there been any since customer choice was implemented. I

[13] Id., page 14.

therefore recommend the Commission close the issue of stranded costs by making my conclusion permanent.

Staff's Treatment of Transfers Into and Out of Choice Service

Q. What are Staff's proposals with respect to the transfer of customers into and out of customer choice service?

A. Staff witness Stojic proposes that once a customer leaves for customer choice, that customer cannot return to Edison's bundled rates for three years, and that the customer must provide at least twelve months' notice prior to returning to bundled rate service. Mr. Stojic recommends that if a customer must return to Edison's service prior to these limitations, the customer's rate should be set at the higher of incremental costs to serve the customer or 110 percent of the appropriate tariff rate. [14]

Q. What is your assessment of these proposals?

A. I believe they are unduly burdensome on customers seeking to return to bundled service. Few customers can project their electrical needs three years into the future, and no customer can predict the shape and health of the alternative energy supply market three years out. Moreover, the penalty of 10 percent over the tariff rate is too formulaic. It applies to any returning customer regardless of load curve, time of use, or volume of load.

Q. Is there a better alternative?

A. Yes. I recommend the limitations proposed by Energy Michigan witness Richard Polich. Mr. Polich would establish a one-year notice requirement for any customer choosing to leave Edison's retail service and a corresponding one-year

[14] Id., page 12.

notice for a choice customer returning to Edison. He proposes charging customers taking Edison generated power before the one-year notice elapses the higher of either the PSCR rate or the market rate for the power consumed. [15]

Q. Do you also accept the condition proposed by Mr. Polich that choice customers be excused from paying "subsidies" to full service customers?

A. No. "Subsidies" as Mr. Polich uses that term include securitization and tax charges that are mandated by law or regulation and must be paid by all customers, not just choice customers. Those charges are the price that choice customer must pay to have alternative power resources available to them.

<u>Staff's Return on Equity</u>

Q. What rate of return on common equity does the Staff recommend for Edison?

A. Staff recommends an 11.0 percent return on Edison's equity capital.

Q. What is the basis for Staff's recommendation?

A. This 11.0 percent return is the high end of a range of 10.0 to 11.0 percent that Staff witness Brian Ballinger has identified as Edison's equity capital cost. It is also the rate of return that the Commission approved in the last Edison rate case, Case No. U-10102. [16]

Q. Does Mr. Ballinger's testimony actually support adoption of 11.0 percent as Edison's cost of equity capital?

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[15] March 5, 2004 testimony of Energy Michigan witness Polich, page 17, 18.
[16] March 5, 2004 testimony of Staff witness Ballinger, page 4.

A. No. It does not, for two reasons. First, Mr. Ballinger's various analyses do not support 10.0 to 11.0 percent as the range of Edison's equity return. Second, Mr. Ballinger provides no rationale for selecting the high end of his range as the appropriate rate of return.

Q. Why do you say that Mr. Ballinger's analyses do not support 10.0 to 11.0 percent as the range of Edison's equity return?

A. Mr. Ballinger uses three techniques for estimating Edison's rate of return to equity, Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM"), and the Interest Rate Risk Premium. Mr. Ballinger found the following ranges of return under these three approaches: [17]

Approach	Low	High
DCF	8.99%	10.80%
CAPM	9.43%	11.02%
Risk Premium	10.80%	10.95%

If we take a simple average of the low and the high ends of these three approaches, we find that the range is not 10.0 to 11.0 percent, but 9.74 to 10.92 percent. An 11.0 percent return is outside of this range.

Q. Does Mr. Ballinger explain why he has adopted the high end of his range of equity returns?

A. No. Mr. Ballinger provides no explanation for his recommendation to set Edison's equity return at the high end of his range. Conventionally, rate of return experts select the middle of the range of equity returns that they estimate. That was the approach used by the Company's rate of return witness, Dr. Morin, who developed 14 different equity return estimates and selected the median and the mean value of the entire range.[18]

[17] Id., page 25.
[18] Testimony of Edison witness Morin, page 50.

Q. What would be the return if Mr. Ballinger selected the middle of his range of equity returns?

A. The midpoint of the range of returns Mr. Ballinger has selected would be 10.5 percent. The mid-point of the range of returns that he actually found is 10.33 percent.

Q. At page 4 of his testimony, Mr. Ballinger appears to justify his selection of 11.0 percent on the grounds that it is the equity return adopted by the Commission in Case No. U-10102. Is that a valid reason for accepting an 11.0 percent equity return allowance?

A. No. To the contrary, this is a valid reason for rejecting 11.0 percent as the current equity return allowance. There are two reasons to believe Edison's current equity return is lower than that approved by the Commission in Case No. U-10102, one external to Edison, the other internal.

Q. What is the external reason for believing that Edison's current equity return is lower than the 11.0 percent approved in Case No. U-10102?

A. The external reason is that capital costs are lower now than they were when Case No. U-10102 was decided. The Commission order in that case is dated January 21, 1994, and so its capital cost findings would have reflected conditions during the year 1993. In 1993, the average yield on Moody's Baa corporate bonds was 7.93 percent. During the week of March 12, 2004, the corresponding yield was 6.06 percent. In 1993, the average yield on 10-year Treasury Bonds was 5.87 percent. As of March 12, 2004, 10-year Treasury bonds were yielding 3.75 percent.[19]

[19] www.federalreserve.gov/releases/h15

While there is no direct correspondence between the yields on bonds and the required returns on equity, there is little doubt that bond yields and equity return requirements change over time in the same direction. That is because bonds and equity are competitors for investors' money. Investors would not purchase low-yielding bonds if they believed that much better returns are obtainable from stocks. Low bond yields are therefore evidence of lower expected returns from stocks. For this reason, it is inconceivable that a cost of equity found appropriate based on 1993 data would still be appropriate in 2004.

Q. What is the internal reason for believing that Edison's current equity return is lower than the 11.0 percent approved in Case No. U-10102?

A. The internal reason for rejecting the Case No. U-10102 equity return is found in the testimony of Edison's own policy witness, Michael Champley. At page 35 of his prefiled testimony,[20] he notes that the securitization of the Company's investment in the Fermi 2 nuclear plant has made Edison a financially smaller utility, with somewhat less financial risk, than it had prior to securitization. Mr. Ballinger himself acknowledges this change in Edison's risk at page 16 of his testimony.

A further reduction in financial risk relates to the change in Edison's capital structure. In its decision in Case No. U-10102, the Commission found that the equity proportion of Edison's capital structure was 40 percent.[21] In the current case, Staff witness Kirk Megginson recommends a 46 percent equity structure.[22] It appears that Edison's capital structure is now less levered, that is, less risky than it was in 1993.

[20] 6 T 742
[21] Opinion and Order, Case No. 10102, January 21, 1994, page 18.
[22] March 5, 2004 testimony of Staff witness Megginson, page 3.

Thus, even if everything else were the same, Edison's substantially reduced financial risk should translate into a lower equity return requirement than was found Case No. U-10102.

Q. What is your recommendation as regards Edison's equity return?

A. I have performed no independent analyses of Edison's equity return. However, based solely on Mr. Ballinger's and Mr. Megginson's testimony and exhibits, an equity return of 10.33 percent would be appropriate.

SUPPLEMENTAL TESTIMONY

Q. What is the purpose of your supplemental testimony?

A. The purpose of this supplemental testimony is to revise my recommended allowances for pensions and Other Post-Employment Benefits ("OPEBs")

Q. What have you recommended with respect to these expense allowances?

A. In my testimony of March 5, 2004 concerning final rates, I recommended that the Commission adopte normalized allowances for pensions and OPEBs based on the average of the last three years' recorded expenses. Accordingly, I recommended pension expense of $74.5 million instead of the Company's proposed $113.3 million and OPEB expenses of $81.7 million instead of the Company's proposed $97.5 million.[23]

Q. Why are you revising these recommended allowances?

[23] March 5, 2004 testimony of Attorney General witness King, pages 16, 18.

A. Staff witness William Aldrich points out that 22 percent of these costs have been capitalized and recognized in the cost of added plant.[24] Accordingly, I am revising my recommended allowances to reflect the fact that only 78 percent of the costs as calculated in my earlier testimony should be recognized as expenses.

Q. What are your revised allowances?

A. My recommended normalized expense allowances are as follows:

Item	Previous	Revised
Pensions	$74,447,667	$58,069,180
OPEBs	$81,737,000	$63,754,860

Q. Does this complete your testimony at this time?

A. Yes. It does.

[24] March 5, 2004 testimony of Staff witness Aldrich, page 7.

Detroit Edison Company
Stranded Cost Calculation, 2002
(Dollars in Thousands)

1	Total Revenue	Ex A-5, Sch E-1, p.2, Col 1, Ln 2	$	3,741,598
2	Less Distribution Revenue	Ex. I-56, p.2, Ln.13D		1,161,613
3	Equals G & T Revenue	Ln 1 - Ln 2		2,579,985
4	Less Fuel & Handling Expense (PSCR)	Ex A-5, Sch E-l, p 2, Col 1, Ln 4		637,312
5	Less Purchased Power (PSCR)	Ex A-5, Sch E-l, p 2, Col 1, Ln 5		385,275
6	Equals Fixed G&T Revenue	Ln 3 - Ln 4 - Ln 5		1,557,398
7	Times Jurisdictional Revenue Factor	Ex A-5, Sch E-l, Ln 2, Col 2/Col 1		0.98357226
8	Equals Jurisdiction G&T Revenue	Ln 6 x Ln 7		1,531,813
9	Less Securitization Surcharge	$.00374 x 53,586,000 (1)		200,412
10	Less Securitization Tax	$.00099 x 53,586,000 (1)		53,050
11	Less Nuclear Decommissioning	$.000818 x 53,586,000 (1)		43,833
12	Equals Jurisdictional Base Rate G&T Revenue	Ln 8 - Ln 9 - Ln 10 - Ln 11		1,234,518
13	Less Staff Fixed Generation Revenue Requirement.	Ex. S-_____(WJK-1), p 2		561,186
14	Less MISO and ITC Expense	Ex A-16, Sch F7-4		125,031
15	Less Edison Transmission Revenue Requirement	Page 2		164,371
15	Equals Excess Revenue over Rev. Requirement	Ln 12 - Ln 13 - Ln 14	$	383,930

(1) Annual MWH Sales from Ex. A-16, Sch F1-2, Col f, Ln 5.

Detroit Edison Company
Transmission Revenue Requirement, 2002
(Dollars in Thousands)

		Source		
1	Jurisdictional Transmission Rate Base	WP A5E12, p 7, Col 2, Ln3		290,131
2	Pre-Tax Rate of Return	Ex S-_____(WJK-1), Ln 2		9.88%
3	Return Required	Ln 1 * Ln 2		28,665
4	Depreciation	WP A5E12, p 148, Col 2, Lns 15, 19, 23		4,049
5	Property Tax Factor	Kusiak Sheet 2, Ln 13		2.7959%
6	Transmission Property Tax	Ln 1 * Ln 5		8,112
7	Total Jurisdictional Rate Base	WP A5E12, p 7, Col 2, Ln 1		8,528,159
8	% Transmission	Ln 1/Ln 7		3.402%
9	Total Insurance	Kusiak Sheet 2, Ln 19		7,426
10	Jurisdictional Factor	Kusiak Sheet 2, Ln 22		98.001%
11	Jurisdictional Insurance	Ln 9 * Ln 10		7,278
12	Transmission Insurance	Ln 8 * Ln 11		248
13	Operating expense	WP A5E12, p 17, Col 2, Ln 19		120,847
14	Maintenance expense	WP A5E12, p 17, Col 2, Ln 20		2,451
19	Transmission Revenue Requirement	Sum Lns 3, 4, 6, 12, 13, 14	$	164,371

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

JUL 2 2 2004

In the matter of the application of THE DETROIT EDISON COMPANY to increase rates, amend its rate schedules governing the distribution and supply of electric energy, implement Power Supply Cost Recovery plans, factors and reconciliations in its rate schedules for jurisdictional sales of electricity and for miscellaneous accounting authority and regulatory asset recovery.

MPSC Case No. U-13808

______________________________________/

Rebuttal and Supplemental Testimony and Exhibit of Charles W. King

March 26, 2004

INTRODUCTION

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

A. My name is Charles W. King. I am President of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. For whom are you testifying in this proceeding?

A. I am testifying on behalf of the Attorney General of Michigan.

Q. Are you the same Charles W. King who submitted prefiled testimony concerning interim rate relief on December 12, 2003 and final rates on March 5, 2004?

A. Yes. I am.

Q. Did your initial testimony on interim rates have attachments that described your qualifications and prior appearances before regulatory bodies?

A. Yes. Attachment A to that testimony is a resume of my experience and education. Attachment B is a list of my appearances before regulatory agencies as an expert witness.

REBUTTAL TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the testimony submitted by the Michigan Public Service Commission Staff ("Staff") and by Energy

Michigan. First, I will point out several instances where Staff has adopted positions consistent with those taken by The Detroit Edison Company ("Edison" or "the Company") to which the Attorney General has already objected. Second, I will address Staff's approach to the definition, measurement and recovery of stranded costs. Third, I will discuss Staff's proposed treatment of customers leaving to and returning from customer choice service. Finally, I will comment on Staff's proposed acceptance of the 11.0 percent return to equity capital that was prescribed by the Commission in Edison's last rate case, Case No. U-10102.

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Q. Which of Edison's positions has Staff adopted to which you have already objected?

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- Results are highly sensitive to sales volumes.
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- After rate freezes expire the current method implies that customers going to choice have an indefinite obligation to pay fixed generating costs for generating plant they do not use or intend to use because the Commission's current method does not have an obvious termination point for stranded cost calculations.[9]

Q. Has Staff used the Case No. U-12639 methodology to calculate stranded costs in this case?

A. Yes. Notwithstanding the infirmities of the Case No. U-12639 stranded cost methodology, Staff has adopted it to calculate Edison's net stranded costs for 2002, 2003, and for that portion of 2004 for which rates have been frozen. Mr. Stojic recommends a transition charge to recover these "historical production fixed costs." based on this methodology. In doing so, he goes beyond the definition of stranded costs in Case No. U-11290 by examining whether the revenue requirements of non-securitized production assets have been covered by production-related revenue during the years since the "regulated era."

Q. What has Staff calculated with respect to historical production fixed costs?

A. Staff purports to have found the following stranded costs:[10]

[9] March 5, 2004 Testimony of Staff witness Stojic, page 6.
[10] Id., page 15.

• 2002	$3,518,000
• 2003	52,150,000
• January, February 2004	8,690,000
Total	$64,358,000

Q. How does Staff propose to recover these stranded costs?

A. Mr. Stojic proposes either of two methods. One would be to maintain the 4-mill transition charge adopted by the Commission in the interim phase of this proceeding. This charge would recover Staff's $64.36 million in 24 to 28 months, depending on the assumed level of choice customer migration. The second proposal is to amortize the stranded costs over five years through a transition charge beginning at 2 mills, but trued up as the volume of choice consumption changes over time. [11]

Q. Is Staff's position on stranded cost definition, measurement and recovery consistent?

A. No. Staff begins by proposing to return to the concept of stranded costs as they were defined in Case No. U-11290. As Mr. Stojic has noted, all stranded costs incurred during the regulated era under this definition have been securitized, and the remaining transition costs, those relating to employee retraining and choice implementation, are (or will be) recovered through charges to choice customers. Going forward, there should be no further stranded costs because current and future costs are not incurred "during the regulated era."

Having adopted the original Case No. U-11290 definition of stranded costs, Staff then superimposes further stranded costs based on the methodology of Case No. U-12639. But Staff is unwilling to have stranded costs go on forever, which would be the result of the indefinite application of the U-12639 methodology. Instead, Staff proposes to cut off all further U-12639–based stranded costs at the

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[11] Id., page 15.

end of February 2004. Staff apparently adopts this proposal simply to provide closure to the issue of stranded costs.[12]

Q. What do you recommend with respect to the treatment of stranded costs?

A. I agree with Staff that some closure must be brought to this issue. This closure requires resolving the question posed by the Commission in Case No. U-12639 and the other stranded cost cases. In each of those cases, the Commission inquired whether there were any further stranded production costs beyond those identified in Case No. U-11290. It did so by comparing the fixed costs of production plant and purchased power with the revenue that can be related to those costs. In every case to date, the Commission found that there were no stranded costs.

As I have demonstrated in earlier testimony – and will further demonstrate in this testimony -- a proper application of the Commission's test reveals that there continue to be no further stranded production plant costs beyond those identified in Case No. U-11290 and subsequently securitized. I therefore recommend closing the issue of stranded costs with a finding that all such costs have been captured in securitization bond and tax charges.

Q. Why has the Staff found $64.36 million in stranded costs when you have recommended none?

A. Pursuant to the Case No. U-12639 methodology, Staff witness William Kusiak has calculated the revenue requirement applicable to the fixed components of

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12 Implementation costs have been separated from the first three categories of stranded costs identified in U-11290. See pages 2-3 in the MPSC's Opinion and Order for Case Nos. U-11955 and U-11956 dated October 24, 2000. Staff proposes a separate component of its stranded cost charge for customer choice implementation costs and a third component for a low income and energy efficiency charge. I am not addressing those components in this testimony.

Edison's non-nuclear generating facilities and purchased power contracts for the years 2002, 2003, and he has projected the 2003 costs into the first two months of 2004.

The weakness in Staff's analysis lies in the development of fixed production-related revenue, sponsored by Staff witness Daniel Blair. According to Mr. Stojic's testimony, Staff followed a three-step procedure:

- Use the Company's last cost of service study considered by the Commission in setting rates prior to the rate freeze to estimate the percentage of revenue in the cost of service attributable to production fixed costs;
- Multiply that percentage times current revenue to estimate the amount of revenue in current rates allocable to production fixed costs;
- Add net revenue from third party sales. [13]

Mr. Blair has based production-related revenue on production-related costs. This procedure virtually guarantees that whenever there is an overall revenue shortfall, some of that shortfall will be allocated to the production function. The shortfall may have nothing whatever to do with the implementation of customer choice. Indeed, the shortfall would appear even if there were no choice customers at all.

Q. Is there an alternative method for determining production-related revenue?

A. Yes. It is fairly simple matter to determine the revenue allocable to the distribution function and thereby, through subtraction, the revenue relevant to the production and transmission functions. Edison purports to have identified the unit revenue requirements of each of the functions that it continues to provide to choice customers through its Retail Access Service Tariff ("RAST"). On page 2 of my Exhibit I-56, I have applied the RAST rates to the corresponding billing determinants for the entirety of Edison's 2002 customer base. From this procedure I derive the revenue that can be ascribed to the distribution and sub-transmission functions. All remaining revenue must relate to transmission and production functions.

Q. Have you applied your estimate of production and transmission-related revenue to the costs developed by Staff witness Kusiak?

A. Yes. Exhibit I-____(CWK-7) compares my estimate of production and transmission-related revenue with production and transmission-related revenue requirement using Mr. Kusiak's fixed production costs, all for the year 2002. I begin with total revenue for the year (line 1) and subtract distribution revenue, developed in Exhibit I-56 (line 2) to derive total generation and transmission revenue (line 3). I then subtract fuel and purchased power (lines 4 and 5) on the grounds that, absent the rate freeze, these will be recovered dollar-for-dollar through the PSCR mechanism. After applying a jurisdictional factor (line 8), I further subtract revenue generated by the Securitization Bond, Securitization Tax, and Nuclear Decommissioning Surcharges (lines 9-11) to derive the jurisdictional base rate generating and transmission revenues (line 12).

I then compare these revenues with the fixed production-related revenue requirement developed by Mr. Kusiak, the MISO and ITC charges identified in Exhibit A-16, Schedule F7-4, and the revenue requirement pertaining to Edison's remaining transmission facilities, developed on page 2 of my exhibit.. I find that the revenues exceed the revenue requirements by $384 million.

Q. What is your conclusion with respect to stranded costs?

A. I conclude that there are no stranded production costs outside of those already securitized, nor have there been any since customer choice was implemented. I

[13] Id., page 14.

therefore recommend the Commission close the issue of stranded costs by making my conclusion permanent.

Staff's Treatment of Transfers Into and Out of Choice Service

Q. What are Staff's proposals with respect to the transfer of customers into and out of customer choice service?

A. Staff witness Stojic proposes that once a customer leaves for customer choice, that customer cannot return to Edison's bundled rates for three years, and that the customer must provide at least twelve months' notice prior to returning to bundled rate service. Mr. Stojic recommends that if a customer must return to Edison's service prior to these limitations, the customer's rate should be set at the higher of incremental costs to serve the customer or 110 percent of the appropriate tariff rate.[14]

Q. What is your assessment of these proposals?

A. I believe they are unduly burdensome on customers seeking to return to bundled service. Few customers can project their electrical needs three years into the future, and no customer can predict the shape and health of the alternative energy supply market three years out. Moreover, the penalty of 10 percent over the tariff rate is too formulaic. It applies to any returning customer regardless of load curve, time of use, or volume of load.

Q. Is there a better alternative?

A. Yes. I recommend the limitations proposed by Energy Michigan witness Richard Polich. Mr. Polich would establish a one-year notice requirement for any customer choosing to leave Edison's retail service and a corresponding one-year

[14] Id., page 12.

notice for a choice customer returning to Edison. He proposes charging customers taking Edison generated power before the one-year notice elapses the higher of either the PSCR rate or the market rate for the power consumed.[15]

Q. Do you also accept the condition proposed by Mr. Polich that choice customers be excused from paying "subsidies" to full service customers?

A. No. "Subsidies" as Mr. Polich uses that term include securitization and tax charges that are mandated by law or regulation and must be paid by all customers, not just choice customers. Those charges are the price that choice customer must pay to have alternative power resources available to them.

<u>Staff's Return on Equity</u>

Q. What rate of return on common equity does the Staff recommend for Edison?

A. Staff recommends an 11.0 percent return on Edison's equity capital.

Q. What is the basis for Staff's recommendation?

A. This 11.0 percent return is the high end of a range of 10.0 to 11.0 percent that Staff witness Brian Ballinger has identified as Edison's equity capital cost. It is also the rate of return that the Commission approved in the last Edison rate case, Case No. U-10102.[16]

Q. Does Mr. Ballinger's testimony actually support adoption of 11.0 percent as Edison's cost of equity capital?

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[15] March 5, 2004 testimony of Energy Michigan witness Polich, page 17, 18.
[16] March 5, 2004 testimony of Staff witness Ballinger, page 4.

A. No. It does not, for two reasons. First, Mr. Ballinger's various analyses do not support 10.0 to 11.0 percent as the range of Edison's equity return. Second, Mr. Ballinger provides no rationale for selecting the high end of his range as the appropriate rate of return.

Q. Why do you say that Mr. Ballinger's analyses do not support 10.0 to 11.0 percent as the range of Edison's equity return?

A. Mr. Ballinger uses three techniques for estimating Edison's rate of return to equity, Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM"), and the Interest Rate Risk Premium. Mr. Ballinger found the following ranges of return under these three approaches: [17]

Approach	Low	High
DCF	8.99%	10.80%
CAPM	9.43%	11.02%
Risk Premium	10.80%	10.95%

If we take a simple average of the low and the high ends of these three approaches, we find that the range is not 10.0 to 11.0 percent, but 9.74 to 10.92 percent. An 11.0 percent return is outside of this range.

Q. Does Mr. Ballinger explain why he has adopted the high end of his range of equity returns?

A. No. Mr. Ballinger provides no explanation for his recommendation to set Edison's equity return at the high end of his range. Conventionally, rate of return experts select the middle of the range of equity returns that they estimate. That was the approach used by the Company's rate of return witness, Dr. Morin, who developed 14 different equity return estimates and selected the median and the mean value of the entire range.[18]

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[17] Id., page 25.
[18] Testimony of Edison witness Morin, page 50.

Q. What would be the return if Mr. Ballinger selected the middle of his range of equity returns?

A. The midpoint of the range of returns Mr. Ballinger has selected would be 10.5 percent. The mid-point of the range of returns that he actually found is 10.33 percent.

Q. At page 4 of his testimony, Mr. Ballinger appears to justify his selection of 11.0 percent on the grounds that it is the equity return adopted by the Commission in Case No. U-10102. Is that a valid reason for accepting an 11.0 percent equity return allowance?

A. No. To the contrary, this is a valid reason for rejecting 11.0 percent as the current equity return allowance. There are two reasons to believe Edison's current equity return is lower than that approved by the Commission in Case No. U-10102, one external to Edison, the other internal.

Q. What is the external reason for believing that Edison's current equity return is lower than the 11.0 percent approved in Case No. U-10102?

A. The external reason is that capital costs are lower now than they were when Case No. U-10102 was decided. The Commission order in that case is dated January 21, 1994, and so its capital cost findings would have reflected conditions during the year 1993. In 1993, the average yield on Moody's Baa corporate bonds was 7.93 percent. During the week of March 12, 2004, the corresponding yield was 6.06 percent. In 1993, the average yield on 10-year Treasury Bonds was 5.87 percent. As of March 12, 2004, 10-year Treasury bonds were yielding 3.75 percent.[19]

[19] www.federalreserve.gov/releases/h15

While there is no direct correspondence between the yields on bonds and the required returns on equity, there is little doubt that bond yields and equity return requirements change over time in the same direction. That is because bonds and equity are competitors for investors' money. Investors would not purchase low-yielding bonds if they believed that much better returns are obtainable from stocks. Low bond yields are therefore evidence of lower expected returns from stocks. For this reason, it is inconceivable that a cost of equity found appropriate based on 1993 data would still be appropriate in 2004.

Q. What is the internal reason for believing that Edison's current equity return is lower than the 11.0 percent approved in Case No. U-10102?

A. The internal reason for rejecting the Case No. U-10102 equity return is found in the testimony of Edison's own policy witness, Michael Champley. At page 35 of his prefiled testimony,[20] he notes that the securitization of the Company's investment in the Fermi 2 nuclear plant has made Edison a financially smaller utility, with somewhat less financial risk, than it had prior to securitization. Mr. Ballinger himself acknowledges this change in Edison's risk at page 16 of his testimony.

A further reduction in financial risk relates to the change in Edison's capital structure. In its decision in Case No. U-10102, the Commission found that the equity proportion of Edison's capital structure was 40 percent.[21] In the current case, Staff witness Kirk Megginson recommends a 46 percent equity structure.[22] It appears that Edison's capital structure is now less levered, that is, less risky than it was in 1993.

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[20] 6 T 742
[21] Opinion and Order, Case No. 10102, January 21, 1994, page 18.
[22] March 5, 2004 testimony of Staff witness Megginson, page 3.

Thus, even if everything else were the same, Edison's substantially reduced financial risk should translate into a lower equity return requirement than was found Case No. U-10102.

Q. What is your recommendation as regards Edison's equity return?

A. I have performed no independent analyses of Edison's equity return. However, based solely on Mr. Ballinger's and Mr. Megginson's testimony and exhibits, an equity return of 10.33 percent would be appropriate.

SUPPLEMENTAL TESTIMONY

Q. What is the purpose of your supplemental testimony?

A. The purpose of this supplemental testimony is to revise my recommended allowances for pensions and Other Post-Employment Benefits ("OPEBs")

Q. What have you recommended with respect to these expense allowances?

A. In my testimony of March 5, 2004 concerning final rates, I recommended that the Commission adopte normalized allowances for pensions and OPEBs based on the average of the last three years' recorded expenses. Accordingly, I recommended pension expense of $74.5 million instead of the Company's proposed $113.3 million and OPEB expenses of $81.7 million instead of the Company's proposed $97.5 million.[23]

Q. Why are you revising these recommended allowances?

[23] March 5, 2004 testimony of Attorney General witness King, pages 16, 18.

A. Staff witness William Aldrich points out that 22 percent of these costs have been capitalized and recognized in the cost of added plant.[24] Accordingly, I am revising my recommended allowances to reflect the fact that only 78 percent of the costs as calculated in my earlier testimony should be recognized as expenses.

Q. What are your revised allowances?

A. My recommended normalized expense allowances are as follows:

Item	Previous	Revised
Pensions	$74,447,667	$58,069,180
OPEBs	$81,737,000	$63,754,860

Q. Does this complete your testimony at this time?

A. Yes. It does.

[24] March 5, 2004 testimony of Staff witness Aldrich, page 7.

Detroit Edison Company
Stranded Cost Calculation, 2002
(Dollars in Thousands)

1	Total Revenue	Ex A-5, Sch E-1, p.2, Col 1, Ln 2	$	3,741,598
2	Less Distribution Revenue	Ex. I-56, p.2, Ln.13D		1,161,613
3	Equals G & T Revenue	Ln 1 - Ln 2		2,579,985
4	Less Fuel & Handling Expense (PSCR)	Ex A-5, Sch E-l, p 2, Col 1, Ln 4		637,312
5	Less Purchased Power (PSCR)	Ex A-5, Sch E-l, p 2, Col 1, Ln 5		385,275
6	Equals Fixed G&T Revenue	Ln 3 - Ln 4 - Ln 5		1,557,398
7	Times Jurisdictional Revenue Factor	Ex A-5, Sch E-l, Ln 2, Col 2/Col 1		0.98357226
8	Equals Jurisdiction G&T Revenue	Ln 6 x Ln 7		1,531,813
9	Less Securitization Surcharge	$.00374 x 53,586,000 (1)		200,412
10	Less Securitization Tax	$.00099 x 53,586,000 (1)		53,050
11	Less Nuclear Decommissioning	$.000818 x 53,586,000 (1)		43,833
12	Equals Jurisdictional Base Rate G&T Revenue	Ln 8 - Ln 9 - Ln 10 - Ln 11		1,234,518
13	Less Staff Fixed Generation Revenue Requirement.	Ex. S-_____(WJK-1), p 2		561,186
14	Less MISO and ITC Expense	Ex A-16, Sch F7-4		125,031
15	Less Edison Transmission Revenue Requirement	Page 2		164,371
15	Equals Excess Revenue over Rev. Requirement	Ln 12 - Ln 13 - Ln 14	$	383,930

(1) Annual MWH Sales from Ex. A-16, Sch F1-2, Col f, Ln 5.

Detroit Edison Company
Transmission Revenue Requirement, 2002
(Dollars in Thousands)

		Source		
1	Jurisdictional Transmission Rate Base	WP A5E12, p 7, Col 2, Ln3		290,131
2	Pre-Tax Rate of Return	Ex S-_____(WJK-1), Ln 2		9.88%
3	Return Required	Ln 1 * Ln 2		28,665
4	Depreciation	WP A5E12, p 148, Col 2, Lns 15, 19, 23		4,049
5	Property Tax Factor	Kusiak Sheet 2, Ln 13		2.7959%
6	Transmission Property Tax	Ln 1 * Ln 5		8,112
7	Total Jurisdictional Rate Base	WP A5E12, p 7, Col 2, Ln 1		8,528,159
8	% Transmission	Ln 1/Ln 7		3.402%
9	Total Insurance	Kusiak Sheet 2, Ln 19		7,426
10	Jurisdictional Factor	Kusiak Sheet 2, Ln 22		98.001%
11	Jurisdictional Insurance	Ln 9 * Ln 10		7,278
12	Transmission Insurance	Ln 8 * Ln 11		248
13	Operating expense	WP A5E12, p 17, Col 2, Ln 19		120,847
14	Maintenance expense	WP A5E12, p 17, Col 2, Ln 20		2,451
19	Transmission Revenue Requirement	Sum Lns 3, 4, 6, 12, 13, 14	$	164,371

Charles W. King
City of O'Fallon

REBUTTAL TESTIMONY OF CHARLES W. KING

INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Charles W. King. I am president of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. My business address is Suite 410, 1220 L Street, N.W., Washington, DC 20005.

Q. FOR WHOM ARE YOU APPEARING IN THIS CASE?

A. I am appearing on behalf of the City of O'Fallon, Illinois.

Q. ARE YOU THE SAME CHARLES W. KING WHO SUBMITTED DIRECT TESTIMONY ON BEHALF OF THE CITY OF O'FALLON IN THIS CASE ON FEBRUARY 5, 2003?

A. Yes, I am.

Q. DOES THAT TESTIMONY CONTAIN DESCRIPTIONS OF YOUR EXPERIENCE AND QUALIFICATIONS?

A. Yes, it does. Exhibit 1.1 to that testimony is a resume of my experience. Exhibit 1.2 is a listing of my expert witness appearances before regulatory agencies.

Q. DO YOU HAVE ANY CORRECTIONS TO MAKE TO YOUR DIRECT TESTIMONY?

A. Yes. On page 9 of my prefiled direct testimony, at line 30, the word "prices" should be changed to "yields," so that the line reads, "...their stocks will trade at high yields, and the rate of return indicators..."

On page 34, at line 16, the number "150" should be changed to 70; on line 18, the number "$145.6" should be changed to "$145.9;" and the number "$218.4" should be changed to "$102.1." The entire paragraph should read as follows:

> "They are enormous. For IAWC's largest single plant account, Transmission and Distribution Mains (#331.11), retirement costs amount to 70 percent of the original cost. The test year amount in this account for the Southern/Peoria/Streator/Pontiac Districts is $145.9 million. The retirement cost that is being depreciated is therefore $102.1 million."

I should also correct a column heading on O'Fallon Exhibit 1.4. Column B of that exhibit should read, "Discount @ 5.01%." A revised version of that exhibit is attached.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My Direct Testimony addressed three topics, rate of return, depreciation, and the need for a wholesale rate classification. This rebuttal testimony will address the representations of the other parties that have been made with respect to these issues. First, I will respond to the agreement among the Commission Staff ("Staff"), the Illinois-American Water Company ("IAWC" or "the Company"), and the Illinois Large Water Consumers ("ILWC") regarding the cost of IAWC's equity capital. I will also address the capital structure proposed by Staff witness Sheena Kight.

I will next respond to the rebuttal testimony of IAWC witnesses Ronald Stafford and Earl Robinson concerning my proposed treatment of retirement costs.

Finally, I will present a revised cost of service study for wholesale customers in the Southern Division. That study will show the adjustments that should be made to the rate structures recommended by the Company, Staff and the Attorney General to recognize the characteristics of wholesale customers. I will conclude by responding to the comments of IAWC witness Stafford concerning my wholesale rate proposal.

RATE OF RETURN

Q. WHAT RATE OF RETURN HAVE THE STAFF, THE COMPANY AND ILWC AGREED TO RECOMMEND TO THE COMMISSION?

A. Mr. Moul reports that these parties have agreed to the Staff's recommended rate of return to equity. In her original testimony, Staff witness Sheena Kight recommended a return to equity of 10.24 percent, but I have received a revised version of Ms. Kight's Schedule 6.01 that shows a return to equity of 10.27 percent. I presume that this is the agreed value that these parties will recommend to the Commission.

Q. IS THIS RECOMMENDATION REASONABLE?

A. No. The Commission's last equity return finding for IAWC was 10.20 percent in Docket No. 00-0340, decided on February 15, 2000. This value is seven basis points lower than the 10.27 percent that Staff witness Kight has recommended. As I point out in my direct testimony, interest rates have declined since February 2000. In February of 2003, the yield on 10-year Treasury bonds was 3.90 percent, which is 262 basis points lower than the 6.52 percent yield on the same bonds when the Commission last set IAWC's equity return. Yields on high-grade corporate bonds were 6.98 percent when the Commission last examined IAWC's equity return. In February of this year, they were 5.95 percent. Baa corporate bonds were yielding 8.29 percent in February 2000; three years later they were yielding 7.06 percent.[1]

While I do not contend that required equity returns have declined in lock step with interest rates, it is inconceivable that they have increased. Accordingly, there is no justification whatever for assuming that IAWC's equity cost is higher now than it was two years ago. Yet, that is Ms. Kight's assumption.

Q. WHY HAS MS. KIGHT ARRIVED AT A HIGHER RATE OF RETURN THAN YOU BELIEVE JUSTIFIED BY THE TREND IN INTEREST RATES?

A. Ms. Kight has committed the same two fundamental errors that IAWC witness Paul Moul committed. First, she has included gas distribution in her comparison samples for purposes of her Discounted Cash Flow ("DCF") analysis. Second, she has relied on the Capital Asset Pricing Model ("CAPM"), which is an unreliable and somewhat subjective measure of equity return.

Q. WHY IS IT AN ERROR FOR MS. KIGHT TO INCLUDE GAS DISTRIBUTION COMPANIES IN HER SAMPLE OF COMPARISON COMPANIES?

A. At pages 11 and 12 of my prefiled direct testimony, I present a number of reasons why the business risk of gas distribution companies is greater than that of water companies. I point out that IAWC witness Paul Moul's own data demonstrate that investors find gas distribution companies to be more risky than water companies. He finds that the DCF rate of return for gas distribution companies is 11.97 percent, while that for water companies is only 9.68 percent. This difference of 229 basis points is too great to be discounted as a mere chance

[1] www.federalreserve.gov/releases/h15

happening created by data variability. It has to reflect perceived differences in risk.

Ms. Kight finds much the same thing. Her DCF analysis develops a required return to gas distribution companies of 10.64 percent, but her return to water companies is only 9.39 percent. She provides no explanation for the 125 basis point difference between these two values. Instead, she regards that an average of the returns to gas and water companies is appropriate for IAWC, which is exclusively a water company. However, since gas company returns are not relevant or appropriate, factoring them into an "average" leaves the average irrelevant and inappropriate.

Q. WHY DO YOU OBJECT TO MS. KIGHT'S RELIANCE ON THE CAPITAL ASSET PRICING MODEL?

A. What Ms. Kight refers to as her "Risk Premium Analysis" is in fact the Capital Asset Pricing Model, at least as described by Mr. Moul. It encounters all of the problems that I discuss on pages 22 and 23 of my direct testimony.

Ms. Kight does a rather better job of describing the risk-free rate of return than does Mr. Moul, but her discussion still conveys the very great amount of discretion that goes into selecting this basic measure. I question her conclusion that because common equity theoretically has an infinite life, its market-required rate of return reflects the inflation and real risk-free rates anticipated to prevail over the long run.[2] While common equity may have an infinite life, the average holding time of most common shares is not indefinite. It varies from company to company, and it does conform to any given period.

Ms. Kight uses "adjusted" betas and those of Value Line, which are also adjusted. The adjustment assumes that there is an irreducible minimum value to beta of .35

[2] ICC Staff Exhibit 6.0 (Kight Testimony), page 23.

to which the specific beta of the firm or portfolio should be added. The source of this .35 minimum beta is an article by Marshall E. Blume that was published in the March 1971 issue of The Journal of Finance. The cause of the .35 minimum beta is the period-to-period relationship of portfolios of stock. The .35 is the intercept of regressions of beta coefficients of these portfolios from one period to the next as measured by portfolios dating from 1933 to 1968.

Ms. Kight asserts two reasons for using these adjusted betas. First, betas tend to regress towards the market mean value of 1.0 over time, and second, empirical tests suggest that the relationship between risk and required return is flatter than the raw betas predict. The first of these reasons is true for portfolios of stocks, because as time goes on, the benefits of diversification tend to apply to any portfolio, even one with a very low or very high beta. This is true of portfolios, but it does not follow that the beta of an individual stock tends towards 1.0. I accept that the second reason is correct, simply because, as I discussed in my direct testimony, the assumption of linearity between beta and relative risk leads to absurd conclusions.

In any case, Mr. Kight's CAPM analysis displays the extreme sensitivity of this approach to the analyst's selection of parameters. For example, had Ms. Kight picked as her risk-free rate the 10-year Treasury yield of 3.9 percent (February 2003)[3] instead of the long-term Treasury yield, her CAPM return for water companies would have been 8.77 percent instead of 10.11 percent. If she had just used her .44 regression beta, rather than the .52 average of that beta and Value Line's beta, her water company return would have been 9.40 percent, matching almost exactly her DCF return.

Q. WHAT RATE OF EQUITY RETURN IS APPROPRIATE FOR IAWC BASED ON MS. KIGHT'S TESTIMONY?

[3] www.federalreserve.gov/releases/h15

A. If we simply disregard her gas distribution companies, and apply her method of selecting an equity return allowance just to the water companies, the rate of equity return would be the average of her 9.39 percent DCF return and her 10.11 percent risk premium return, or 9.75 percent. Adding the two basis points for flotation costs yields an allowed return of 9.77 percent.

If we accept only Ms. Kight's beta regression and not that of Value Line, we have a consensus finding of 9.4 percent using both the DCF and the risk premium approaches. Adding the two basis points for flotation costs produces a rate of equity return of 9.42 percent.

These rates of return pertain to Ms. Kight's sample of eight water companies, all of which are much smaller than the IAWC's parent company, American Water Works, or its new parent, RWE Aktiegesellchaft. Mr. Moul claims that small companies incur greater risk than large companies. If so, then the rate of return should be lower than the 9.4 percent developed by Ms. Kight.

Q. DO YOU AGREE WITH MS. KIGHT'S CAPITAL STRUCTURE?

A. I do, but with one relatively small exception. I question the propriety of including any added equity to reflect the increased revenue resulting from this rate case. As I point out in my direct testimony, this practice has the effect of making the rate case circular. The greater the rate increase, the more the retained earnings, the higher the cost of capital, and the greater the rate increase. Admittedly, the effect is not dollar-for-dollar, but I believe it is a poor regulatory practice to have any component of the revenue requirement influenced by the level of revenue to be allowed in the rate case at hand.

Q. ACCEPTING THE RATE OF EQUITY RETURN WHICH MS. KIGHT'S TESTIMONY INDICATES, WHAT IS THE COMPOSITE COST OF CAPITAL TO IAWC?

A. The data presented on Ms. Kight's Revised Schedule 6.01 indicate the following composite cost of capital:

Table 1
Cost of Capital – Illinois-American Water Company

Class of Capital	Amount	Percent	Cost	Weighted Cost
Short-Term Debt	9,707,764	1.81%	1.60%	0.03%
Long-Term Debt	284,559,791	53.08%	5.06%	2.69%
Common Equity	241,836,431	45.11%	9.42%	4.25%
Total	536,103,986	100.00%		6.96%

This revised rate of return of 6.96 percent based on Staff's presentation is actually slightly lower than the 7.14 percent that I recommended in my direct testimony.

RETIREMENT COSTS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR REBUTTAL TESTIMONY?

A. In this section of my rebuttal testimony, I will respond to the objections to my proposed treatment of retirement costs that are stated in the testimonies of IAWC witnesses Ronald Stafford and Earl Robinson.

Q. PLEASE RESTATE BRIEFLY YOUR PROPOSED TREATMENT OF RETIREMENT COST.

A. In my direct testimony, I propose as an interim measure that retirement costs be treated in manner set forth in Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*. Unlike the present treatment of retirement costs, SFAS 143 recognizes the lower present value of retirement costs that will not be incurred until many years into the future. It requires that those costs be stated at their present value using a risk-free interest rate as the discount factor. That restated value is amortized each year over the life of the asset. Because the present value increases each year as the asset ages and the retirement costs approach, a second cost must be recognized, and that is the increment in the present value of the retirement costs. These two components, amortization of the present value of the retirement costs and the increment in that present value, constitute the appropriate recovery of retirement costs that should be built into the depreciation rates.

In O'Fallon Exhibit 1.4, I calculate the negative salvage ratios based on the present value of the retirement costs. I discount the existing negative salvage ratios based on the remaining life of each account for which retirement costs are incurred. I also present the increment in the present value of those retirement cost. In O'Fallon Exhibit 1.5, I demonstrate that application of these rates to the Company's test year plant investment would reduce depreciation expense for the Southern/Peoria/Streator/Pontiac Districts by $4.25 million.

I recommend the SFAS 143 treatment only as an interim measure, except possibly for large, individual assets such as treatment plants. The long run solution to the problem of retirement costs for "mass property" accounts is to incorporate the retirement costs of pipes, meters, hydrants or other plant into the capital cost of the replacement facilities. The remaining retirement costs of abandoned facilities that are not replaced should be incorporated into depreciation rates based on the relationship of a five-year average of such costs to total plant in service.

Q. WHAT ARE THE OBJECTIONS OF MESSRS. STAFFORD AND ROBINSON TO YOUR PROPOSED SFAS 143 TREATMENT?

A. Their objections can be summarized as follows:

- SFAS 143 does not apply to ratemaking in this proceeding because there are no legal obligations associated with the retirement of IAWC's transmission and distribution mains, services, meters, and hydrants (Stafford, page 42).
- SFAS 143 is an accounting rule that applies to financial accounting, not ratemaking (Stafford, page 43; Robinson, pages 5, 8).
- The existing methodology has been approved by the Commission (Stafford, page 43)
- The retirement costs recovered under the current system are not enormous (Stafford, page 43-44)
- The retirement costs recovered under the current system are justified by data presented in the last case (Stafford, page 43-44).
- Under my approach, current plant costs would have to be inflated up to future costs in order to match net salvage values (Stafford, page 45).
- The SFAS 143 approach unfairly "back loads" the recovery of retirement costs to the end of its life when the property has the highest level of maintenance expense and the lowest level of utility (Robinson, page 8).
- The SFAS 143 procedure will create "intergenerational inequity" (Robinson, page 9)
- All components of depreciation must be based upon a straight line recovery mechanism (Robinson, pages 9,13)
- Additional inflation will cause future retirements to cost more than current retirements so that the retirement costs of present plant will increase even more than current indications show (Robinson, page 11-12)
- Ratepayers benefit from the current depreciation proposal in the form of a lower rate base (Robinson, page 12)

I have chosen to ignore unsupported conclusionary statements such as Mr. Robinson's assertions on page 12 of his testimony that my future net salvage ratio for Services is "so far from reality that [it] is not even on the radar screen" and that "my proposal to ignore the impact of inflation on net salvage factors as well as to incorporate net salvage on a present value basis is just plain wrong."

Q. WHAT IS YOUR RESPONSE TO MR STAFFORD'S STATEMENT THAT SFAS 143 DOES NOT APPLY TO THIS PROCEEDING BECAUSE THERE ARE NO LEGAL OBLIGATIONS ASSOCIATED WITH THE RETIREMENT OF IAWC'S TRANSMISSION AND DISTRIBUTION MAINS, SERVICES, METERS AND HYDRANTS?

A. It never was my contention that SFAS 143 would necessarily apply to these facilities. My statement is that SFAS 143 provides the template for the proper accounting for future retirement costs, one that recognizes that future costs have lower value than present costs and that it is unfair to charge present ratepayers in current dollars for costs expressed in future dollars.

Q. WHAT IS YOUR RESPONSE TO THE STATEMENTS OF MESSRS. STAFFORD AND ROBINSON THAT SFAS 143 IS AN ACCOUNTING RULE THAT APPLIES TO FINANCIAL ACCOUNTING, NOT RATEMAKING?

A. It is true that the Commission is not bound by accounting rules, but it is not true that accounting and regulation are totally disconnected, as implied by Messrs Stafford and Robinson. Indeed, regulation is based on accounting and accounting concepts. Usually, when regulators depart from Generally Accepted Accounting Principals, they feel obliged to explain the reasons for that departure. Thus, if IAWC were to find that it had legal asset retirement obligations, the Commission would probably have to determine whether to adopt SFAS 143 and, if not, why not. That is what the Federal Communications Commission has done[4] and the Federal Energy Regulatory Commission ("FERC") is in the process of doing.[5]

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[4] WCB/Pricing 02-35, Order by the Chief, Wireline Competition Bureau, December 20, 2002.
[5] FERC Docket No. RM02-7-000.

However, as I noted in response to the previous question, the reason for my citation of SFAS 143 is not that it necessarily is applicable to IAWC's distribution plant, but that it provides a template for the appropriate treatment of future retirement costs.

Q. HOW DO YOU RESPOND TO MR. STAFFORD'S STATEMENT THAT THE EXISTING METHODOLOGY HAS BEEN APPROVED BY THE COMMISSION IN PREVIOUS CASES?

A. I do not question his assertion. The reason, I suspect, is that the Commission has been required to respond to the IAWC's depreciation proposals and has never had the opportunity to examine any alternatives. The existing methodology provides IAWC with a permanent and growing advance against costs it has not incurred, so it is unlikely to be challenged by IAWC. I have not seen any evidence of other parties' challenging this methodology in previous IAWC rate cases. The publishing of SFAS 143 provides a good basis for making such a challenge now.

Q. HOW DO YOU RESPOND TO MR. STAFFORD'S DENIAL THAT THE RETIREMENT COSTS RECOVERED UNDER CURRENT RATES ARE ENORMOUS?

A. They <u>are</u> enormous, as demonstrated by the following table, which covers just the four largest transmission and distribution accounts.

Table 2
Plant Balances and Removal Cost Recovery

Acct.	Description	12/31/98 Balance	Salvage	Removal Cost
331	Transmission & Distr. Mains	112,420,988	-40%	44,968,395
333	Services	35,282,323	-300%	105,846,970
334.2	Meter Installations	12,690,820	-250%	31,727,051
335	Hydrants	11,280,788	-100%	11,280,788
	Total Four Accounts	171,674,920		193,823,204

Source: AUS Consultants, IAWC Depreciation Study as of December 31, 1998.

The retirement cost that the Company is recovering for just these four accounts amounts to 62 percent of the Company's $308.7 million plant in service as of the end of 1998.

These very large retirement cost allowances might be justified if the Company actually spent that much money retiring plant. The reality is otherwise. The retirement costs collected annually through depreciation rates are multiples of the amount actual spent annually in retiring plant, as demonstrated by the following table.

Table 3
Annual Cost of Retirement ("COR") Allowances and Costs

	Mains	Services	Meter Install	Hydrants
Balance 12/31/98	112,420,988	35,282,323	12,690,820	11,280,788
Depreciation Rate	1.60%	6.48%	5.05%	3.97%
Net Salvage Ratio	40%	300%	250%	100%
Salvage Portion of Rate	0.46%	4.86%	3.60%	1.98%
Annual COR Allowance	517,137	1,714,721	456,870	223,360
Annual COR 1996-98	154,096	360,918	54,200	70,151
Multiple Allowance/Actual	3.4	4.8	8.4	3.2

Source: AUS Consultants, IAWC Depreciation Study as of December 31, 1998.

These enormous disparities between the retirement costs collected from ratepayers and the retirement costs actually incurred will continue indefinitely. The characteristic of these "mass property" accounts is that they do not consist of individual assets so much as flows of dollars – additions and retirements – into and out of the plant accounts. Those flows are not static. Each year, more new plant is added than old plant retired, and the accounts grow indefinitely. This is due not only to system growth, but also to inflation. The claim that eventually all of the removal cost allowances will be spent is a fallacy. By the time the present collections for removal costs are spent, the Company will have collected vastly more removal costs for yet another distant future generation of retirements.

The existing system for calculating retirement cost allowances results in a permanent and growing loan from ratepayers to the Company. This is the reason the Company defends this procedure so vehemently.

Q. WHAT IS YOUR RESPONSE TO MR. STAFFORDS STATEMENT THAT THE RETIREMENT COSTS RECOVERED WERE JUSTIFIED IN THE LAST CASE?

A. The data that I have presented in Tables 2 and 3 were taken from the last case. They demonstrate the enormous impact on the revenue requirement from the application of grossly overstated negative salvage ratios. They also demonstrate that the Company recovering each year at least three times the retirement costs it is spending.

The assertion that the last case "justifies" these overstated negative salvage ratios is flatly false. In my direct testimony, I demonstrate how these ratios result from a comparison of very old dollars in the salvage ratio denominator to very new dollars in the numerator.

Mr. Robinson makes much of the fact that, as a simplifying assumption, I overstated the age of recently retired Services. The average Service retired was placed in 1964, not 1923 which I used in my illustration. The Handy-Whitman construction index for Plastic Services in 1964 was 57; in 1998 it was 329.[6] The 300 percent ratio that the Company uses results from the numerator having 17 percent (57/329) of the purchasing power of the denominator. If the two were rendered to the same dollar value, the 300/100 ratio would instead be 300/577, and the negative salvage ratio would be 52 percent, not 300 percent.

[6] *The Handy-Whitman Index of Public Utility Costs*, Bulletin No. 156, Whitman, Requart & Associates

Q. WHAT IS YOUR RESPONSE TO MR. STAFFORD'S ASSERTION THAT, UNDER YOUR METHODOLOGY, CURRENT PLANT COST WOULD HAVE TO BE INFLATED TO FUTURE COSTS IN ORDER TO MATCH FUTURE NET SALVAGE RATIOS?

A. I do not understand this assertion. The SFAS approach to setting salvage ratios does not require any restatement of future net salvage. As a consequence, it does not require any restatement of current plant costs. Indeed, I have started with the Commission approved net salvage ratios. The only difference between the SFAS 143 approach and the Company's calculation of net salvage is that the former recognizes the present value of costs that will not be incurred until many years into the future. It is designed to recover fully the retirement costs by the time they are incurred. The Company's witnesses do not acknowledge this basic point.

Q. WHAT IS YOUR RESPONSE TO MR. ROBINSON'S ASSERTION THAT MY PROPOSAL UNFAIRLY "BACK LOADS" THE RECOVERY OF RETIREMENT COSTS TO THE END OF THE ASSET'S LIFE WHEN THE PROPERTY HAS THE HIGHEST LEVEL OF MAINTENANCE EXPENSE AND THE LOWEST UTILITY?

A. The "back loading" to which Mr. Robinson refers is merely the recognition that future dollars are worth less than present dollars, particularly in light of inflation. In "real" dollars of constant buying power, the Company's present system "front loads" the recovery of retirement costs by charging ratepayers with more expensive current dollars to pay for future inflated costs. Moreover, the rate base effect of any given asset's addition further front loads the burden on ratepayers. That is because the asset earns return and incurs income tax costs on the entire amount of the initial investment when the asset is first installed. As it ages, depreciation reserves build and the return and income tax requirements decline. By the end of the asset's life, it is fully depreciated, and there is no return and income tax burden on ratepayers. The present system thus front-loads the revenue requirement for any given asset.

However, as I have stated, we are not dealing with individual assets but mass property accounts consisting of multiple units of plant that flow into and out of the corporate property records. Because there is always more new plant flowing into the plant accounts than retiring plant flowing out, the present system converts "front loading" into a continuous and permanent advance from ratepayers to the Company against future retirement costs. That is why retirement costs allowances are, and will be forever (if the present system is maintained), multiples of the actual costs of retirement.

Q. WHAT IS YOUR RESPONSE TO MR. ROBINSON'S CONTENTION THAT THE SFAS 143 CREATES "INTERGENERATIONAL IINEQUITY"?

A. Nothing could be more inequitable to generations of ratepayers than the present system of charging current ratepayers for the undiscounted, inflated future cost of retirements that will not be incurred for years to come. The weighted average remaining life of the Mains account is 72 years; that of the Services account is 60 years. By the time this plant is retired, most present ratepayers, now paying for retirement costs, will be dead.

The SFAS procedure <u>does</u> collect from present ratepayers the eventual cost of retiring the plant that they use. Unlike the present system, however, it recognizes that a dollar paid today is worth much more than a dollar spent 20 or 30 years from now. Year-by-year, it recognizes the growth in the present value of that future dollar of cost. By the time the cost is incurred, the Company is fully compensated.

Q. WHAT IS YOUR RESPONSE TO THE ASSERTION BY MR. ROBINSON THAT ALL COMPONENTS OF DEPRECIATION MUST BE BASED ON A STRAIGHT LINE RECOVERY MECHANISM.

A. Straight-line recovery is appropriate for costs already incurred. This is not true of distant future costs when they are inflated for future price increases. Rather, it is more appropriate to remove the effect of future inflation and to recognize the present value of dollars collected now relative to dollars spent in the future.

Q. WHAT IS YOUR RESPONSE TO MR. ROBINSON'S CLAIM THAT ADDITIONAL INFLATION WILL CAUSE THE RETIREMENT COST OF PRESENT PLANT TO INCREASE TO LEVELS EVEN GREATER THAN SHOWN IN HIS DEPRECIATION STUDY?

A. If we were speaking purely of present plant, Mr. Robinson might have a point. As the present plant ages, retirement costs will increase to levels considerably greater than recent experience shows. But we are not speaking only of the existing plant. The Company does not propose to freeze its plant acquisition and depreciate only the installed vintages of plant. It proposes to use the current depreciation rates (or replacement rates calculated in the same manner) to depreciate all future vintages of plant as well. As a consequence, the average age of plant in service will not necessarily increase. To the contrary, if the Company expands its construction program, the average age could decrease, and the remaining life would then increase. When that happens, the average date of retirement cost incurrence will recede yet further into the future.

Q. WHAT IS YOUR RESPONSE TO MR. ROBINSON'S CLAIM THAT RATEPAYERS BENEFIT FROM THE CURRENT DEPRECIATION PRACTICE THROUGH THE LOWER RATE BASE?

A. Basically, what Mr. Robinson is arguing is that over-depreciation is good for ratepayers. Inaccuracy is never good for anyone. Even if Mr. Robinson were correct, his argument would hardly be a justification for over-depreciation. Depreciation rates should be based on accurate parameters and recovery mechanisms that are fair to ratepayers.

But it is not true that over-depreciation is good for ratepayers. I address this point in my direct testimony. Like so much else in depreciation, it is important to recognize that depreciation involves flows of plant into and out of mass property accounts. For all the major accounts, the inflow of new plant is always larger than the outflow of retiring plant. That is why, when depreciation rates are excessive, the expense of depreciating the new plant outweighs the benefit of the depreciation reserve built up by old plant. When plant is be over-depreciated, the Company is always ahead; ratepayers never catch up.

Q. WHAT ARE THE COMPANY'S WITNESSES' OBJECTIONS TO YOUR ULTIMATE RECOMMENDATION TO ASSIGN RETIREMENT COSTS OF PLANT BEING REPLACED TO THE REPLACEMENT PLANT AND TO EXPENSE THE REST ON A NORMALIZED BASIS?

A. The Company's witnesses have expressed the following objections to these proposals:

- The proposal is based on a FERC rulemaking that has not been adopted (Stafford, page 45)
- FERC has no jurisdiction over water utilities (Staffort, page 46).
- The proposal is inconsistent with the Commission's Uniform System of Accounts. The required accounting treatment is to charge retirement costs to the depreciation reserve (Robinson, page 6)
- Retirement costs have nothing to do with new plant being added.

- Incorporating retirement costs for the prior assets results in a total mismatch between the facilities being utilized and the users who benefit from those facilities.
- The proposal adds to the cost of new facilities and hence results in higher rates (Robinson, page 6-7).
- The proposal to expense retirement costs results in a shortfall in asset recovery due to retirement between rate cases (Robinson, page 7)
- The proposal to expense retirement costs results in deferral of recovery to the end of the plant life (Robinson, page 7)

Q. HOW DO YOU RESPOND TO MR. STAFFORD'S CLAIM THAT YOUR PROPOSAL IS BASED ON A FERC RULEMAKING THAT HAS NOT BEEN ADOPTED?

A. Mr. Stafford must be speaking of my proposed use of the SFAS 143 methodology, not my proposal to add retirement costs to the capital costs of replacement plant. That rule already exists in the FERC Uniform System of Accounts, as I point out in my direct testimony.

Q. HOW DO YOU RESPOND TO MR. STAFFORD'S STATEMENT THAT FERC HAS NO JURISDICTION OVER WATER UTILITIES?

A. Mr. Stafford is absolutely correct. I cite FERC's rules solely to demonstrate that my proposal is not without precedent. One of the reasons I have proposed the SFAS 143 procedure as an interim measure is that the capitalization of retirement costs into replacement plant may require a modification of the I.C.C.'s accounting rules.

Q. HOW DO YOU RESPOND TO THE STATEMENTS OF BOTH COMPANY WITNESSES THAT YOUR PROPOSAL IS INCONSISTENT WITH THE COMMISSION'S RULES?

A. My proposal for the ultimate resolution of the retirement cost issue may be inconsistent with Commission rules, and that is why I recommend the SFAS 143 procedure as an interim measure. The SFAS 143 procedure could be implemented without any change in Commission rules. All that are changed are the negative salvage ratios.

Q. WHAT IS YOUR RESPONSE TO MR. ROBINSON'S ASSERTION THAT RETIREMENT COSTS HAVE NOTHING TO DO WITH NEW PLANT BEING ADDED?

A. I quite disagree, at least with respect to mains, services, meters, and hydrants – the principal accounts at issue here. There are only four possible reasons that these facilities would be retired:

- the plant is physically deteriorated and must be replaced;
- the plant has inadequate capacity for the current and future load and must be replaced;
- the plant is technologically obsolete; or
- the customers served by the plant are no longer there.

I suspect that the overwhelming majority of the retirement from these four accounts result from the first three of these reasons. With respect to each of those reasons, there is a direct causal relationship between the retirement of the old plant and the installation of the new plant. It is therefore not at all unreasonable to incorporate the cost of removing the old plant into that of the new. Only when plant is totally abandoned and not replaced can the retirement costs be ascribed exclusively to the old plant.

As a practical matter, much of the physical operation of retiring and replacing is commingled. When a trench is dug to replace a section of main, that trenching serves both purposes: retiring the old main and placing the new one. The distinction between retirement costs and construction costs is to a large extent arbitrary. Treating the entire cost of the operation as new construction would simplify accounting in these circumstances.

Q. HOW DO YOU RESPOND TO MR. ROBINSON'S STATEMENT THAT INCORPORATION OF RETIREMENT COSTS INTO THE CAPITAL COST OF REPLACEMENT PLANT CREATES A MISMATCH BETWEEN THE COST OF THE NEW FACILITIES AND THE BENEFICIARIES OF THAT PLANT?

A. The beneficiaries of new plant that has replaced old plant are the users of the new plant. The old plant had to be removed because it was worn out, too small or obsolete. Had the old plant not been retired, those users would be served by inadequate facilities. They, much more than the users of the old plant, benefit because the old plant was retired.

Q. HOW DO YOU RESPOND TO MR. ROBINSON'S ASSERTION THAT YOUR PROPOSAL ADDS TO THE COST OF NEW FACILITIES AND RESULTS IN HIGHER RATES?

A. I acknowledge that in the short run my proposal adds marginally to the cost of new plant, but it does not result in higher rates in the long run. It is much cheaper for ratepayers to pay depreciation on removal costs that have already incurred than to pay the future projected, inflated costs of future removal that has not yet occurred.

Q. HOW DO YOU RESPOND TO MR. ROBINSON'S ASSERTION THAT THE COMPANY WILL REALIZE A SHORTFALL IN ASSET RECOVERY DUE TO RETIREMENTS THAT OCCUR BETWEEN RATE CASES?

A. My proposal to "expense" the normalized amount of removal costs is possibly misunderstood. This cost would continue to be recovered through negative salvage ratios. Effectively, the current procedure for computing these ratios would be followed except that the denominator of the salvage ratio would not be the original cost of the plant retired, but the original cost of all plant in service. As plant in service increases between rate cases, so the recovery of retirement costs would increase. There is no reason to believe that the Company would incur any shortfall in its cost recovery.

Q. HOW DO YOU RESPOND TO THE MR. ROBINSON'S ASSERTION THAT YOUR PROPOSAL TO EXPENSE RETIREMENT COSTS WOULD DEFER RECOVERY TO THE END OF THE PLANT LIFE?

A. There is no basis for this assertion. Retirement costs would be recovered as they are incurred. What would cease to exist is the permanent and growing advance that the present system extracts from ratepayers against future inflated costs without recognition of present value.

The exception might be large, single assets such as water treatment plants. For these assets, the appropriate mechanism for recovering retirement costs is the SFAS 143 procedure, regardless of whether the Company has a legal obligation to retire the plant. As discussed earlier, this mechanism properly reflects the time value of money to both ratepayers and the Company.

<u>WHOLESALE RATE PROPOSAL</u>

Q. WHAT IS THE OBJECTIVE OF THIS PORTION OF YOUR TESTIMONY?

A. In this portion of my testimony, I present a revised version of my cost of service study using the Staff's proposed rates for the Southern Division. I also respond to some of the comments by IAWC witness Stafford concerning the proposal in my initial testimony for a wholesale rate classification.

Q. PLEASE DESCRIBE YOUR REVISED COST OF SERVICE STUDY.

A. O'Fallon Exhibit R1.1 is my revised cost of service study. In this study, I have input the data used by Staff witness Mike Luth for the Southern and Peoria Districts, including his proposed rates.

I have also modified the reallocation procedure to apply the General and Administrative overheads to expenses only, rather than to the revenue requirement; to separate A&G allocators for each of the categories of cost, base, peak day, peak hour; and to use the same pre-tax rate of return for the reallocated plant as for all plant.

Q. WHAT DOES YOUR REVISED COST OF SERVICE STUDY SHOW?

A. It continues to show that the "Sales for Resale" classification earns well above the system average, as follows:

Residential	109%
Commercial	105%
Industrial	68%
Large Industrial	71%
Public Authority	95%
Sales for Resale	**117%**
Non-metered	60%
Total	100%

Q. HAVE YOU COMPUTED THE ADJUSTMENT TO THE STAFF RATE THAT WOULD BE REQUIRED TO MATCH THE SALES FOR RESALE RATE TO ITS COST INCURRENCE?

A. Yes. Exhibit R1.2 presents the same calculation as I presented in O'Fallon Exhibit 1.7. It shows that the single wholesale rate should be set at $1.13 per 100 cubic feet if Staff rates are adopted. If Staff's rate structure is adopted but the revenue requirement is different, then the Wholesale rate should be set 21.9 percent lower than the tail block of the Southern Division usage charges.

Q. AT PAGE 48 OF HIS TESTIMONY, MR. STAFFORD STATES THAT HIS COUNSEL HAS ADVISED HIM THAT AS A MATTER OF LAW, MY PROPOSAL IS BEYOND THE SCOPE OF THIS PROCEEDING. DOES YOUR COUNSEL AGREE?

A. No, he does not.

Q. ALSO ON PAGE 48 OF HIS TESTIMONY, MR. STAFFORD STATES THAT O'FALLON HAS NOT PROVIDED ADEQUATE INFORMATION ON ITS PEAK USAGE AND STORAGE BY WHICH TO JUDGE THE PROPRIETY OF YOUR WHOLESALE RATE PROPOSAL. WHAT IS YOUR RESPONSE TO THESE COMMENTS?

A. First of all, O'Fallon has provided detailed information regarding the location, type and capacity of its storage facilities. What O'Fallon cannot provide is the level and timing of its peak hour and peak day consumption. That information is in the hands of IAWC, which owns and reads the meters that record O'Fallon's consumption. O'Fallon's practice is to draw water from the IAWC system primarily during the hours of 11 pm to 4 am in order to fill its storage facilities. These, of course, are the lowest hours for IAWC's own system. However, O'Fallon has no way of measuring hourly consumption either of its system or of the customers that are on its system.

For IAWC to assert that my proposal is without merit by reason of inadequate data is therefore a self-fulfilling claim. IAWC has the data by which to determine the propriety of my recommendation. It has simply declined to access it. O'Fallon respectfully requests that the Commission require IAWC to provide the required data on O'Fallon's average, peak day and peak hour consumption.

Q. MR. STAFFORD STATES THAT O'FALLON MIGHT QUALIFY FOR THE LARGE WATER USER TARIFF RATE. IS THIS CORRECT?

A. Again, only the Company can advise O'Fallon on this matter, as the Company has the necessary data by which to determine O'Fallon's suitability for this rate. It is unlikely, however, that O'Fallon would benefit. The Large Water User rate rewards large consumers whose daily consumption is not significantly greater than its average consumption. Since O'Fallon serves primarily residential customers, it is unlikely that its peak day demand is close to its average day demand. The basis of O'Fallon's savings to the Company is in its ability to shave the peak <u>hour</u> demand through the use of its storage facilities.

Q. MR. STAFFORD ALSO STATES THAT O'FALLON MIGHT QUALIFY FOR THE COMPETITIVE ALTERNATIVE TARIFF. WHAT IS YOUR RESPONSE?

A. I understand that O'Fallon and the Company are in active negotiation with respect to this possibility. The success, or lack thereof, of these negotiations will probably determine O'Fallon's continued participation in this case, and its ultimate decision to become independent of IAWC.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Charles W. King
City of O'Fallon

REBUTTAL TESTIMONY OF CHARLES W. KING

INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Charles W. King. I am president of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. My business address is Suite 410, 1220 L Street, N.W., Washington, DC 20005.

Q. FOR WHOM ARE YOU APPEARING IN THIS CASE?

A. I am appearing on behalf of the City of O'Fallon, Illinois.

Q. ARE YOU THE SAME CHARLES W. KING WHO SUBMITTED DIRECT TESTIMONY ON BEHALF OF THE CITY OF O'FALLON IN THIS CASE ON FEBRUARY 5, 2003?

A. Yes, I am.

Q. DOES THAT TESTIMONY CONTAIN DESCRIPTIONS OF YOUR EXPERIENCE AND QUALIFICATIONS?

A. Yes, it does. Exhibit 1.1 to that testimony is a resume of my experience. Exhibit 1.2 is a listing of my expert witness appearances before regulatory agencies.

Q. DO YOU HAVE ANY CORRECTIONS TO MAKE TO YOUR DIRECT TESTIMONY?

A. Yes. On page 9 of my prefiled direct testimony, at line 30, the word "prices" should be changed to "yields," so that the line reads, "...their stocks will trade at high yields, and the rate of return indicators..."

On page 34, at line 16, the number "150" should be changed to 70; on line 18, the number "$145.6" should be changed to "$145.9;" and the number "$218.4" should be changed to "$102.1." The entire paragraph should read as follows:

> "They are enormous. For IAWC's largest single plant account, Transmission and Distribution Mains (#331.11), retirement costs amount to 70 percent of the original cost. The test year amount in this account for the Southern/Peoria/Streator/Pontiac Districts is $145.9 million. The retirement cost that is being depreciated is therefore $102.1 million."

I should also correct a column heading on O'Fallon Exhibit 1.4. Column B of that exhibit should read, "Discount @ 5.01%." A revised version of that exhibit is attached.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My Direct Testimony addressed three topics, rate of return, depreciation, and the need for a wholesale rate classification. This rebuttal testimony will address the representations of the other parties that have been made with respect to these issues. First, I will respond to the agreement among the Commission Staff ("Staff"), the Illinois-American Water Company ("IAWC" or "the Company"), and the Illinois Large Water Consumers ("ILWC") regarding the cost of IAWC's equity capital. I will also address the capital structure proposed by Staff witness Sheena Kight.

I will next respond to the rebuttal testimony of IAWC witnesses Ronald Stafford and Earl Robinson concerning my proposed treatment of retirement costs.

Finally, I will present a revised cost of service study for wholesale customers in the Southern Division. That study will show the adjustments that should be made to the rate structures recommended by the Company, Staff and the Attorney General to recognize the characteristics of wholesale customers. I will conclude by responding to the comments of IAWC witness Stafford concerning my wholesale rate proposal.

RATE OF RETURN

Q. WHAT RATE OF RETURN HAVE THE STAFF, THE COMPANY AND ILWC AGREED TO RECOMMEND TO THE COMMISSION?

A. Mr. Moul reports that these parties have agreed to the Staff's recommended rate of return to equity. In her original testimony, Staff witness Sheena Kight recommended a return to equity of 10.24 percent, but I have received a revised version of Ms. Kight's Schedule 6.01 that shows a return to equity of 10.27 percent. I presume that this is the agreed value that these parties will recommend to the Commission.

Q. IS THIS RECOMMENDATION REASONABLE?

A. No. The Commission's last equity return finding for IAWC was 10.20 percent in Docket No. 00-0340, decided on February 15, 2000. This value is seven basis points lower than the 10.27 percent that Staff witness Kight has recommended. As I point out in my direct testimony, interest rates have declined since February 2000. In February of 2003, the yield on 10-year Treasury bonds was 3.90 percent, which is 262 basis points lower than the 6.52 percent yield on the same bonds when the Commission last set IAWC's equity return. Yields on high-grade corporate bonds were 6.98 percent when the Commission last examined IAWC's equity return. In February of this year, they were 5.95 percent. Baa corporate bonds were yielding 8.29 percent in February 2000; three years later they were yielding 7.06 percent.[1]

While I do not contend that required equity returns have declined in lock step with interest rates, it is inconceivable that they have increased. Accordingly, there is no justification whatever for assuming that IAWC's equity cost is higher now than it was two years ago. Yet, that is Ms. Kight's assumption.

Q. WHY HAS MS. KIGHT ARRIVED AT A HIGHER RATE OF RETURN THAN YOU BELIEVE JUSTIFIED BY THE TREND IN INTEREST RATES?

A. Ms. Kight has committed the same two fundamental errors that IAWC witness Paul Moul committed. First, she has included gas distribution in her comparison samples for purposes of her Discounted Cash Flow ("DCF") analysis. Second, she has relied on the Capital Asset Pricing Model ("CAPM"), which is an unreliable and somewhat subjective measure of equity return.

Q. WHY IS IT AN ERROR FOR MS. KIGHT TO INCLUDE GAS DISTRIBUTION COMPANIES IN HER SAMPLE OF COMPARISON COMPANIES?

A. At pages 11 and 12 of my prefiled direct testimony, I present a number of reasons why the business risk of gas distribution companies is greater than that of water companies. I point out that IAWC witness Paul Moul's own data demonstrate that investors find gas distribution companies to be more risky than water companies. He finds that the DCF rate of return for gas distribution companies is 11.97 percent, while that for water companies is only 9.68 percent. This difference of 229 basis points is too great to be discounted as a mere chance

[1] www.federalreserve.gov/releases/h15

happening created by data variability. It has to reflect perceived differences in risk.

Ms. Kight finds much the same thing. Her DCF analysis develops a required return to gas distribution companies of 10.64 percent, but her return to water companies is only 9.39 percent. She provides no explanation for the 125 basis point difference between these two values. Instead, she regards that an average of the returns to gas and water companies is appropriate for IAWC, which is exclusively a water company. However, since gas company returns are not relevant or appropriate, factoring them into an "average" leaves the average irrelevant and inappropriate.

Q. WHY DO YOU OBJECT TO MS. KIGHT'S RELIANCE ON THE CAPITAL ASSET PRICING MODEL?

A. What Ms. Kight refers to as her "Risk Premium Analysis" is in fact the Capital Asset Pricing Model, at least as described by Mr. Moul. It encounters all of the problems that I discuss on pages 22 and 23 of my direct testimony.

Ms. Kight does a rather better job of describing the risk-free rate of return than does Mr. Moul, but her discussion still conveys the very great amount of discretion that goes into selecting this basic measure. I question her conclusion that because common equity theoretically has an infinite life, its market-required rate of return reflects the inflation and real risk-free rates anticipated to prevail over the long run.[2] While common equity may have an infinite life, the average holding time of most common shares is not indefinite. It varies from company to company, and it does conform to any given period.

Ms. Kight uses "adjusted" betas and those of Value Line, which are also adjusted. The adjustment assumes that there is an irreducible minimum value to beta of .35

[2] ICC Staff Exhibit 6.0 (Kight Testimony), page 23.

to which the specific beta of the firm or portfolio should be added. The source of this .35 minimum beta is an article by Marshall E. Blume that was published in the March 1971 issue of The Journal of Finance. The cause of the .35 minimum beta is the period-to-period relationship of portfolios of stock. The .35 is the intercept of regressions of beta coefficients of these portfolios from one period to the next as measured by portfolios dating from 1933 to 1968.

Ms. Kight asserts two reasons for using these adjusted betas. First, betas tend to regress towards the market mean value of 1.0 over time, and second, empirical tests suggest that the relationship between risk and required return is flatter than the raw betas predict. The first of these reasons is true for portfolios of stocks, because as time goes on, the benefits of diversification tend to apply to any portfolio, even one with a very low or very high beta. This is true of portfolios, but it does not follow that the beta of an individual stock tends towards 1.0. I accept that the second reason is correct, simply because, as I discussed in my direct testimony, the assumption of linearity between beta and relative risk leads to absurd conclusions.

In any case, Mr. Kight's CAPM analysis displays the extreme sensitivity of this approach to the analyst's selection of parameters. For example, had Ms. Kight picked as her risk-free rate the 10-year Treasury yield of 3.9 percent (February 2003)[3] instead of the long-term Treasury yield, her CAPM return for water companies would have been 8.77 percent instead of 10.11 percent. If she had just used her .44 regression beta, rather than the .52 average of that beta and Value Line's beta, her water company return would have been 9.40 percent, matching almost exactly her DCF return.

Q. WHAT RATE OF EQUITY RETURN IS APPROPRIATE FOR IAWC BASED ON MS. KIGHT'S TESTIMONY?

[3] www.federalreserve.gov/releases/h15

A. If we simply disregard her gas distribution companies, and apply her method of selecting an equity return allowance just to the water companies, the rate of equity return would be the average of her 9.39 percent DCF return and her 10.11 percent risk premium return, or 9.75 percent. Adding the two basis points for flotation costs yields an allowed return of 9.77 percent.

If we accept only Ms. Kight's beta regression and not that of Value Line, we have a consensus finding of 9.4 percent using both the DCF and the risk premium approaches. Adding the two basis points for flotation costs produces a rate of equity return of 9.42 percent.

These rates of return pertain to Ms. Kight's sample of eight water companies, all of which are much smaller than the IAWC's parent company, American Water Works, or its new parent, RWE Aktiegesellchaft. Mr. Moul claims that small companies incur greater risk than large companies. If so, then the rate of return should be lower than the 9.4 percent developed by Ms. Kight.

Q. DO YOU AGREE WITH MS. KIGHT'S CAPITAL STRUCTURE?

A. I do, but with one relatively small exception. I question the propriety of including any added equity to reflect the increased revenue resulting from this rate case. As I point out in my direct testimony, this practice has the effect of making the rate case circular. The greater the rate increase, the more the retained earnings, the higher the cost of capital, and the greater the rate increase. Admittedly, the effect is not dollar-for-dollar, but I believe it is a poor regulatory practice to have any component of the revenue requirement influenced by the level of revenue to be allowed in the rate case at hand.

Q. ACCEPTING THE RATE OF EQUITY RETURN WHICH MS. KIGHT'S TESTIMONY INDICATES, WHAT IS THE COMPOSITE COST OF CAPITAL TO IAWC?

A. The data presented on Ms. Kight's Revised Schedule 6.01 indicate the following composite cost of capital:

Table 1
Cost of Capital – Illinois-American Water Company

Class of Capital	Amount	Percent	Cost	Weighted Cost
Short-Term Debt	9,707,764	1.81%	1.60%	0.03%
Long-Term Debt	284,559,791	53.08%	5.06%	2.69%
Common Equity	241,836,431	45.11%	9.42%	4.25%
Total	536,103,986	100.00%		6.96%

This revised rate of return of 6.96 percent based on Staff's presentation is actually slightly lower than the 7.14 percent that I recommended in my direct testimony.

RETIREMENT COSTS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR REBUTTAL TESTIMONY?

A. In this section of my rebuttal testimony, I will respond to the objections to my proposed treatment of retirement costs that are stated in the testimonies of IAWC witnesses Ronald Stafford and Earl Robinson.

Q. PLEASE RESTATE BRIEFLY YOUR PROPOSED TREATMENT OF RETIREMENT COST.

A. In my direct testimony, I propose as an interim measure that retirement costs be treated in manner set forth in Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*. Unlike the present treatment of retirement costs, SFAS 143 recognizes the lower present value of retirement costs that will not be incurred until many years into the future. It requires that those costs be stated at their present value using a risk-free interest rate as the discount factor. That restated value is amortized each year over the life of the asset. Because the present value increases each year as the asset ages and the retirement costs approach, a second cost must be recognized, and that is the increment in the present value of the retirement costs. These two components, amortization of the present value of the retirement costs and the increment in that present value, constitute the appropriate recovery of retirement costs that should be built into the depreciation rates.

In O'Fallon Exhibit 1.4, I calculate the negative salvage ratios based on the present value of the retirement costs. I discount the existing negative salvage ratios based on the remaining life of each account for which retirement costs are incurred. I also present the increment in the present value of those retirement cost. In O'Fallon Exhibit 1.5, I demonstrate that application of these rates to the Company's test year plant investment would reduce depreciation expense for the Southern/Peoria/Streator/Pontiac Districts by $4.25 million.

I recommend the SFAS 143 treatment only as an interim measure, except possibly for large, individual assets such as treatment plants. The long run solution to the problem of retirement costs for "mass property" accounts is to incorporate the retirement costs of pipes, meters, hydrants or other plant into the capital cost of the replacement facilities. The remaining retirement costs of abandoned facilities that are not replaced should be incorporated into depreciation rates based on the relationship of a five-year average of such costs to total plant in service.

Q. WHAT ARE THE OBJECTIONS OF MESSRS. STAFFORD AND ROBINSON TO YOUR PROPOSED SFAS 143 TREATMENT?

A. Their objections can be summarized as follows:

- SFAS 143 does not apply to ratemaking in this proceeding because there are no legal obligations associated with the retirement of IAWC's transmission and distribution mains, services, meters, and hydrants (Stafford, page 42).
- SFAS 143 is an accounting rule that applies to financial accounting, not ratemaking (Stafford, page 43; Robinson, pages 5, 8).
- The existing methodology has been approved by the Commission (Stafford, page 43)
- The retirement costs recovered under the current system are not enormous (Stafford, page 43-44)
- The retirement costs recovered under the current system are justified by data presented in the last case (Stafford, page 43-44).
- Under my approach, current plant costs would have to be inflated up to future costs in order to match net salvage values (Stafford, page 45).
- The SFAS 143 approach unfairly "back loads" the recovery of retirement costs to the end of its life when the property has the highest level of maintenance expense and the lowest level of utility (Robinson, page 8).
- The SFAS 143 procedure will create "intergenerational inequity" (Robinson, page 9)
- All components of depreciation must be based upon a straight line recovery mechanism (Robinson, pages 9,13)
- Additional inflation will cause future retirements to cost more than current retirements so that the retirement costs of present plant will increase even more than current indications show (Robinson, page 11-12)
- Ratepayers benefit from the current depreciation proposal in the form of a lower rate base (Robinson, page 12)

I have chosen to ignore unsupported conclusionary statements such as Mr. Robinson's assertions on page 12 of his testimony that my future net salvage ratio for Services is "so far from reality that [it] is not even on the radar screen" and that "my proposal to ignore the impact of inflation on net salvage factors as well as to incorporate net salvage on a present value basis is just plain wrong."

Q. WHAT IS YOUR RESPONSE TO MR STAFFORD'S STATEMENT THAT SFAS 143 DOES NOT APPLY TO THIS PROCEEDING BECAUSE THERE ARE NO LEGAL OBLIGATIONS ASSOCIATED WITH THE RETIREMENT OF IAWC'S TRANSMISSION AND DISTRIBUTION MAINS, SERVICES, METERS AND HYDRANTS?

A. It never was my contention that SFAS 143 would necessarily apply to these facilities. My statement is that SFAS 143 provides the template for the proper accounting for future retirement costs, one that recognizes that future costs have lower value than present costs and that it is unfair to charge present ratepayers in current dollars for costs expressed in future dollars.

Q. WHAT IS YOUR RESPONSE TO THE STATEMENTS OF MESSRS. STAFFORD AND ROBINSON THAT SFAS 143 IS AN ACCOUNTING RULE THAT APPLIES TO FINANCIAL ACCOUNTING, NOT RATEMAKING?

A. It is true that the Commission is not bound by accounting rules, but it is not true that accounting and regulation are totally disconnected, as implied by Messrs Stafford and Robinson. Indeed, regulation is based on accounting and accounting concepts. Usually, when regulators depart from Generally Accepted Accounting Principals, they feel obliged to explain the reasons for that departure. Thus, if IAWC were to find that it had legal asset retirement obligations, the Commission would probably have to determine whether to adopt SFAS 143 and, if not, why not. That is what the Federal Communications Commission has done[4] and the Federal Energy Regulatory Commission ("FERC") is in the process of doing.[5]

[4] WCB/Pricing 02-35, Order by the Chief, Wireline Competition Bureau, December 20, 2002.
[5] FERC Docket No. RM02-7-000.

However, as I noted in response to the previous question, the reason for my citation of SFAS 143 is not that it necessarily is applicable to IAWC's distribution plant, but that it provides a template for the appropriate treatment of future retirement costs.

Q. HOW DO YOU RESPOND TO MR. STAFFORD'S STATEMENT THAT THE EXISTING METHODOLOGY HAS BEEN APPROVED BY THE COMMISSION IN PREVIOUS CASES?

A. I do not question his assertion. The reason, I suspect, is that the Commission has been required to respond to the IAWC's depreciation proposals and has never had the opportunity to examine any alternatives. The existing methodology provides IAWC with a permanent and growing advance against costs it has not incurred, so it is unlikely to be challenged by IAWC. I have not seen any evidence of other parties' challenging this methodology in previous IAWC rate cases. The publishing of SFAS 143 provides a good basis for making such a challenge now.

Q. HOW DO YOU RESPOND TO MR. STAFFORD'S DENIAL THAT THE RETIREMENT COSTS RECOVERED UNDER CURRENT RATES ARE ENORMOUS?

A. They <u>are</u> enormous, as demonstrated by the following table, which covers just the four largest transmission and distribution accounts.

Table 2
Plant Balances and Removal Cost Recovery

Acct.	Description	12/31/98 Balance	Salvage	Removal Cost
331	Transmission & Distr. Mains	112,420,988	-40%	44,968,395
333	Services	35,282,323	-300%	105,846,970
334.2	Meter Installations	12,690,820	-250%	31,727,051
335	Hydrants	11,280,788	-100%	11,280,788
	Total Four Accounts	171,674,920		193,823,204

Source: AUS Consultants, IAWC Depreciation Study as of December 31, 1998.

The retirement cost that the Company is recovering for just these four accounts amounts to 62 percent of the Company's $308.7 million plant in service as of the end of 1998.

These very large retirement cost allowances might be justified if the Company actually spent that much money retiring plant. The reality is otherwise. The retirement costs collected annually through depreciation rates are multiples of the amount actual spent annually in retiring plant, as demonstrated by the following table.

Table 3
Annual Cost of Retirement ("COR") Allowances and Costs

	Mains	Services	Meter Install	Hydrants
Balance 12/31/98	112,420,988	35,282,323	12,690,820	11,280,788
Depreciation Rate	1.60%	6.48%	5.05%	3.97%
Net Salvage Ratio	40%	300%	250%	100%
Salvage Portion of Rate	0.46%	4.86%	3.60%	1.98%
Annual COR Allowance	517,137	1,714,721	456,870	223,360
Annual COR 1996-98	154,096	360,918	54,200	70,151
Multiple Allowance/Actual	3.4	4.8	8.4	3.2

Source: AUS Consultants, IAWC Depreciation Study as of December 31, 1998.

These enormous disparities between the retirement costs collected from ratepayers and the retirement costs actually incurred will continue indefinitely. The characteristic of these "mass property" accounts is that they do not consist of individual assets so much as flows of dollars – additions and retirements – into and out of the plant accounts. Those flows are not static. Each year, more new plant is added than old plant retired, and the accounts grow indefinitely. This is due not only to system growth, but also to inflation. The claim that eventually all of the removal cost allowances will be spent is a fallacy. By the time the present collections for removal costs are spent, the Company will have collected vastly more removal costs for yet another distant future generation of retirements.

The existing system for calculating retirement cost allowances results in a permanent and growing loan from ratepayers to the Company. This is the reason the Company defends this procedure so vehemently.

Q. WHAT IS YOUR RESPONSE TO MR. STAFFORDS STATEMENT THAT THE RETIREMENT COSTS RECOVERED WERE JUSTIFIED IN THE LAST CASE?

A. The data that I have presented in Tables 2 and 3 were taken from the last case. They demonstrate the enormous impact on the revenue requirement from the application of grossly overstated negative salvage ratios. They also demonstrate that the Company recovering each year at least three times the retirement costs it is spending.

The assertion that the last case "justifies" these overstated negative salvage ratios is flatly false. In my direct testimony, I demonstrate how these ratios result from a comparison of very old dollars in the salvage ratio denominator to very new dollars in the numerator.

Mr. Robinson makes much of the fact that, as a simplifying assumption, I overstated the age of recently retired Services. The average Service retired was placed in 1964, not 1923 which I used in my illustration. The Handy-Whitman construction index for Plastic Services in 1964 was 57; in 1998 it was 329.[6] The 300 percent ratio that the Company uses results from the numerator having 17 percent (57/329) of the purchasing power of the denominator. If the two were rendered to the same dollar value, the 300/100 ratio would instead be 300/577, and the negative salvage ratio would be 52 percent, not 300 percent.

[6] *The Handy-Whitman Index of Public Utility Costs,* Bulletin No. 156, Whitman, Requart & Associates

Q. WHAT IS YOUR RESPONSE TO MR. STAFFORD'S ASSERTION THAT, UNDER YOUR METHODOLOGY, CURRENT PLANT COST WOULD HAVE TO BE INFLATED TO FUTURE COSTS IN ORDER TO MATCH FUTURE NET SALVAGE RATIOS?

A. I do not understand this assertion. The SFAS approach to setting salvage ratios does not require any restatement of future net salvage. As a consequence, it does not require any restatement of current plant costs. Indeed, I have started with the Commission approved net salvage ratios. The only difference between the SFAS 143 approach and the Company's calculation of net salvage is that the former recognizes the present value of costs that will not be incurred until many years into the future. It is designed to recover fully the retirement costs by the time they are incurred. The Company's witnesses do not acknowledge this basic point.

Q. WHAT IS YOUR RESPONSE TO MR. ROBINSON'S ASSERTION THAT MY PROPOSAL UNFAIRLY "BACK LOADS" THE RECOVERY OF RETIREMENT COSTS TO THE END OF THE ASSET'S LIFE WHEN THE PROPERTY HAS THE HIGHEST LEVEL OF MAINTENANCE EXPENSE AND THE LOWEST UTILITY?

A. The "back loading" to which Mr. Robinson refers is merely the recognition that future dollars are worth less than present dollars, particularly in light of inflation. In "real" dollars of constant buying power, the Company's present system "front loads" the recovery of retirement costs by charging ratepayers with more expensive current dollars to pay for future inflated costs. Moreover, the rate base effect of any given asset's addition further front loads the burden on ratepayers. That is because the asset earns return and incurs income tax costs on the entire amount of the initial investment when the asset is first installed. As it ages, depreciation reserves build and the return and income tax requirements decline. By the end of the asset's life, it is fully depreciated, and there is no return and income tax burden on ratepayers. The present system thus front-loads the revenue requirement for any given asset.

However, as I have stated, we are not dealing with individual assets but mass property accounts consisting of multiple units of plant that flow into and out of the corporate property records. Because there is always more new plant flowing into the plant accounts than retiring plant flowing out, the present system converts "front loading" into a continuous and permanent advance from ratepayers to the Company against future retirement costs. That is why retirement costs allowances are, and will be forever (if the present system is maintained), multiples of the actual costs of retirement.

Q. WHAT IS YOUR RESPONSE TO MR. ROBINSON'S CONTENTION THAT THE SFAS 143 CREATES "INTERGENERATIONAL IINEQUITY"?

A. Nothing could be more inequitable to generations of ratepayers than the present system of charging current ratepayers for the undiscounted, inflated future cost of retirements that will not be incurred for years to come. The weighted average remaining life of the Mains account is 72 years; that of the Services account is 60 years. By the time this plant is retired, most present ratepayers, now paying for retirement costs, will be dead.

The SFAS procedure <u>does</u> collect from present ratepayers the eventual cost of retiring the plant that they use. Unlike the present system, however, it recognizes that a dollar paid today is worth much more than a dollar spent 20 or 30 years from now. Year-by-year, it recognizes the growth in the present value of that future dollar of cost. By the time the cost is incurred, the Company is fully compensated.

Q. WHAT IS YOUR RESPONSE TO THE ASSERTION BY MR. ROBINSON THAT ALL COMPONENTS OF DEPRECIATION MUST BE BASED ON A STRAIGHT LINE RECOVERY MECHANISM.

A. Straight-line recovery is appropriate for costs already incurred. This is not true of distant future costs when they are inflated for future price increases. Rather, it is more appropriate to remove the effect of future inflation and to recognize the present value of dollars collected now relative to dollars spent in the future.

Q. WHAT IS YOUR RESPONSE TO MR. ROBINSON'S CLAIM THAT ADDITIONAL INFLATION WILL CAUSE THE RETIREMENT COST OF PRESENT PLANT TO INCREASE TO LEVELS EVEN GREATER THAN SHOWN IN HIS DEPRECIATION STUDY?

A. If we were speaking purely of present plant, Mr. Robinson might have a point. As the present plant ages, retirement costs will increase to levels considerably greater than recent experience shows. But we are not speaking only of the existing plant. The Company does not propose to freeze its plant acquisition and depreciate only the installed vintages of plant. It proposes to use the current depreciation rates (or replacement rates calculated in the same manner) to depreciate all future vintages of plant as well. As a consequence, the average age of plant in service will not necessarily increase. To the contrary, if the Company expands its construction program, the average age could decrease, and the remaining life would then increase. When that happens, the average date of retirement cost incurrence will recede yet further into the future.

Q. WHAT IS YOUR RESPONSE TO MR. ROBINSON'S CLAIM THAT RATEPAYERS BENEFIT FROM THE CURRENT DEPRECIATION PRACTICE THROUGH THE LOWER RATE BASE?

A. Basically, what Mr. Robinson is arguing is that over-depreciation is good for ratepayers. Inaccuracy is never good for anyone. Even if Mr. Robinson were correct, his argument would hardly be a justification for over-depreciation. Depreciation rates should be based on accurate parameters and recovery mechanisms that are fair to ratepayers.

But it is not true that over-depreciation is good for ratepayers. I address this point in my direct testimony. Like so much else in depreciation, it is important to recognize that depreciation involves flows of plant into and out of mass property accounts. For all the major accounts, the inflow of new plant is always larger than the outflow of retiring plant. That is why, when depreciation rates are excessive, the expense of depreciating the new plant outweighs the benefit of the depreciation reserve built up by old plant. When plant is be over-depreciated, the Company is always ahead; ratepayers never catch up.

Q. WHAT ARE THE COMPANY'S WITNESSES' OBJECTIONS TO YOUR ULTIMATE RECOMMENDATION TO ASSIGN RETIREMENT COSTS OF PLANT BEING REPLACED TO THE REPLACEMENT PLANT AND TO EXPENSE THE REST ON A NORMALIZED BASIS?

A. The Company's witnesses have expressed the following objections to these proposals:

- The proposal is based on a FERC rulemaking that has not been adopted (Stafford, page 45)
- FERC has no jurisdiction over water utilities (Staffort, page 46).
- The proposal is inconsistent with the Commission's Uniform System of Accounts. The required accounting treatment is to charge retirement costs to the depreciation reserve (Robinson, page 6)
- Retirement costs have nothing to do with new plant being added.

- Incorporating retirement costs for the prior assets results in a total mismatch between the facilities being utilized and the users who benefit from those facilities.
- The proposal adds to the cost of new facilities and hence results in higher rates (Robinson, page 6-7).
- The proposal to expense retirement costs results in a shortfall in asset recovery due to retirement between rate cases (Robinson, page 7)
- The proposal to expense retirement costs results in deferral of recovery to the end of the plant life (Robinson, page 7)

Q. HOW DO YOU RESPOND TO MR. STAFFORD'S CLAIM THAT YOUR PROPOSAL IS BASED ON A FERC RULEMAKING THAT HAS NOT BEEN ADOPTED?

A. Mr. Stafford must be speaking of my proposed use of the SFAS 143 methodology, not my proposal to add retirement costs to the capital costs of replacement plant. That rule already exists in the FERC Uniform System of Accounts, as I point out in my direct testimony.

Q. HOW DO YOU RESPOND TO MR. STAFFORD'S STATEMENT THAT FERC HAS NO JURISDICTION OVER WATER UTILITIES?

A. Mr. Stafford is absolutely correct. I cite FERC's rules solely to demonstrate that my proposal is not without precedent. One of the reasons I have proposed the SFAS 143 procedure as an interim measure is that the capitalization of retirement costs into replacement plant may require a modification of the I.C.C.'s accounting rules.

Q. HOW DO YOU RESPOND TO THE STATEMENTS OF BOTH COMPANY WITNESSES THAT YOUR PROPOSAL IS INCONSISTENT WITH THE COMMISSION'S RULES?

A. My proposal for the ultimate resolution of the retirement cost issue may be inconsistent with Commission rules, and that is why I recommend the SFAS 143 procedure as an interim measure. The SFAS 143 procedure could be implemented without any change in Commission rules. All that are changed are the negative salvage ratios.

Q. WHAT IS YOUR RESPONSE TO MR. ROBINSON'S ASSERTION THAT RETIREMENT COSTS HAVE NOTHING TO DO WITH NEW PLANT BEING ADDED?

A. I quite disagree, at least with respect to mains, services, meters, and hydrants – the principal accounts at issue here. There are only four possible reasons that these facilities would be retired:

- the plant is physically deteriorated and must be replaced;
- the plant has inadequate capacity for the current and future load and must be replaced;
- the plant is technologically obsolete; or
- the customers served by the plant are no longer there.

I suspect that the overwhelming majority of the retirement from these four accounts result from the first three of these reasons. With respect to each of those reasons, there is a direct causal relationship between the retirement of the old plant and the installation of the new plant. It is therefore not at all unreasonable to incorporate the cost of removing the old plant into that of the new. Only when plant is totally abandoned and not replaced can the retirement costs be ascribed exclusively to the old plant.

As a practical matter, much of the physical operation of retiring and replacing is commingled. When a trench is dug to replace a section of main, that trenching serves both purposes: retiring the old main and placing the new one. The distinction between retirement costs and construction costs is to a large extent arbitrary. Treating the entire cost of the operation as new construction would simplify accounting in these circumstances.

Q. HOW DO YOU RESPOND TO MR. ROBINSON'S STATEMENT THAT INCORPORATION OF RETIREMENT COSTS INTO THE CAPITAL COST OF REPLACEMENT PLANT CREATES A MISMATCH BETWEEN THE COST OF THE NEW FACILITIES AND THE BENEFICIARIES OF THAT PLANT?

A. The beneficiaries of new plant that has replaced old plant are the users of the new plant. The old plant had to be removed because it was worn out, too small or obsolete. Had the old plant not been retired, those users would be served by inadequate facilities. They, much more than the users of the old plant, benefit because the old plant was retired.

Q. HOW DO YOU RESPOND TO MR. ROBINSON'S ASSERTION THAT YOUR PROPOSAL ADDS TO THE COST OF NEW FACILITIES AND RESULTS IN HIGHER RATES?

A. I acknowledge that in the short run my proposal adds marginally to the cost of new plant, but it does not result in higher rates in the long run. It is much cheaper for ratepayers to pay depreciation on removal costs that have already incurred than to pay the future projected, inflated costs of future removal that has not yet occurred.

Q. HOW DO YOU RESPOND TO MR. ROBINSON'S ASSERTION THAT THE COMPANY WILL REALIZE A SHORTFALL IN ASSET RECOVERY DUE TO RETIREMENTS THAT OCCUR BETWEEN RATE CASES?

A. My proposal to "expense" the normalized amount of removal costs is possibly misunderstood. This cost would continue to be recovered through negative salvage ratios. Effectively, the current procedure for computing these ratios would be followed except that the denominator of the salvage ratio would not be the original cost of the plant retired, but the original cost of all plant in service. As plant in service increases between rate cases, so the recovery of retirement costs would increase. There is no reason to believe that the Company would incur any shortfall in its cost recovery.

Q. HOW DO YOU RESPOND TO THE MR. ROBINSON'S ASSERTION THAT YOUR PROPOSAL TO EXPENSE RETIREMENT COSTS WOULD DEFER RECOVERY TO THE END OF THE PLANT LIFE?

A. There is no basis for this assertion. Retirement costs would be recovered as they are incurred. What would cease to exist is the permanent and growing advance that the present system extracts from ratepayers against future inflated costs without recognition of present value.

The exception might be large, single assets such as water treatment plants. For these assets, the appropriate mechanism for recovering retirement costs is the SFAS 143 procedure, regardless of whether the Company has a legal obligation to retire the plant. As discussed earlier, this mechanism properly reflects the time value of money to both ratepayers and the Company.

WHOLESALE RATE PROPOSAL

Q. WHAT IS THE OBJECTIVE OF THIS PORTION OF YOUR TESTIMONY?

A. In this portion of my testimony, I present a revised version of my cost of service study using the Staff's proposed rates for the Southern Division. I also respond to some of the comments by IAWC witness Stafford concerning the proposal in my initial testimony for a wholesale rate classification.

Q. PLEASE DESCRIBE YOUR REVISED COST OF SERVICE STUDY.

A. O'Fallon Exhibit R1.1 is my revised cost of service study. In this study, I have input the data used by Staff witness Mike Luth for the Southern and Peoria Districts, including his proposed rates.

I have also modified the reallocation procedure to apply the General and Administrative overheads to expenses only, rather than to the revenue requirement; to separate A&G allocators for each of the categories of cost, base, peak day, peak hour; and to use the same pre-tax rate of return for the reallocated plant as for all plant.

Q. WHAT DOES YOUR REVISED COST OF SERVICE STUDY SHOW?

A. It continues to show that the "Sales for Resale" classification earns well above the system average, as follows:

Residential	109%
Commercial	105%
Industrial	68%
Large Industrial	71%
Public Authority	95%
Sales for Resale	**117%**
Non-metered	60%
Total	100%

Q. HAVE YOU COMPUTED THE ADJUSTMENT TO THE STAFF RATE THAT WOULD BE REQUIRED TO MATCH THE SALES FOR RESALE RATE TO ITS COST INCURRENCE?

A. Yes. Exhibit R1.2 presents the same calculation as I presented in O'Fallon Exhibit 1.7. It shows that the single wholesale rate should be set at $1.13 per 100 cubic feet if Staff rates are adopted. If Staff's rate structure is adopted but the revenue requirement is different, then the Wholesale rate should be set 21.9 percent lower than the tail block of the Southern Division usage charges.

Q. AT PAGE 48 OF HIS TESTIMONY, MR. STAFFORD STATES THAT HIS COUNSEL HAS ADVISED HIM THAT AS A MATTER OF LAW, MY PROPOSAL IS BEYOND THE SCOPE OF THIS PROCEEDING. DOES YOUR COUNSEL AGREE?

A. No, he does not.

Q. ALSO ON PAGE 48 OF HIS TESTIMONY, MR. STAFFORD STATES THAT O'FALLON HAS NOT PROVIDED ADEQUATE INFORMATION ON ITS PEAK USAGE AND STORAGE BY WHICH TO JUDGE THE PROPRIETY OF YOUR WHOLESALE RATE PROPOSAL. WHAT IS YOUR RESPONSE TO THESE COMMENTS?

A. First of all, O'Fallon has provided detailed information regarding the location, type and capacity of its storage facilities. What O'Fallon cannot provide is the level and timing of its peak hour and peak day consumption. That information is in the hands of IAWC, which owns and reads the meters that record O'Fallon's consumption. O'Fallon's practice is to draw water from the IAWC system primarily during the hours of 11 pm to 4 am in order to fill its storage facilities. These, of course, are the lowest hours for IAWC's own system. However, O'Fallon has no way of measuring hourly consumption either of its system or of the customers that are on its system.

For IAWC to assert that my proposal is without merit by reason of inadequate data is therefore a self-fulfilling claim. IAWC has the data by which to determine the propriety of my recommendation. It has simply declined to access it. O'Fallon respectfully requests that the Commission require IAWC to provide the required data on O'Fallon's average, peak day and peak hour consumption.

Q. MR. STAFFORD STATES THAT O'FALLON MIGHT QUALIFY FOR THE LARGE WATER USER TARIFF RATE. IS THIS CORRECT?

A. Again, only the Company can advise O'Fallon on this matter, as the Company has the necessary data by which to determine O'Fallon's suitability for this rate. It is unlikely, however, that O'Fallon would benefit. The Large Water User rate rewards large consumers whose daily consumption is not significantly greater than its average consumption. Since O'Fallon serves primarily residential customers, it is unlikely that its peak day demand is close to its average day demand. The basis of O'Fallon's savings to the Company is in its ability to shave the peak <u>hour</u> demand through the use of its storage facilities.

Q. MR. STAFFORD ALSO STATES THAT O'FALLON MIGHT QUALIFY FOR THE COMPETITIVE ALTERNATIVE TARIFF. WHAT IS YOUR RESPONSE?

A. I understand that O'Fallon and the Company are in active negotiation with respect to this possibility. The success, or lack thereof, of these negotiations will probably determine O'Fallon's continued participation in this case, and its ultimate decision to become independent of IAWC.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Office of the People's Counsel
District of Columbia

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Elizabeth A. Noël
People's Counsel

August 21, 2003

JUL 2 2 2004

Mr. Sanford Speight, Esq.
Acting Commission Secretary
Public Service Commission of the
District of Columbia
1333 H Street, N.W., 2nd Floor, West Tower
Washington, D.C. 20005

Re: **Formal Case No. 1016, In the Matter of the Application of the Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Gas Service**

Dear Mr. Speight,

Please find enclosed the Office of the People's Counsel ("OPC") Revised Testimony and Exhibits of Witness Charles King. The revisions supplements the original documents, OPC (E), filed on June 26, 2003.

Please contact me if you have any questions regarding this matter at (202) 727-3071.

Sincerely yours,

Jennifer L. Emma

Jennifer L. Emma, Esq.
Assistant People's Counsel

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

In the Matter Of The Application Of Washington Gas Light Company District of Columbia Division For Authority to Increase Existing Rates and Charges for Gas Service	)))))	Formal Case No. 1016

PRE-FILED DIRECT TESTIMONY OF CHARLES W. KING

I. INTRODUCTION

Q PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Charles W. King. I am President of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. PLEASE DESCRIBE SNAVELY KING.

A. Snavely King, formerly Snavely, King & Associates, Inc., was founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. The firm has a professional staff of 12 economists, accountants, engineers and cost analysts. Most of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 33-year history, members of the firm have participated in over 500 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. Attachment 1 is a summary of my qualifications and experience. I should add to the educational portion of that resume that I received my primary and secondary education in the public schools of the District of Columbia.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. Attachment 2 is a tabulation of my appearances as an expert witness before state and federal regulatory agencies. Based on that tabulation, this is my 29th appearance before this Commission since 1978.

Q. FOR WHOM ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the District of Columbia Office of the People's Counsel ("OPC").

Q. WHICH OF THE DESIGNATED ISSUES IN FORMAL CASE NO. 1016 DOES YOUR TESTIMONY ADDRESS?

A. The Public Service Commission of the District of Columbia's ("Commission") Order and Report on Prehearing Conference, Order No. 12715, dated April 25, 2003, included Attachment A, specifically identifying the Designated Issues in this case. My testimony addresses Issues 8:

Issue 8: What are the appropriate depreciation rates for WGL's plant?

Q. PLEASE BRIEFLY DESCRIBE THE EXHIBITS ATTACHED TO YOUR TESTIMONY.

A. There are eight exhibits attached to my testimony, as follows:

Appendix I	Qualifications and Experience
Appendix II	Previous Testimony
Exhibit OPC (E)-1	Proposed Depreciation and Removal Cost Rates and Accruals
Exhibit OPC (E)-2	Reporting of Depreciation and Cost of Removal
Exhibit OPC (E)-3	Summary of Statement 143
Exhibit OPC (E)-4	Cost of Removal Allowance Based on SFAS 143 Methodology
Exhibit OPC (E)-5	Cost of Removal Factors
Exhibit OPC (E)-6	Account Depreciation Accrual Rates

Q. WAS YOUR TESTIMONY AND EXHIBITS PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, they were.

II. SUMMARY

Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS WITH REGARD TO ISSUE NO. 8?

A. Exhibit OPC (E)-1 presents my recommended depreciation and removal cost rates and test year accruals, and it compares them with the present depreciation rates and accruals and with those proposed by the Washington Gas Light Company ("Washington Gas" or "the Company"). The last line on the exhibit shows that my recommended depreciation rates, when applied to the December 31, 2001 depreciable D.C. plant, generate depreciation accruals of ~~9,358,562~~ $9,318,006. Additionally, I have adopted explicit cost of removal allowances in accordance with newly issued changes in the Uniform System of Accounts ("USOA") by the Federal Energy Regulatory Commission ("FERC"). These accruals come to an additional $717.454~~705.103~~, for a total depreciation and removal cost recovery of $~~10.063.666~~10.023.109.

Exhibit (E)-1 reveals that my recommended accruals are $~~6.550.661~~6.591.218 or 39.~~4~~7 percent lower than the depreciation accruals generated by the Company's present depreciation rates. They are $7.785.524~~7.503.067~~ and 43.7~~0~~ percent less than the accruals recommended by the Company in this case.

Q. WHAT ACCOUNTS FOR THE VERY DIFFERENT ACCRUALS THAT YOU RECOMMEND AND THOSE THAT THE COMPANY PROPOSES?

A. The difference in our respective depreciation accruals relates to two factors. The first is a change in the treatment of allowances for future costs to remove plant. In accordance with recently issued FERC rules, I have established separate accounting for removal costs. In computing these allowances, I have eliminated the Company's procedure of inflating the amount to be recovered by projections of future removal costs. Instead, I establish removal cost allowances based upon the actual experience of removal costs during the most recent five years for which data are available.

The second reason for the difference in our accruals is my rejection of the 10-year amortization of the ENSCAN automatic meter reading equipment. I have retained the existing depreciation parameters for this equipment.

III. DEPRECIATION- GENERAL

Q. WHAT IS DEPRECIATION?

A. In 1958, the National Association of Railroad and Utility Commissioners sanctioned the following definition of depreciation:

"Depreciation," as applied to depreciable utility plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of elements, inadequacy, obsolescence, changes in the art, changes in demand, and requirements of public authorities.[1]

The second commonly cited definition of depreciation is that of the American Institute of Certified Public Accountants:

Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any) over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation. Depreciation for the year is the portion of the total charge under such a system that is allocated to the year. Although the allocation may properly take into account occurrences during the year, it is not intended to be a measurement of the effect of all such occurrences.[2]

Significantly, it should be noted that neither of the foregoing definitions of depreciation mention retirement or removal costs.

Q. CAN DEPRECIATION BE CALCULATED WITH PRECISION?

A. No. Depreciation can no more be calculated with precision than can the required rate of return to equity investors. Both are developed from analyses that, while based on quantitative values, require considerable application of judgment. In the case of rate of return, that judgment pertains to the earnings expectations of investors as indicated by the stock market and corporate financial data. In the case of depreciation, the judgment pertains to the estimation of the future surviving life of plant as indicated by past patterns of retirements.

[1] Uniform System of Accounts for Class A and Class B Electric Utilities, 1958, rev. 1962.
[2] American Institute of Certified Public Accountants, *Accounting Research and Terminology Bulletin #1*.

Additionally, as will be demonstrated in this testimony, there are strongly divergent approaches to the treatment of what is known as "net salvage." These approaches yield widely divergent rates and annual accruals. In this proceeding, the Commission will be asked to choose among these approaches based on its understanding of sound economic theory and the appropriate balance of ratepayer and utility interests.

Q. WHAT ARE THE BASIC PARAMETERS REQUIRED TO DEVELOP A DEPRECIATION RATE?

A. At its simplest level, the only parameter that is absolutely required is an estimate of the service life of the plant. The reciprocal of that number can be used as the depreciation rate.

However, because most utility depreciation is applied to "mass property" accounts that are multiple units of plant, it is usually necessary to estimate the dispersion of retirements around an average service life. In the gas and electric utility industries, this dispersion is usually described in terms of "Iowa Curves," so named because they were developed at Iowa State University. These curves describe how closely the retirements are grouped around the average service life and whether they tend to occur more rapidly before, after or coincident with the average service life.

Another parameter that is typically included in the calculation of a depreciation rate is salvage. Salvage is the scrap or resale value of the asset's material. It is expressed as a ratio to the cost of the asset and included as a subtraction from the amount to be recovered in depreciation charges.

Until this year, it has been the practice of most utilities to include the cost of removing or retiring plant as a component of depreciation. These retirement costs were treated as "negative salvage," that is, the reverse of salvage and incorporated as an addition to the amount to be recovered through the depreciation rate. As I shall discuss, recent changes in FERC's accounting regulations now require that retirement costs be accounted for separately from depreciation.

Finally, virtually all major utilities, including Washington Gas, employ what is known as "remaining life depreciation." This procedure computes the depreciation rate by dividing the unrecovered net investment, adjusted for salvage, by the estimated remaining years of the asset (or group of assets). It effectively ensures that any past under- or over-accruals of depreciation are recovered during the remaining life of the asset.

Q. PLEASE ILLUSTRATE HOW THE PARAMETERS YOU HAVE JUST DESCRIBED ARE USED TO DEVELOP DEPRECIATION RATES?

A. Beginning with the simplest example, assume a single asset with a 20 year life. Its depreciation rate is the reciprocal of 20:

$$1/20 = 5\%$$

Now, let us assume that the asset is expected to have salvage value equivalent to 5 percent of its investment value. The depreciation rate declines:

$$\frac{1-.05}{20} = \frac{.95}{20} = 4.75\%$$

This is called a "whole life" rate because it is based on the whole life of 20 years. To develop the remaining life rate, we must identify some additional items of data: the original investment, the depreciation reserve (the amount of depreciation that has already been recovered), and the remaining life of the asset.

In this illustration, let us assume that the asset originally cost $1 million and that past depreciation charges have recovered $400,000. This means that we have yet to recover $600,000 in original cost, less five percent, or $50,000. The total amount yet to be recovered is thus $550,000. Let us further assume that the asset is 10 years old, leaving 10 years of remaining life. In remaining life depreciation, the unrecovered amount is divided by the remaining life years:

$$\frac{\$550{,}000}{10 \text{ years}} = \$55{,}000 \text{ required annual accrual}$$

The depreciation rate is then calculated by dividing the annual amount to be recovered by the gross investment, in this case:

$$\frac{\$55{,}000}{\$1{,}000{,}000} = 5.5\%$$

In the past, it has been the practice to offset the positive salvage with "negative salvage." To illustrate, if the cost of removing this asset amounts to 15 percent of its value, the depreciation rate increases:

$$\frac{\text{Amount to be recovered: } \$550{,}000 + \$150{,}000}{\text{Remaining life years:}} = \frac{\$700{,}000}{10}$$

Annual Accrual = $70,000

$$\text{Depreciation Rate} \quad \frac{\$70{,}000}{\$1{,}000{,}000} = 7.0\%$$

With the recent change in accounting rules, removal or retirement costs are to be accounted for separately. In this illustration, the 15 percent removal cost would be reflected in a separate allowance:

Removal cost allowance: 15% x $1,000,000 (original cost)

= $150,000

This removal cost expense would be accrued in a separate removal cost reserve.

Q. WHAT IS MEANT BY "AMORTIZATION"?

A. Amortization is a general term used to describe the annual allocation of the expiration of intangible assets such as computer software, land rights and leaseholds, or the original cost of tangible assets over some fixed period of time.

The principal difference between depreciation and amortization as these terms are used by Washington Gas has to do with record-keeping. For its depreciated asset accounts, Washington Gas maintains records of the date of placement of each plant unit, so that property can be identified by "vintage." When a unit of plant is retired, that retirement is reflected not only in the overall plant account and reserve, but in the record of the surviving plant in the particular vintage.

For accounts subject to amortization, there is no effort to identify retirements by vintage. Instead, a fixed proportion of the plant installed each year is expensed each subsequent year over a pre-determined amortization period. Amortization is useful for accounts, such as furniture, equipment and computers that consist of many small, movable items for which it is difficult, arguably impossible, to identify the placement date of each unit when it is retired.

IV. REMOVAL COSTS

Q. WHAT IS THE NEW ACCOUNTING RULE THAT REQUIRES REMOVAL COSTS TO BE ACCOUNTED FOR SEPARATELY FROM DEPRECIATION?

A. On April 9, 2003, FERC issued Order No. 631 in Docket No. 02-7-000 relating to accounting, financial reporting, and rate filing requirements for asset retirement obligations. Most of this order dealt with the effects of the Financial Accounting Standards Board's recently issued Statement of Financial Accounting Standards No. 143 ("SFAS 143"), which deals with the treatment of future costs associated with legal obligations to retire assets. That standard requires that entities must declare those future obligations as liabilities on their balance sheets. It also establishes the procedures for recognizing those obligations on annual income statements.

FERC declined to apply the SFAS 143 standards to removal costs that were not legal obligations. It did, however, require that all jurisdictional entities maintain separate records for cost of removal for non-legal retirement obligations when allowances for these costs could be identified. Accordingly, the FERC added a new paragraph 2C to its instructions with regard to Account 108 – "Accumulated Provision for Depreciation of Gas Utility Plant" for Natural Gas Companies:

> Separate subsidiary records shall be maintained for the amount of accrued cost of removal other than legal obligations for the retirement of plant recorded in account 108, Accumulated provision for depreciation of gas utility plant.

This new provision necessarily requires that utilities separately identify annual additions and deletions from this account. Each utility must show the annual accrual for removal costs and the annual amount of removal costs incurred.

This requirement is a major change from the previous treatment of removal costs. In the past, removal costs have always been incorporated into depreciation. Depreciation rates were inflated to recover removal costs. These removal cost allowances were recorded as part of depreciation expense, and plant removal expenditures were charged to depreciation reserves. Except through careful analysis, it has been impossible to identify how may dollars of annual depreciation went to recover past capital expenditures – true depreciation – and how many dollars were accrued to offset future removal costs.

Q. HAS WASHINGTON GAS IMPLEMENTED THESE NEW FERC ACCOUNTING RULES?

A. No. As noted, the new FERC rules were issued on April 9, 2003, and they went into effect 30 days after their publication in the <u>Federal Register</u>, presumably a few days later. Washington Gas has not yet had time to implement these new requirements.

Q. IF WASHINGTON GAS WERE TO IMPLEMENT THESE RULES, WHAT WOULD BE THE RESULT?

A. Exhibit OPC (E) –2 provides a separation of the Company's proposed depreciation into two categories, removal cost allowances and depreciation charges. Based on the Company's proposed depreciation and net salvage parameters, removal cost accruals would come to $5,049,621, or 28 percent of the total $17,808,635 in accruals based on year-end 2001 plant. The remaining $12,759,014 is pure depreciation.

Q. HOW DOES THIS REMOVAL COST ACCRUAL COMPARE WITH THE ACTUAL COSTS OF REMOVAL THAT THE COMPANY HAS EXPERIENCED DURING THE PAST FEW YEARS?

A. During the five-year period 1996 through 2000, Washington Gas spent a total of $3,360,551 on removing plant and equipment in, or allocable to the District of Columbia. This means that in one year, the Company proposes to recover half again the removal cost it actually incurred over five years. The average annual cost of removal was $672,110. The proposed annual removal cost allowance is 7.6 times this actual expenditure.

Q. WHAT ACCOUNTS FOR THE VERY GREAT DIFFERENCE BETWEEN THE REMOVAL COST ACCRUALS AND THE ACTUAL EXPERIENCE OF REMOVAL COSTS?

A. The extraordinary difference between the size of the annual removal cost accruals and the actual removal cost experience is the product of the method by which removal cost, also known as "negative salvage," is calculated for purposes of its incorporation into depreciation rates. Washington Gas – or rather its consultants – calculate "negative salvage ratios" by comparing the original cost of the plant recently retired with the cost of removing that plant. Because the booking of the retirements does not always match the booking of removal cost, the consultants, Foster Associates, employ "bands" of five years, in this case 1996 through 2000.

The difficulty with this procedure is that it compares dollars of very different value. The denominator, the original cost of the plant, is expressed in dollars having the value of the year of placement. For some types of gas plant, this can be decades ago. The numerator, which is the cost of removal, is expressed in recently spent dollars, worth much less than the dollars that make up the denominator. With a relatively few old, high-valued dollars in the denominator and many recent, low-valued dollars in the numerator, the fraction is quite large.

These very large fractions then become the basis for "negative salvage" ratios that are used to inflate the depreciation rates. If recent removal costs were, say, $500,000, and the original cost of the removed plant was $1 million, the negative salvage ratio is –50 percent. This -50 percent increases the depreciation rate corresponding, so that for every dollar of depreciation, there is an added 50 cents in removal cost allowance.

None of this might matter if the removal cost allowance were applied just to plant retired, or soon to be retired. But it is applied to the entire plant account, including plant just installed. Since the average age of plant in service is much less than that of plant recently retired, the effect of this procedure is to extrapolate into the future all of the inflation in removal costs that occurred between the average age of retiring plant and the present.

Q. COULD YOU PROVIDE A REAL-LIFE EXAMPLE OF THIS EXTRAPOLATION?

A. Yes. The dollar-weighted average age of the distribution mains retired during the year 2000 was 25.5 years. Their collective original cost was $986,236. The aggregate cost to remove these mains was $174,685. Washington Gas would calculate a removal cost ratio for the year of –17.7 percent ($174,685/$986,236). But these dollars have very different buying power. In 1974, 25.5 years prior to 2000, the Handy-Whitman index for steel gas mains construction was 114.[3] In mid-year 2000, that same index was 396, for an inflation of 3.47 times. Were the original cost of the mains removed in 2000 expressed in same dollars as the removal costs, their value would be $3,422,239, and the removal cost ratio would be only –5.1 percent ($174,685/$3,422,239).

The Company projects that the average steel main has 37 more years of service life. When it applies its apples-and-oranges negative salvage ratio (which is not –17 percent, but –65 percent), it effectively projects the past 25.5 years of inflation 37 years into the future. When it incorporates that ratio into its depreciation rate, it effectively requires ratepayers to pay now for to the cost to remove gas mains in the year 2037.

Q. WHAT IS WRONG WITH PROJECTING PAST INFLATION INTO THE FUTURE FOR PURPOSES OF RECOVERING REMOVAL COSTS?

A. Even if there were a conceptual justification for collecting now for distant future costs, the assumption that past inflation will continue at the same rate into the future is almost certainly false. In January of 1974, the Consumer Price Index was 46.8 (1984-1986 = 100). In mid-2000, it was 172.5, for an average annual rate of inflation between those two years of 5.25 percent.[4] At least in the near future, no one expects inflation anywhere close to this level. The *Economist* pole of forecasters, for example, predicts inflation in the U.S. to be 2.3 percent in 2003 and

[3] The Handy-Whitman Index of Public Utility Construction Costs, North Atlantic Region, Whitman, Requart and Associates, LLP
[4] www.bls.gov/data/

1.7 percent in 2004.[5] Nowhere in the developed world is inflation expected to exceed 2.5 percent. The extrapolation of 5.25 percent into the future clearly overstates currently expected price increase and correspondingly overstates future costs.

But even if it were possible to forecast accurately the cost of removing gas plant in the future, there would still be no justification whatever for collecting now, in current dollars, a future cost expressed in future dollars. Quite regardless of inflation, a dollar received now is worth more than a dollar spent 37 years from now. The only way these two dollars can be compared meaningfully is to express them in the same present value. That expression captures the fact that a dollar provides value to its holder throughout the time that it is held. This is true for two reasons. First, the holder of the dollar has the ability to invest it. Second, the holder has the opportunity to spend the dollar, enjoy the goods or services purchased, and then to borrow it later for repayment.

The practice of collecting allowances now for removal costs decades from now totally ignores the present value of money. Ignoring inflation, ignoring the time value of money, Washington Gas is extracting dollars from present ratepayers to cover costs it will not incur for years to come.

Q. BUT DON'T RATEPAYERS RECEIVE THE BENEFIT OF THE RATE BASE DEDUCTION REPRESENTED BY THE ACCRUAL OF THESE REMOVAL COST ALLOWANCES?

A. No. An argument might be made that removal cost charges build up the depreciation reserve, which in turn reduces the net investment rate base. The reduced rate base lowers the requirement for return and income taxes. Over time, one might think this reduction should cancel out the increase in revenue requirement represented by the excessive depreciation expenses.

[5] *The Economist,* June 14, 2003 issue, page 96.

Only it doesn't. That is because the dollar value of the Company's plant is always expanding. The Company is growing, but even if it were not, inflation causes the dollars added each year to exceed the dollars retired. There is always more new plant generating higher removal cost charges than old plant that has accumulated removal cost reserve. Ratepayers never catch up.

Q. IS THERE AN ACCOUNTING PROCEDURE THAT RESOLVES THESE PROBLEMS YOU HAVE IDENTIFIED WITH RESPECT TO REMOVAL COST RATIOS?

A. Yes. The Financial Accounting Standards Board has recently published an accounting procedure for dealing with the retirement costs of long-lived assets that must be removed by reason of legal obligations. These procedures were published in 2001 in Statement of Financial Account Standards No. 143 ("SFAS 143"). A summary of that statement is attached to this testimony as Exhibit OPC (E) – 3.

Q PLEASE DESCRIBE SFAS 143.

A. As I have just noted, SFAS 143 addresses long-lived assets for which there are legal obligations to incur retirement costs. A legal obligation is defined as "an obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel." A good example of such an obligation is the requirement to dismantle, entomb or decontaminate a nuclear generating plant.

When a company finds that it has a legal obligation that fits this description, it must declare the retirement cost as a liability on its balance sheet. That liability is not the ultimate cost of the retirement, but the present value of that cost, using as the discount factor the risk-free interest rate when the liability was recognized.

The annual expense associated with this liability consists of two parts. One is the amortization of the liability, which is the present value of the liability divided by the life of the asset – comparable to depreciation. The second expense is the annual accretion in the present value of the liability.

Q. CAN YOU ILLUSTRATE HOW THIS PROCEDURE WORKS?

A. Assume that Washington Gas installs a gas storage facility that it expects to last for 40 years. It is obligated to dismantle that plant when it retires at an estimated cost of $1 million. Washington Gas would book a liability for this retirement cost, not at $1 million, but at $1 million discounted at the risk-free interest rate. The risk free interest rate over 40 years is 5 percent, which is the current yield on long-term Treasury bonds.[6] The liability would therefore be booked as $ 142,046 ($1 mil/$1.05^{40}$)

Each year, Washington Gas would show two items of expense. The first would be the amortization of the liability, $142,046/ 40 years = $3,551. The second expense would be the annual accretion in present value of the liability. In this instance, it would be $1 million times 1.05^{39} - 1.05^{40}. This is $1 million ~~142,046~~ x (0.149148 - 0.142046 =.00710) or $~~1,~~7,102~~000~~. As the present value factors increase, that is, as they approach 1.0, this annual amount would also increase. Total expense in the first year of operation would be $3,551 + $~~1,000 = $4,560~~7,102 = 10,653.

Q. HOW DOES THE SFAS 143 PROCEDURE RESOLVE THE PROBLEMS YOU HAVE IDENTIFIED WITH THE WASHINGTON GAS' PROCEDURE FOR CALCULATING AND REMOVAL COST RATIOS?

[6] www.federalreserve.gov/releases/ Series H-15.

A. Unlike Washington Gas' procedure for recovering removal cost allowances, the SFAS 143 procedure recognizes the present value of future costs. It therefore resolves the unfairness of charging present ratepayers with an inflated cost that the Company will not incur until many years from now.

Q. HAVE YOU CALCULATED THE COST OF REMOVAL ALLOWANCES IN CONFORMANCE WITH SFAS 143?

A. Yes. Exhibit OPC (E) – 4 develops cost of removal allowances that would result from applying the SFAS 143 methodology to the year-end 2001 plant investment, and accepting Washington Gas' removal cost estimates. The investment totals are shown in column A of the exhibit for each account for which the Company expects to incur removal costs. Column B replicates the removal cost percentages the Company proposes to use in computing its depreciation rates. By applying these percentages to the investment totals, the forecast removal costs are reported in column C. In Column D, I have shown the remaining lives predicted by the Company for each account.

For purposes of this exposition, I make the simplifying assumption that all plant in each account retires at the end of the average remaining life of each account. A more refined analysis might break each account into retirement vintages, that is, plant that retires each year into the future. This refinement would have little effect on the final results, and it would, in my opinion, amount to "specious precision," since no one can predict with any degree of accuracy how much plant will actually retire each year in the future.

Using this simplifying assumption, I develop the present value of the future removal costs in columns E and F. Column E presents the present value factors at 5 percent, which, in conformance with SFAS 143's requirement for a "risk-free" rate, is the current yield on long-term Treasury bonds. Column F shows the present value of the future retirements. These figures are the future removal costs discounted by 5 percent annually from the predicted end of the remaining life of the existing plant.

In columns G and H, I develop the first element of the annual SFAS 143 charge, which is the depreciation of the present value of the future costs. I do this by dividing the discounted future cost by the average service life assumed by the Company. The annual charges are set forth in column H.

In columns I and J, I develop the second element of the SFAS annual charge, which is the increment in the present value represented by the passage of this year into the next. Column I shows the difference between the PV factors in column E and the next year's PV factors. These values are then applied to the present value of the removal costs (column F) to derive the increments in present value in column J.

Column K presents the annual cost of removal allowances that would be appropriate for December 31, 2001 plant were the Commission to adopt the SFAS 143 methodology as the means to recognize future removal costs. The figure of $3,583,216~~1,776,927~~ is approximately 30~~5~~ percent less than ~~of~~ the amount ($5,049,621) that Washington Gas would charge ratepayers for future removal costs under its proposed methodology.

The final column L shows the recovery factors that the Commission could adopt were it to decide to use the SFAS 143 methodology. These factors are not comparable to the Company's negative salvage percentages in column B because they are annual accrual rates, not inflators of the total amount to be recovered. While arguably they should be revised each year as the remaining lives change, I suspect that the revisions would have relatively little impact on the total rate of accrual. That is because the largest plant accounts have "mass property" characteristics in which the inflows of new additions and outflows of retirements do not vary significantly from year to year. As a result, the basic parameters –

service life, remaining life, removal costs – do not change very much from year to year.

Q. DO YOU RECOMMEND THAT THE COMMISSION ADOPT THE SFAS 143 METHODOLOGY FOR RECOGNIZING REMOVAL COSTS?

A. No, I do not. While the SFAS 143 methodology is certainly fairer and more economically justified than that recommended by the Company, it still suffers from the requirement to predict future removal costs. As I have noted, the Company's procedure is essentially an extrapolation of past inflation into the future. Given that future inflation is predicted to be considerably less than past inflation, this practice results in excessive removal cost allowances, even under the SFAS methodology.

Q. WHAT ALTERNATIVE PROCEDURE DO YOU RECOMMEND FOR RECOGNIZING REMOVAL COSTS?

A. I recommend that removal cost allowances be based on the actual experience of the most recent few years. Specifically, I recommend that removal cost ratios be based on the relationship of total investment to the average annual cost of removing plant during the most recent five years. Any over- or under-recoveries of removal costs can be amortized following the next represcription of removal cost allowances.

My further recommendation relates to replacements in the mains and service accounts. Whenever a main or service is removed and replaced, either *in situ* or on a parallel route, the cost of removing the old plant should be added to the capital cost of the replacement plant. This is, of course, a going-forward proposal because past removal costs have already been written off against the depreciation reserve.

Q. HAVE YOU QUANTIFIED THE REMOVAL COSTS ALLOWANCES THAT REFLECT YOUR RECOMMENDATIONS?

A. Yes. Exhibit OPC (E) – 5 develops the removal cost allowance factors that I recommend be adopted for Washington Gas' D.C. plant. Columns A through E show the actual removal costs each year from 1996 through 2000. Column F sums these costs by account, and column G sums them by major plant category. Column H presents the annual averages in each category. Column I shows the December 31, 2000 investment in each category. The final column presents the ratios of average annual removal costs to investment that I recommend be used to establish removal cost allowances going forward.

It should be noted that these ratios, like the ratios on OPC (E) – 4, are not comparable to the "negative salvage" percentages presented in the Company's depreciation report. These ratios are applied directly to the plant account totals to generate annual allowances. By contrast, the Company's negative salvage ratios are used to inflate the numerator of the fraction used to calculate the accrual amounts needed to be recovered over the remaining life of each plant account.

Q. WHAT IS THE JUSTIFICATION FOR REFLECTING ACTUAL REMOVAL COSTS IN CURRENT REMOVAL COST ALLOWANCES?

A. There are two justifications for my proposal to set removal cost allowances based on recent actual cost experience. The first and most important justification is that it eliminates the permanent and continuously growing loan from ratepayers to the Company for undiscounted future costs that the Company will not incur until years, in some case decades, into the future. As demonstrated in Exhibit OPC (E)-2, the Company's proposed treatment of removal costs adds $5.1 million in annual charges to ratepayers. Yet, the costs that this allowance is intended to cover have averaged only about $675,000 during recent years, yielding a new loan from ratepayers to the Company of $4,425,000 each year.

This annual loan amount will grow indefinitely. That is because there is always more new plant being added than old plant retired. The new plant generates the inflated removal cost reserves, in the amount of $5.1 million and growing, while the old plant experiences removal costs, on the order of less than $1 million. For the indefinite future, the Company will continue to collect more in removal costs allowances than it spends in actual removal costs.

The second justification for the procedure I recommend is that it avoids the need to forecast future removal costs. There is no extrapolation of past inflation rates into the future. My procedure recovers actual removal costs, no more and no less, with no guesswork as to how much those costs will be.

Q. WHAT DO YOU RECOMMEND BE DONE ABOUT THE REMOVAL COST RESERVES THAT THE COMPANY HAS ALREADY COLLECTED?

A. These reserves should be retained in the depreciation reserve accounts and amortized through the remaining life procedure. They should not be added to the removal cost reserve account because, using my allowance procedure, they will never be eliminated. Under my recommended procedure, removal cost allowances will grow as actual removal costs increase. If the accumulated reserve now on the books were to be treated as a reserve against future removal costs, it would remain at approximately its present level indefinitely. By incorporating the present removal cost reserve into the depreciation reserve, these past over-collections are flowed back to ratepayers in the form of lower depreciation rates over the remaining life of the plant now in service.

Q. WHAT OBJECTIONS WILL THE COMPANY RAISE AGAINST YOUR PROPOSALS?

A. The Company will argue that my proposal violates the "matching" principle of cost recovery of long-lived assets. It will contend that removal costs are part of the capital cost of each asset whenever such costs are anticipated. It is therefore appropriate that such costs, predicted as accurately as possible, should be recovered from the ratepayers that use the assets that will incur them.

The Company will strongly object to my proposal to add the removal cost of plant being replaced to the capital cost of the replacement. It will argue that this defers the recognition of a cost of retiring plant by shifting it to new plant.

The Company may also argue that my proposal violates FERC's Uniform System of Accounts, which requires that removal costs be charged to the depreciation reserve.

Finally, the Company will contend that its approach is the conventional procedure used across the country and approved by almost all state and federal commissions. It is cited as the conventional methodology in *Public Utility Depreciation Practices*, the more or less official manual on depreciation published by the National Association of Regulatory Utility Commissioners ("NARUC"). My approach, the Company will contend, is highly unusual and departs radically from the "standard" procedures.

Q. WHAT IS YOUR RESPONSE TO THE CONTENTION THAT YOUR APPROACH VIOLATES THE "MATCHING" PRINCIPLE?

A. If we were considering the depreciation of single assets, such as power plants, that have fixed lifetimes and single, predictable retirement dates and removal costs, this argument might have validity. In that circumstance, it would be appropriate to declare the removal cost of each asset as a future liability and charge it to ratepayers over the life of the plant.

But if we followed this approach, the procedure would emphatically not be the one advocated by the Company. Rather, we would employ the accounting procedures prescribed by SFAS 143 that recognize the present value of the future retirement obligation and recover the costs through a mechanism that captures the increase in that present value throughout the life of the plant. As I have demonstrated in Exhibit OPC (E)-4, the SFAS 143 procedure applied to Washington Gas' D.C. plant would yield removal cost allowances approximately 35 percent the amount proposed by the Company.

As it is, we are not considering single-unit assets, but mass property accounts where the costs of many units of asset flow into and out of plant accounts. Because of inflation and the general growth of the gas distribution system, the inflow into these accounts in the form of new additions is always greater than the outflow in the form of retirements. As a result, the so-called "matching" principle results in a continuous and growing front-loading of removal cost recognition. There is always more new plant generating very large removal cost allowances than old plant incurring removal costs. This explains the permanent nature of the removal cost loan from ratepayers to the Company. There is no matching. Current ratepayers are always paying for much larger future costs than are now being incurred. As long as the Company can retain its method of calculating removal cost allowances, this inter-generational inequity will continue.

Q. WHAT IS YOUR RESPONSE TO THE LIKELY CONTENTION THAT CAPITALIZING THE REMOVAL COSTS OF REPLACED PLANT INTO THE INVESTMENT COST OF THE REPLACEMENT PLANT CONSTITUTES UNREASONABLE DEFERRAL OF COST RECOGNITION AND RECOVERY?

A. First of all, it should be noted that when buried mains and services are replaced *in situ*, the distinction between the removal costs of the old plant and the capital costs of the new plant is in large measure arbitrary. The excavation of the line is likely to be for both purposes. Unless the old pipe is physically removed from the ground, the only functions that are explicitly related to the retirement of the old line are the evacuation of gas from the old line and the capping of it at either end.

More to the point, however, is the placement of benefit, which goes to the "matching" principle. There are likely to be only two reasons to remove an old main or service and replace it with another. Either the old pipe is physically deteriorated or its capacity is insufficient for the forecast load. In either case, the beneficiaries of the retirement of the old pipe are not the users of the old pipe, but the users of the new main or service. They enjoy the benefit of a physically functional and adequately sized pipe. It is therefore not unreasonable that they should bear the cost of removing the previous main or service.

Q. WHAT IS YOUR RESPONSE TO THE CONTENTION THAT YOUR PROPOSALS ARE INCONSISTENT WITH THE UNIFORM SYSTEM OF ACCOUNTS?

A. I have already noted that the Company's current filing is itself inconsistent with the USOA in that it does not separately account for removal costs. When removal costs are accounted for separately, there will be accruals into a reserve account and, when removal costs are incurred, those costs will be charged to that account. That treatment is thoroughly consistent with FERC's USOA. The only difference is that the reserve will not be called the "depreciation reserve" but the "removal (or retirement) cost reserve."

As regards the capitalization of removal costs of retired plant that is replaced, the USOA is itself somewhat inconsistent. Paragraph 10 on page 529 of the USOA requires that cost of removal shall be charged to the depreciation reserve account. But Paragraph 31 contains the following definition:

Replacing or replacement, when not otherwise indicated in the context, means the construction or installation of electric (gas) plant in place of property retired, together with the removal of the property retired. [Emphasis supplied]

It thus appears that the USOA does contemplate that the removal cost of retired property can be considered as part of capital cost of replacement plant.

Q. WHAT IS YOUR RESPONSE TO THE CONTENTION THAT THE COMPANY'S METHODOLOGY IS THE CONVENTIONAL PROCEDURE FOR TREATING REMOVAL COSTS?

A. First of all, the Company's methodology is not always the conventional procedure. All of the utilities in the State of Pennsylvania account for removal costs using the procedure that I have recommended. The largest electric and gas utilities in Georgia – Georgia Power and the Atlanta Gas Light Company -- also account for their removal costs through a method very similar to that which I have recommended.

The NARUC manual *Public Utility Depreciation Practices* does indeed observe that historically most commissions have included both positive and negative salvage (cost of removal) in depreciation rates. However, it also notes:

> Some commissions have abandoned the above procedure [of including net salvage in depreciation] and moved to current-period accounting for gross salvage and/or cost of removal. In some jurisdictions gross salvage and cost of removal are accounted for as income and expense, respectively, when they are realized. Other jurisdictions consider only gross salvage in depreciation rates, with the cost of removal being expensed in the year incurred.[7]

I strongly suspect that the combination of FERC's recent requirement to separate removal cost accounting from depreciation and the implementation of SFAS 143 will accelerate this trend away from the use of negative salvage ratios in computing depreciation rates. The separate accounting of removal costs will

[7] *Public Utility Depreciation Practices*, National Association of Regulatory Utility Commissioners, August 1996, page 157.

demonstrate just how large these previously hidden charges are, particularly for gas distribution companies. SFAS 143 will demonstrate the utter irrationality of an accounting system that charges more for removal costs that do not have legal obligations than it charges for removal cost that are legal obligations.

V. ENSCAN EQUIPMENT

Q. WHAT IS ENSCAN EQUIPMENT?

A. This equipment includes encoder, recorder and transmitter devices installed on meters that allow for remotely accessing the volume of gas used by the meter. In addition to the cost of these devices, the related costs of installing the units are included in the account.[8]

Q. WHAT CHANGES IS WASHINGTON GAS PROPOSING FOR THE DEPRECIATION OF THIS EQUIPMENT?

A. Washington Gas has been depreciating this equipment on the basis of a 40 year service life. It now proposes to amortize its ENSCAN equipment over 10 years. As of the end of 2001, the Company had $17,605,039 of this equipment in the District of Columbia. The effect of its proposed changes in depreciation method and recovery period is to increase the annual charges for this equipment by 2.75 times from $514,243 to $1,420,727.

Q. WHAT JUSTIFICATION HAS WASHINGTON GAS OFFERED FOR THESE CHANGES?

[8] Washington Gas response to OPC Data Request No. 8-201.

A. None. Neither the Foster Associates study nor Dr. White's testimony contain any mention of the ENSCAN equipment, let alone a justification for the changes proposed.

Q. DID YOU ATTEMPT TO DETERMINE THE JUSTIFICATION FOR THIS CHANGES?

A. Yes. First, I asked for all workpapers supporting the amortization periods selected by Washington Gas for the accounts proposed for amortization within the General Plant functional category. The Company objected to this question on the grounds that the workpapers requested are unavailable. I then submitted a follow-up question asking for all facts, data, rationale or other bases upon which the Company relied in selecting its proposed amortization periods. The Company replied:

> Washington Gas objects to this follow-up question on the grounds that a follow-up data request is not an appropriate response to an objection.[9]

Separately, I asked for all cost/benefit, feasibility, or any other studies upon which the Company relied in its decision to purchase ENSCAN equipment. The Company responded with a one-page document that showed the purported costs and savings but conveyed nothing about the life expectancy of this equipment or the range of time over which these costs and savings were expected to occur.[10]

In still another data request, I inquired why the proposed amortization periods for six General Plant accounts, including ENSCAN equipment, were shorter than the previously determined remaining lives of those accounts. Washington Gas' response was as follows:

> Amortization accounting is not intended to achieve cost allocation over an estimate of service life. Amortization accounting is adopted when it is

[9] OPC Data Request No. 8-88.
[10] OPC Data Request No. 8-202

difficult or impossible to maintain plant records with sufficient accuracy to estimate service lives. The measured service life of equipment categories in which retirements are difficult to identify and record often provides a measurement of the mean interval between physical inventories. The current estimate of remaining lives for the proposed amortization categories is not indicative of the service life of the category.[11]

Q. WHAT DO YOU CONCLUDE FROM THESE RESPONSES OF WASHINGTON GAS?

A. I conclude that Washington Gas apparently made no effort to identify amortization periods that conform, or even resemble, the service lives of the plant being amortized. That explains the absence of workpapers and the apparent unwillingness to explain how these amortization periods were derived.

Q. DO YOU AGREE WITH THE COMPANY'S CONTENTION THAT AMORTIZATION ACCOUNTING IS NOT INTENDED TO ACHIEVE COST ALLOCATION OVER AN ESTIMATED SERVICE LIFE?

A. No. The objective of both depreciation and amortization accounting is to allocate capital costs fairly and reasonably over the years during which the assets depreciated or amortized are being used. The use of amortization in lieu of depreciation does not abrogate this objective. Specifically, it does not offer the utility the opportunity to pick amortization periods significantly shorter than the service lives of the plant being amortized.

The only valid reason for amortizing General Plant accounts is the one cited in the middle of the final response quoted above, that it is difficult or impossible to trace the retirement of specific units of plant to the installation dates. In these circumstances, amortization becomes a convenient and less complicated method for recognizing costs over plant life than depreciation. However, contrary to the Company's claim, there are techniques for estimating the service lives of undated

[11] OPC Data Request No. 8-200

plant, and the Dr. White could have employed them to estimate the service lives of several of the accounts proposed for amortization, including the ENSCAN equipment account.

Q. IS THERE ANY REASON TO BELIEVE THAT THE 10 YEAR AMORTIZATION PERIOD PROPOSED FOR THE ENSCAN EQUIPMENT IS SHORTER THAN THAT EQUIPMENT'S SERVICE LIFE?

A. Yes. According to the attachment to the Company's response to OPC Data Request No. 202, all of the ENSCAN equipment in the District of Columbia had been installed by December 1994, which means that it is now at least nine years old. Since 1994, this plant has been depreciated based on a 40 year service life using an L 1.5 survivor curve and a 20 percent positive salvage factor.[12]

A 10 year service life would imply that approximately half of the plant should retire by next year. Yet, even with the very long service life assumption used to depreciate this plant during the past years, the reserve has built to approximately 65 percent of the original cost.[13] This indicates that there have been virtually no retirements of ENSCAN equipment to date. Moreover, the capital budget for the District of Columbia does not show the sort of heavy replacement costs that one would expect were this plant to wear out during the next few years.[14]

I conclude from these indications that 10 years is a gross under-estimation of the service life of the ENSCAN equipment. Lacking any other basis for estimating service life, I recommend that the existing 40 year life assumption be retained. In light of the apparent over-depreciation of this account that has already taken place, I also recommend that remaining life depreciation be applied to flow back to ratepayers the excess accruals that already have been recovered by the

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[12] See Statement E, Foster Associates Depreciation Studies.
[13] See Statement C, Foster Associates Depreciation Studies.

Company. In computing the depreciation rate for this account, I have used Dr. White's estimate of 23.4 years of remaining life.

VI. SERVICE LIVES

Q. HAVE YOU ANALYZED THE SERVICE LIVES AND SURVIVOR CURVES RECOMMENDED BY THE COMPANY?

A. No. I have not been able to analyze the reasonableness of the Company's life and survivor curve recommendations because I have not received the underlying workpapers and calculations by which they were developed. The diskettes provided by the Company display only the statements contained in the reports that are attached to the testimony of Ronald White. The critical values – remaining lives, average service lives and survivor curves – are presented as "givens."

Lacking any way to examine Dr. White's analyses, the only way I could test the reasonableness of his recommended service lives would be to replicate his study from the Company plant records that he was supplied.

The Company has provided those plant records on eight diskettes, but they were not delivered to OPC until late on June 9. OPC transmitted them to me the next day. I did not realize that I would have to conduct a "ground up" depreciation study until I received what were purported to be Dr. White's workpapers on June 11. It is physically impossible to perform a full depreciation by the time this testimony must be filed.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO SERVICE LIVES AND SURVIVOR CURVES?

[14] Response to OPC Data Request No. 8-112.

A. I have reviewed the Company's recommendations as regards service lives and survivor curves and, based on my experience with gas distribution company depreciation, I can attest that they appear reasonable. I therefore recommend that they be adopted.

Q. HAVE YOU CALCULATED DEPRECIATION RATES REFLECTING THE COMPANY'S LIFE AND SURVIVOR CURVE PARAMETERS?

A. Yes. Exhibit OPC (E) – 6 develops depreciation rates based on the Company's data on life, survivor curve, depreciation reserve and remaining lives. The only difference between these depreciation rates and those developed by the Company's consultants is that my rates contain no allowance for cost of removal. I have used these rates to develop the total depreciation and removal cost accruals presented in my Exhibit OPC (E) – 1.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Washington Gas Light Company
Present, Company Proposed, and OPC Proposed Depreciation and Removal Cost Rates and Accruals

Account	Description	A	B	C	D	E	F	G	H	I	J	K	L
		31-Dec-01	Present		Company Proposed		OPC Recommended					Difference	
		Plant Investmen	Rate	Accrual	Rate	Accrual	Depreciation		Cost of Removal		Total	OPC vs. Present	OPC vs. WG Proposed
		2002 Update Stmt B, Col B	2002 Update Stmt A, Col D	A x B	2002 Update Stmt A, Col H	A x D	OPC (E)-6 Col F	A x F	OPC (E)-5 Col J	A x H	H + I	J - C	J - E
Storage and Processing Plant													
Allocable Property													
361.0	Structures and Improvements												
	Maryland	373,837	1.88%	7,013	4.23%	15,813	2.58%	9,223			9,223	2,210	(6,591)
	Virginia	353,981	1.88%	6,641	3.74%	13,239	2.79%	10,339			10,339	3,698	(2,900)
362.0	Gas Holders												
	Maryland	3,697,021	1.78%	65,807	2.62%	96,862	0.85%	21,277			21,277	(44,530)	(75,585)
	Virginia	2,653,580	1.78%	47,234	2.24%	59,440	1.06%	38,219			38,219	(9,015)	(21,221)
363.5	Other Equipment												
	Maryland	78,393	4.21%	3,299	6.94%	5,440	6.94%	5,442			5,442	2,143	2
	Virginia	37,159	4.21%	1,564	6.73%	2,501	6.73%	2,626			2,626	1,062	125
	Total Storage and Processing Plant	7,193,971		131,558		193,295	1.21%	87,126	0.53%	38,128	125,254	(6,304)	(68,041)
Transmission Plant													
Situs Property													
367.1	Mains- Steel	1,642,462	1.75%	28,825	2.82%	46,317	2.32%	37,949			37,949	9,124	(8,368)
369.0	Measuring and Regulating Equipment	2,106,826	3.13%	65,902	4.03%	84,905	3.35%	70,845			70,845	4,943	(14,060)
	Total Situs Property	3,749,288		94,727		131,222		108,794	0.20%	7,499	116,292	21,565	(14,930)
Allocable Property													
365.2	Rights of Way												
	District	622	1.48%	9	0.00%		0.00%				-	(9)	-
	Maryland	677,664	1.48%	10,043	2.59%	17,551	2.59%	17,521			17,521	7,478	(30)
	Virginia	370,994	1.48%	5,498	2.81%	10,425	2.81%	10,429			10,429	4,931	4
	Total Account 365.2	1,049,280		15,550		27,976		27,950			27,950	12,400	(26)
366.0	Meas and Reg Station Structures												
	Maryland	502,304	3.10%	15,586	2.40%	12,055	2.10%	10,540			10,540	(5,046)	(1,515)
	Virginia	211,178	3.10%	6,553	2.64%	5,575	2.30%	4,848			4,848	(1,705)	(727)
	Total Account 366	713,482		22,139		17,630		15,388			15,388	(6,751)	(2,242)
367.1	Mains- Steel												
	District	1,396,682	1.57%	21,900	1.75%	24,442	1.18%	17,268			17,268	(4,632)	(7,174)
	Maryland	5,695,177	1.57%	89,300	1.89%	107,639	1.60%	94,111			94,111	4,811	(13,528)
	Virginia	4,485,006	1.57%	70,325	2.05%	91,943	1.45%	61,363			61,363	(8,962)	(30,580)
	Total Account 367.1	11,576,865		181,525		224,024		172,742			172,742	(8,783)	(51,282)
369.0	Measuring and Regulating Equipment												
	District	96,892	2.51%	2,432	2.47%	2,393	1.42%	1,741			1,741	(691)	(652)
	Maryland	2,374,313	2.51%	59,595	2.62%	62,207	1.81%	42,925			42,925	(16,670)	(19,282)
	Virginia	1,584,531	2.51%	39,772	3.24%	51,339	2.17%	34,153			34,153	(5,619)	(17,186)
	Total Account 369	4,055,736		101,799		115,939		78,820			78,820	(22,979)	(37,119)
	Total Allocable Plant	17,395,363		321,013		385,569		294,900	0.071%	12,351	294,900	(26,113)	(90,669)
	Total Transmission Plant	21,144,651		415,740		516,791	1.91%	403,694	0.094%	19,849	411,193	(4,547)	(105,598)

Account	Description	31-Dec-01 Plant Investment	Proposed Depreciation Rate	Proposed Removal Cost Ratio	Removal Proportion of Rate	Depreciation Rate	Removal Cost Allowance	Depreciation	Total Accruals
Distribution Plant									
Situs Property									
376.1	Mains - Steel	60,581,194	2.78%	-60.00%	1.04%	1.74%	631,559	1,052,598	1,684,157
376.2	Mains - Plastic	94,934,440	2.70%	-60.00%	1.01%	1.69%	961,211	1,602,019	2,563,230
376.3	Mains - Cast Iron	6,482,244	3.41%	-60.00%	1.28%	2.13%	82,892	138,153	221,045
378.0	Measuring and Regulating Equipment	4,957,328	4.18%	-20.00%	0.70%	3.48%	34,536	172,680	207,216
380.1	Services - Steel	18,490,625	4.11%	-75.00%	1.76%	2.35%	325,699	434,266	759,965
380.2	Services- Plastic	135,308,753	4.52%	-75.00%	1.94%	2.58%	2,621,124	3,494,832	6,115,956
380.3	Services - Copper	3,706,470	4.53%	-75.00%	1.94%	2.59%	71,958	95,945	167,903
381.1	Meters - Tin Case	131,439	3.57%			3.57%		4,692	4,692
381.2	Meters - Hard Case	12,654,298	4.43%			4.43%		560,585	560,585
381.3	Meters- Electronic Devices	1,276,027	6.79%			6.79%		86,642	86,642
381.5	Meters - Electronic Demand Recorders	678,429	6.45%			6.45%		43,759	43,759
382.0	Meter Installations	20,240,063	2.96%	-30.00%	0.68%	2.28%	138,255	460,851	599,106
383.0	House Regulators	1,588,969	3.40%	-30.00%	0.78%	2.62%	12,467	41,558	54,025
384.0	House Regulator Installations	2,327,483	3.12%			3.12%		72,617	72,617
386.1	Other Property on Customers' Premises	486,225	10.85%			10.85%		52,755	52,755
387.0	Other Equipment	107,578	11.66%	-300.00%	8.75%	2.92%	9,408	3,136	12,544
Total Situs Property		363,951,565					4,889,110	8,317,088	13,206,197
Allocable Property									
378.0	Measuring and Regulating Equipment								
	Maryland	219,037	15.43%	-20.00%	2.57%	12.86%	5,633	28,165	33,797
	Virginia	53,216	14.55%	-15.00%	1.90%	12.65%	1,010	6,733	7,743
Total Allocable Plant		272,253					6,643	34,897	41,540
Total Distribution Plant		364,223,818					4,895,752	8,351,985	13,247,738
General Plant									
Situs Property									
397.2	ENSCAN Equipment	17,605,039	8.07%			8.07%		1,420,727	1,420,727
Allocable Property							-	-	-
390.0	Structures and Improvements						-	-	-
	District	1,856,732	3.70%	-10.00%	0.34%	3.36%	6,245	62,454	68,699
	Maryland	778,715	3.97%	-10.00%	0.36%	3.61%	2,810	28,105	30,915
	Virginia	4,951,326	4.12%	-10.00%	0.37%	3.75%	18,545	185,450	203,995
Allocable Property (Amortizable)									-
303.05	Software - 5 years	1,925,891	17.85%			17.85%		343,772	343,772
303.10	Software - 10 years	8,018,095	10.00%			10.00%		801,810	801,810
391.11	Office Furniture & Equipment	1,892,436	4.13%			4.13%		78,158	78,158
391.21	Computer Equipment	5,767,748	9.86%			9.86%		568,700	568,700
393.00	Stores Equipment	140,597	3.72%			3.72%		5,230	5,230
391.00	Tools, Shop & Garage Equipment	2,657,926	4.89%			4.89%		129,973	129,973
395.00	Laboratory Equipment	150,979	3.72%			3.72%		5,616	5,616
397.00	Communications Equipment	2,116,164	5.84%			5.84%		123,584	123,584
397.10	Communications Equipment - Telephones	745,443	6.67%			6.67%		49,721	49,721
398.00	Miscellaneous Equipment	411,361	4.84%			4.84%		19,910	19,910
Total General Plant		49,018,452					27,601	3,823,209	3,850,810
Total Jurisdiction		$ 441,580,892					$ 5,049,621	$ 12,759,014	$ 17,808,635

Summary of Statement 143

By the

Financial Accounting Standards Board

Recent Additions
Action Alert
Project Activities
Exposure Drafts
Technical Inquiry
EITF
DIG (Derivatives)
International
BRRP
Articles & Reports
Publications
FAS Summaries
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Summary of Statement No. 143

Accounting for Asset Retirement Obligations (Issued 6/01)

Summary

This Statement addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. This Statement applies to all entities. It applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and (or) the normal operation of a long-lived asset, except for certain obligations of lessees. As used in this Statement, a legal obligation is an obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel. This Statement amends FASB Statement No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies.*

Reasons for Issuing This Statement

The Board decided to address the accounting and reporting for asset retirement obligations because:

- Users of financial statements indicated that the diverse accounting practices that have developed for obligations associated with the retirement of tangible long-lived assets make it difficult to compare the financial position and results of operations of companies that have similar obligations but account for them differently.
- Obligations that meet the definition of a liability were not being recognized when those liabilities were incurred or the recognized liability was not consistently measured or presented.

Differences between This Statement, Statement 19, and Existing Practice

This Statement requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. This Statement differs from Statement 19 and current practice in several significant respects.

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- Under Statement 19 and most current practice, an amount for an asset retirement obligation was recognized using a cost-accumulation measurement approach. Under this Statement, the amount initially recognized is measured at fair value.

- Under Statement 19 and most current practice, amounts for retirement obligations were not discounted and therefore no accretion expense was recorded in subsequent periods. Under this Statement, the liability is discounted and accretion expense is recognized using the credit-adjusted risk-free interest rate in effect when the liability was initially recognized.

- Under Statement 19, dismantlement and restoration costs were taken into account in determining amortization and depreciation rates. Consequently, many entities recognized asset retirement obligations as a contra-asset. Under this Statement, those obligations are recognized as a liability. Also, under Statement 19 the obligation was recognized over the useful life of the related asset. Under this Statement, the obligation is recognized when the liability is incurred.

Some current practice views a retirement obligation as a contingent liability and applies FASB Statement No. 5, *Accounting for Contingencies,* in determining when to recognize a liability. The measurement objective in this Statement is fair value, which is not compatible with a Statement 5 approach. A fair value measurement accommodates uncertainty in the amount and timing of settlement of the liability, whereas under Statement 5 the recognition decision is based on the level of uncertainty.

This Statement contains disclosure requirements that provide descriptions of asset retirement obligations and reconciliations of changes in the components of those obligations.

How the Changes in This Statement Improve Financial Reporting

Because all asset retirement obligations that fall within the scope of this Statement and their related asset retirement cost will be accounted for consistently, financial statements of different entities will be more comparable. Also,

- Retirement obligations will be recognized when they are incurred and displayed as liabilities. Thus, more information about future cash outflows, leverage, and liquidity will be provided. Also, an initial measurement at fair value will provide relevant information about the liability.

- Because the asset retirement cost is capitalized as part of the asset's carrying amount and subsequently allocated to expense over the asset's useful life, information about the gross investment in long-lived assets will be provided.

- Disclosure requirements contained in this Statement will provide more information about asset retirement obligations.

How the Statement Generally Changes Financial Statements

Because of diverse practice in current accounting for asset retirement obligations, various industries and entities will be affected differently. This Statement will likely have the following effects on current accounting practice:

- Total liabilities generally will increase because more retirement obligations will be recognized. For some entities, obligations will be recognized earlier, and they will be displayed as liabilities rather than as contra-assets. In certain cases, the amount of a recognized liability may be lower than that recognized in current practice because a fair value measurement entails discounting.

- The recognized cost of assets will increase because asset retirement costs will be added to the carrying amount of the long-lived asset. Assets also will increase because assets acquired with an existing retirement obligation will be displayed on a gross rather than on a net basis.

- The amount of expense (accretion expense plus depreciation expense) will be higher in the later years of an asset's life than in earlier years.

How the Conclusions in the Statement Relate to the Conceptual Framework

The Board concluded that all retirement obligations within the scope of this Statement that meet the definition of a liability in FASB Concepts Statement No. 6, *Elements of Financial Statements,* should be recognized as a liability when the recognition criteria in FASB Concepts Statement No. 5, *Recognition and Measurement in Financial Statements of Business Enterprises,* are met.

The Board also decided that the liability for an asset retirement obligation should be initially recognized at its estimated fair value as discussed in FASB Concepts Statement No. 7, *Using Cash Flow Information and Present Value in Accounting Measurements.*

Effective Date

This Statement is effective for financial statements issued for fiscal years beginning after June 15, 2002. Earlier application is encouraged.

Washington Gas Light Company
Cost of Removal Allowance Based on SFAS 143 Methodology
Using December 31, 2001 Investment and Washington Gas Removal Cost Parameters

Account	Description	A 31-Dec-01 Plant Investment	B Proposed Removal Cost Ratio	C Forecast Removal Cost	D Remaining Life	E PV Factor @ 5%	F PV Removal Cost	G Average Projection Life	H Depreciation of COR Liability	I Increment In PV Factor	J Increment In Present Value	K Total COR Allowance	L Percent of Plant Investment
		2002 Update Stmt B, Col B	2002 Update Stmt A, Col F	A x B x -1	2002 Update Stmt A, Col E	PV Table	C x E	2002 Update Stmt E, Col H	F/G	PV Table	I x F	H + J	K/A
Storage and Processing Plant													
Allocable Property													
361.0	Structures and Imporvements												
	Maryland	373,837	-50%	186,919	28	0.26147	48,874	45	1,086	0.01307	2,444	3,530	0.94%
	Virginia	353,981	-20%	70,796	25	0.30269	21,429	45	476	0.01513	1,071	1,548	0.44%
362.0	Gas Holders			-			-						
	Maryland	3,697,021	-50%	1,848,511	24	0.31782	587,493	45	13,055	0.01589	29,375	42,430	1.15%
	Virginia	2,653,580	-20%	530,716	25	0.30269	160,640	45	3,570	0.01513	8,032	11,602	0.44%
Transmission Plant				-			-						
Situs Property				-			-						
367.1	Mains- Steel	1,642,462	-15%	246,369	29	0.24902	61,351	55	1,115	0.01245	3,068	4,183	0.25%
369.0	Measuring and Regulating Equipment	2,106,826	-15%	316,024	22	0.35040	110,734	35	3,164	0.01752	5,537	8,700	0.41%
Allocable Property				-			-						
366.0	Meas and Reg Station Structures			-			-						
	Maryland	502,304	-10%	50,230	34	0.19511	9,801	40	245	0.00976	490	735	0.15%
	Virginia	211,178	-10%	21,118	29	0.24902	5,259	35	150	0.01245	263	413	0.20%
367.1	Mains- Steel			-			-						
	District	1,396,682	-15%	209,502	29	0.24902	52,170	55	949	0.01245	2,609	3,557	0.25%
	Maryland	5,695,177	-10%	569,518	42	0.13206	75,211	55	1,367	0.00660	3,761	5,128	0.09%
	Virginia	4,485,006	-25%	1,121,252	37	0.16855	188,983	55	3,436	0.00843	9,449	12,885	0.29%
369.0	Measuring and Regulating Equipment			-			-						
	District	96,892	-15%	14,534	22	0.35040	5,093	35	146	0.01752	255	400	0.41%
	Maryland	2,374,313	-30%	712,294	37	0.16855	120,055	45	2,668	0.00843	6,003	8,671	0.37%
	Virginia	1,584,531	-30%	475,359	28	0.26147	124,293	35	3,551	0.01307	6,215	9,766	0.62%
Distribution Plant				-			-						
Situs Property				-			-						
376.1	Mains - Steel	60,581,194	-60%	36,348,716	37	0.16855	6,126,450	60	102,107	0.00843	306,322	408,430	0.67%
376.2	Mains - Plastic	94,934,440	-60%	56,960,664	52	0.08107	4,618,015	60	76,967	0.00405	230,901	307,868	0.32%
376.3	Mains - Cast Iron	6,482,244	-60%	3,889,346	9	0.66072	2,569,785	60	42,830	0.03304	128,489	171,319	2.64%
378.0	Measuring and Regulating Equipment	4,957,328	-20%	991,466	15	0.49304	488,835	27	18,105	0.02465	24,442	42,547	0.86%
380.1	Services - Steel	18,490,625	-75%	13,867,969	26	0.28827	3,997,744	40	99,944	0.01441	199,887	299,831	1.62%
380.2	Services- Plastic	135,308,753	-75%	101,481,565	28	0.26147	26,534,484	40	663,362	0.01307	1,326,724	1,990,086	1.47%
380.3	Services - Copper	3,706,470	-75%	2,779,853	12	0.57076	1,586,624	45	35,258	0.02854	79,331	114,590	3.09%
382.0	Meter Installations	20,240,063	-30%	6,072,019	30	0.23716	1,440,051	45	32,001	0.01186	72,003	104,004	0.51%
383.0	House Regulators	1,588,969	-30%	476,691	29	0.24902	118,706	40	2,968	0.01245	5,935	8,903	0.56%
387.0	Other Equipment	107,578	-300%	322,734	21	0.36792	118,739	35	3,393	0.01840	5,937	9,329	8.67%
Allocable Property				-			-						
378.0	Measuring and Regulating Equipment			-			-						
	Maryland	219,037	-20%	43,807	15	0.49304	21,599	25	864	0.02465	1,080	1,944	0.89%
	Virginia	53,216	-15%	7,982	15	0.49304	3,936	25	157	0.02465	197	354	0.67%
General Plant							-						
Allocable Property							-						
390.0	Structures and Improvements			-			-						
	District	1,856,732	-10%	185,673	36	0.17697	32,859	50	657	0.00885	1,643	2,300	0.12%
	Maryland	778,715	-10%	77,872	34	0.19511	15,194	50	304	0.00976	760	1,064	0.14%
	Virginia	4,951,326	-10%	495,133	33	0.20487	101,437	50	2,029	0.01024	5,072	7,101	0.14%
Total									$1,115,924		$ 2,467,292	$3,583,216	

Washington Gas Light Company
Cost of Removal Factors - District of Columbia
Based on 1996-2000 Experience and December 31, 2000 Investment

	A	B	C	D	E	F	G	H	I	J
	1996	1997	1998	1999	2000	5 Year Total	5 Year Category Total	Annual Average	Dec 31 00 Investment	COR/ Investment
		Washington Gas Plant Records				Sum A-E	Category Sums	G/5	2001 Study Stmt B, Col B	H/I
STORAGE										
STRUCTURES & IMPROVEMENTS			402		41,253	41,655				
GAS HOLDERS	611	208		52,506	81,843	135,168				
OTHER EQUIPMENT						-		-		
TOTAL STORAGE							176,823	35,365	6,713,220	0.527%
TRANSMISSION - SITUS						-		-		
RIGHTS OF WAY						-		-		
STRUCTURES & IMPROVEMENTS					617	617				
MAINS						-				
MEASURING & REGULATING STATION EQUIPMENT		2,053	1,892	27,218		31,162				
TOTAL TRANSMISSION SITUS							31,780	6,356	3,123,171	0.204%
TRANSMISSION - ALLOCABLE						-		-		
RIGHTS OF WAY						-		-		
STRUCTURES & IMPROVEMENTS			158			158		-		
MAINS	570	316	1,635	3,390		5,911		-		
MEASURING & REGULATING STATION EQUIPMENT	3,140	9,566	28,891	54	15,693	57,343		-		
TOTAL TRANSMISSION ALLOCABLE							63,412	12,682	17,974,734	0.071%
DISTRIBUTION - SITUS						-		-		
MAINS - CAST IRON	21,756	98,717	199,975	77,446	121,149	519,042		-		
MAINS - STEEL	14,094	29,706	95,376	130,034	50,848	320,058		-		
MAINS - COPPER						-		-		
MAINS - PLASTIC	1,226	2,209	8,227	22,391	2,687	36,740		-		
MAINS - SPECIAL STRUCTURES						-		-		
MAINS - UNIDENTIFIED						-		-		
TOTAL DISTRIBUTION MAINS - SITUS							875,841	175,168	152,184,629	0.115%
MEASURING & REGULATING STATION EQUIPMENT	1,737				687	2,425	2,425	485	4,842,365	0.010%
SERVICES - STEEL	274,602	195,026	344,273	320,289	332,150	1,466,339		-		
SERVICES - PLASTIC	47,543	26,273	62,148	89,030	115,167	340,159		-		
SERVICES - COPPER	9,403	16,611	102,985	43,078	49,221	221,299		-		
SERVICES - UNIDENTIFIED						-		-		
GAS LIGHT SERVICES	10,381	2,619	3,884	7,319	4,813	29,016		-		
TOTAL SERVICES							2,056,813	411,363	148,408,103	0.277%
METERS - TIN CASE	2,936				706	3,642		-		
METERS - HARD CASE	3,978		4,826	85	7,907	16,796		-		
METERS - INDEX CORRECTORS	40				52	92		-		
METERS - DEMAND RECORDERS						-		-		
METERS - UNIDENTIFIED	(1,883)					(1,883)		-		
METERS - INSTALLATIONS	21,591	24,033	18,891	21,184	2,277	87,976		-		
TOTAL METERS AND METER INSTALLATIONS							106,624	21,325	33,801,202	0.063%
HOUSE REGULATORS AND INSTALLATIONS	7,128	19,658	5,079	2,037		33,903	33,903	6,781	1,570,057	0.432%
DISTRIBUTION - ALLOCABLE						-		-		
STRUCTURES & IMPROVEMENTS						-		-		
COMPRESSOR STATION EQUIPMENT	3,310				251	3,561		-		
MEASURING & REGULATING EQUIPMENT	945	880				1,825		-		
TOTAL DISTRIBUTION - ALLOCABLE							5,386	1,077	276,961	0.389%
TOTAL DISTRIBUTION							3,080,991	616,198	344,480,172	0.179%
GENERAL-ALLOCABLE						-		-		
STRUCTURES & IMPROVEMENTS					6,983	6,983		-		
OFFICE FURNITURE & EQUIPMENT					562	562		-		
TOTAL GENERAL - ALLOCABLE (DEPRECIABLE)							7,546	1,509	7,357,815	0.021%
GENERAL (AMORTIZABLE)							-		23,158,300	
TOTAL GENERAL							7,546	1,509	30,516,115	0.005%
TOTAL	$ 423,108	$ 427,874	$ 878,642	$ 796,061	$ 834,867	$ 3,360,551	$3,360,551	$ 672,110		

Washington Gas Light Company
Account Depreciation Accrual Rates

Account	Description	A 31-Dec-01 Plant Investment	B Resdistributed Reserve	C Amount to Be Recovered	D Remaining Life	E Accrual	F Depreciation Rate
		2002 Update Stmt B, Col B	2002 Update Stmt C. Col G	A - B	2002 Update Stmt A, Col E	C/D	E/A
Storage and Processing Plant							
Allocable Property							
361.0	Structures and Imporvements						
	Maryland	373,837	100,212	273,625	28.40	9,635	2.577%
	Virginia	353,981	111,859	242,122	24.55	9,862	2.786%
362.0	Gas Holders			-			
	Maryland	3,697,021	2,928,023	768,998	24.45	31,452	0.851%
	Virginia	2,653,580	1,949,939	703,641	24.92	28,236	1.064%
363.5	Other Equipment			-			
	Maryland	78,393	(845)	79,238	14.56	5,442	6.942%
	Virginia (Note 1)	37,159	(1,453)	36,754	14.70	2,500	6.729%
Total Storage and Processing Plant		7,193,971	5,087,735	2,106,236		87,127	1.211%
Transmission Plant				-			
Situs Property				-			
367.1	Mains- Steel	1,642,462	$ 518,434	1,124,028	29.48	38,128	2.321%
369.0	Measuring and Regulating Equipment	2,106,826	$ 531,568	1,575,258	22.31	70,608	3.351%
Total Situs Property		3,749,288	1,050,002	2,699,286		108,736	2.900%
Allocable Property				-			
365.2	Rights of Way			-			
	District	622	622	-			0.000%
	Maryland	677,664	124,341	553,323	31.56	17,532	2.587%
	Virginia	370,994	157,517	213,477	20.47	10,429	2.811%
Total Account 365.2		1,049,280	282,480	766,800		27,961	
366.0	Meas and Reg Station Structures			-			
	Maryland	502,304	148,366	353,938	33.63	10,524	2.095%
	Virginia	211,178	69,335	141,843	29.15	4,866	2.304%
Total Account 366		713,482	217,701	495,781		15,390	
367.1	Mains- Steel			-			
	District	1,396,682	908,900	487,782	29.48	16,546	1.185%
	Maryland	5,695,177	1,824,387	3,870,790	42.38	91,335	1.604%
	Virginia	4,485,006	2,096,521	2,388,485	36.66	65,152	1.453%
Total Account 367.1		11,576,865	4,829,809	6,747,056		173,034	
369.0	Measuring and Regulating Equipment			-			
	District	96,892	66,091	30,801	22.31	1,381	1.425%
	Maryland	2,374,313	775,436	1,598,877	37.16	43,027	1.812%
	Virginia	1,584,531	637,624	946,907	27.60	34,308	2.165%
Total Account 369		4,055,736	1,479,152	2,576,584		78,716	
				-			
Total Allocable Plant		17,395,363	6,809,142	10,586,221		295,101	1.696%
Total Transmission Plant		21,144,651	7,859,144	13,285,507		403,837	1.910%

Account	Description	31-Dec-01 Plant Investment	Redistributed Reserve	Amount to Be Recovered	Remaining (Amortization) Life	Accrual	Depreciation Rate
Distribution Plant							
Situs Property							
376.1	Mains - Steel	60,581,194	35,591,274	24,989,920	36.50	684,655	1.130%
376.2	Mains - Plastic	94,934,440	18,744,885	76,189,555	52.01	1,464,902	1.543%
376.3	Mains - Cast Iron	6,482,244	8,433,512	(1,951,268)	9.00	(216,808)	0.000%
378.0	Measuring and Regulating Equipment	4,957,328	3,761,006	1,196,322	15.17	78,861	1.591%
380.1	Services - Steel	18,490,625	11,587,159	6,903,466	26.06	264,907	1.433%
380.2	Services- Plastic	135,308,753	58,596,507	76,712,246	28.33	2,707,810	2.001%
380.3	Services - Copper	3,706,470	4,068,227	(361,757)	12.35	(29,292)	0.000%
381.1	Meters - Tin Case	131,439	157,126	(25,687)	7.19	(3,573)	0.000%
381.2	Meters - Hard Case	12,654,298	5,882,387	6,771,911	16.01	422,980	3.343%
381.3	Meters- Electronic Devices	1,276,027	620,598	655,429	10.26	63,882	5.006%
381.5	Meters - Electronic Demand Recorders	678,429	426,663	251,766	9.44	26,670	3.931%
382.0	Meter Installations	20,240,063	9,901,520	10,338,543	30.33	340,869	1.684%
383.0	House Regulators	1,588,969	676,902	912,067	28.62	31,868	2.006%
384.0	House Regulator Installations	2,327,483	1,291,951	1,035,532	21.06	49,171	2.113%
386.1	Other Property on Customers' Premises	486,225	257,331	228,894	6.19	36,978	7.605%
387.0	Other Equipment	107,578	71,379	36,199	21.34	1,696	1.577%
Total Situs Property		363,951,565	160,068,428	203,883,137		5,925,576	1.628%
Allocable Property				-			
378.0	Measuring and Regulating Equipment			-			
	Maryland	219,037	(238,553)	457,590	14.89	30,731	14.030%
	Virginia	53,216	(54,981)	108,197	14.78	7,320	13.756%
Total Allocable Plant		272,253	(293,534)	565,787		38,052	
				-			
Total Distribution Plant		364,223,818	159,774,894	204,448,924		5,963,628	1.637%
General Plant				-			
Situs Property				-			
397.2	ENSCAN Equipment (Notes 1 and 4)	17,605,039	8,183,754	5,900,278	23.4	252,149	1.432%
Allocable Property				-			
390.0	Structures and Improvements			-			
	District (Note 3)	1,856,732	(438,867)	2,086,908	36.16	57,713	3.108%
	Maryland	778,715	(204,059)	982,774	34.33	28,627	3.676%
	Virginia (Note 3)	4,951,326	(1,352,391)	5,730,652	33.31	172,040	3.475%
Total Allocable Property		7,586,773	(1,995,317)			258,380	
Allocable Property (Amortizable)							
303.05	Software - 5 years	1,925,891			5	343,772	17.850%
303.10	Software - 10 years	8,018,095			10	801,810	10.000%
391.11	Office Furniture & Equipment	1,892,436			15	78,158	4.130%
391.21	Computer Equipment	5,767,748			7	568,700	9.860%
393.00	Stores Equipment	140,597			15	5,230	3.720%
391.00	Tools, Shop & Garage Equipment	2,657,926			15	129,973	4.890%
395.00	Laboratory Equipment	150,979			15	5,616	3.720%
397.00	Communications Equipment	2,116,164	1,113,353		15	123,584	5.840%
397.10	Communications Equipment - Telephones	745,443			15	49,721	6.670%
398.00	Miscellaneous Equipment	411,361			15	19,910	4.840%
Total Allocable Property (Amorizable)		23,826,640	14,571,755			2,126,474	
Total Distribution Plant		49,018,452	20,760,192			2,637,003	5.380%
Total Jurisdiction		$ 441,618,145	$ 193,481,965			$ 24,593,609	

Note 1: Amount to be recovered reduced by 5% for positive salvage.
Note 2: Amount to be recovered reduced by 20% for positive salvage.
Note 3: Amount to be recovered reduced by 10% to eliminate negative salvage.
Note 4: Reserve calculated based on reserve ratio in Account 381.2

Washington Gas Light Company
Reporting of Depreciation and Cost of Removal
Based on December 31, 2001 Plant

Account	Description	A 31-Dec-01 Plant Investment	B Proposed Depreciation Rate	C Proposed Removal Cost Ratio	D Removal Proportion of Rate	E Depreciation Rate	F Removal Cost Allowance	G Depreciation	H Total Accruals
		2002 Update Stmt B, Col B	2002 Update Stmt A, Col H	2002 Update Stmt A, Col F	B x (C/(-1.0-C))	B - D	A x D	A x E	F + G
Storage and Processing Plant									
Allocable Property									
361.0	Structures and Improvements								
	Maryland	373,837	4.23%	-50.00%	1.41%	2.82%	5,271	10,542	15,813
	Virginia	353,981	3.74%	-20.00%	0.62%	3.12%	2,206	11,032	13,239
362.0	Gas Holders						-	-	-
	Maryland	3,697,021	2.62%	-50.00%	0.87%	1.75%	32,287	64,575	96,862
	Virginia	2,653,580	2.24%	-20.00%	0.37%	1.87%	9,907	49,533	59,440
363.5	Other Equipment								-
	Maryland	78,393	6.94%			6.94%		5,440	5,440
	Virginia	37,159	6.73%			6.73%		2,501	2,501
Total Storage and Processing Plant		7,193,971					49,672	143,624	193,296
Transmission Plant									
Situs Property									
367.1	Mains- Steel	1,642,462	2.82%	-15.00%	0.37%	2.45%	6,041	40,276	46,317
369.0	Measuring and Regulating Equipment	2,106,826	4.03%	-15.00%	0.53%	3.50%	11,075	73,831	84,905
Allocable Property							-	-	-
365.2	Rights of Way							-	-
	District	622	0.00%					-	-
	Maryland	677,664	2.59%			2.59%		17,551	17,551
	Virginia	370,994	2.81%			2.81%		10,425	10,425
366.0	Meas and Reg Station Structures						-	-	-
	Maryland	502,304	2.40%	-10.00%	0.22%	2.18%	1,096	10,959	12,055
	Virginia	211,178	2.64%	-10.00%	0.24%	2.40%	507	5,068	5,575
367.1	Mains- Steel						-	-	-
	District	1,396,682	1.75%	-15.00%	0.23%	1.52%	3,188	21,254	24,442
	Maryland	5,695,177	1.89%	-10.00%	0.17%	1.72%	9,785	97,853	107,639
	Virginia	4,485,006	2.05%	-25.00%	0.41%	1.64%	18,389	73,554	91,943
369.0	Measuring and Regulating Equipment						-	-	-
	District	96,892	2.47%	-15.00%	0.32%	2.15%	312	2,081	2,393
	Maryland	2,374,313	2.62%	-30.00%	0.60%	2.02%	14,355	47,852	62,207
	Virginia	1,584,531	3.24%	-30.00%	0.75%	2.49%	11,847	39,491	51,339
Total Transmission Plant		21,144,651					76,596	440,196	516,792

Account / Description	A 31-Dec-01 Plant Investment	B Present Rate	C Present Accrual	D Company Proposed Rate	E Company Proposed Accrual	F OPC Proposed Depreciation Rate	G OPC Proposed Depreciation Accrual	H OPC Proposed Cost of Removal Rate	I OPC Proposed Cost of Removal Accrual	J Total	K OPC vs. Present	L OPC vs. Co. Proposed
Distribution Plant												
Situs Property												
376.1 Mains - Steel	60,581,194	3.09%	1,871,353	2.78%	1,684,157	1.13%	684,655	0.12%	72,697	757,353	(1,114,000)	(926,804)
376.2 Mains - Plastic	94,934,440	2.96%	2,811,958	2.70%	2,563,230	1.54%	1,464,902	0.12%	113,921	1,578,823	(1,233,135)	(984,407)
376.3 Mains - Cast Iron	6,482,244	2.93%	189,930	3.41%	221,045	0.00%	-	0.12%	7,779	7,779	(182,151)	(213,266)
378.0 Measuring and Regulating Equipment	4,957,328	4.62%	229,276	4.18%	207,216	1.59%	78,861	0.01%	496	79,357	(149,919)	(127,859)
380.1 Services - Steel	18,490,625	4.79%	885,516	4.11%	759,965	1.43%	264,907	0.28%	51,774	316,680	(568,836)	(443,285)
380.2 Services- Plastic	135,308,753	4.49%	6,076,716	4.52%	6,115,956	2.00%	2,707,810	0.28%	378,865	3,086,674	(2,990,042)	(3,029,282)
380.3 Services - Copper	3,706,470	4.94%	183,248	4.53%	167,903	0.00%	-	0.28%	10,378	10,378	(172,870)	(157,525)
381.1 Meters - Tin Case	131,439	3.84%	5,049	3.57%	4,692	0.00%	-	0.06%	79	79	(4,970)	(4,613)
381.2 Meters - Hard Case	12,654,298	2.92%	369,632	4.43%	560,585	3.34%	422,980	0.06%	7,593	430,573	60,941	(130,012)
381.3 Meters- Electronic Devices	1,276,027	2.87%	36,660	6.79%	86,642	5.01%	63,882	0.06%	766	64,648	27,988	(21,994)
381.5 Meters - Electronic Demand Recorders	678,429	2.80%	19,010	6.45%	43,759	3.93%	26,670	0.06%	407	27,077	8,067	(16,682)
382.0 Meter Installations	20,240,063	4.29%	867,692	2.96%	599,106	1.68%	340,869	0.06%	12,144	353,013	(514,679)	(246,093)
383.0 House Regulators	1,588,969	2.12%	33,607	3.40%	54,025	2.01%	31,868			31,868	(1,739)	(22,157)
384.0 House Regulator Installations	2,327,483	2.44%	56,814	3.12%	72,617	2.11%	49,171			49,171	(7,643)	(23,446)
386.1 Other Property on Customers' Premises	486,225	5.00%	24,311	10.85%	52,755	7.61%	36,978			36,978	12,667	(15,777)
387.0 Other Equipment	107,578	5.83%	6,273	11.66%	12,544	1.58%	1,696			1,696	(4,577)	(10,848)
Total Situs Property	363,951,565		13,667,045		13,206,197		6,175,248		656,898	6,832,146	(6,834,899)	(6,374,051)
Allocable Property							-					
378.0 Measuring and Regulating Equipment							-					
Maryland	219,037	3.82%	8,378	15.43%	33,797	14.03%	30,731			30,731	22,353	(3,066)
Virginia	53,216	3.83%	2,036	14.55%	7,743	13.76%	7,320			7,320	5,284	(423)
Total Allocable Plant	272,253		10,414		41,540		38,052	0.39%	1,062	39,114	28,700	(2,426)
Total Distribution Plant	364,223,818		13,677,459		13,247,737	1.71%	6,213,300	0.18%	657,960	6,871,260	(6,806,199)	(6,376,477)
General Plant												
Situs Property												
397.2 ENSCAN Equipment	17,605,039	2.92%	514,243	8.07%	1,420,727	1.43%	252,149			252,149	(262,094)	(1,168,578)
Allocable Property												
390.0 Structures and Improvements												
District	1,856,732	2.00%	37,116	3.70%	68,699	3.11%	63,484			63,484	26,368	(5,215)
Maryland	778,715	2.00%	15,567	3.97%	30,915	3.68%	28,627			28,627	13,060	(2,288)
Virginia	4,951,326	2.00%	98,977	4.12%	203,995	3.47%	189,244			189,244	90,267	(14,751)
Total Allocable Property	7,586,773		151,660		303,609		281,356	0.02%	1,517	282,873	131,213	(20,736)
Allocable Property (Amortizable)												
303.05 Software - 5 years	1,925,891	20.00%	385,178	17.85%	343,772	17.85%	343,772			343,772	(41,406)	0
303.10 Software - 10 years	8,018,095	10.00%	801,810	10.00%	801,810	10.00%	801,810			801,810	-	0
391.11 Office Furniture & Equipment	1,892,436	3.35%	63,378	4.13%	78,158	4.13%	78,158			78,158	14,780	0
391.21 Computer Equipment	5,767,748	3.35%	193,162	9.86%	568,700	9.86%	568,700			568,700	375,538	0
393.00 Stores Equipment	140,597	3.61%	5,077	3.72%	5,230	3.72%	5,230			5,230	153	0
391.00 Tools, Shop & Garage Equipment	2,657,926	3.35%	89,067	4.89%	129,973	4.89%	129,973			129,973	40,906	0
395.00 Laboratory Equipment	150,979	3.90%	5,894	3.72%	5,616	3.72%	5,616			5,616	(278)	0
397.00 Communications Equipment	2,116,164	5.47%	115,648	5.84%	123,584	5.84%	123,584			123,584	7,936	0
397.10 Communications Equipment - Telephones	745,443	5.47%	40,738	6.67%	49,721	6.67%	49,721			49,721	8,983	0
398.00 Miscellaneous Equipment	411,361	5.77%	23,715	4.84%	19,910	4.84%	19,910			19,910	(3,805)	0
Total Allocable Property (Amorizable)	23,826,640		1,723,667		2,126,474		2,126,474			2,126,474	402,807	0
Total General Plant	49,018,452		2,389,570		3,850,810	5.43%	2,659,978	0.003%	1,517	2,661,496	271,926	(1,189,314)
Total Jurisdiction	$ 441,580,892		$ 16,614,327		$ 17,808,633	2.12%	$ 9,364,099	0.162%	$ 717,454	$ 10,069,202	$ (6,545,125)	$ (7,739,431)

DIRECT TESTIMONY OF CHARLES W. KING

INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Charles W. King. I am President of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. PLEASE DESCRIBE SNAVELY KING.

A. Snavely King, formerly Snavely, King & Associates, Inc., was founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. The firm has a professional staff of 15 economists, accountants, engineers and cost analysts. Much of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 32-year history, members of the firm have participated in over 500 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. Attachment A is a summary of my qualifications and experience.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. Attachment B is 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.

Q. WHAT ISSSUES WILL YOU ADDRES IN YOUR TESTIMONY?

A. My testimony addresses three issues. In Part I, I address the appropriate rate of return to be applied to the jurisdictional rate base of Columbia of Kentucky ("CKY" or "the Company"). In Part II, I address the Company's proposed Margin Loss Recovery Rider. In Part III, I address the subject of cost allocation and rate design.

Q. WHAT INFORMATION DID YOU OBTAIN FROM THE COMPANY IN PREPARING YOUR TESTIMONY?

A. I have obtained the Company's minimum filing requirements and the testimony and exhibits of its witnesses, including Paul Moul, its rate-of-return witness; Kimra Cole, who sponsors the Margin Loss Recovery Rider; and John Skirtich, who sponsors the Company's class cost of services studies. I also obtained the Company's responses to the Commission Staff's data requests. I propounded my own data requests and follow-up data requests.

PART I – RATE OF RETURN

Q. WHAT HAVE YOU FOUND TO BE THE APPROPRIATE RATE OF RETURN FOR THE COMPANY'S GAS DISTRIBUTION OPERATIONS?

Q. A. Based on the analyses presented in this part of my testimony, I find that the appropriate rate of return on the Company's rate base is **8.14 percent,** inclusive of a return to equity of **10.3 percent.**

Q. HOW WILL YOU STRUCTURE THIS PART OF YOUR TESTIMONY?

A. I will first discuss the capital structure of the Company, that is, the mix of debt and common equity. I will next quantify the cost of the Company's debt. I will then discuss the theory of return to equity, the methodology for estimating it, and my development of the Company's equity return requirement. In the course of this discussion, I will explain the differences between my approach and data selection and those of Paul R. Moul, the Company's rate of return witness. I will conclude by applying the respective cost rates to the components of the capital structure to develop the appropriate return to total capital.

A. CAPITAL STRUCTURE

Q. WHAT IS THE COMPANY'S CAPITAL STRUCTURE?

A. The answer to this question differs according to the level within the NiSource family of companies. There is a different capital structure for CKY, its immediate parent, the Columbia Energy Group ("CEG"), and the ultimate parent company, NiSource, Inc. The respective capital structures are as follows:

Table 1
Capital Structure, December 31, 2001
(Dollars in Millions)

	Columbia of KY		Columbia Energy Grp.		NiSource, Inc.	
Long-term Debt	$42.1	32.9%	$1,356.9	35.6%	$5,780.8	48.2%
Preferred Equity	0	0.0%	0	0.0%	433.6 (1)	3.6%
Short-term Debt	5.8	4.5%	281.7 (2)	7.4%	2,295.5 (2)	19.2%
Common Equity	80.0	62.6%	2,177.1	57.0%	3,469.4	29.0%
Total	$127.9	100.0%	$3,815.70	100.0%	$11,979.3	100.0%

(1) Includes Company-obligated mandatory redeemable preferred securities of subsidiary trust holding solely Company debentures.
(2) Includes current mandatory redeemable portion of debt and preferred stock.
Sources: CKY: FERC Form 2, pages 112, 113.
CEG: Form 10K, Securities & Exchange Commission, page 16.
NiSource: Form 10-K, Securities & Exchange Commission, page 51.

Q. WHICH OF THESE CAPITAL STRUCTURES DOES THE COMPANY USE IN MEASURING ITS RETURN?

The Company purports to use the capital structure of the Columbia Energy Group. The principal difference between the figures shown in Table 1 and those in Mr. Moul's Attachment PRM-5 is Mr. Moul's inclusion $281.5 million in debt due November 28, 2002 as long-term debt. Conventionally, debt that matures within one year is treated as short-term debt, as shown in Table 1. Other than that difference, figures shown by Mr. Moul are close, although not exactly matching (e.g. equity of $2,169.9m vs. $2,177.1m) those reported in the CEG's Form 10-K.

Q. IS THE YEAR-END 2001 CAPITAL STRUCTURE OF THE COLUMBIA ENERGY GROUP APPROPRIATE FOR FINDING THE COMPOSITE COST OF CAPITAL FOR COLUMBIA OF KENTUCKY?

A. No. CEG's capital structure has clearly been influenced by its acquisition by NiSource. As Table 1 demonstrates, NiSource is currently heavily leveraged, that is, its overall debt and mandatory preferred obligations are very large relative to its common equity. For this reason, it is probably constraining its subsidiaries from incurring any more debt and is requiring them to pay off as much debt as possible. That is why both CKY and CEG have very high year-end 2001 equity ratios. These ratios are not reflective of any management assessment of the financial risk appropriate to the respective subsidiaries. Rather, they reflect the financial risk facing the parent, principally because of its acquisition activities.

Additionally, there is an issue of "double leverage." NiSource, the parent, has issued a small amount of debt ($116.9 million) in its own name, bearing a cost of only 5.95 percent.[1] When CEG passes its equity earnings up to its parent, a portion of those earnings do not flow to the ultimate stockholders, that is the shareholders of NiSource. Instead, some of the earnings pay for NiSource's own low-cost debt. As a result, not all of CEG's equity return is, in fact, return to equity investors.

Q. WHAT CAPITAL STRUCTURE DO YOU RECOMMEND BE USED IN CALCULATING THE RETURN TO CAPITAL FOR COLUMBIA OF KENTUCKY?

A I recommend using the capital structure of the Columbia Energy Group as of the end of 2000. This structure reflects the makeup of CEG's capital only one month after its acquisition by NiSource, too soon to have been influenced by NiSource's own capital structure problems. Accordingly, it reflects the most recent assessment by management of the level of financial risk it believes should be incurred relative to the business risks of its operations. That capital structure is as follows:

[1] Response to AG-1-99

Table 2
Columbia Energy Group Capital Structure
December 31, 2000
(Dollars in Million)

Long-term Debt	$1,639.1	40.0%
Short-term Debt	521.2	12.7%
Common Equity	1,935.1	47.3%
Total	$4,095.4	100.0%

Source: Year 2001 CEG Form 10-K to the SEC, page 16.

Q. WHY HAVE YOU INCLUDED SHORT-TERM DEBT IN THE CAPITAL STRUCTURE WHEN CKY PURPORTS TO HAVE NO SHORT-TERM DEBT?

A. Page 1 of Mr. Moul's Attachment PRM-2 shows that CKY never has short-term debt. This is not true. As of the end of 2001, CKY had $5.8 million in "Notes Payable to Associated Companies."[2] Moreover, the Company has indicated in response to a data request that during the winter season between October 2000 and March 2001, it incurred short-term debt which, in December 2000, amounted to $12 million, or about 10 percent of its capitalization.[3] Between March and December of 2001, the Company avoided external short-term debt by using "internally generated funds."[4] Such funds were not free. Rather, they represented cash flow withheld from CKY's parent, CEG, causing CEG to incur short-term debt. That is why I have included CEG's short-term debt in CKY's capital structure.

Since December 2001, CKY has been able to obtain short-term borrowings from the NiSource system money pool. The amounts available for short-term borrowings consist of surplus funds in the money pool and proceeds received from the sale of commercial paper, borrowings from banks and other lenders, and other financing arrangements.[5]

[2] CKY, Year 2001 FERC Form 2, page 113, line 36.
[3] Response to AG-1-95.
[4] Response to AG-1-96.
[5] Response to AG-1-98.

B. THE COST OF DEBT

Q. HAS THE COMPANY PROVIDED A CALCULATION OF THE COST OF ITS LONG-TERM DEBT?

A. Yes. In Attachment PRM-6 to his testimony, Mr. Moul calculates the cost of the CEG's long-term debt as 7.25 percent.

Q. WHAT IS THE COST OF THE SHORT-TERM DEBT COMPONENT OF THE COMPANY'S CAPITAL STRUCTURE?

A. Since NiSource is now the source of CKY's short-term borrowing, I propose to use the cost of NiSource's short-term debt. That cost is presented in NiSource's 2001 Form 10-K, as follows:

Table 3
NiSource, Inc Short Term Debt Cost
December 31, 2001

	Amount	Interest Rate	Annualized Interest
Commercial Paper	$1,004.3	3.14%	$31.5
Credit Facility	850.0	2.58%	21.9
Total	$1,854.3	**2.88%**	$53.5

Source: NiSource Form 10-K to the Securities & Exchange Commission, 2001, page 76.

C. THE COST OF EQUITY

Q. WHAT IS THE BASIS FOR FINDING A RATE OR RETURN TO THE EQUITY COMPONENT OF THE CKY'S CAPITAL?

A. In its landmark Hope Natural Gas decision, the United States Supreme Court established the following standards for the return to equity that must be allowed a regulated public utility:

> ..the return to the equity owner should be commensurate with the returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[6]

It can be seen from this excerpt that there are essentially three standards for determining an appropriate return to equity. The first is the "comparable earnings" standard, that the earnings must be "commensurate with the returns on investments in other enterprises having corresponding risks." The second is that they must be sufficient to assure "confidence in the financial integrity of the enterprise," and the third is that they must allow the utility to be able to attract capital.

Q. HOW CAN THE COMPARABLE EARNINGS STANDARD BE APPLIED IN ESTIMATING THE RATE OF RETURN TO EQUITY CAPITAL?

A. There is a certain circularity to the comparable earnings standard because the competitive nature of the capital markets virtually ensures that the returns to all enterprises having corresponding risks are comparable with each other. Investors establish the price of each traded stock based on that stock's present and prospective earnings in comparison with the present and prospective earnings of all other stocks and other investments available to them. If the earnings of a firm are depressed, then investors will pay only a low price for that firm's stock. As a result, their return on the market value of that stock will be comparable to the return on the market value of the stock of other highly profitable companies which, as a consequence of their profitability, have been bid up to a very high price. Thus, if "return" is defined as the earnings of an equity investment relative to its current market price, then the comparable earnings test becomes a cipher. All returns are comparable with all other returns.

In public utility regulation the conventional procedure for resolving this circularity is to identify the required equity return based on the market value of a utility's stock. That

[6] Federal Power Commission et. al. vs. Hope Natural Gas Company, 320 U.S. 592, at 603.

return is combined with the cost of debt and preferred stock, using either the actual or a hypothetical minimum-cost capital structure. The blended return to total capital is then applied to a rate base reflective of the book value of the utility's investment. The book value is the accountant's quantification of the original cost of the utility's assets adjusted for ratepayer contributions such as deposits and deferred taxes. Under this procedure, the market price of a stock is used only to determine the return that investors expect from that stock. That expectation is then applied to the book value of the utility's investment to identify the level of earnings which regulation will allow the utility's common shareholders to recover.

Q. HOW CAN THE FINANCIAL INTEGRITY AND CAPITAL ATTRACTION STANDARDS BE APPLIED IN ESTIMATING THE RATE OF RETURN TO EQUITY CAPITAL?

A. If the utility can earn a return on its investment comparable to that required by enterprises of comparable risk, then it should have no difficulty in attracting capital and maintaining credit. Investors would have no reason to shun such a utility in favor of other investment opportunities. Thus, if the comparable earnings test is met, then the financial integrity and capital attraction standards are met as well.

Q. IN SEEKING "ENTERPRISES OF COMPARABLE RISK," WHAT IS THE RELEVANT "RISK" FOR PURPOSES OF THIS INQUIRY?

A. The purpose of this inquiry is to find the cost of the equity capital of CKY that is devoted to providing regulated gas distribution service in the Company's monopoly service area. The relevant risk is therefore that associated with providing regulated gas distribution service.

This level of risk is <u>not</u> the same risk as that of NiSource, CKY's ultimate parent corporation. That is because NiSource has substantial activities beyond retail gas distribution, as demonstrated in the following table:

Table 4
2001 CEG and NiSource Revenue Sources
(Dollars in Millions)

Business Segment	Columbia Energy Group		NiSource	
Electric Operations			$1,014.8	10.7%
Natural Gas Distribution	2,794.4	76.2%	4,281.9	45.4%
Gas Transmission & Storage	869.7	23.7%	963.7	10.2%
Exploration and Production	235.7	6.4%	235.7	2.5%
Merchant Operations			3,390.7	35.8%
Other Products and Services	27.4	0.7%	159.7	1.6%
Intersegment Eliminations	(257.3)	(7.0%)	(587.8)	(6.2%)
Total Company	$3,669.9	100.0%	$9,458.7	100.0%

Source: Forms 10-K to the Securities & Exchange Commission, page 38 for CEG; page 87 for NiSource.

Q. FOR PURPOSES OF THIS INQUIRY, WHAT TYPES OF ENTERPRISES HAVE COMPARABLE RISK TO CKY'S GAS DISTRIBUTION SERVICE?

A. The enterprises likely to have business risks most comparable to CKY's gas distribution service are those engaged in the same business, that is, the distribution of gas to retail customers under rate base/rate-of-return regulation.

Q. HAVE YOU IDENTIFIED SPECIFIC COMPANIES THAT YOU BELIEVE COMPARABLE TO CKY'S GAS DISTRIBUTION SERVICE?

A. To minimize controversy, I have used the same basic list of gas distribution companies as used by Mr. Moul in selecting his "barometer group." The original group consisted of 19 companies, of which he eliminated nine to leave his final barometer group at 10 companies.

I have adopted all of Mr. Moul's criteria for company selection except one, and I have added one more criterion. I have rejected Mr. Moul's claimed requirement that the Companies operate within the Northeast, Great Lakes and Southeastern regions of the

U.S., and I have added a requirement that at least 75 percent of the company's revenue be generated from natural gas distribution.

While geography may play an important part in the value of a gas transmission company, I do not believe it significantly influences the relative risk of providing natural gas service. Mr. Moul has eliminated six companies based on "geography."[7] Two of these eliminations are inexplicable. Atmos Energy has gas distribution operations in Kentucky, as well as 11 other states. The LaClede Group is the principal gas distribution company for the St. Louis area, only a few miles from Kentucky's western border. The other four companies serve areas in the western United States, but I do not see how that significantly affects their relative risk vis-à-vis CKY.

What <u>does</u> affect relative risk is the extent to which the company in question derives its revenue and earnings from natural gas distribution. Mr. Moul has included in his barometer group several companies that evidently have substantial operations in addition to gas distribution. The proportions of revenue derived from gas distribution for Mr. Moul's barometer group, plus the six geographically eliminated utilities, are as follows.

[7] Response to AG-1-105.

Table 5

Percent Gas Distribution Revenue
Selected Companies

Company	Gas Distr.
Atmos Energy	95.6%
AGL Resources	94.2%
Cascade Natural Gas	100.0%
Energen Corp	65.9%
Keyspan Corp	49.9%
LaClede Group, Inc.	92.8%
New Jersey Resources Grp	64.3%
Nicor, Inc	82.5%
Northwest Natural Gas	98.2%
ONEOK, Inc.	22.3%
People's Energy Corp	78.7%
Piedmont Natural Gas	100.0%
SEMCO Energy, Inc.	72.8%
Southwest Gas	85.4%
South Jersey Industries	86.6%
WGL Holdings	82.5%

Source: Response to AG-1-106 and the companies' Forms 10-K to the SEC.

It is obvious that investors' perceptions of the business risk of many of these companies would be colored by their involvement in activities unrelated to gas distribution. Since most of these unrelated activities are likely to be unregulated and competitive, their effect is to increase the perceived risk of the overall enterprise. For this reason, it is necessary to exclude companies that have significant revenue sources other than regulated gas distribution.

Where to draw the line is a rather arbitrary decision. It involves a balance between eliminating companies influenced by unrelated activities and having enough companies within my comparison group to provide an adequate cross-section of the gas distribution industry.

Since Mr. Moul evidently believes that ten companies represent an adequate cross-section of the gas distribution industry, I have adopted a criterion that yields almost the same number. The criterion is that 75 percent of revenue must be from gas distribution revenue. The 11 companies that fit this criterion are, as follows:

Atmos Energy
AGL Resources, Inc.
Cascade Natural Gas
LaClede Group, Inc
Nicor, Inc.
Northwest Natural Gas
People's Energy Corp.
Piedmont Natural Gas Co.
South Jersey Industries
Southwest Gas
WGL Holdings

Q. HOW WILL YOU IDENTIFY THE MARKET-DETERMINED RATE OF RETURN TO THE EQUITY CAPITAL INVESTMENT IN YOUR BAROMETER GROUP OF GAS DISTRIBUTION COMPANIES?

A. I shall first apply the Discounted Cash Flow ("DCF") procedure, which I consider to be the most accurate test of a market return. I shall then consider the interest rate risk premium approach as a "sanity check" on my DCF results.

1. DISCOUNTED CASH FLOW PROCEDURE

Q. PLEASE DESCRIBE THE DISCOUNTED CASH FLOW PROCEDURE.

A. The basic premise of the Discounted Cash Flow (" DCF") procedure is that the market values each stock at the discounted present value of all future flows of cash that investors expect from purchasing that stock. The discount rate that equates those future cash flows with the market value of the stock is the investors' required rate of return.

The DCF approach is usually represented by the following formula:

$$k = {}^{d}/_{P} + g$$

where k = required rate of return
d = dividend in the immediate period
P = market price
g = expected growth rate in dividends

While the DCF method is usually presented in mathematical notation format (as above), it can also be described in narrative fashion. The formula says that the return that any investor expects from the purchase of a stock consists of two components. The first is the immediate cash flow in the form of a dividend. The second is the prospect for future growth in dividends. The sum of the rates of these two flows, present and future, equals the return that investors require. Investors adjust the price they are willing to pay for the stock until the sum of the dividend yield and the annual rate of expected future growth in dividends equals the rate of return they expect from other investments of comparable risk. The DCF test thus determines what the investing community requires from the company in terms of present and future dividends relative to the current market price.

Q. DON'T MOST INVESTORS REGARD CAPITAL APPRECIATION AS A PORTION OF THEIR EXPECTED RETURN?

A. Yes. The expectation of capital appreciation is captured in the "g" or growth portion of the DCF formula. If dividends grow, then it follows that the market price of the stock will grow as well. It is this growth that most equity investors seek, at least in part, in purchasing shares in a traded company.

Q. IS THERE A CONVENTIONAL PROCEDURE FOR CALCULATING DCF RETURNS?

A. Yes. There is a conventional procedure for calculating equity return under the DCF formula that is often referred to as the "classic" DCF calculation. The Federal Communications Commission ("FCC") has concluded that this method should be given the greatest weight in determining the rate of return to equity.[8] I agree with this conclusion.

Q. HOW IS THE "g" OR GROWTH FACTOR IN THE DCF FORMULA IDENTIFIED UNDER THE CLASSIC DCF CALC0ULATION?

A According to the DCF theory, the relevant measure of "g" should be the growth in dividends. Dividends, however, are largely a function of management discretion, and they do not necessarily reflect the underlying driver of earnings. Simply by changing the dividend payout ratio, a company's management can create a rate of dividend growth that is unsustainable. For this reason, I believe that earnings per share ("EPS") is the most reliable indicator of the "g" factor.

The classic DCF calculation employs predictions of EPS growth, usually in the three to five year time horizon. Investment analysts routinely attempt to forecast future earnings of traded companies. No one forecast can be considered reliable, but presumably a consensus of forecasts might be a good indication of investors' collective expectations as regards the company's future prospects.

The two most commonly used sources of investment analysts' predictions are the Institutional Brokers Estimate System ("I/B/E/S") and a somewhat broader survey of investment analysts by Zacks Investment Research, Inc., which includes retail as well as institutional brokers.

Q. WHAT ARE THE CONSENSUS ESTIMATES OF EPS GROWTH FOR THE COMPARABLE COMPANIES THAT YOU HAVE IDENTIFIED?

A. The Zacks' five year consensus growth estimates are as follows:

[8] *Notice Initiating a Prescription Proceeding and Notice of Proposed Rulemaking,* CC Docket No. 98-166, October 5, 1998.

Table 6
Zacks Five Year Consensus EPS Forecasts

Atmos Energy Corp.	6.43%
AGL Resources	11.73%
Cascade Natural Gas Corp.	5.50%
LaClede Group, Inc.	4.50%
NICOR, Inc.	6.60%
Northwest Natural Gas Co.	6.42%
People's Energy Corp.	6.80%
Piedmont Natural Gas Co.	4.50%
South Jersey Industries, Inc.	3.50%
Southwest Gas	6.80%
WGL Holdings, Inc.	3.73%

Source: Zacks Investments Research, Inc., Company Reports.

Q. MR. MOUL USES FIVE DIFFERENT SOURCES OF EPS GROWTH FORCASTS. WHY HAVE YOU USED ONLY ONE?

A. Mr. Moul uses growth forecasts from Zacks, the Institutional Brokers Estimation System ("I/B/E/S"), First Call, Market Guide and Value Line. The first four of these are largely redundant, in that they all involve surveys of market analysts. Zacks covers retail as well as institutional analysts, so that it is somewhat broader than I/B/E/S. As Mr. Moul's Attachment PRM-9 shows, the results of the four surveys are fairly close together, as would be expected.

In spite of Mr. Moul's characterization, Value Line does not perform a five-year projection of earnings growth rates. Rather, it predicts a series of financial indicators, including earnings per share, for a span of three years in the future. While the middle year is five years out, the breadth of this span suggests the general lack of precision. Moreover, Value Line reflects the judgement of a single analyst (whose name is at the bottom of each Value Line company report), while the other forecasts are the result of surveys of up to 20 or 30 analysts. I therefore regard those surveys, including Zacks, as more indicative of the market's expectations than Value Line.

Q. HOW DOES THE CLASSIC DCF CALCULATION DERIVE THE DIVIDEND YIELD PORTION OF THE DCF FORMULA?

A. Under the classic calculation, the dividend yield is calculated as the next year's dividend divided by an average of recent prices of the stock. The resultant yield should reasonably match the dividend yields shown by the financial reporting services.

There are several ways to predict next year's dividend. Several investors' services provide forecasts of dividends. Another, somewhat more mechanical approach is to compute the next year's dividend as the most recent dividend annualized and then increased by one half of the analysts' prediction of long-term annual growth rate in earnings per share.

Q. WHAT ARE THE NEXT YEAR'S DIVIDENDS FOR THE COMPARISON COMPANIES YOU HAVE IDENTIFIED?

A. Using the mechanical approach, I calculate the following dividends for the comparison companies.

Table 7
Next Period Dividends

Company	Dividend (1)	½ Growth	Next Year Dividend
Atmos Energy Corp.	1.18	3.22%	1.22
AGL Resources	1.08	5.87%	1.14
Cascade Natural Gas Corp.	0.96	2.75%	0.99
LaClede Group, Inc.	1.34	2.25%	1.37
NICOR, Inc.	1.84	3.30%	1.90
Northwest Natural Gas Co.	1.26	3.21%	1.30
People's Energy Corp.	2.08	3.40%	2.15
Piedmont Natural Gas Co.	1.60	2.25%	1.64
South Jersey Industries, Inc.	1.50	1.75%	1.53
Southwest Gas	0.82	3.40%	0.85
WGL Holdings, Inc.	1.27	1.87%	1.29

(1) Zacks Company Reports

Q. HOW IS THE DENOMINATOR IN THE DIVIDEND YIELD CALCULATION, THE RECENT PRICE OF THE STOCKS, IDENTIFIED?

A. Some judgement is required to establish a set of price observations that capture the investing public's current perception of value, while at the same time reflecting some stability in the market. Given the fluctuations of the markets, a price observation for a single day, week, or even month runs the risk of becoming obsolete in a very short time. Market fluctuations also mean that the use of monthly highs and lows may exaggerate the effect of some of the sharp drops and rises that the markets have experienced recently. For this reason, I believe it is best to use the average of prices over a period somewhat longer than a month. Since CBS MarketWatch routinely publishes the average of the 50 most recent trading day closing prices, I have chosen this series as the price basis for the calculation of dividend yield.

Q. WHAT IS THE DIVIDEND YIELD OF YOUR COMPARISON COMPANIES?

A. Using the foregoing dividends and the MarketWatch price averages, I calculate the dividend yields as follows:

Table 8
Next Period Dividend Yields

Company	Dividend	50-Day Avg.Price	Dividend Yield
Atmos Energy Corp.	$ 1.22	$ 21.97	5.54%
AGL Resources	$ 1.14	$ 22.15	5.16%
Cascade Natural Gas Corp.	$ 0.99	$ 20.57	4.80%
LaClede Group, Inc.	$ 1.37	$ 22.78	6.01%
NICOR, Inc.	$ 1.90	$ 43.79	4.34%
Northwest Natural Gas Co.	$ 1.30	$ 28.33	4.59%
People's Energy Corp.	$ 2.15	$ 36.97	5.82%
Piedmont Natural Gas Co.	$ 1.64	$ 34.69	4.72%
South Jersey Industries, Inc.	$ 1.53	$ 33.53	4.55%
Southwest Gas	$ 0.85	$ 23.27	3.64%
WGL Holdings, Inc.	$ 1.29	$ 24.97	5.18%

Note: 50 day prices prior to July 12, 2002. Source: CBS MarketWatch.

Q. DOES MR. MOUL USE THE SAME PROCEDURE TO CALCULATE THE DIVIDEND YIELDS OF HIS BAROMETER GROUP?

A. No. Mr. Moul uses average month-end prices during the last three months. While I question whether these three spot prices are as representative of the respective stocks' market values as 50-day average closing prices, I doubt that their use introduces any significant bias into the calculation. What does introduce bias -- upward in each case -- are two other adjustments that Mr. Moul has made that I have not included in my calculations.

Mr. Moul's first adjustment is to reduce the month-end prices by the fraction of the quarterly dividend since the time of the last ex-dividend date. If the ex-dividend dates for a $1.00 dividend are, say, December 31 and March 31, Mr. Mould subtracts $0.33 from the January 31 price of the stock and $.66 from the February 28 price. He believes these amounts reflect the dividend value that the market has imputed into the price of the stock and therefore should be removed to yield the "true" value of the stock.

Mr. Moul's other adjustment is to compound the quarterly dividends throughout the year on the theory that the investor reinvests the dividend and earns further return. A $1.00 dividend on April 1 has a value of $1.025 on July 1 if the average return is 10 percent. That dividend is worth $1.075 by year-end. The June 30 dividend is worth $1.050 by year-end, and so on.

Q. IS MR. MOUL'S EX-DIVIDEND PRICE ADJUSTMENT APPROPRIATE?

A. No. First of all, I am unaware of any empirical studies that demonstrate a decline in the value of the typical stock on the ex-dividend date by the amount of the dividend. While there may be investors who calculate their expected returns with this degree of precision, it would take an almost unanimous agreement among all investors to achieve a predictable drop in every stock's value on its ex-dividend date. Moreover, if there were such a predictable drop in every stock's price, speculators would soon put an end to it by selling stocks short on their ex-dividend dates in anticipation of the drop in price.

But even if Mr. Moul's highly questionable assumptions as to stock price were true, his procedure of reducing the stock's price by the anticipated amount of the dividend effectively double-counts the same dividend in the dividend yield calculation. The dividend itself makes up the numerator, but it is again subtracted from the denominator to inflate further the level of the yield.

Q. IS MR. MOUL'S COMPOUNDING OF QUARTERLY DIVIDENDS APPROPRIATE?

A. No. It is true that investors can reinvest their dividends and earn a return on them throughout the rest of the year, but that investment is made outside of the enterprise being studied. That is, the Company issuing the dividend does not have to generate the compounded returns; investors do it on their own. To provide them with supplemental return to recognize this compounding effectively double-counts that compounding benefit.

Q. WHAT ARE THE RESULTS FOR THE "CLASSIC" DCF FORMULATION?

A. The "classic" formulation of the DCF procedure is the sum the growth rates identified in Table 6 with the dividend yields in Table 8, as follows:

Table 9
"Classic" DCF Results

Company	Growth	Dividend Yield	DCF Return
Atmos Energy Corp.	6.43%	5.54%	11.97%
AGL Resources	11.73%	5.16%	16.89%
Cascade Natural Gas Corp.	5.50%	4.80%	10.30%
LaClede Group, Inc.	4.50%	6.01%	10.51%
NICOR, Inc.	6.60%	4.34%	10.94%
Northwest Natural Gas Co.	6.42%	4.59%	11.01%
People's Energy Corp.	6.80%	5.82%	12.62%
Piedmont Natural Gas Co.	4.50%	4.72%	9.22%
South Jersey Industries, Inc.	3.50%	4.55%	8.05%
Southwest Gas	6.80%	3.64%	10.44%
WGL Holdings, Inc.	3.73%	5.18%	8.91%
Average	5.97%	5.07%	**10.99%**

Q. **ARE THERE ALTERNATIVE FORMULATIONS OF THE DCF PROCEDURE?**

A. Yes. There are broadly two alternative formulations to the DCF procedure that have been used in utility rate of return studies, both reflecting different ways of estimating the "g" or growth factor. The first is based on the proposition that growth in earnings and dividends for a regulated public utility is constrained by the growth in book value per share. This is because public utility regulation has traditionally authorized earnings in relation to a "rate base" reflective of the book value of the investment devoted to utility service. The rate of growth in per-share book value is a function of (1) the earnings retention ratio, (2) the authorized rate of return and (3) dilution or accretion from sales of new stock.

The other alternative uses historical trends in growth in earnings and dividends to calculate the "g" factor in the DCF formula.

Q. WHAT IS YOUR ASSESSMENT OF THE EARNINGS GROWTH MODEL FOR THE COMPARABLE COMPANIES YOU HAVE IDENTIFIED?

A. The book value growth model is less useful for gas utilities than it used to be for two reasons. Although I have limited my selection of comparable utilities to those deriving over 75 percent of their revenues from gas distribution, only two of these companies generate all of their revenue from this source. The remaining eight still have some unregulated – or FERC regulated – activities for which the book value growth model does not apply as well.

Possibly more relevant is the fact that very few utilities are so closely regulated that the only source of growth in earnings is the increase in book value. Since the late 1980s, when the gas distribution utility industry generally began experiencing declining costs, there have been relatively few rate cases. CKY is a good example. It has not filed for a rate case since 1994, which means that it apparently has earned more than its authorized rate of return during the intervening years. If CKY has been able to enjoy returns above what regulation might have established as the authorized rate of return, then its "g" factor would be greater than would be indicated by the earnings growth model.

Q. RECOGNIZING THESE LIMITATIONS TO THE BOOK VALUE GROWTH MODEL, HAVE YOU DEVELOPED "g" FACTORS FOR YOUR COMPARISON COMPANIES REFLECTING THAT APPROACH?

A. Yes. Exhibit_____(CWK-1) develops this approach using data forecast by Value Line for the period 2004-2006. I divide the predicted dividend by the forecast earnings and use the complement as the earnings retention ratio, that is, the proportion of earnings not distributed as dividends. I multiply this ratio by Value Line's forecast return on book common equity to derive the growth in book value from retained earnings.

The second factor in the book value growth model is the opportunity to augment book value by selling stock at prices that exceed book value. For each company, I chart the annual percentage increase in shares of stock between 2002 and 2005 as predicted by Value Line. I then multiply the average percentage increase in shares by the percentage that recent market prices (last 50 days) have exceeded book value.

The results for this version of the DCF model are as follows:

Table 10
Book Value Growth DCF Results

Company	Earnings Retention Growth	Stock Sales Increment	Dividend Yield	DCF Return
Atmos Energy Corp.	4.61%	2.96%	5.54%	13.11%
AGL Resources	5.86%	1.01%	5.16%	12.04%
Cascade Natural Gas Corp.	7.75%	1.93%	4.80%	14.47%
LaClede Group, Inc.	4.23%	0.94%	6.01%	11.19%
NICOR, Inc.	10.05%	0.00%	4.34%	14.39%
Northwest Natural Gas Co.	5.04%	0.00%	4.59%	9.63%
People's Energy Corp.	5.60%	0.00%	5.82%	11.42%
Piedmont Natural Gas Co.	4.47%	0.43%	4.72%	9.61%
South Jersey Industries, Inc.	6.14%	3.00%	4.55%	13.70%
Southwest Gas	4.45%	0.19%	3.64%	8.29%
WGL Holdings, Inc.	5.65%	0.16%	5.18%	10.99%
Average	5.80%	0.97%	4.94%	**11.71%**

Q. **HOW DO YOU INTERPRET THE RESULTS OF THIS APPROACH?**

A. This application of the book value growth model is entirely dependent on Value Line's forecasts of growth between now and the period 2004-2006. Value Line, like most Wall Street analysts, tends to be quite optimistic regarding business prospects. For example, there are no examples of level or declining earnings, even though the historical record of these companies show a number of years in which earnings have declined. There are no examples where the return to book equity is assumed to be any lower than recent years, even where the earnings (e.g. NICOR at 20%) are clearly above those that regulators would likely allow in formal rate cases. For these reasons, I believe that the results of the earnings growth model must be considered the upper bound of the likely return requirements of my comparison companies.

Another factor suggesting a possible up-side bias is the probability that the companies will not realize the increments in share value resulting from the sale of share above book value. In many cases, the new shares are not sold, or if they are sold, not at market value. For example, when officers exercise stock options for which they pay prices much lower than market, the effect can be to dilute the book value of the shares, not increase them. In this analysis, however, I have assumed that every new share results in an increment in equity equivalent to the market price.

Q. WHAT IS THE RELEVANCE OF HISTORICAL GROWTH MODEL TO THE ESTIMATION OF EARNINGS REQUIREMENTS?

A. Historical trends in dividends and earnings are relevant to an estimation of the "g" factor only to the extent that investors regard them as indicators of their future expectations. Most financial reports display considerable historical data, including past earnings per share and dividends, which suggests that this information is of interest to investors and analysts. The weight that they give to the trends in these indicators is, of course, unknown and unknowable.

Q. WHAT IS THE RESULT OF THE DCF MODEL IF HISTORICAL TRENDS IN EARNINGS PER SHARE ARE USED TO ESTIMATE THE "g" FACTOR?

A. Using the record of average growth in diluted earnings per share before non-recurring items from Zacks Research Reports beginning in 1997 and running through Value Line's forecast for 2002, the DCF model yields the following estimates of earnings requirements.

Table 11

Historical 1997-2002 EPS Growth DCF Results

	EPS Growth	Dividend Yield	DCF Return
Atmos Energy Corp.	14.08%	5.54%	19.62%
AGL Resources	6.94%	5.16%	12.10%
Cascade Natural Gas Corp.	12.25%	4.80%	17.04%
LaClede Group, Inc.	-1.56%	6.01%	4.45%
NICOR, Inc.	4.55%	4.34%	8.89%
Northwest Natural Gas Co.	3.21%	4.59%	7.80%
People's Energy Corp.	4.18%	5.82%	10.00%
Piedmont Natural Gas Co.	3.69%	4.72%	8.40%
South Jersey Industries, Inc.	10.03%	4.55%	14.59%
Southwest Gas	32.86%	3.64%	36.50%
WGL Holdings, Inc.	0.91%	5.18%	6.10%
Mean	8.29%	4.94%	13.23%
Median			10.00%

Q. WHAT IS YOUR ASSESSMENT OF THE USE OF HISTORICAL EARNINGS GROWTH AS AN INDICATOR OF THE "g" FACTOR IN THE DCF FORMULA?

A. I doubt that investors take seriously earnings trends that are at either the high or the low end of the earnings growth spectrum. For example, it is unlikely that anyone expects Southwest Gas to continue to experience earnings growth of 36.5 percent annually, particularly as that number is an average of annual changes that range from an increase 170 percent to a decrease of 23 percent. At the other extreme, investors clearly do not expect LaClede's earnings to continue to decline. If they did, the stock would not be experiencing a dividend yield of only 6.01 percent. Possibly there is credence to the evidence of earnings trends that reflect a consistent pattern of growth from year to year. For this reason , I would give more weight to the median growth weight than to the mean, particularly as the mean rate of growth is heavily affected by the extremely high numbers for Atmos Energy and Southwest Gas. Without those companies, the mean growth rate falls to 9.9 percent.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR DCF ANALYSES.

A I have applied the "classic" DCF procedure and two modifications based on alternative ways of calculating the "g" or growth factor. The results can be summarized as follows:

Table 12
Discounted Cash Flow Analysis Results

	Classic	Book Value Growth	Historical Growth
Atmos Energy Corp.	11.97%	13.11%	19.62%
AGL Resources	16.89%	12.04%	12.10%
Cascade Natural Gas Corp.	10.30%	14.47%	17.04%
LaClede Group, Inc.	10.51%	11.19%	4.45%
NICOR, Inc.	10.94%	14.39%	8.89%
Northwest Natural Gas Co.	11.01%	9.63%	7.80%
People's Energy Corp.	12.62%	11.42%	10.00%
Piedmont Natural Gas Co.	9.22%	9.61%	8.40%
South Jersey Industries, Inc.	8.05%	13.70%	14.59%
Southwest Gas	10.44%	8.29%	36.50%
WGL Holdings, Inc.	8.91%	10.99%	6.10%
Average	**10.99%**	**11.71%**	**13.23%**

Q. HOW DO YOU INTERPRET THESE RESULTS?

A. As noted earlier, the "classic" form of the DCF model should be given the most weight. However, when those results are widely different from the book value growth model, there is reason to question the sustainability of the earnings forecasts derived from Zacks survey of investment analysts. For example, Zacks' survey shows that analysts are predicting earnings growth of 11.7 percent annually for AGL. However, the pattern of earnings retention by this company indicates that it would support book value growth of only 5.9 percent. In this case, it is reasonable to assume that the classic DCF model is overestimating the earnings expectation of serious investors in this company. The reverse is true of South Jersey holdings, where Zacks reports that analysts are forecasting earnings growth of only 3.5 percent, yet the rate of earnings retention will generate a growth in book value, hence earnings capability, of over 6 percent. In other cases, e.g. LaClede, Piedmont, the classic and book value growth models appear to coincide.

Q. CAN YOU PROVIDE AN ESTIMATE OF THE DCF RETURNS FOR EACH OF YOUR COMPARISON COMPANIES?

A. While precision is impossible, I can estimate the DCF returns of each company by using the classic result as the baseline and adjusting upward or downward where there are marked differences between that result and the book value growth, and to a lesser extent, the historical growth models. Here is my best set of estimates:

Table 13
Discounted Cash Flow Results

Company	Return
Atmos Energy Corp.	12.0%
AGL Resources	14.5%
Cascade Natural Gas Corp.	11.0%
LaClede Group, Inc.	10.5%
NICOR, Inc.	11.0%
Northwest Natural Gas Co.	11.0%
People's Energy Corp.	12.5%
Piedmont Natural Gas Co.	9.5%
South Jersey Industries, Inc.	9.5%
Southwest Gas	10.3%
WGL Holdings, Inc.	9.5%
Average	**11.1%**

Q. CAN YOU EXPLAIN THE VARIATIONS AMONG THESE RETURNS?

A. Considerable light can be shed on the differences among these companies' returns by looking at two sets of data, the proportion of revenue derived from regulated gas distribution service and the proportion of common equity in the company's capital structure:

Table 14
Proportions of Gas Distribution Revenue and Equity in Capital Structure

Company	% Gas Distribution	% Equity
Atmos Energy Corp.	95.6%	39.0%
AGL Resources	94.2%	35.1%
Cascade Natural Gas Corp.	100.0%	42.4%
LaClede Group, Inc.	92.8%	41.7%
NICOR, Inc.	82.5%	49.9%
Northwest Natural Gas Co.	98.3%	45.5%
People's Energy Corp.	78.7%	39.2%
Piedmont Natural Gas Co.	100.0%	50.8%
South Jersey Industries, Inc.	86.6%	32.5%
Southwest Gas	85.4%	31.9%
WGL Holdings, Inc.	82.5%	49.8%
Columbia of Kentucky	**100.0%**	**47.3%**

The very high return requirements of Atmos, AGL and People's Energy can be explained by their relatively low equity proportions. The less equity in the capital structure, the greater the financial risk from variations in operating income. In the case of People's Energy, there is the added risk that the proportion of gas distribution revenue is relatively low in comparison to the other members of the comparison group. The relatively low proportion of gas distribution revenue may also explain the high return for NICOR, in spite of its high equity ratio and consequent low financial risk.

The companies showing very low return requirements can also be explained. Piedmont is a clear example of a low-risk company, with 100 percent of its revenue derived from gas distribution service and an equity proportion of over 50 percent. WGL also has a low-risk capital structure. Its 82.5 percent gas distribution revenue percentage might suggest higher risk except that most of the non-regulated revenue is derived from Washington Gas Energy Services, a supplier of gas to the very same customers who receive gas distributed by its regulated subsidiary.

South Jersey Industries appears to be an anomaly, with a very low return requirement in spite of having 86.6 percent of its revenue from gas distribution and a common equity proportion of only 32.5 percent. These figures are somewhat deceiving, however. The low common equity proportion is exaggerated because it excludes preferred stock, which makes up an additional 5.4 percent of its capital structure. The company's business risk is significantly lowered by a Temperature Adjustment Clause that protects its revenues from fluctuations resulting from milder or colder than normal winters.

Q. HOW DOES CKY FIT INTO THIS PICTURE?

A. Table 14 shows that CKY, with 100 percent gas distribution revenue and an equity proportion of 47.3 percent, is at the low end of the risk spectrum. It's profile most closely corresponds to that of Piedmont Natural Gas, with a return requirement of only 9.5 percent. Moreover, like South Jersey Industries, CKY enjoys the risk-reducing benefits of a Weather Normalization Adjustment.

Q. WHAT RATE OF RETURN DO YOU RECOMMEND FOR CKY?

A. In light of low level of CKY's business and financial risk, I believe a good case could be made for setting its rate of return to equity at the very bottom of the scale shown on Table 13, 9.5 percent. However, the rate of return set in this proceeding is likely to remain in effect for a number of years. I therefore believe it unadvisable to lock the company into a relatively low return for an extended period during which business conditions, capital costs and the company's outlook might change. For this reason, I recommend a return at the mid-point between the average for the 10 comparison companies, 11.1 percent, and the return requirement for three lowest-risk companies, 9.5 percent. That mid-point is **10.3 percent.**

Q. YOU HAVE TAKEN THE STRAIGHTFORWARD RESULTS OF THE DCF MODEL AS INDICATORS OF EQUITY RETURN REQUIREMENTS. HAS MR. MOUL DONE THE SAME THING?

A. No. Mr. Moul has made two upward adjustments to the straightforward results of the DCF model. The first is to increase the DCF returns for the differences in the capital structure indicated by market capitalization and the book capital structure used in this rate case. The second adjustment is to add an allowance for the costs of issuing new shares of stock, that is, "flotation costs."

Q. IS THE CAPITAL STRUCTURE ADJUSTMENT APPROPRIATE?

A. No. The purported logic underlying Mr. Moul's adjustment is that investors set their return requirements based on the market value of each company's equity, which in every case is considerably higher than the book equity amount. This higher market equity value implies a much lower level of financial risk than the book equity value. Therefore, when the DCF return is applied to book equity, its must be adjusted upward to reflect that risk.

As demonstrated in Exhibit_____(CWK-1), each of my comparison companies has a per-share market value greater than its book value. I would agree with Mr. Moul that a company having a capital structure that reflects the average market valuation of the equity of my comparison companies would have lower financial risk than a company having a capital structure based on those companies' book equity.

But this is not the comparison we are making in this study. There are not two companies having different capital structures, but a single company in every case. While investors are aware that the market valuation might provide a cushion of equity value over book value that reduces the risk of the company, their assessment of the company's equity risk does not change when applied to the book equity value. The Company does not suddenly become more risky as a result of that exercise. Indeed, it is the same company, and its equity return requirements are the same.

Mr. Moul's adjustment makes the implicit assumption that investors buy stock based on a balance sheet that does not exist. I know of no company financial report that presents a balance sheet in which the equity value of the company is stated in terms of its market value. Investors evaluate the book balance sheet, in which equity is compared with the hard, monetary value of the corresponding assets. Certainly that is the case with bond rating agencies, where all ratios are based on the book income statements and balance sheets.

Q. IS MR. MOUL'S FLOTATION COST ADJUSTMENT APPROPRIATE?

A. No. Flotation costs are incurred only when a company issues new stock, and then only when there is a public stock offering. Existing stock incurs no flotation cost, and even new stock incurs no such costs if it is distributed as an employee or shareholder benefit either through options or as bonuses.

Exhibit_____(CWK-1) shows that according to Value Line's predictions, only one of my ten comparison companies will issue more than one percent additional stock per year during the coming five years. Assuming that one percent of new stock is issued each year and each share incurs the 2 percent cost Mr. Moul assumes, the incremental cost to the company's equity would amount to .02 percent per year. This *de minimis* adjustment is effectively lost in the rounding.

2. <u>INTEREST RATE RISK PREMIUM APPROACH</u>

Q. WHAT IS THE INTEREST RATE RISK PREMIUM APPROACH?

A. While equity return requirements are difficult to estimate, bond yields and interest rates can be measured with precision and currency. Indeed, they are reported daily in business publications and weekly by the Federal Reserve Board. The interest rate risk premium approach attempts to analyze the relationship between measurable interest rates and bond yields and immeasurable equity returns.

The reason for this relationship is that fixed income investments – bonds and preferred stock – compete with common stock for investors' dollars. If interest rates fall, then (all other things being equal) investors have an increased incentive to commit their funds to the stock market. As more funds flow into stocks, their prices increase, reducing the return available from current and forecast profits. Conversely, if interest rates increase, then stock prices fall, and the return to the newly repriced equity market increases.

To be sure, the return requirements of the two forms of investment do not move in lock step. Bonds suffer inflation risk, while stocks are considered a hedge against inflation. Conversely, stocks are far more susceptible to the effects of the business cycle than bonds, so when recession threatens, the spread between bond yields and required stock returns is likely to increase. Nonetheless, over time, a decline in bond yields should signal a corresponding (although not directly correlated) decline in equity return requirements.

Q. WHAT IS THE VALUE OF THE INTEREST RATE RISK PREMIUM APPROACH?

A. It is worthwhile to examine the trend in bond yields and interest rates over the time since earlier equity return prescriptions were made for gas utilities in Kentucky to determine whether a finding of 10.3 percent is reasonable. If it appears that bond yields have increased, but I am recommending a reduced return to equity, then there may be reason to question my finding. On the other hand, if my proposed equity return tracks with the changes in bond yields, then there is at least a "sanity check" on the propriety of my finding.

Q. WHAT IS THE RELATIONSHIP BETWEEN EQUITY RETURN ALLOWANCES AND BOND YIELDS OVER THE YEARS?

Exhibit______(CWK-2) provides this comparison. It shows the average monthly yields to 10-year Treasury and Moody's Aaa Corporate bonds from 1990 through to the latest month 2000 and to June 2002. It also shows the eight gas equity return findings by Kentucky Commission since 1990. The chart shows that bond yields have been declining generally and are now at almost their lowest level in 12 years, significantly below their position when the previous return findings were made.

The specific relationship between the equity return findings and the then-current bond yields is as follows:

Table 15
Gas Equity Return Allowances and Contemporaneous Bond Yields

Case	Utility	Date	ROE Allowed	10-Yr Treas.	Aaa Utilities
1990-041	Union LH&P	Oct 2, 1990	13.0%*	8.72%	9.53%
1990-158	Louisville G&E	Dec 21, 1990	12.5%*	8.08%	9.05%
1990-013	Western Ky Gas	May 29, 1991	12.5%	8.07%	8.86%
1992-346	Union LH&P	Sept 23, 1993	11.5%	5.36%	6.66%
1997-066	Delta Nat Gas	Dec 8, 1997	11.6%	5.81%	6.76%
1999-176	Delta Nat Gas	Dec 27, 1999	11.6%	6.28%	7.55%
2000-080	Louisville G&E	Sept 27, 2000	11.25%	5.80%	7.62%
2001-092	Union LH&P	Jan 31, 2002	11.0%	5.04%	6.55%
2002-145	**Columbia**	(Jul 19,2002)	**10.3%****	4.68%	6.54%

*Gas and Electric
**AG Proposed
Source: PSC Records and Federal Reserve Statistical Releases.

Q. WHAT DO YOU CONCLUDE FROM THESE COMPARISONS?

A. I conclude that while my recommended equity return allowance is lower than any that have been approved for gas utilities in the past 15 years, this result is justified by the evidence of lower overall capital costs. Those lower capital costs are demonstrated by a dramatic reduction in bond yields relative to the experience of the past 12 years. For this reason, I conclude that my recommended equity return of 10.3 percent is reasonable.

Q. HOW HAS MR. MOUL APPLIED THE INTEREST RATE RISK PREMIUM APPROACH?

A Mr. Moul has sought to use this approach to develop a point estimate of the cost of CKY's equity. That point estimate is 12.75 percent before his flotation cost adder. Mr. Moul started with the Blue-Chip Financial Forecast of 5.5 percent as the second quarter 2002 forecast of 30-year Treasury bond yields, to which he applied a premium of 2.25 percent to represent the return to A-rated utility bonds. He has then examined the differentials between the earned returns to public utility stocks and utility bonds over a series of time periods ranging from 1928-2001 to 1979-2001. He selected a risk premium of 5.00 percent, based principally on the experienced bond vs. stock return differentials during the periods 1974-2001 and 1979-2001. Adding 5.00 percent to the 7.75 percent return on utility bonds generated his 12.75 percent equity return. He then added .26 percent for flotation cost to derive a purported cost of equity of 13.01 percent.

Q. WHAT IS YOUR RESPONSE TO THIS CALCULATION?

A. I have encountered this same historical risk premium approach in a number of rate-of-return proceedings and have always found it so flawed, both conceptually and statistically, as to be virtually worthless.

At the conceptual level, the historical risk premium approach is based on two utterly unsupportable assumptions. The first is that the experienced differences in return between stocks and bonds represent the expected differences in return. The theory is that over a long enough period, actual return differentials between stocks and bonds will equate to required or expected return differentials.

This is a statement of faith, not experience, and it defies logic. If investors' short-term expectations are continually being frustrated (as they certainly have been during the last two years), what possible logic supports the proposition that the sum of those failed short-term expectations represents a valid long-term representation of their expectations?

The second unsupportable assumption is that the spread between the required returns of bonds and stocks is fixed and unchanging over extended periods of time. This presumption is flatly untrue. The perceived safety/risk relationship of bonds differs from stocks, and their relative desirability as investment vehicles changes continually depending on such factors as inflation, economic growth, and the capital structures of the enterprises issuing the securities.

Quite apart from this conceptual failing, the theory fails statistically, as demonstrated on page 1 of Mr. Moul's Attachment PRM-12. For all four series, the standard deviations exceed the means, in one case (public utility stock index) by a factor of two. Since the means lack statistical significance, the differentials between these means are statistically useless as a predictive tool.

3. <u>CAPITAL ASSET PRICING MODEL</u>

Q. WHAT IS THE CAPITAL ASSET PRICING MODEL?

A. The Capital Asset Pricing Model ("CAPM") is described on pages 39 of Mr. Moul's testimony and in more detail in his Attachment I. As noted by Mr. Moul, it employs a measure called "beta," which tests the covariance of the stock at issue with that of the overall market, to assess the relative risk of the stock against the market. As conventionally used by rate-of-return analysts, the beta is assumed to measure the cost of the company's equity on a continuum between the average required return of the equity market overall and a risk-free return.

Q. WHAT IS YOUR ASSESSMENT OF THE CAPM?

A. I believe that CAPM's beta has value in assessing the relative risk of different stocks and portfolios of stocks. It can therefore be useful in checking the results of other, more reliable, methods of measuring equity return, such as the DCF procedure. However, I question whether it has much value in directly estimating the required return to the equity of a specific company owing to the following problems:

- <u>The measurement of beta.</u> As noted, beta measures the degree of covariance of the stock with that of the market overall. But neither the fluctuations of the stock nor those of the market are constant, or even consistent with each other over any extended period of time. As a result, there are as many estimates of beta for a given company as there are analysts making the measurement.

- <u>The risk-free rate</u>. Usually, the yields to U.S. government securities are assumed to be risk-free, but there are quite a number of U.S. government securities that have different yields. Which one to pick is to some extent a matter of judgement.

- <u>The return to the overall market.</u> The complexities and uncertainties associated with measuring the return to equity of an individual company are not reduced when the object of the analysis is expanded to the entire market for equities. Generally, CAPM analysts use one of two procedures. Either they perform simplistic DCFs for a wide variety of stocks, in which case why not use the same DCF for the stock under study? Or they use the historical return to market equities, which assumes, totally unrealistically, that the investors in the equity markets during the period under study actually realized the return that they were expecting. This approach tells us nothing about future expectations from the market.

- <u>The assumption of linearity.</u> CAPM assumes that there is a linear relationship between beta and the difference between the market's return and a risk-free return. A stock with a .5 beta, for example, is assumed to have an equity return requirement mid-way between these two measures. Carried to its logical extremes, this assumption is absurd. A stock that does not vary with the market, and therefore has a beta of 0, is assumed to have the same risk as a U.S. Treasury bond. More absurd yet, stocks that vary inversely with the market – and they certainly exist – would have equity return requirements lower than the yield on a Treasury bond.

Q. HOW HAS MR. MOUL APPLIED THE CAPM ?

A. Mr. Moul has applied the CAPM in the conventional fashion, but with some embellishments of his own. He has adopted Value Line's betas for his Barometer group of companies, a value of .61, but he has decided that these betas must be adjusted for the difference in the market vs. the book capital structures. In this manner, he inflates the beta to .76. As his risk-free rate, Mr. Moul adopts the 30-year government bond, with an assumed average yield of 5.50 percent.

To derive his risk premium, Mr. Moul uses two approaches. His forecast approach adds the dividend yield predicted by Value Line for 1700 stocks to an annualized expression of the median appreciation potential forecast to the period 2004-2006 by Value Line for these same 1700 stocks. This yields an estimate of the total expected market return of 15.14 percent. When he subtracts the long term Treasury bond yield of 5.50 from the market return of 15.14 percent, he derives a market risk premium of 9.64 percent.

Separately, Mr. Moul develops an historical risk premium based on the difference between the earned returns to stocks and yields to government bonds over the 76 year period 1926-2000. This differential is 7.3 percent. Mr. Moul then averages his forecast 9.64 percent and historical 7.3 percent to create a risk premium of 8.47 percent.

When he adds his risk free rate of 5.50 percent to the product of his .76 beta and his market risk premium of 8.47 percent, he generates a CAPM return of 11.94 percent. He then applies his .26 percent flotation cost adder to derive a CAPM return of 12.20 percent.

Mr. Moul further inflates this return by .58 percent for the purported risk effect of the size differential between CKY and the ten companies in his barometer group. His final CAPM based return is 12.78 percent.

Q. DOES MR. MOUL'S CAPM SUFFER FROM THE FOUR PROBLEM AREAS YOU HAVE IDENTIFIED?

A. Yes. It does.

Q. WHAT ARE THE BETA MEASUREMENT PROBLEMS IN MR. MOUL'S CAPM ANALYSIS?

A. Mr. Moul has used Value Line's betas, which differ quite dramatically from those of other analysts. To illustrate, the average Value Line beta for my eleven comparison companies is .59, not too much different from the .61 Mr. Moul identifies for his barometer group. Zacks Investor Services, however, has a very different view: its average beta for my companies is .11, an altogether different number. My experience is that there are as many betas as there are analysts attempting to measure them, and that most of them are lower than Value Line's beta.

Mr. Moul's capital structure adjustment to his Value Line beta has no conceptual justification whatever. Whatever the appropriate beta, it measures the movement of the specific stock relative to the movement of the market. To the extent that financial risk (caused by capital structure effects) is reflected in this covariance, it does not change because of the difference in the market relative to the book valuation. Indeed, beta has nothing to do with market-to-book ratios, or necessarily with the level of financial risk. It is purely a measure of market price fluctuations.

Q. WHAT PROBLEMS DOES MR. MOUL'S ANALYSIS ENCOUNTER WITH RESPECT TO THE MEASUREMENT OF THE RISK FREE RATE?

A. Mr. Moul uses as his risk-free return the yield on 30-year Treasury bonds. This seems like a risk-free return, but the yields on all other Treasury instruments are lower, as is clearly demonstrated by the chart that Mr. Moul provides on page 2 of his Attachment PRM-13. In January 2002, 30-year Treasury bonds were yielding 5.45 percent, but one-year bonds were yielding only 2.16 percent.

It is logically impossible for 30 year Treasury bonds that have a yield of 5.45 percent to be totally risk free when there are other Treasury securities with dramatically lower yields. In reality, long-term Treasury bonds are not risk free. They face the very substantial risk that an acceleration in inflation sometime in the future could erode their value and diminish their real return. That is why one-year bonds are much less risky than 30-year bonds.

Q. WHAT PROBLEMS DOES MR. MOUL'S ANALYSIS ENCOUNTER WITH RESPECT TO THE MEASUREMENT OF THE RETURN TO THE OVERALL MARKET?

A. As noted, Mr. Moul uses two sources for his estimate of the return to the overall market. His forecast return is based on a quasi-DCF application of Value Line data for the period 2004-2006. The predicted dividend yields are arguably acceptable, but for his growth factor he uses Value Line's estimates of capital appreciation, not its forecasts of earnings per share, which is the indicator he uses in his DCF analysis. Mr. Moul's historical return has all of the same problems that I have discussed with respect to his interest rate risk premium application.

Q. WHAT PROBLEMS DOES MR. MOUL'S ANALYSIS ENCOUNTER WITH RESPECT TO THE ASSUMPTION OF LINEARITY BETWEEN THE MARKET RETURN AND THE RISK-FREE RETURN?

A. Arguably, Mr. Moul does not encounter these problems because he uses Value Line's betas and not those of other analysts. Had he used Zacks betas, he would have had to deal with a zero beta for People's Energy. This beta reflects Zacks' apparent finding that there no correlation whatever between the variation in People's stock prices and those of the market. Yet People's stock is certainly not risk free, as postulated by the CAPM theory. If People's CAPM results are non-sensical, then there is no reason to suppose that the CAPM results for companies with higher betas make any more sense.

Q. IS THERE ANY JUSTIFICATION FOR THE SMALL COMPANY ADJUSTMENT THAT MR. MOUL MAKES TO HIS CAPM RESULTS?

A. No. While CKY is a small company, it does not sell stock. It's parent, CEG, used to sell stock, and it was an enterprise with $2 billion in annual revenues. CEG's parent company, NiSource, which is the entity that now sells stock on behalf of CKY, has annual gross revenues of $9.5 billion, considerably more than some of the companies in both Mr. Moul's barometer group and my comparison group. There is no small company effect whatever associated with CKY's equity capital cost.

Q. OVERLOOKIING ALL OF THE CONCEPTUAL PROBLEMS WITH THE CAPM, CAN YOU PROVIDE AN ESTIMATE OF YOUR COMPARISON GROUP'S EQUITY COST USING THIS APPROACH?

A. Yes, although I cannot attach much significance to the result. If we average Value Line's beta of .58 and Zacks' beta .07 for my comparison companies, we arrive at a beta of .33. If we then substitute the one-year Treasury bond yield for Mr. Moul's 30-year Treasury bond yield, we have a risk free rate of 2.16 percent.[9] Then, for purposes of this exercise, I will accept Mr. Moul's Value Line based market return of 15.14 percent, which yields an equity risk premium of 12.98 percent. (15.14%-2.16%). Applying the .33 beta to this risk premium generates a premium for my comparison companies of 3.93 percent (12.98 * .33). When this premium is added to the risk-free rate of 2.16 percent, the resultant

[9] Moul's Attachment PRM-13, page 2.

CAPM return is only 6.06 percent. This is an unacceptable result because it is no higher than the current return on Aaa rated utility bonds, clearly a lower-risk investment instrument than utility stocks.

If anything, this exercise proves the uselessness of the CAPM approach.

4. COMPARABLE EARNINGS APPROACH

Q. PLEASE DESCRIBE MR. MOUL'S COMPARABLE EARNINGS APPROACH.

A. Mr. Moul adopts six criteria that he believes establish comparability of risk and financial performance to his barometer group of gas distribution companies. Applying these criteria to the 1600 companies in Value Line's Investment Survey for Windows, he identifies 55 non-regulated companies of comparable risk to his barometer group. He then calculates the average return to book value of these companies over the past five years and identifies Value Line's forecast book value return into the 2004-2006 horizon. The historical median return to book equity value is 16.8 percent and the prospective median return is 15.0 percent.

Q. WHAT IS YOUR ASSESSMENT OF MR. MOUL'S COMPARABLE EARNINGS APPROACH?

A. Mr. Moul's rationale for his comparable earnings approach is that the companies in his barometer group must compete for capital with the other non-regulated companies. Implicit in this rationale is that if comparable non-regulated companies earn more than CKY, then CKY will be unable to attract capital. Therefore, CKY should earn on the order of 15.0 to 16.8 percent.

The weakness of this approach is that investors cannot access the rates of return that Mr. Moul calculates. I doubt that there is a single company in his list of 55 that would generate a 15 percent return in the current year to an investor now committing his funds.

That is because the market values of all of these companies substantially exceed their book values, and the investor must pay the market value to acquire the stock. If the market value of a company is twice its book value, then the realizable return to a new investor is not the 15 percent return on book value, but the 7.5 percent return on the market value.

Book value is important to a regulated firm only because regulation makes it so. The authorized return that the regulatory commission allows is set in relation to a rate base that is calculated from the book asset value of the company. This tie between book value and earnings does not exist for non-regulated companies. For them, book value is an historical number, representing the value of the dollars that have been invested in the company, not the value of the company to a prospective purchaser. Mr. Moul's calculations of return to book value for these companies are irrelevant to the return requirements of CKY.

Q. BUT AREN'T THE MARKET VALUES OF YOUR COMPARABLE COMPANIES ALSO ABOVE BOOK VALUE?

A. Yes, they are, as demonstrated in my Exhibit_____(CWK-1). There are two reasons why even regulated companies have market values higher than book value. First, even if every regulated company earned exactly the rate of return authorized by its regulatory commission, their market values would exceed their book values. That is because a portion of the return allowed by the regulator represents future growth in earnings that the investor expects in the future but does not require in the current year. This is a built-in upward bias in the regulatory system, where regulation effectively awards investors with somewhat more return than they actual require on a current basis.

More important is the fact that most regulated companies are in fact earning more than a regulatory commission would allow them in a rate case. That is because most utility services have become declining cost operations, where the marginal cost of expanding service is less than the embedded costs. "Regulatory lag," which used to penalize utilities during inflationary periods, now rewards them. Most commissions do not attempt to hold the utilities' earnings down to the minimum required level. As a consequence, most utilities earn more than they actually need, and the market values of their stock increase substantially above book value

D. RETURN TO TOTAL CAPITAL

Q. WHAT IS YOUR RECOMMENDED RETURN TO TOTAL CAPITAL?

A. My recommended return to total capital is **8.14 percent**, calculated as follows:

Table 16
Return to Total Capital

Item	Proportion	Cost	Weighted Cost
Long-term Debt	40.0%	7.25%	2.90%
Short Term Debt	12.7%	2.88%	0.37%
Equity	47.3%	10.3%	4.87%
Total	100.00%		**8.14%**

PART II – MARGIN LOSS RECOVERY RIDER

Q. WHAT IS THE MARGIN LOSS RECOVERY RIDER?

A. The Margin Loss Recovery ("MLR") Rider is a proposal contained in the testimony of CKY witness Kimra Cole. The proposal calls for the surcharge to be computed semi-annually to recover one half of all discounts granted to industrial customers in order to avoid their by-pass of CKY's system or to prevent their switching to alternative fuels. This surcharge would apply to all remaining customers.

Q. SHOULD THE COMMISSION APPROVE THE MLR RIDER?

A. No. The MLR Rider is an example of prospective, single-issue ratemaking that imposes rate increases on customers without Commission review and prior approval. It constitutes a revenue award that is unsupported by evidence of any corresponding cost incurrence. Moreover, it is blatantly anti-competitive.

Q. WHY DO YOU DESCRIBE THE MLR RIDER AS PROSPECTIVE, SINGLE-ISSUE RATEMAKING?

A. When the Commission determines CKY's revenue requirement in this proceeding (or in any proceeding), that finding is based on the costs and revenues experienced in the test year, in this case the year ending December 31, 2001. There is no presumption that those costs and revenues will continue into 2002, except where there have been specific adjustments for known and measurable post-test-year changes. As a practical matter, none of the revenue and cost conditions will likely continue unchanged. The number and consumption of customers will change; the number of employees will change; the amount of investment will change. Yet, none of these changes will be used to adjust CKY's rates until the next rate case, when a new set of test year conditions will determine whether the Company is realizing too much, too little, or about the right amount of revenue.

The MLR Rider takes one source of prospective revenue change – discounts to industrial customers – and flows it into the Company's revenue recovery stream as an automatic semi-annual rate increase. Why are these discounts special? Should we not offer a surcredit for the margin on new customers who are added to the system each year? Should we not surcredit or surcharge customers for annual increases or decreases in consumption by existing customers? On the cost side, should we not surcharge or surcredit customers for annual changes in the number of CKY employees or the amount of its investment?

The reason we do not make these special adjustments is that CKY's revenue requirement is a composite of revenue and cost effects that together demonstrate the Company's need for a rate change. They do this only when they are considered collectively and at the same time, that is, during a consistent test year. There is no justification whatever for singling out one revenue or cost effect for a special surcharge.

Q. WHY ARE YOU CONCERNED THAT THE COMMISSION DOES NOT REVIEW AND APPROVE THE MLR RIDER?

A. The discounts that CKY proposes as the basis for the MLR Rider are negotiated bi-laterally, in private and without any public input. The amounts of these discounts are to some extent subjective, based on the customers' and CKY's perception of the alternative of using by-pass or an alternate fuel. The Company's proposal offers no regulatory protection from arbitrary and excessive discounts that would then be passed on to the general body of ratepayers.

Q. ARE YOU SUGGESTING THAT THE COMMISSION SHOULD REVIEW AND APPROVE EVERY DISCOUNT?

A. No. CKY needs the flexibility to respond to competition in whatever form it takes. But it should do so at its own risk, at least until the next rate case. In the course of that next rate case, the Company should be required to defend the reasonableness of its discounts. It should be obliged to demonstrate that these discounts are competitively necessary and that they do not represent unreasonable discrimination among customers.

Q. WHY DO YOU SAY THAT THE MLR RIDER IS BLATANTLY ANTI-COMPETITIVE?

A. The asserted justification for the MLR Rider is that CKY must respond to the competition of pipelines and of alternative fuel providers. Neither of those competitors enjoy the luxury of assessing a large group of monopolized customers for the revenue losses they might incur to meet CKY's competition. Yet that is what CKY proposes for itself. Clearly, this arrangement is unfair to alternative fuel suppliers, and it may be unfair to the pipelines that seek direct connections to industrial customers.

Q. WITNESS COLE STATES THAT THE COMMISSION HAS APPROVED A SIMILAR MECHANISM FOR WESTERN KENTUCKY GAS. DOESN'T THAT REPRESENT A PRECEDENT THAT THE COMMISSION BELIEVES A MLR RIDER TO BE REASONABLE?

A. I do not believe so. The MRL Rider was presented to the Commission as part of a settlement package in Case No. 99-070. Typically, such packages are "take it or leave it" propositions. The Commission could have disallowed this rider, but then the settlement might have fallen apart as a result.

The fact is that the Commission never had a chance to review this rider, hear witnesses for and against, and direct questions to its advocates. It described the rider as a "proposal of first impression before this Commission" and approved it only as a pilot for a period of three years.[10]

Q. WITNESS COLE STATES THAT IF THE MLR RIDER IS NOT APPROVED, THERE SHOULD BE NO INCREASE TO THE RATE SCHEDULES THAT HAVE ALTERNATIVE FUEL CAPABILITY OR THAT ARE SUBJECT TO THE THREAT OF BY-PASS. WHAT IS YOUR RESPONSE?

A. The issue is arguably moot, since Mr. Majoros has found that the Company's rates should be reduced rather than increased. However, if rates are increased, I would support the Company's proposal only with respect to individual customers for which the Company can provide a demonstration of possible loss of load. The Company's has not demonstrated that all customers on Main Line Delivery Service and the flex arrangements would reduce their gas consumption or abandon CKY's service if they received any increase whatever in their rates.

[10] Case No. 99-070, <u>Order</u>, December 21, 1999, page 5.

III. COST ALLOCATION AND RATE DESIGN

Q. HAS THE COMPANY SUBMITTED COST ALLOCATION STUDIES IN THIS PROCEEDING?

A. Yes. Mr. Skirtich has submitted two class cost allocation studies.

Q. WHAT IS THE DIFFERENCE BETWEEN THESE TWO STUDIES?

A The difference pertains entirely to the allocation of the costs of mains. Mains constitute almost exactly half of the Company's plant in service, and their allocation affects the allocation of other costs, such as those in the "General Plant" category. For this reason, the allocation of mains has a major impact on the results of any class cost of service study.

Mr. Skirtich's first study uses the "Demand-Commodity" approach in which 50 percent of mains costs are allocated according to the peak day usage of the respective classes, and 50 percent is allocated according to their total annual consumption of gas.

Mr. Skirtich's second study uses the "Demand-Customer" approach, which involves designing a hypothetical "minimum system," that is, a system of mains that would be capable of carrying the very minimum amount of gas. According to Mr. Skirtich, this minimum system accounts for 70.78 percent of the total cost of mains. This 70.78 percent is allocated according to the number of customers. The remaining 29.22 percent, which reflects the added cost of sizing the pipes to the volume of gas delivered, is allocated on the basis of peak day demand.

Q. DO YOU HAVE A PREFERENCE BETWEEN THESE TWO STUDIES?

A. Yes, I do. I favor a demand-commodity allocation of mains costs.

The issue is whether the mains system has been built to serve customers or to deliver gas. Arguably, the purpose is both, but the value derived and the benefits received from the mains system is more related to the amount of gas delivered than it is to the number of customers. One customer receiving twice as much gas as another customer enjoys exactly twice the BTU heating content. The two cannot be equated in terms of benefit received, yet that is what the customer allocation of the minimum system of mains does.

Proponents of the customer allocation argue that the purpose of the minimum system is to reach customers, and that when more customers are added, the mains system has to be extended. That is true only at the very edges of the system, where gas mains are being extended to serve new developments in previously unserved areas. Even then, the added cost of mains for new customers can vary dramatically depending on the location of those customers.

The vast majority of customers are served through the existing, embedded system of gas mains. For them, the customer allocation is irrational. Consider a 1,000-foot section of main line. Suppose that in 1995, that line served a single factory. In that year, its cost would be allocated to the commercial class on the basis of a single customer – a very small allocation. Then, in 1996, the factory moves, and the property is turned into a residential development of 10 homes. The same main is then given a weighting ten times as great as its previous allocation and assigned to the residential class. Then, in 2001, a strip mall containing 10 stores replaces five of the homes. The customer weighting of the main then increases to 15, split one third to the residential and two thirds to the commercial class. Yet it has been the same main all along, and its costs have remained the same.

Assume that the main delivered the same amount of gas throughout these changes in configuration. The benefit in terms of heating content was the same for the single factory as it was for the 10 homes. The 10 homes derived the same heating value as did the five homes and 10 stores. The heating content was the value delivered, and it should be the allocator of the main's cost.

Q. DO YOU THEREFORE ENDORSE MR. STITICH'S DEMAND-COMMODITY STUDY?

A. No, I do not. I believe that the minimum system approach is a rational way to determine the portion of the mains costs that relates to peak day demand. That allocation of 29.22 percent should be retained. The remaining costs should be allocated on the basis of the respective classes' total throughput. As noted, this throughput is the most appropriate measure of value received.

Q. HAVE YOU BEEN ABLE TO PERFORM THIS STUDY?

A. No, I have not. There is no question, however, that the effect would be to increase the rate of return for the GS-RES class and reduce the GS-OTHER class. That is because the residential demand allocator is 62.9 percent, while the throughput allocator is only 35.7 percent. If the throughput component of mains costs is increased from 50 to 70.78 percent, the allocation of cost to the residential class will fall.

Q. WHAT IMPACT WOULD SUCH A RECALCULATION HAVE ON THE RATE DESIGN IN THIS PROCEEDING?

A. Hopefully none, because the Company has proposed no change in the structure of its rates. The benefit of the recalculation would be to reduce the pressure that might otherwise exist to grant a greater decrease to the non-residential classes than to the residential class.

Q. DO YOU THEREFORE ENDORSE THE COMPANY'S PROPOSAL TO MAINTAIN THE EXISTING RATE STRUCTURE?

A. Yes, I do. Whatever rate change is determined appropriate in this case should be applied on an equal percentage basis among the classes and the rate elements.

Q. DO YOU SUPPORT THE COMPANY'S PROPOSED REVISION IN ITS LINE EXTENSION POLICY?

A. I support the concept that the Company has proposed, although I recommend that its implementation be somewhat more explicit. It is appropriate that new customers who employ gas for peripheral uses but not as the main heating source should pay for a portion of the service line. Otherwise, such customers are drawing a subsidy from the remaining body of customers.

My objection is to the vagueness of the provision. The proposed tariff states that customers not using gas as their main energy source will be "required to contribute a portion of the cost of the service line as a non-refundable deposit. This amount will vary depending upon the appliances but will not exceed the Company's average cost of a service line."

First of all, this is not a "deposit" in any sense of the word. It should be called what it is, a contribution toward the cost of the line. More important, the language leaves the amount of the contribution to the total discretion of the Company and arguably of the person who happens to be making the estimate.

In the interests of transparency, the Company should publish the average service line cost and a schedule of credits against this cost for various types of appliances. Since it will likely change each year, this schedule should not be made part of the tariff, but it should be published on the Company's web page and referred to in the tariff.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A Yes, it does.

Exhibit_____(CWK-1)

Book Value Growth Model
Comparison Gas Distribution Companies

Value Line Forecasts	1/ Earnings per Share (1)	1/ Dividends per Share (2)	2/ Earnings Retention (3)	1/ Return on Book (4)	3/ Book Value Growth (5)	1/ Shares 2002 (6)	1/ Shares 2005 (7)	4/ Annual Growth Rate (8)	5/ 2001 Book Value (9)	6/ 50 Day Avg. Market Price (10)	7/ % Mkt Over Book (11)	8/ Share Sales Increment (12)	9/ Total "g" Factor (13)	Dividend Yield (14)	10/ DCF Return (15)
Atmos Energy Corp.	2.05	1.35	34.1%	13.5%	4.61%	42.5	50.0	5.57%	14.35	21.97	53.1%	2.96%	7.57%	5.54%	13.11%
AGL Resources	2.05	1.16	43.4%	13.5%	5.86%	55	57.0	1.20%	12.00	22.15	84.6%	1.01%	6.87%	5.16%	12.04%
Cascade Natural Gas Corp.	1.90	0.98	48.4%	16.0%	7.75%	11.05	12.0	2.79%	12.15	20.57	69.3%	1.93%	9.68%	4.80%	14.47%
LaClede Group, Inc.	2.15	1.45	32.6%	13.0%	4.23%	18.9	20.0	1.90%	15.25	22.78	49.4%	0.94%	5.17%	6.01%	11.19%
NICOR, Inc.	4.10	2.04	50.2%	20.0%	10.05%	44	43.0	0.00%	16.45	43.79	166.2%	0.00%	10.05%	4.34%	14.39%
Northwest Natural Gas Co.	2.40	1.30	45.8%	11.0%	5.04%	25.2	25.0	0.00%	18.40	28.33	54.0%	0.00%	5.04%	4.59%	9.63%
People's Energy Corp.	4.05	2.16	46.7%	12.0%	5.60%	34	32	0.00%	23.95	36.97	54.4%	0.00%	5.60%	5.82%	11.42%
Piedmont Natural Gas Co.	2.90	1.82	37.2%	12.0%	4.47%	32.5	33	0.51%	18.90	34.69	83.5%	0.43%	4.90%	4.72%	9.61%
South Jersey Industries, Inc.	2.95	1.50	49.2%	12.5%	6.14%	12.4	13.5	2.87%	16.40	33.53	104.5%	3.00%	9.15%	4.55%	13.70%
Southwest Gas	1.90	0.96	49.5%	9.0%	4.45%	32.5	33	0.51%	16.85	23.27	38.1%	0.19%	4.65%	3.64%	8.29%
WGL Holdings, Inc.	2.55	1.35	47.1%	12.0%	5.65%	48.55	49	0.31%	16.40	24.97	52.3%	0.16%	5.81%	5.18%	10.99%
					5.80%							0.97%	6.77%	4.94%	11.71%

1/ Value Line Company Reports 2004 - 2006
2/ (3) = 1-((2)/(1))
3/ (5) = (3) * (4)
4/ (8) = (((7)/(6))^1/3)-1
5/ Value Line Company Reports
6/ CBS MarketWatch
7/ (11) = ((10)/(9))-1
8/ (12) = (8) * (11)
9/ (13) = (5) + (12)
10/ (15) = (13) + (14)

2 2 2004

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of THE DETROIT EDISON COMPANY to increase rates, amend its rate schedules governing the distribution and supply of electric energy, implement Power Supply Cost Recovery plans, factors and reconciliations in its rate schedules for jurisdictional sales of electricity and for miscellaneous accounting authority and regulatory asset recovery.

MPSC Case No. U-13808

Direct Testimony and Exhibits of Charles W. King Concerning Interim Rate Relief

December 12, 2003

Qualifications

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

A. My name is Charles W. King. I am President of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. Please describe Snavely King.

A. Snavely King, formerly Snavely. King & Associates, Inc., was founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. The firm has a professional staff of 13 economists, accountants, engineers and cost analysts. Most of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 33-year history, members of the firm have participated in over a thousand different 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. Attachment A is a summary of my qualifications and experience.

Q. Have you previously submitted testimony in regulatory proceedings?

A. Yes. Attachment B is a tabulation of my appearances as an expert witness before state and federal regulatory agencies.

Testimony

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Attorney General of the State of Michigan.

Q. What is the purpose of your testimony?

A. For purposes of partial and immediate (interim) rate relief, my testimony will describe the Attorney General's position with respect to major policy issues in this case. Those issues are:

- How must the provisions in 2000 PA 141 ("Act 141") and 2000 PA 142 ("Act 142") be taken into account for this rate case?
- Should the MPSC adopt the request of the Detroit Edison Company ("Edison" or "the Company") for $378,622,000 as a partial and immediate (interim) rate increase and $31,358,000 as a regulatory asset interim surcharge? [1]
- Would Edison's proposed interim increases shift costs among classes contrary to Sections 10d(2) and 10d(5) of Act 141?
- How should costs be allocated among classes for purposes an interim increase?
- What costs should be included in the Power Supply Cost Recovery ("PSCR") mechanism?
- Should the MPSC adopt interim transition charges for stranded costs as proposed by Edison?
- Should the MPSC take interim action regarding the Company's proposed Earnings Sharing Mechanism (ESM)?
- Should Financial Accounting Standards Board Statement No. 143 (SFAS 143) be reflected in the interim phase of this case?

Q. Would you please summarize your testimony with respect to these issues?

[1] Revised Exhibit A-24. Schedule A1, page 1.

A. First. Act 141 and 142 have significant impact upon this rate case. Those two acts justify and require some actions that differ from typical decisions in a general rate case.[2]

Second, most and arguably all of the rate increase proposed by Edison in this phase of the case may not qualify for partial and immediate interim relief as such relief is defined by the Commission. Virtually all of the proposed increase is controversial and represents departures from past Commission ratemaking practices.

Third, the interim increases proposed by Edison reflect the total Company jurisdictional revenue requirements and revenue deficiency identified by Edison. Since rates for residential and small commercial customers are statutorily capped, the MPSC should at least limit the level of any approved interim increases to the portion of any revenue deficiency that is attributable only to customers whose rates are not statutorily capped. Rate increases for customers with capped rates should not be established in this case because test year information applicable to capped customers during 2004 will probably change by the future years when their rates are no longer capped.

Fourth, by proposing to increase rates based on overall Company costs, Edison is shifting costs among customer classes contrary to Sections 10d(2) and 10d(5) of Act 141. When the costs specifically attributable to the classes are compared with those classes' revenue, there may be no justification for any interim increase to the General Service or Large Customer

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[2] Section 10d(2) in Act 141 imposes a rate cap upon the rates Edison can charge to residential customers and to commercial and manufacturing customers having an annual peak load of less than 15 kW during 2004. During 2005, Section 10d(2) imposes a rate cap upon the rates Edison can charge to residential customers. Section 10d(2) and 10d(5) in Act 141 bar reallocation of costs by the MPSC. Beginning January 1, 2004, Section 10d(3) requires accrual and deferral of amounts for capital expenditures and expenses so long as the amounts satisfy the conditions specified in that statute. Finally, as a result of the Commission's order in Case No. U-12478, Act 142 requires removal of certain assets from Edison's ratebase and base rates because those assets have been securitized.

Contract classes, and only a small interim increase may be justified for the Primary Service customers.

Fifth, the allocation of costs to customers whose rates are not statutorily capped in 2004 should reflect the fact that the Company's base load plants provide the power to serve the base loads of the respective customer classes, while cycling and peaker plants serve their peak loads.

Sixth, the Attorney General has stated basic positions regarding PSCR costs in the briefs filed pursuant to the Commission's August 18, 2003 order. In addition, including transmission costs in Edison's PSCR cost recovery is a new ratemaking proposal that should be deferred until the final relief phase of this case.

Seventh, in Case No. U-12639, the Commission explicitly rejected a "lost revenues" methodology for calculating stranded costs. That rejected method was similar to the procedure Edison is proposing in this case to identify stranded costs. In Case No. U-12639, the Commission adopted Staff's proposal that stranded costs should be based on a finding that generation-related bundled service revenues plus wholesale revenues do not recover the generation-related revenue requirement. Using this methodology, Edison did not have stranded costs in 2002 and may not have them in 2004.

Eighth, the Company's proposed Earnings Sharing Mechanism is a new and controversial mechanism that should not be included in any interim rate decision.

Ninth, Mr. VanHaerants' assertion that FAS 143 is irrelevant to ratemaking is incorrect. It is certainly relevant to the propriety of Edison's nuclear decommissioning charge, and it should affect depreciation expenses. Again, this is a new issue that should be decided in the final rate phase of this case, not in the interim rate phase.

The Interim Rate Increase

Q. What is the background of this rate case?

A. Section 10d(1) of Act 141 froze the rates of the State's two largest electric utilities, Edison and Consumers Energy Company, until December 31, 2003. Section 10d(2) caps the rates of commercial and manufacturing customers with annual peak demands of less than 15 kW until January 1, 2005, and it caps the rates to residential customers until December 31, 2006. That same section also prohibits shifting of costs from capped to uncapped customers as a result of these rate caps. Edison is seeking interim rate relief for the customers whose rates will be uncapped on January 1, 2004.

Q. What interim rate relief is Edison seeking in this case?

A. Edison is requesting the Commission to grant interim rate relief totaling $227,369,000 for full service tariff customers and $284,253,000 for choice customers.[3] Edison proposes to offset the increases to choice customers by $133,000,000 in "mitigation" sales of energy freed up by their departure from Edison's generation and transmission services. The net increase in revenue from choice customers would $151,253,000. In addition, Edison proposes 2004 surcharges for regulatory asset recovery that would total $31,358,000.[4] Therefore, Edison is requesting approval of interim increases totaling $409,980,000.

Q. What standards govern the granting of partial and immediate interim rate relief?

A. Edison Witness VanHaerents identifies four standards that the Commission has used for interim rate

3 Revised Exhibit A-24, Schedule A1, page 1.

relief:

1. There is evidence of a significant revenue deficiency and that the utility's rates are unreasonable.
2. Interim rate relief will not be based on highly controversial issues.
3. Interim rate relief will not be based upon issues that are clear departures from past Commission ratemaking practices.
4. The Company must file a bond guaranteeing a refund of interim amounts if the final order reflects a rate increase in an amount less than the interim order.

Q. How does Edison interpret these standards as applying to this case?

A. Edison's interpretation is that the only highly controversial issue is the rate of return on rate base. Edison claims that all other issues are non-controversial and do not represent departures from past Commission ratemaking practices. As a consequence, Edison's proposed interim rate increase of \$409,980,000 is almost 90 percent of its proposed \$458,736,000 final rate increase.[5]

Q. Do you agree that rate of return is the only highly controversial issue in this case?

A. No. The rate increase applicable to bundled service customers is highly controversial because it involves very different interpretations of the proscription in Section 10d(2) against shifting costs from capped to uncapped customers, as I shall discuss. Even if this issue is overlooked, there is considerable controversy with regard to pension costs, which constitute the largest component of the interim request. In Case No. U-13715, the Commission excluded Consumers Energy's pension costs from securitization on the grounds that the liability was the result of the general economic downturn and the likelihood that a rebounding economy could reverse recent losses and

4 Revised Exhibit A-24, Schedule A1, page 1.

restore the Company's pension fund.[6]

I have not investigated the matter in detail, but I note that the Midwest Independent System Operator ("MISO") is not yet in operation, so there is a possibility that the charges assumed to this operation are uncertain and therefore controversial. The same might be said of the infrastructure costs if they are found to be speculative.

The net of $151 million that Edison proposes to collect from choice customers is certainly controversial, both as to method and amount. As I shall discuss, the method for developing these costs has been rejected by the Commission. The amount to be collected is based on highly speculative assumptions as to the penetration of choice into Edison's market and the price of wholesale power.

Q. Do you agree that Edison's interim application involves no departures from past Commission ratemaking practices?

A. No. The increase to bundled service customers is a departure from past Commission ratemaking practices because the requirements of Section 10d(2) create issues never before confronted by the Commission. Specifically, the Commission must consider how to change the rates for customers with uncapped rates and not those with capped rates without shifting costs among the customer classes.

Edison's proposal for a transition charge to choice customers is a departure from past Commission ratemaking practices. As I shall discuss, the Company has used a methodology that was explicitly rejected by the Commission and has not used the methodology that the Commission has adopted.

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[5] Revised Exhibit A-24, Schedule A1, page 1.

Q. What about the statutory prohibition on cost shifting?

A. The only rates, and consequently the only costs that are at issue in this case are those applicable to commercial and manufacturing customers with annual peak demands 15 kW or above. These are the only rates that can be increased on January 1, 2000.

Q. What about capped rates?

A. If the Commission finds that there is a revenue sufficiency justifying a rate reduction, then the capped rates could be at issue in this case. Given Edison's contention that it has a net revenue deficiency, this outcome seems quite improbable.

Q. Why shouldn't the Commission determine rate increases that would apply to the capped customer classes, as Edison proposes?

A. Any rate increase to the capped customer classes should be based on the revenue requirements appropriate to the year in which rates are uncapped. This means that the rates for the small (under 15 kW) commercial and manufacturing customers should be based on 2005 costs. Those for residential customers should be based on predicted 2006 costs.

Q. Doesn't Edison show that its revenue requirements will continue to increase after 2004, and if so, why shouldn't the Commission approve a rate increase now to apply to capped customers when their rates become uncapped?

A. Edison Exhibit A-21 does indeed purport to show that the Company's revenue deficiency will continue to worsen through 2008. However, the value of these predictions is somewhat doubtful

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[6] Opinion and Order, Case No. U-13715, June 2, 2003, page 27.

owing to the unpredictable nature of some of the underlying cost and revenue factors. For this reason they should not be the basis for determining now whether a rate increase will be appropriate a year or two years from now.

Q. Can you identify unpredictable cost and revenue factors that might render Edison's revenue deficiency predictions incorrect?

A. Yes. Among the major drivers of Edison's proposed rate increase is the increasing cost of its employee pensions. Edison Witness Brudzynski testifies that key drivers of increased pension costs are lower interest rates and investment returns on pension assets.[7] If interest rates rise and the returns on pension assets increase, Edison's pension costs could decline, reversing a trend that has contributed to a potential shortfall in the Company's pension and health care costs.

Similarly, an important offset to Edison's generation costs is revenue from wholesale sales. The wholesale market in the upper Midwest is currently affected by an oversupply of generating resources, leading to relatively low wholesale energy prices. Given the poor financial performance, including bankruptcies, in the merchant generation industry, it is unlikely that future additions to merchant capacity will match those in the past few years. If so, and if economic growth accelerates in the region, then wholesale prices will probably increase, and Edison's margin losses from customer choice could turn into margin gains.

Q. Edison proposes that the overall deficiency be allocated across-the-board as a common percentage increase to all customers, capped and uncapped. What is wrong with that?

A. Edison's proposal is contrary to the requirements in Sections 10d(2) and 10d(5) of Act 141, which forbid the shifting of costs among customer classes. Section 10d(2) specifically prohibits cost shifting from capped to uncapped customers.

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7 Brudzynski Testimony, page 9.

Edison's cost of service study shows that in 2002 its Primary Service customers had a revenue sufficiency of $10.5 million and that its commercial secondary customers had a revenue sufficiency of $121.4 million. Yet Edison proposes an interim increase to both classes of 6.55 percent.[8]

If we assume that Edison's cost of service studies are accurate, then there may be no justification for any increase in the rates for the commercial and manufacturing customers whose rates are being uncapped at the end of 2003. Exhibit I-_____(CWK-1) shows the 2002 revenue and Edison's claimed revenue deficiency or sufficiency for each of the rate schedules in the commercial, industrial and government classes.

Q. Should Edison's cost of service studies be the basis for rate relief in this case?

A. No. The allocation of production costs should be revised. The Company has allocated 75 percent of production plant costs based on the respective classes' 12 monthly coincident peaks and 25 percent on their respective energy consumption. The 12 coincident peak allocator does not reflect the Company's need to provide peaking resources because it includes the peak loads in months that are well below the annual peaking requirements of Edison's generation resources. The 75 percent allocation to demand grossly overstates the proportion of cycling and peaking production plant cost relative to base load plant cost.

Q. But hasn't the Commission adopted the 75 percent 12 CP/25 percent energy allocation of production plant in past cases?

8 Exhibit A-24.

A. Yes, it has. The Commission first adopted this allocation in 1975. It most recently adopted that allocation for Edison in Case No. U-10102.[9]

Q. Why should the Commission reconsider this allocation methodology in this case?

A. There are two reasons. In this case, class cost of service allocations take on far greater significance than they have in any previous case. In past cases, class cost allocations were used as a guide to the distribution of overall rate changes. The rate changes were determined independently of the class cost of service studies. Even then, class cost of service studies rarely, if ever, determined the specific distribution of revenue increases or decreases among classes.

In this case, the class cost of service allocation explicitly determines the rate increase. That is because PA 141 prohibits cost shifting among classes, and particularly between capped and uncapped customers. For this reason, the Commission must take a much closer look at class cost responsibility than it has in the past. There must be a clear, direct link between the load and voltage characteristics of the each class and the costs that are assigned to it.

The second reason has to do with competition and "rate skewing." The retail rates that Edison charges to its bundled service customers for the generation function should match, as nearly as possible, the profile of costs that independent power suppliers incur in providing electricity in competition with Edison. Otherwise, competition is skewed either in favor of or against Edison's bundled services.

Q. Why do you say that the 75/25 demand/energy allocation grossly overstates peak load costs?

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[9] Opinion and Order, Case No. U-10102, January 21, 1994, page 87.

A. The relative cost of the plants that provide peak load and cycling power is far less than 75 percent of the overall cost of Edison's production facilities. This fact is demonstrated on Exhibit I-___(CWK-2), which lists all of Edison's production plants in declining order of capacity factor (column D). Capacity factor is the ratio of each plant's MWh of generation to its rated capacity times 8760, the number hours in the year.

The exhibit demonstrates that Edison's plants fall into three groups. There are four plants with capacity factors greater than the system-wide average of 46 percent. These are the Company's base load plants. Five more plants have capacity factors between 10 and 46 percent. They can be characterized as "cycling" plants. The remaining plants all have

capacity factors under 10 percent, five of them less than one percent. These are Edison's peaking plants.

Column E in Exhibit I-_____(CWK-2) shows the original investment costs in each plant on Edison's books as of December 31, 2002. Column F shows the percent of total plant investment represented by the three categories of plants. Far from representing 75 percent of the total, the peaking plants constitute only 5.4 percent of Edison's production plant investment, and the cycling plants another 29.2 percent. The largest share of plant investment – 65.4 percent -- is in base load facilities.

Q. How do you recommend that production plant costs be allocated?

A. I recommend the following allocation of production costs to the respective customers classes:

- 65.4 percent on the basis of energy consumption at the point of generation;
- 29.2 percent on the basis of the 12 monthly peak demands at the time of the system's coincident peak; and

- 5.4 percent on the basis of the average of the four summer coincident peaks.

Not only does this allocation match the cost makeup of Edison's production plants, but it corresponds with the cost profile of generation resources that competitors must employ in luring away choice customers from the respective customer classes.

Q. How do your recommended production plant allocators compare with those used by Edison in its cost of service study?

A. Exhibit I-_____(CWK-3) displays the development of the production plant allocators I recommend and compares them with those employed by Edison. Page 1 shows the development of the 4 CP allocators that I recommend be used for assigning peaker plant

costs. Page 2 shows the energy, 12 CP and 4 CP allocators and the mix of these factors as used by Edison and recommended by me.

The exhibit reveals that the assignment of base load plant costs on an energy basis more than offsets the effect of allocating peaker plant costs by the four summer coincident peaks. As a result, the revised allocators for the low load factor classes, residential and general service (small commercial and industrial), are lower than those used by Edison. The revised allocators for remaining classes are all higher than Edison's allocators.

Q. Have you estimated the class revenue deficiencies and sufficiencies using your proposed production plant allocators?

A. Yes. Exhibit I-_____(CWK-4) presents my calculation of the revenue deficiencies and sufficiencies of the five largest customer classes that will be affected by the unfreezing of rates on

January 1, 2004. They are:

- General Service (only customers having a peak load of 15 kW or above),
- Large General Service,
- Primary,
- Special Manufacturing Contracts ("SMC"), and
- Large Customer Contracts ("LCC").

Page 1 of Exhibit I-_____(CWK-4) presents the results for 2002. The columns titled "Per Company" are taken directly from the workpapers underlying Edison's cost of service study. The only modification is that municipal and state income taxes are subtracted from "Other Taxes," leaving real estate, social security and unemployment taxes as the principal component of that category. Aggregate income taxes are shown separately and are the remainder after subtracting expenses and return from the Company's total revenue requirement.

The column titled "Adjusted" reflects the application of the revised production plant allocators developed in Exhibit I-_____(CWK-3). The production component of rate base is adjusted by the ratios of the revised allocators to Edison's allocators. These same ratios are used to adjust the production-related Operating and Maintenance ("O&M") expenses, depreciation, and other taxes. Income taxes change in proportion to the change in return, and "Additional Revenue Requirement" changes as the base revenue requirements change.

The exhibit shows that the adjustment in the production plant allocators has only a modest effect on the results. The revenue sufficiency for the General Service class increases by $16.5 million to $81.2 million. The sufficiency for the Large General Service class increases by $946,000 to $35.4 million. The revenue sufficiencies for the primary and the LCC classes decline, but they remain at substantial levels relative to total class revenues. Only the SMC class shows a revenue deficiency: $51.5 million after adjustment for revised production plant allocators.

Q. **Have you estimated the revenue deficiencies and sufficiencies that would occur in 2004 based on Edison's predicted costs and revenues?**

A Edison has performed no class cost of service study for 2004, so the only way to estimate class revenue deficiencies and sufficiencies in that year is to trend forward the results for 2002. This trending is performed on page 2 of Exhibit I-____(CWK-4). On this page, I employ the assumption that the increase in Company jurisdictional revenue requirement between 2002 and 2004 will be distributed uniformly among the customer classes based on their 2002 revenue requirements. Line 1 presents the 2002 adjusted revenue requirements carried over from page 1 of that exhibit, but with the addition of Edison's quantification of its total jurisdictional (excluding wholesale) revenue requirement. Line 2 presents the percentage of that revenue requirement represented by each class. Line 3 is the respective classes' 2002 revenue sufficiency or deficiency, again carried over from page 1. Line 4 is the Company's estimate of its total 2004 revenue deficiency, and line 5 is the portion of that deficiency that Edison proposes to recover from choice customers.

In line 6, I calculate the increase in retail bundled service revenue requirement between 2002 and 2004, and I distribute it among the customer classes according to the percentages in line 2. These increases are then added to the year 2002 revenue deficiencies or sufficiencies in line 3 to derive indications of the deficiencies or sufficiencies in 2004.

Page 2 of Exhibit I-_____(CWK-4) indicates that the General Service classes will continue to experience revenue sufficiencies into 2004. Edison cannot increase the rates to these customers without shifting costs among classes, in violation of Sections 10d(2) and 10d(5) of PA 141. It appears that Edison could increase its Primary Service rates by $10.9 million, about 1.5 percent relative to 2002 revenues. The only major class to show a significant revenue deficiency is the

Special Manufacturing Contract class. It appears, however, that Edison is either unable or unwilling to increase the rates to its SMC customers.

Q. Do you regard these results as definitive?

A. No. To make a definitive finding as to class revenue requirements, Edison must conduct a class cost of service analysis of forecast 2004 costs using projected class costs, revenues and, if possible, projected class allocation factors. If the allocation factors – energy and peak demands – cannot be projected, then Edison should use the most recent data available, presumably that for the most recent 12 months, normalized for weather.

However, in the absence of such a cost of service study, I recommend that the Commission rely on the results of my analysis in allowing rate increases to the major classes of customers subject to uncapped rates on January 1, 2004.

Q. Do your results justify rate reductions?

A. The point of this testimony is that if rate increases to uncapped customers are the result of cost shifting from capped to uncapped customers, then they are in violation of Section 10d(2) in Act 141.

Q. Would it be just and reasonable to deny rate increases if the Commission determines that Edison has an overall revenue deficiency?

A. When the requirements of Act 141 limit rate increases, it may be just and reasonable to restrict increases. The Act contains both benefits to and burdens on Edison. The benefits have been substantial. In Cases Nos. U-11800-R, U-11495, and U-12121, the Commission interpreted Act 141 as ending customers' rights to refunds or rate reductions In addition, Act 142 enabled Edison to receive over $1.75 billion in cash from securitization bonds and over $500 million in securitization tax charges. Given these benefits to Edison, it may be just and reasonable in this case to implement the rate caps and to prohibit cost shifting pursuant to Section 10d(2). These provisions are part of an overall legislative plan.

Power Supply Cost Recovery ("PSCR")

Q. What does Edison propose with respect to the PSCR?

A. Most of the PSCR-related issues have already been litigated pursuant to the Commission's August 18th order, but I will briefly discuss this subject.

Revised Exhibit A-13, Schedule E6.1, page 1, line 22 identified a negative 1.05 mill PSCR factor, and as I understand that calculation, it reflects Edison's PSCR revenues ($771,271,000) minus expense ($645,221,000) for an over recovery ($126.050,000).[10] This does not include so-called mitigation sales, revenues and costs, which are identified in

Exhibit A-16, Schedule F11-2, lines 11-28. Revised Exhibit A-13. Schedule E6.1, page 2 also proposes to add $126,870,000 for transmission expense to Edison's PSCR costs.

Q. Should transmission charges from MISO be included in the PSCR?

A. No, and for three reasons. First, those charges do not fall within the definitions in Section 6j(1) of 1982 PA 304.

Second, the MISO transmission charges do not fit the character of costs to be recovered in a true-

10 WP A-13, E6.1, Page 1.

up cost recovery mechanism. The justification for such mechanisms is that some costs are totally unpredictable, so that fixing them at any predetermined level without true-up runs the risk of severe over- or under-recovery. The MISO charges are not unpredictable. Rather, they are set in FERC-approved tariffs and are fully predictable for the duration of their effectiveness.

Third, the MISO transmission charges are not based on energy consumption, but on aggregate demand. This is true even of the MWh rates because they are set on the assumption of a 100 percent load factor. The PSCR is a per-kWh rate and therefore unrelated to the incurrence of transmission charges.

For these reasons, transmission charges should be incorporated into base rates, just as transmission costs were incorporated prior to the sale of Edison's transmission system.

Stranded Costs and Transition Charges

Q. What does Edison propose with regard to stranded costs and the transition charges required to recover them?

A. Edison calculates the revenues lost and the costs saved from the departure of choice customers from the Company's generation services. Edison proposes that choice customers should be responsible for 90 percent of these lost generation margins, amounting to $273 million in 2004. These generation margin losses will be offset by sales of electricity into the wholesale market from the generation capacity freed by departure of the choice customers' load. These "mitigation" savings are predicted to be $133 million in 2004. The net lost margins, which Edison defines as its stranded costs, will come to $140 million.[11] Edison proposes to recover this amount in transition charges imposed on choice customers.

11 Revised Exhibit A-24, page 1.

Q. Is Edison's calculation consistent with Commission's policy on stranded costs?

A. No. In Case No. U-12639, Edison proposed this same "lost margins" approach to calculating stranded costs. The Commission explicitly rejected Edison's methodology and adopted instead the procedure proposed by its Staff. That procedure calculates the revenue requirement for the generation component of the Company's services and compares it with the revenue that can be ascribed to power supply, as opposed to transmission, distribution and customer service. If generation-related revenues cover generation-related costs (including return), there are no stranded costs. Staff used historical data to perform a separation of generation costs and revenues. It found that revenues covered costs and therefore, as of that time, Edison had no stranded costs.[12]

Q. Have you conducted a comparison of generation-related costs and revenues, consistent with the Commission approved methodology?

A. Yes. That calculation is contained in Exhibit I-_____(CWK-5). Page 1 presents a calculation of the functional revenue requirements for generation, transmission, distribution and all others in the year 2002. The data are taken from the "total electric" columns in the workpapers underlying Edison's cost of service study, Exhibit A-5. That study identifies rate base, depreciation and O&M costs according to these four functional classifications. I have allocated property taxes and the regulatory debit/credit according to rate base. I have allocated social security and unemployment taxes based on the distribution of O&M expenses.

Edison has no explicit charges that are designed to recover generation and transmission costs. It has, however, developed such charges for the functions that are not related to generation and transmission. These are the Retail Access Service Tariff ("RAST") rates that the Company

12 Opinion and Order, Case No. U-12639, December 20, 2001

proposes to charge to its choice customers for the functions that it continues to perform on their behalf. If these RAST charges are applied to all customers on the system, then they can be considered to represent the portion of revenue that is associated with distribution and customers accounting. The residual revenue can be assumed to relate to the functions that are not performed for choice customers, that is, generation and transmission.

This process of subtraction is presented on page 2 of Exhibit I-____(CWK-5) for the year 2002. The distribution revenue data – which correspond with the total Company distribution costs – are taken from Exhibit A-13, Schedule E-6.3. The customer counts for the Customer Service Charges are derived from Edison's response to AG 2.47/260. The only estimation that was required to prepare this page relates to the split of secondary customers between those receiving single phase vs. three-phase service. I have assumed that no residential customers and 75 percent of all commercial secondary customers receive three-phase service. Line 13 of page 2 of Exhibit I-____(CWK-5) presents the total revenue that would be recovered from all customers if Edison charged the RAST rates to its entire body of ratepayers, both choice and bundled service. This revenue is then subtracted from the total Company reported revenue on line 14 to yield the residual generation and transmission related revenue on line 15. Lines 16 and 17 present the generation and transmission revenue requirements developed on page 1 of the exhibit. Line 18 reveals that in 2002 the generation and transmission functions recovered $279,260,000 more revenue than their functional revenue requirements. There were no stranded costs in that year.

Q. Should Edison's proposed transition charges be included in any interim rate increase?

A. Edison's proposed transition charge represents a departure from prior Commission ratemaking decisions. Therefore, the Commission not should adopt Edison's transition charge testimony and exhibits in granting interim rate increases. This is true even if Edison ultimately is able to justify a transition charge in the final rate phase of this case.

Earnings Sharing Mechanism

Q. What does Edison propose as an earnings sharing mechanism?

A. Edison proposes that a "deadband" of 100 basis points (one percent) be established around its authorized rate of return on common equity. Using the currently approved rate of return of 11.5 percent, the deadband would be from 10.5 percent to 12.5 percent. If the Company's earned return on equity falls within that deadband, there would be no adjustments to the rates. As the earned returns depart from that deadband, ratepayers would share in the shortfall or the surplus in increasing proportions as the departure from the deadband increases. Again using 11.5 percent as the approved return to equity, the division between ratepayers and shareholders would be as follows:

Under-earnings			Over-earnings		
ROE Range	To Shareholders	To Ratepayers	ROE Range	To Shareholders	To Ratepayers
10.5%-11.5%	100%	0%	11.5%-12.5%	100%	0%
10.0%-10.5%	80%	20%	12.5%-13.0%	80%	20%
9.5%-10.0%	60%	40%	13.0%-13.5%	60%	40%
9.0%-9.5%	40%	60%	13.5%-14.0%	40%	60%
Below 9.0%	20%	80%	Over 14.0%	20%	80%

Q. What is your recommendation with regard to the earnings sharing mechanism?

A It is not clear whether the ESM is part of Edison's motion for partial and immediate rate relief. Since it is a clear departure from past Commission ratemaking practices, it should not be. I therefore recommend excluding the ESM from any interim rate order, and the merits of the plan can be addressed in the final rate phase of this case.

Statement of Financial Accounting Standards No. 143

Q. What is Statement of Financial Accounting Standards No. 143?

A. Statement of Financial Accounting Standards No. 143 ("FAS 143") was adopted last year by the Financial Accounting Standards Board to require the recognition by public corporations of legal obligations to retire assets. Under FAS 143, when a company installs a capital asset that it is legally obligated to remove when it is retired, the company must declare the present value of its forecasted removal cost as a liability on its books. Each year, the company depreciates that liability and declares, as an additional expense, the accretion in the present value of that liability.

Q. Can you illustrate how FAS 143 works?

A. Yes. Exhibit I-______(CWK-6) provides an illustration. Assume that an asset is being placed that has to be removed 20 years from now at an estimated cost of $1 million. FAS 143 requires that this $1 million be discounted at the risk-free cost of capital, which for purposes of illustration I assume to be seven percent. The discounted cost of retirement is $276,508, and that is the liability that is put on the company's books. Each year, there are two items of expense, the fixed depreciation of the liability (column A) and the annual increase, or "accretion," in the liability's present value (column C). The second item increases each year as the present value increases. The total expense (column D) grows over the life of the asset that will have to be removed.

Q. Is FAS 143 an issue in this case?

A. Pages 48-52 in Mr. VanHaerents' testimony discuss that subject, and he has said that FAS 143 is not an issue in this case because Edison is satisfied with its nuclear decommissioning surcharge and because Edison is not scheduled to file a new depreciation case until January 1, 2006.

I believe FAS 143 should not be addressed in the interim rate phase of this case. However, the propriety of Edison's nuclear decommissioning surcharge, which does relate to FAS 143, could be an issue in the final rate phase of this case. In addition, I note that FAS 143 is likely to have a very significant impact upon Edison's depreciation expense, as indicated by the comparison with Edison's current removal cost procedure in the final columns of Exhibit I-_____(CWK-6). This issue is an additional reason for not attempting to address prematurely rate increases applicable to customers whose rates are presently capped.

Q. Does this conclude your testimony?

A. Yes. It does.

Exhibit I-_____(CWK-1)

Detroit Edison Company
Indicated 2002 Rate Increases (Decreases) to Customers over 15 kW
(Dollars in Thousands)

		2002 Revenue	Revenue Deficiency (Sufficiency)	Indicated Rate Increase (Decrease)
Commercial Secondary				
D-3	General Service (Note 1)	546,757	(55,343)	-10.1%
Comm	Large General Service	146,863	(36,298)	-24.7%
	LCC Secondary	8,216	(1,478)	-18.0%
	Total Commercial Secondary	988,782	(121,414)	-12.3%
Primary Service				
D-6	Primary	698,757	(46,014)	-6.6%
D-8	Interruptible Supply	19,776	(3,366)	-17.0%
R-1.1	Alt Metal Melting	4,191	(553)	-13.2%
R-1.2	Process Heating	29,953	(3,606)	-12.0%
R-10	Interruptible Supply	44,161	(3,885)	-8.8%
	SMC Firm	277,239	44,265	16.0%
	SMC Non-Firm	7,373	2,302	31.2%
	LCC Firm	99,282	(7,878)	-7.9%
	LCC Non-Firm	8,050	8,269	102.7%
	Total Primary	1,188,784	(10,466)	-0.9%
Government				
D-10	Electric Schools	4,018	(1,250)	-31.1%
E-5	Secondary Pumping	8,064	(1,851)	-23.0%
E-2	Traffic Signals	3,884	525	13.5%
	Street Lighting	37,153	4,353	11.7%
	Total Government	53,119	1,777	3.3%
Total Company		4,174,422	(231,911)	-5.6%

Source: Exhibit A-5, Schedul E1

Note 1 - From Exhibit A-13, Schedule E4.

Exhibit I-_____(CWK-2)

Detroit Edison Company
Production Plants

Plant	A Type	B Installed Capacity MW	C Net Generation MHW	D Capacity Factor	E Original Cost	F Percent of Total
Fermi 2	Nuclear	1,094	9,300,969	97.10%	51,841,341	
Trenton Channel	Steam	776	4,339,842	63.88%	259,219,425	
Belle River (DECo)	Steam	1,135	6,292,915	63.29%	1,598,742,210	
Monroe	Steam	3,280	16,721,027	58.20%	1,636,929,198	
Total Base Load		**6,284**	**36,654,753**	**66.59%**	**3,546,732,174**	**65.4%**
St. Clair	Steam	1,905	6,963,987	41.73%	697,282,215	
River Rouge	Steam	933	3,398,287	41.57%	268,756,579	
Harbor Beach	Steam	121	240,329	22.67%	35,999,616	
Greenwood	Steam	815	1,123,770	15.73%	388,531,326	
Ludington	Pumped Storage	969	1,216,232	14.33%	195,661,913	
Total Cycling		**4,744**	**12,942,605**	**31.15%**	**1,586,231,649**	**29.2%**
Greenwood	Internal Combustion	278	141,989	5.83%	75,086,833	
Delray	Gas Turbine	159	63,807	4.58%	45,216,995	
Belle River IC	Internal Combustion	292	114,127	4.47%	83,019,863	
Connors Creek	Steam	330	50,486	1.75%	58,646,723	
Oliver	Internal Combustion	14	916	0.76%	1,481,356	
Hancock	Gas Turbine	160	6,734	0.48%	14,098,839	
River Rouge	Internal Combustion	11	434	0.45%	1,233,313	
Wilmont	Internal Combustion	14	484	0.39%	1,451,702	
Putnam	Internal Combustion	14	221	0.18%	1,516,432	
St. Clair	Gas Turbine	19	188	0.12%	1,999,256	
Enrico Fermi	Gas Turbine	64	241	0.04%	8,763,112	
Total Peaking		**1,354**	**379,627**	**3.20%**	**292,514,424**	**5.4%**
Total Production Plant		**12,381**	**49,976,985**	**46.08%**	**5,425,478,247**	**100.0%**

Sources: Production Plant Data from Detroit Edison MPSC Form P-521, Pages 402, 403.
Note: Plants showing negative net generation (except Ludington) not included.

Detroit Edison Company
4 Coincident Peak Allocators, 2002

Description	June 26 5:00 PM	July 1 5:00 PM	August 1 3:00 PM	September 9 5:00 PM	Average 4 CP	Losses & Adjustments	Adjusted 4 CP	4 CP Allocator
Residential	4,044,924	4,790,847	4,289,592	4,175,428	4,325,198	1.12187	4,852,310	43.66%
General Service	1,771,686	2,091,967	2,481,865	2,092,549	2,109,517	1.12187	2,366,604	21.29%
Large General Service	268,207	260,638	226,485	259,117	253,612	1.12187	284,519	2.56%
Other Small Light & Power	31,501	39,002	50,880	35,502	39,221	1.12187	44,001	0.40%
					-		-	
Primary	1,735,924	1,659,105	1,654,366	2,074,068	1,780,866	1.08601	1,934,038	17.40%
Special Manufacturing Contracts								
Base	1,142,987	974,340	1,058,790	820,499	999,154	0.93134	930,556	8.37%
Interruptible	102,276	54,797	115,323	60,291	83,172	0.36887	30,680	0.28%
Large Customer Contracts								
Base	324,740	303,482	322,497	236,881	296,900	1.08057	320,821	2.89%
Interruptible	74,823	75,311	72,271	40,014	65,605	0.37143	24,367	0.22%
Interruptible Supply - Primary	79,468	65,393	73,827	50,979	67,417	0.15412	10,390	0.09%
Alternative Metal Melting	13,202	7,231	8,085	7,506	9,006	0.37113	3,342	0.03%
Process Heat	81,707	58,816	76,546	77,577	73,662	0.38483	28,347	0.26%
Electric Schools	5,240	5,227	5,356	11,213	6,759	1.09741	7,417	0.07%
Interruptible Rider	115,989	152,600	141,197	131,269	135,264	0.36444	49,296	0.44%
Street Lights					-		-	0.00%
Wholesale for Resale								
Firm	220,500	220,299	220,500	220,500	220,450	1.02901	226,845	2.04%
Interruptible	47,627	57,245	53,222	54,608	53,176	-	-	0.00%
Total Company Load	10,060,801	10,816,300	10,850,802	10,348,001	10,518,976		11,113,534	100.00%

Source: Edison Response to EMDE4.41/76

The Detroit Edison Company
Production Plant Allocators

Description	A Energy at Generation	B 12 Coincident Peaks	C 4 Coincident Peaks	D Edison 25% Energy 75% 12 CP	E 65.4% Energy 29.2% 12 CP 5.4% 4 CP	F Difference
Residential	32.41%	38.37%	43.66%	36.88%	34.76%	-2.12%
General Service	16.25%	20.90%	21.29%	19.74%	17.88%	-1.86%
Large General Service	3.25%	2.96%	2.56%	3.03%	3.13%	0.10%
Other Small Light & Power	0.63%	0.45%	0.40%	0.50%	0.56%	0.07%
Primary	22.48%	19.61%	17.40%	20.33%	21.37%	1.04%
Special Manufacturing Contracts						
Base	12.10%	10.07%	8.37%	10.58%	11.30%	0.73%
Interruptible	0.40%	0.20%	0.28%	0.25%	0.34%	0.09%
Large Customer Contracts						
Base	3.38%	3.14%	2.89%	3.20%	3.28%	0.08%
Interruptible	0.74%	0.23%	0.22%	0.35%	0.56%	0.21%
Interruptible Supply - Primary	0.80%	0.10%	0.09%	0.27%	0.56%	0.28%
Alternative Metal Melting	0.14%	0.04%	0.03%	0.07%	0.11%	0.04%
Process Heat	0.99%	0.32%	0.26%	0.49%	0.75%	0.26%
Electric Schools	0.08%	0.09%	0.07%	0.09%	0.08%	0.00%
Interruptible Rider	2.09%	0.52%	0.44%	0.92%	1.54%	0.63%
Street Lights	0.46%	0.30%	0.00%	0.34%	0.39%	0.05%
Wholesale for Resale						
Firm	3.80%	2.70%	2.04%	2.98%	3.38%	0.41%
Interruptible	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total Company Load	100.00%	100.00%	100.00%	100.00%	100.00%	0.00%

Sources: Column A - Workpaper A5WPE1, pages 269, 270
Column B - Workpaper A5WPE1, pages 271, 271
Column C - Exhibit I-_____(CWK-3), page 1

Detroit Edison Company
Estimated Class Revenue Deficiencies (Sufficiencies) - 2002
(Dollars in Thousands)

	General Service			Large General Service			Primary			S.M.C. Firm			L.C.C.Firm		
	Per Company Note 1	Adjustment	Adjusted	Per Company	Adjustment	Adjusted	Per Company	Adjustment	Adjusted	Per Company	Adjustment	Adjusted	Per Company	Adjustment	Adjusted
Rate Base															
Production	472,849	(44,554)	428,294	93,207	2,153	95,360	625,213	29,216	654,429	325,314	19,986	345,300	92,977	2,034	95,011
Other	677,095		677,095	93,231		93,231	375,224		375,224	108,901		108,901	47,721		47,721
Total	1,149,944	(44,554)	1,105,390	186,438	2,153	188,591	1,000,437	29,216	1,029,653	434,215	19,986	454,201	140,698	2,034	142,732
Revenue	638,789		638,789	146,883		146,883	698,757		698,757	277,239		277,239	99,282		99,282
Expenses															
Fuel & Handling	82,970		82,970	20,509		20,509	141,443		141,443	75,809		75,809	20,105		20,105
Purchased Power	49,677		49,677	12,437		12,437	85,888		85,888	46,098		46,098	12,181		12,181
O&M Expense	178,256	(6,254)	172,003	32,297	391	32,688	182,859	4,140	186,999	94,142	2,929	97,071	25,851	292	26,143
Depreciation	75,385	(3,406)	71,979	12,119	183	12,302	63,316	1,904	65,220	27,228	1,318	28,546	8,971	138	9,109
Reg Debit	4,316		4,316	851		851	5,706		5,706	2,969		2,969	849		849
Taxes Other than Income	37,716	(1,654)	36,063	6,293	97	6,390	34,038	632	34,670	14,592	677	15,269	4,800	73	4,873
Amortizations	(1,037)		(1,037)	(205)		(205)	(1,372)		(1,372)	(714)		(714)	(204)		(204)
Total Expenses	427,283	(11,313)	415,970	84,301	671	84,972	511,878	6,675	518,553	260,124	4,924	265,048	72,553	503	73,056
Return @ 7.51%	86,361	(3,346)	83,015	14,001	162	14,163	75,133	2,194	77,327	32,610	1,501	34,111	10,566	153	10,719
Income Taxes	17,478	(677)	16,801	2,647	31	2,677	12,860	376	13,236	5,292	244	5,536	1,737	25	1,762
Base Revenue Requirement	531,122	(15,336)	515,786	100,949	863	101,812	599,871	9,245	609,116	298,026	6,668	304,694	84,856	681	85,537
Additional Revenue Requirement	43,009	(1,242)	41,767	9,636	82	9,718	52,872	815	53,687	23,478	525	24,003	6,548	53	6,601
Total Revenue Requirement	574,130	(16,578)	557,553	110,585	946	111,531	652,743	10,060	662,803	321,504	7,193	328,697	91,404	734	92,138
					-										
Revene Deficiency (Sufficiency)	(64,658)	(16,578)	(81,236)	(36,298)	946	(35,352)	(46,014)	10,060	(35,954)	44,265	7,193	51,458	(7,878)	734	(7,144)
% Deficiency	-10.12%	-2.60%	-12.72%	-24.71%	0.64%	-24.07%	-6.59%	1.44%	-5.15%	15.97%	2.59%	18.56%	-7.93%	0.74%	-7.20%

Sources: Workpapers A5E1, pages 27-46; Exhibit_____(CWK-4), page 1
Note 1: Proportion over 15 kW: 5,771,878 MWH/7,410,694 MWH = 77.89%
From Exhibit A-13, Schedule E4.

Detroit Edison Company
Estimated Class Revenue Deficiencies (Sufficiencies) 2004
(Dollars in Thousands)

		A Total Jurisdictional	B General Service	C Large General Service	D Primary	E S.M.C. Firm	F L.C.C. Firm
1	Adjusted Revenue Requirement 2002	3,813,013	557,553	111,531	662,803	328,697	92,138
2	Percentage of Total Company Jurisdictional	100.00%	14.62%	2.93%	17.38%	8.62%	2.42%
3	Revenue Deficiency (Sufficiency) 2002	132,881	(81,236)	(35,352)	(35,954)	51,458	(7,144)
4	Total Revenue Deficiency 2004	553,427					
5	Less Allocation to Choice	151,000					
6	Net Increase in Revenue Deficiency 2002-2004	269,546	39,414	7,884	46,854	23,236	6,513
7	Revenue Deficiency (Sufficiency) 2004	402,427	(41,822)	(27,468)	10,900	74,694	(631)

Sources: Line 1, col.A - Exhibit A-5, Schedule E1, Col 2, Line 25
Sources: Lines 1 & 2, Cols B-F - Exhibit I -______(CWK-4), page 1
Line 3, Col A - Exhibit A-5, Schedule E-1, Col 2, Line 24
Line 4 - Exhibit A-9, Schedule A 1-2 (Revised)
Line 5 - Exhibit A-27, Schedule MEC-13
Line 6, Col A - Line 4 - Line 3 - Line 5; Cols B-F - Col A distributed by Line 2.
Line 7 - Line 3 - Line 6.

Detroit Edison Company
Funtional Category Revenue Requirements, 2002
(Dollars in Thousands)

	A Source :A5E1	B Total Electric	C Generation	D Transmission	E Distribution	F Other
1 Rate Base	p.7 Col 1, L1-5	6,905,454	3,075,896	290,689	2,692,078	846,791
Expenses						
4 Fuel & Handling	p.2, col 1, L4	637,312	637,312			
5 Purchased Power	p.2, col 1, L5	385,275	385,275			
6 O&M Expense	pp. 203 - 223	1,260,017	375,240	124,607	180,213	579,957
7 Depreciation	pp 148 - 163	448,277	181,841	14,260	171,487	80,689
8 Property Tax	p 37, On RB	187,080	83,331	7,875	72,933	22,941
9 Soc Sec. & Unemp	p 37, On O&M	35,714	10,636	3,532	5,108	16,438
10 Regulatory Debit-Credit	p 2, On RB	27,236	12,132	1,147	10,618	3,340
11 Total Expenses	Sum L 4-L10	2,980,911	1,685,767	151,421	440,359	703,365
12 Return @ 7.51%	7.75% of L 3	518,600	231,000	21,831	202,175	63,594
13 Income Taxes	L.14-L12-L11	106,368	47,380	4,478	41,468	13,044
14 Base Revenue Requirement	p.2, L 25	3,605,879	1,964,146	177,729	684,001	780,003
15 Added Revenue Requirement	p. 2, L 23	288,847	145,668	13,181	120,126	62,482
16 Total 2002 Revenue Requirement	L14 + L 15	3,894,726	2,109,814	190,910	804,127	842,484

Detroit Edison Company
Generation and Transmission Revenue Deficiency, 2002
(Dollars in Thousands)

		A Source	B Customers Note 1	C Rate Note 2	D Revenue
	Customer Service Charge Revenue				
	High Voltage Distribution Service				
1	Primary		4,041	$ 333.95	16,194
2	Total Commercial Customers		184,149		
5	Less D6 Primary		2,102		
6	Remainder	L2 - L3-L4-L5	182,047		
7	Assumed 75% 3-Phase		136,535	$ 65.36	107,087
8	Low Voltage Distribution Service	E6.3, D14	1,989,192	$ 8.85	211,252
8	System Use Charge Revenue	Ex A-13, Sch 6.3, p 6, D1			799,539
9	120 kV Radials	Ex A-13,Sch 6.3, p.7, E8			11,462
10	Transformation Charge Revenue				
11	24/41.6 kV	Ex A-13, Sch 6.3, p 8, D17			4,546
12	120+ kV	Ex A-13, Sch 6.3, p 8, C17			11,533
13	Total Distribution Revenue	Sum Col. D			1,161,613
14	Total Electric Revenue	Ex. A-5, Sch E-1, p. 2			3,741,598
15	T&D Related Revenue	L 14 - L13			2,579,985
16	Generation Revenue Requirement	Ex CWK-5, p.1, C16			2,109,814
17	Transmission Revenue Requirement	Ex CWK-5, p.1, D16			190,910
18	G&T Revenue Deficiency (Suffiency)	L16+L17-L15			(279,260)

Note 1: Sources - Response to AGDE2.47/260; MPSC Form P-521, p.304.1.
Note 2: Ex A-13, Sch E6.3, p 3

Exhibit I-_____(CWK-6)

Statement of Financial Accounting Standards No. 143

Forecast Removal Cost $1,000,000
Discount Rate 7.00%

Year	A Depreciation of $276,508	B Present Value	C Acretion in Present Value	D Total Expense	E Negative Salvage Allowance	F Difference
1	13,825	276,508	19,356	33,181	50,000	(16,819)
2	13,825	295,864	20,710	34,536	50,000	(15,464)
3	13,825	316,574	22,160	35,986	50,000	(14,014)
4	13,825	338,735	23,711	37,537	50,000	(12,463)
5	13,825	362,446	25,371	39,197	50,000	(10,803)
6	13,825	387,817	27,147	40,973	50,000	(9,027)
7	13,825	414,964	29,048	42,873	50,000	(7,127)
8	13,825	444,012	31,081	44,906	50,000	(5,094)
9	13,825	475,093	33,256	47,082	50,000	(2,918)
10	13,825	508,349	35,584	49,410	50,000	(590)
11	13,825	543,934	38,075	51,901	50,000	1,901
12	13,825	582,009	40,741	54,566	50,000	4,566
13	13,825	622,750	43,592	57,418	50,000	7,418
14	13,825	666,342	46,644	60,469	50,000	10,469
15	13,825	712,986	49,909	63,734	50,000	13,734
16	13,825	762,895	53,403	67,228	50,000	17,228
17	13,825	816,298	57,141	70,966	50,000	20,966
18	13,825	873,439	61,141	74,966	50,000	24,966
19	13,825	934,579	65,421	79,246	50,000	29,246
20	13,825	1,000,000		13,825	50,000	(36,175)
Total Accrual				1,000,000	1,000,000	(0)

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF THE UNION LIGHT, HEAT AND POWER COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO ACQUIRE CERTAIN GENERATION RESOURCES AND RELATED PROPERTY; FOR APPROVAL OF CERTAIN PURCHASE POWER AGREEMENTS; FOR APPROVAL OF CERTAIN ACCOUNTING TREATMENT; AND FOR APPROVAL OF DEVIATION FROM REQUIREMENTS OF KRS 278.2207 AND 278.2213(6)	)	CASE NO. 2003-00252

**DIRECT TESTIMONY OF
CHARLES W. KING**

ON BEHALF OF

THE OFFICE OF THE ATTORNEY GENERAL
COMMONWEALTH OF KENTUCKY

SEPTEMBER 26, 2003

DIRECT TESTIMONY OF
CHARLES W. KING

INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Charles W. King. I am President of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. PLEASE DESCRIBE SNAVELY KING.

A. Snavely King, formerly Snavely, King & Associates, Inc., was founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. The firm has a professional staff of 15 economists, accountants, engineers and cost analysts. Much of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 33-year history, members of the firm have participated in over 1000 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. Attachment A is a summary of my qualifications and experience.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. Attachment B is 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.

Q. WHAT ISSUES WILL YOU ADDRESS IN YOUR TESTIMONY?

A. I will present the Attorney General's position with respect to the eight items for which Union Light, Heat & Power Company ("ULH&P" or "the Company") seeks approval from the Commission. I will also address the seven conditions that ULH&P witness Turner claims the Company must have before it will consummate the transfer of three plants from the Cincinnati Gas and Electric Company (CG&E) to ULH&P.

<u>SUMMARY OF TESTIMONY</u>

Q. WHAT ARE THE EIGHT ITEMS FOR WHICH THE COMPANY SEEKS APPROVAL FROM THE COMMISSION?

A. Mr. Gregory C Ficke, ULH&P's President, lists the eight items as follows:

1. A Certificate of Public Convenience and Necessity ("CPCN") for ULH&P to acquire CG&E's interest in the East Bend Generating Station, CG&E's Miami Fort Generating Station Unit 6, and CG&E's Woodsdale Generating Station and approval of a form of Asset Purchase Agreement to effectuate such an acquisition;
2. Approval to defer for future recovery the transaction costs Cinergy will incur as a result of such an acquisition;

3. Approval to enter into certain wholesale power agreements with CG&E to provide firm back-up service to the East Bend and Miami Fort 6 plants during periods of maintenance or forced outages and to provide for joint economic dispatch of the plants;

4. Approval to retain the profits from off-system sales of energy from the plants;

5. A deviation from the affiliate transaction pricing requirements embodied in Chapter 278 of the Kentucky Revised Statutes for certain fuel-related affiliate agreements;

6. Order that ULH&P's next IRP shall be due within three years of the Commission's final order in this proceeding;

7. Approval for ULH&P to transfer the plants back to CG&E if the proposed rate treatment described by Mr. Turner (embodied in the seven conditions) is not afforded ULH&P in future rate proceedings before the Commission, and

8. Authority for ULH&P to terminate its current Power Sale Agreement with CG&E.

Q. WHAT ARE YOUR RECOMMENDATIONS WITH RESPECT TO THESE EIGHT ITEMS?

A. In his testimony, David Brown Kinloch has recommended deferring the determination of whether to approve this Application in full or in part until such time as a full investigation has been made into the alternatives available to ULH&P. I join in that recommendation. But, should the Commission chose to approve item nos. 1, 3 and 8 of this application without further investigation into all available alternatives, then I recommend that item nos. 2 and 6 be accepted with modifications that I will describe and that item nos. 4 and 7 be rejected. I cannot make a recommendation on item no. 5 because it is not adequately explained in ULH&P's filing.

Q WHAT ARE THE SEVEN CONDITIONS THAT MR. TURNER CLAIMS THAT ULH&P REQUIRES IN ORDER TO IMPLEMENT THE PLANT TRANSFER?

A. At page 15-16 of his prefiled testimony, UHL&P witness Turner lists the following conditions for the transfer of asset ownership from CG&E to UHL&P:

1a. That the then current net book value of the plants be included in rate base in any future rate proceedings;

1b. That the transaction costs incurred by Cinergy and its subsidiaries for this transfer be deferred for recovery in ULH&P's future general rate proceedings;

2. That the monthly capacity charges in the Back-up Power Sale Agreement and other agreements between CG&E and ULH&P be included in base rates in any future general rate proceedings;

3. That energy charges under the Back-up Agreement be included in the Fuel Adjustment Clause ("FAC") beginning January 1, 2007;

4. That all energy transfer charges from CG&E assessed under the Purchase, Sale and Operation Agreement ("PSOA") be included in the FAC beginning January 1, 2007;

5. That the transferred accumulated deferred investment tax credit ("ADTIC") be amortized over the life of the plants below the line and excluded from retail ratemaking;

6. That the accumulated deferred federal and state income taxes transferred from GC&E to ULH&P not be considered for ratemaking in any future general rate proceedings; and

7. That ULH&P be allowed to retain all profits from off-system sales from the assets being transferred.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS CONCERNING THESE SEVEN CONDITIONS.

A. Again, I recommend further investigation of options available to ULH&P prior to acceptance of the proposal made in this Application. But, should the Commission choose to approve the Application in part or in full without further investigation, then I recommend that condition nos. 1a, 2, 3, 4 be accepted. I recommend that condition no. 1a be accepted with modifications that I will describe. In accompanying testimony, Michael J. Majoros, Jr. recommends that condition nos. 5 and 6 be rejected, and I recommend that condition no. 7 be rejected.

Q. ARE THE APPLICATION ITEMS AND MR. TURNER'S CONDITIONS MUTUALLY EXCLUSIVE?

A. No. Several of them are duplicative, that is, they are both Application items and conditions that Mr. Turner regards as necessary for the implementation of the asset transfer plan. In those cases, I will address them as Application items and note that they have already been considered when they come up as conditions of the transfer plan.

APPLICATION ITEM 1 – CNCP TO TRANSFER PLANTS

Q. WHAT EVIDENCE DOES THE COMPANY PROVIDE IN SUPPORT OF ITS REQUEST FOR A CPCN TO TRANSFER THREE PLANTS AND TO IMPLEMENT AN ASSET PURCHASE AGREEMENT WITH CG&E?

A. UHL&P witness Diane Jenner presents the results of a series of sensitivity analyses that she purports to demonstrate that the plant transfer program embodied in the Company's application is the most cost-effective relative to the best alternative plans. Her model compared up to 2800 resource expansion plans involving supply-side management combined with new coal, combustion turbine and gas-fired combined cycle plants, accompanied by limited power purchases.

The model ultimately selected three mixes of new plants and power purchases that would best serve UHL&P's load over the coming decades.

Ms. Jenner then compared the Present Value of Revenue Requirements ("PVRR") of these three expansion plans with the PVRR of the Company's proposed asset transfer plan and the PVRR of a full requirements purchased power agreement ("PPA"). Under this last PPA plan, every hour's load would be acquired at the then-applicable market price of power.

The results of Ms. Jenner's analysis are presented on page 26 of her prefiled testimony. They demonstrate that under the base assumptions of her analysis, the Company's proposed asset transfer plan has a PVRR that is $643.5 million, or over 16 percent lower than the next most favorable plan. Ms. Jenner then tested these plans against alternative assumptions as to the price of fuel, the market price of energy, and load growth. While the differences varied depending on the assumptions, the Company's asset transfer plan continued to be more favorable than either the all new construction plans or the full requirements PPA plan.

Q. **DO MS. JENNER'S SENSITIVITY STUDIES DEMONSTRATE THAT THE COMPANY'S APPLICATION TO TRANSFER GENERATING ASSETS SHOULD BE APPROVED?**

A. No. Ms. Jenner's studies are notable for what they did not study. Ms. Jenner compared the Company's proposal to only two very limited alternatives. The first alternative considers only newly constructed generating facilities. This alternative is almost certain to be less cost-effective than the Company's asset transfer plan because it surrenders the advantage of "sunk costs" in existing plants, even when the PVRR incorporates recovery of the undepreciated value of those plants. The other alternative is a PPA that prices power at the hour market price. This alternative surrenders the benefit of any long-term commitment of a generating resource and so exposes ULH&P to the risk of spot market prices.

Among the alternatives that Ms. Jenner did not analyze is a continuation of the present arrangement whereby CG&E supplies ULH&P's full power requirements at a fixed capacity and a fixed energy rate. While the current contract between ULH&P and CG&E is due to expire on December 31, 2006, no Company witness has suggested that it could not be renewed.

Q. DO YOU BELIEVE THAT CONTINUATION OF THE PRESENT PPA WOULD BE THE LEAST COST ALTERNATIVE FOR ULH&P'S POWER SUPPLY?

A. Not necessarily. It is possible that extension of the current contract arrangement would not yield the lowest PVRR were it compared with the Company's proposed asset transfer plan. That is because the fixed price full requirements plan passes back to CG&E the risks of market price fluctuations and of weather-driven load variations. CG&E would have to build allowances for these risks into its capacity and energy charges that might drive up the PVRR of this plan.

Q. ARE THERE ALTERNATIVES THAT MIGHT YIELD LOWER COSTS THAN EITHER THE PRESENT PPA OR THE COMPANY'S ASSET TRANSFER PLAN?

A. Possibly. ULH&P and CG&E might agree to a PPA that contains a fixed capacity charge that would reflect the optimal mix of CG&E's much larger fleet of generating assets serving UHL&P's load. This fixed capacity charge would be accompanied by a variable energy charge that would reflect the fuel and variable operating expenses of the hourly mix of plants and power purchases in CG&E/PSI power pool.

This alternative arrangement would avoid most of the weaker aspects of the energy transfer and the market price PPA plans, and yet still provide ULH&P

with reliable power at a price reflecting the underlying costs of the optimal mix of assets required to provide that power.

Compared to the asset transfer plan, this arrangement would avoid the "lumpiness" problem created by the fact that only three units, with capacities of 500, 414 and 163 MW respectively, would be committed to serving a peak load of only 800 MW. These units collectively provide 5 percent more capacity than ULH&P initially requires, and the two baseload units must be backed up by commitments from CG&E equivalent to their entire capacities. If CG&E were to commit capacity appropriate for ULH&P's load out of its much larger fleet of generating assets, there would be no need for ULH&P to overbuy capacity, nor would it be necessary for ULH&P to acquire fully redundant backup capacity .

Compared to a market price PPA, this arrangement would be less expensive and much less subject to price fluctuations. Rather than paying the market price of energy, which presumably equates to the hourly marginal cost of the CG&E/PSI power pool, ULH&P would pay energy charges reflecting the composite energy cost of all units in service in each hour: effectively the "embedded" energy cost. This is a much lower and more stable number than the market price of power.

Q. DO YOU THEREFORE RECOMMEND THAT THE COMMISSION REJECT THE ASSET TRANSFER PLAN IN FAVOR OF THE PPA ARRANGEMENT YOU HAVE JUST DESCRIBED?

A. Not necessarily. The Commission has previously expressed its preference for the "iron in the ground" alternative. There are certain advantages to this plan that are unrelated to cost. Specifically, the acquisition by ULH&P of specific generating assets brings back under the Commission jurisdiction the full provision of electric power to the Company's Kentucky ratepayers. The Commission would not have to rely on the Federal Energy Regulatory Commission ("FERC") to protect the interests of Kentucky ratepayers with respect to power supply.

This advantage applies not only to the regulation of electric rates but to the Commission's oversight of the Company's Integrated Resource Plan ("IRP"). Without the generation function under the Commission's authority, the Commission can oversee only the demand-side aspects of that plan. The supply-side aspects fall principally under FERC jurisdiction.

Q. WHAT, THEN, IS THE RELEVANCE OF YOUR DISCUSSION OF AN ALTERNTIVE PPA BETWEEN ULH&P AND CG&E?

A. The relevance goes to the Commission's response to the terms and conditions posed by the Company in its application. ULH&P's application purports to present an all-or-nothing choice between its asset transfer plan, complete with conditions, and the alternative of throwing its power supply open to the mercy of the competitive market for energy. This stark choice completely overlooks the fact that the source of market-based energy is ULH&P's own parent, CG&E. ULH&P purports to absolve its parent, CG&E, of any public utility responsibilities. If ULH&P does not generate electricity for its ratepayers, CG&E has no responsibility to do so, at least according to ULH&P.

Whether and how the Commission can force CG&E to provide power to ULH&P at cost-based rates is a legal issue which I am not qualified to address. The resolution of that issue determines the extent to which the Commission should or should not be intimidated by the terms and conditions in ULH&P's application. Assuming that the Commission need not believe that unless it accepts all of the conditions spelled out by ULH&P, the Company's Kentucky ratepayers will lose the protection of regulated power supply costs. The following review of these terms and conditions will identify several that should be rejected outright. Such rejection should not be considered as tantamount to rejection the entire asset transfer plan.

APPLICATION ITEM 2 – DEFERRAL OF TRANSACTION COSTS

Q. WHAT ARE THE TRANSACTION COSTS TO WHICH THIS ITEM REFERS?

A. ULH&P President Gregory Ficke states that transaction costs will be incurred by CG&E and ULH&P in order to effectuate the transfer of assets. CG&E will incur income and property taxes and financing-related costs related to the redemption of debt and release of certain assets from its mortgage. ULH&P has already incurred costs associated with the preparation of this filing, and it anticipates additional costs relating to tax matters and financing. Mr. Steffan's Attachment JPS-7 presents the Company's estimates of these costs. They come to $4,865,000.

Q. WHAT TREATMENT DOES THE COMPANY PROPOSE FOR THESE COSTS?

A. ULH&P proposes that these transaction costs, whatever they are, be deferred for recovery in the next rate case, which presumably would set rates for the period after January 1, 2007. Although the Company does not say so, I presume that it would expect to receive compensation for the deferral in the form of a compounding carrying charge.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THESE TRANSACTION COSTS?

A. I recommend that these costs be deferred and recovered, but not necessarily until the next rate case. During the interim between ULH&P's acquisition of the three plants and the January 1, 2007 resetting of retail rates, the Company will be free to earn as much from these three plants as it can under the frozen rates. If the plants generate profits in excess of a reasonable rate of return, then I recommend that the excess profits be applied against the recovery of transaction costs.

Hopefully, this approach will reduce, possibility eliminate the burden of these costs on ratepayers after January 1, 2007.

Q. HOW WOULD THIS PROPOSAL TO APPLY PLANT PROFITS TO TRANSACTIONS COSTS WORK?

A. The Company would book transaction costs in a deferred asset account exactly as it proposes. Between the transfer date and the January 1, 2007 rate proceeding (presumably conducted in 2006), there would be no reduction in this regulatory asset account. As part of the rate case, the Commission would conduct a retrospective analysis of the plants' sales and costs, inclusive of a reasonable rate of return and associated income taxes, to determine whether there were any excess profits earned during the three-year rate freeze period. The applicable revenue in this analysis would include both retail revenues and net revenues from off-system sales.

To the extent that the Commission finds that the plants generated excess revenue over their revenue requirement, that excess would be applied to offset the accumulated transaction costs. If excess profits do not offset the transaction costs, then the residual unrecovered balance would be amortized into rates over a reasonable period after January 1, 2007. If the excess profits exceed the transaction costs, then the deferred asset would be considered fully recovered, and the Company would be allowed to retain any further excess profits.

Hopefully, this procedure will minimize, and possibly eliminate the need to include transaction costs in the January 1, 2007 rates.

APPLICATION ITEM 3 – WHOLESALE POWER AGREEMENTS

Q. PLEASE DESCRIBE THE WHOLESALE POWER AGREEMENTS INCLUDED IN THIS ITEM.

A. There are two wholesale power agreements between ULH&P and CG&E. The first is the Back-up Power Sales Agreement ("Back-up PSA") that commits CG&E to provide back-up power to UHL&P whenever there are planned or unplanned outages at the East Bend or Miami Fort 6 plants. The second is the Purchase, Sales and Operation Agreement ("PSOA") that accommodates joint economic dispatch of UHL&P's plants in conjunction with the fleet of plants operated by CG&E and PSI Energy.

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THIS ITEM?

A. These wholesale power agreements are necessary to ensure the reliability of power supply to UHL&P's Kentucky customers at the lowest cost possible within the construct of the transferred asset plan. Accordingly, they probably should be approved, although not necessarily by this Commission. The ultimate authority to approve these contracts lies with FERC, not this Commission. Unless the Commission and its staff can conduct an informed and expert examination of these contracts, their approval should probably be left to FERC, which has the necessary experience and expertise to evaluate wholesale contracts.

APPLICATION ITEM 4 – RETENTION OF PROFITS FROM OFF-SYSTEM SALES

Q. WHAT JUSTIFICATION DOES UHL&P OFFER FOR THIS ITEM?

A. Mr. Turner testifies that this item is appropriate "because of the significant value that ULH&P's customers are realizing in acquiring 'iron in the ground' at a net book value that is less than potential market value."

Q. **IS THIS A VALID BASIS FOR ALLOWING ULH&P TO RETAIN OFF-SYSTEM PROFITS?**

A. No, it is not. In return for surrendering these plants to regulation at net book value, CG&E gets something in return. That is the assurance provided by regulation that all expenses associated with these plants will be covered, that every cent of investment in them will be recaptured, and that in the meantime they will yield fair and reasonable after-tax return on all outstanding investment.

These are assurances that unregulated plants do not have, and they should not be taken lightly. In recent months, Mirant and NRG Energy have declared Chapter 11 bankruptcy, even though they both own "hard" generating assets. The much reduced risk of regulated generation relative to unregulated merchant generation justifies some apparent sacrifice on the part of CG&E. In this case, the sacrifice should take the form of foregone sale value from its UHL&P plants.

Q. **SHOULD THIS ITEM OF THE APPLICATION BE APPROVED?**

A. Absolutely not. UHL&P will be asking its retail customers to compensate it for all expenses associated with these plants, for the recovery of capital, and for a fair and reasonable post-tax rate of return. In short, ratepayers will fully support these plants. For this reason, ratepayers should be entitled to the earnings these plants generate. If ULH&P were to retain the profits from off-system sales from these plants, then ULH&P should be obliged to cover a portion of the fixed operating and capital costs of the plants. Otherwise, the arrangement is tantamount to granting the Company a supra-competitive rate of return.

Additionally, the arrangement would be asymmetrical. UHL&P expects ratepayers to absorb the cost of off-system purchases when CG&E's generating resources are short, but it proposes to pocket the profits from off-system sales when CG&E is long. This is clearly a one-sided, heads-I-win-tails-you-lose arrangement that the Commission should reject outright.

Q. SHOULD UHL&P RECEIVE NO PROFIT WHATEVER FROM OFF-SYSTEM SALES?

A. No. UHL&P should have some incentive to maximize the utilization of these plants, and to provide this incentive, it should be allowed to retain a percentage of the profits from off-system sales. However, given that retail ratepayers are covering all the costs of these plants, that percentage should be quite small, on the order of 10 percent.

<u>APPLICATION ITEM 5 – DEVIATION FROM AFFILIATE TRANSACTION PRICING REQUIREMENTS</u>

Q. WHAT IS THIS ITEM?

A. Mr. Ficke describes this item as a request for "a deviation from the affiliate transaction pricing requirements embodied in Chapter 278 of the Kentucky Revised Statutes for certain fuel- related affiliate agreements."

Q. DOES ANY UHL&P WITNESS DISCUSS THIS ITEM?

A. No. Mr. Mason describes CC&G's coal purchasing procedures and Mr. Roebel discusses the purchase of gas and propane. Neither these witnesses nor any other discuss the need to deviate from Kentucky's affiliate transaction requirements.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THIS ITEM?

A. I have none at this point. However, absent further explanation from the Company, the Commission should dismiss this item.

APPLICATION ITEM 6 – FILING OF IRP

Q. PLEASE DESCRIBE THIS ITEM.

A. UHL&P requests that the-Commission prescribe that the next Integrated Resource Plan ("IRP") be filed within three years of the Commission's final order in this proceeding.

Q. WHY IS THIS ITEM NECESSARY?

A. As a condition of its approval of ULH&P's current power sales agreement with CG&E, the Commission prescribed that the Company file a stand-alone IRP by June 2004. ULH&P now requests that this filing be deferred until three years after the Commission's decision in this case, which would be a deferral of about 2½ years.

Q. WHAT IS YOUR RECOMMEND WITH RESPECT TO THIS ITEM?

A. I agree that if ULH&P will commit to freezing its generation and transmission rates until 2007, the need for a revised IRP diminishes. However, the deferral requested by the Company is too long. A new IRP should be produced and reviewed by the Commission prior to the rate case that will commence in 2006 to set rates on January 1, 2007. That is because the IRP affects some elements in the rate case, such as the recovery of demand-side management and conservation costs. The Company's proposed deferral would have the IRP filed in late 2006, after the rate case is well under way. Not only would this filing be too late to be considered in the rate case, but it is unlikely that the Commission would be able to give the IRP the attention it deserves if it is simultaneously conducting a major ULH&P rate case.

Accordingly, I recommend that the new IRP be filed by June 30, 2005. That would allow it to be reviewed prior to the initiation of the rate case.

APPLICATION ITEM 7 – TRANSFER OF PLANTS BACK TO CG&E

Q. PLEASE DESCRIBE THIS ITEM.

A. UHL&P proposes that if it does not receive the rate treatment proposed by Mr. Turner in the 2006 rate case, the Company be permitted to transfer the plants back to CG&E.

Q. WHAT IS YOUR RESPONSE TO THIS PROPOSAL?

This proposal should be rejected. It appears that UHL&P does not trust the Commission to keep its word. Even if the Commission provides the requested assurances in this proceeding that the net book value of the plants, the costs of the power purchase agreements, and the transaction costs will all be incorporated into the revenue requirement in the next rate case, the Company apparently anticipates that the Commission will forsake those commitments when it comes to setting rates for January 1, 2007. Against that possibility. the Company would like the opportunity to transfer the plants back to CG&E.

This provision is altogether unnecessary. While it is true the current Commission cannot bind future Commissions, it is inconceivable that the 2006 Commission would disregard commitments made in this proceeding. The regulatory system is filled with commitments from one period to another. Many "regulatory assets" consist of expenses incurred by utilities in one period and recovered from ratepayers in another. All utility investment is essentially made in the expectation that regulators will permit recovery of and on the capital invested over the future life of the plant.

Moreover, the Company has not identified who should determine whether the Commission's commitments are fulfilled or broken. If this provision is adopted, then ULH&P could have effective veto power over the Commission's January 1, 2007 rate award. If the Company does not like the Commission's decision, it will switch its plants back to CG&E, and the Commission will have to live with whatever power purchase arrangement the two affiliated companies come up with.

The Company must make its judgment whether to proceed with the asset transfer based on the results of this proceeding. If it finds the Commission's commitments acceptable, then it should proceed with the transaction trusting that the Commission will keep its word. If the Commission's response in this case is not to the Company's liking, then it should withdraw its application. It should not be allowed to await the 2006 rate case to decide whether it wishes to change its mind.

I recommend that this provision be rejected.

APPLICATION ITEM 8 – TERMINATION OF THE EXISTING PPA

Q. PLEASE DESCRIBE THIS ITEM.

A. The existing power purchase agreement is based on the proposition that CG&E provides all power supply to ULH&P. This condition will not exist when the plants are transferred. For this reason the Company requests that the current PPA be terminated.

Q. DO YOU RECOMMEND THAT THIS ITEM BE ACCEPTED?

A. If the transfer of the pants is approved, I do.

CONDITION NO 1a – NET BOOK COST IN THE RATE BASE

Q. PLEASE DESCRIBE THIS CONDITION.

A. Mr. Turner states that as a condition for the transfer of the plants from CG&E to ULH&P, the net book value of those plants must be recognized and incorporated into the rate base in any future rate proceedings.

Q. WHAT IS YOUR RESPONSE TO THIS CONDITION?

A. As a general proposition, the Company's request is reasonable. The conventional regulatory treatment of generating plants -- indeed, all utility plant – is to incorporate them into the rate base at net book value. For this reason, I recommend that this condition be accepted.

In making this recommendation, I do not necessarily endorse the Company's perception of what constitutes net book value. In particular, there is a considerable difference of opinion as to whether unamortized investment tax credits and accumulated deferred income taxes should be netted against original investment in developing net book value. Acceptance of this condition should not be presumed to be a prejudgment of these issues.

CONDITION 1b – RECOVERY OF TRANSACTION COSTS

Q. PLEASE DESCRIBE THIS CONDITION.

A. Mr. Turner states that, as a condition of the transfer of the plants, the Company would like a commitment from the Commission that transaction costs associated with the transfer will be deferred for recovery in the next general rate case.

Q. HAVE YOU ALREADY ADDRESSED THIS ISSUE?

A. Yes, I have. I have recommended that this condition be accepted with the proviso that any excess profits generated by the plants during the rate freeze period be applied against the deferred transaction costs.

CONDITION NO. 2 – INCLUSION OF PPA CAPACITY CHARGES IN BASE RATES

Q. PLEASE DESCRIBE THIS CONDITION.

A. Mr. Turner states that, as a condition of the asset transfer, the Company would like a commitment from the Commission that the capacity charges contained in the FERC-approved back-up power agreement and the PSOA should be incorporated into base retail rates in the next rate proceeding.

Q. IS THIS CONDITION REASONABLE?

A. Yes, it is. Capacity charges represent resource commitments by the utility to ratepayers. They are fixed over a period of time and do not vary with market conditions. They are therefore appropriate for inclusion in base rates. It is my understanding that if they are approved by FERC, then this Commission has no authority to modify or reject them.

CONDITION NO. 3 – INCLUSION OF BACK-UP ENERGY IN THE FAC

Q. PLEASE DESCRIBE THIS CONDITION.

A. Mr. Turner would like a commitment from the Commission that the energy charges in the back-up purchase power agreement with CG&E will be incorporated into ULH&P's Fuel Adjustment Charge when the Commission sets rates for January 1, 2007.

Q. IS THIS A REASONABLE CONDITION?

A. Yes, it is. Back-up energy will be used when the ULH&P generating plants are unavailable. This energy is thus a substitute for that provided by ULH&P's own plants. Since the variable cost of ULH&P's energy will be collected through the Fuel Adjustment Charge, this substitute energy cost should be recovered in that charge as well.

CONDITION NO. 4 – INCLUSION OF PSOA ENERGY IN THE FAC

Q. PLEASE DESCRIBE THIS CONDITION.

A. Mr. Turner would like a commitment from the Commission that all costs of energy transfers from CG&E under the PSOA on a going forward basis from January 1, 2007 will be recovered in ULH&P's Fuel Adjustment Charge.

Q. IS THIS A REASONABLE CONDITION?

A. It is, provided that credits are passed through the Fuel Adjustment Charge as well. As described by Mr. McCarthy, the PSOA contains provisions that "settle" the cost of power among the various members of the CG&E/PSI power pool. When ULH&P is receiving power from the pool member at a cost less than that of its generating units, it is obliged to pay the supplier of that power the difference between its cost and that of the ULH&P unit that would have been dispatched were the alternative power not available. Conversely, if ULH&P's units are providing power to another pool member at a cost less than that member's next most efficient resource, then ULH&P receives compensation for the cost difference. If it is appropriate to recover ULH&P payments under this arrangement in the Fuel Adjustment Charge, then it is also appropriate to credit ULH&P's ratepayers for all receipts as well.

With this proviso, I find this condition to be reasonable.

CONDITION NO. 5 – EXLUSION OF ADTIC FROM RATEMAKING

Q. PLEASE DESCRIBE THIS CONDITION.

A. Mr. Turner would like a commitment from the Commission that the transferred Accumulated Deferred Income Tax Credit ("ADTIC") balance relating to the plants will be amortized on ULH&P's books "below the line" and excluded from ratemaking in all future rate cases.

Q. WILL YOU ADDRESS THIS CONDITION?

A. No. This condition is addressed in the accompanying testimony of Michael J. Majoros, Jr.

Q. WHAT DOES MR. MAJOROS RECOMMEND?

A. Mr. Majoros recommends that this condition be rejected.

CONDITION NO. 6 – EXLUSION OF DEFERRED TAXES FROM RATEMAKING

Q. PLEASE DESCRIBE THIS CONDITION.

A. Mr. Turner would like a commitment from the Commission that the transferred Accumulated Deferred Income Taxes relating to the plants will be excluded from ratemaking in all future rate cases.

Q. WILL YOU ADDRESS THIS CONDITION?

A. No. This condition is addressed in the accompanying testimony of Michael J. Majoros, Jr.

Q. WHAT DOES MR. MAJOROS RECOMMEND?

A. Mr. Majoros recommends that this condition be rejected.

CONDITION NO. 7 – RETENTION OF OFF-SYSTEM SALES PROFITS

Q. PLEASE DESCRIBE THIS CONDITION.

A. Mr. Turner would like a commitment from the Commission that ULH&P will be allowed to retain all profits from off-system sales of power generated by the ULH&P plants.

Q. HAVE YOU ALREADY ADDRESSED THIS CONDITION?

A. Yes, I have in connection with Application Item No. 4, which is the same request.

Q. WHAT WAS YOUR RECOMMENDATION?

A. I recommended that this condition be rejected.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

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ON BEHALF OF

THE OFFICE OF THE ATTORNEY GENERAL
COMMONWEALTH OF KENTUCKY

SEPTEMBER 26, 2003

DIRECT TESTIMONY OF
CHARLES W. KING

INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Charles W. King. I am President of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. PLEASE DESCRIBE SNAVELY KING.

A. Snavely King, formerly Snavely, King & Associates, Inc., was founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. The firm has a professional staff of 15 economists, accountants, engineers and cost analysts. Much of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 33-year history, members of the firm have participated in over 1000 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. Attachment A is a summary of my qualifications and experience.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. Attachment B is 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.

Q. WHAT ISSUES WILL YOU ADDRESS IN YOUR TESTIMONY?

A. I will present the Attorney General's position with respect to the eight items for which Union Light, Heat & Power Company ("ULH&P" or "the Company") seeks approval from the Commission. I will also address the seven conditions that ULH&P witness Turner claims the Company must have before it will consummate the transfer of three plants from the Cincinnati Gas and Electric Company (CG&E) to ULH&P.

SUMMARY OF TESTIMONY

Q. WHAT ARE THE EIGHT ITEMS FOR WHICH THE COMPANY SEEKS APPROVAL FROM THE COMMISSION?

A. Mr. Gregory C Ficke, ULH&P's President, lists the eight items as follows:

1. A Certificate of Public Convenience and Necessity ("CPCN") for ULH&P to acquire CG&E's interest in the East Bend Generating Station, CG&E's Miami Fort Generating Station Unit 6, and CG&E's Woodsdale Generating Station and approval of a form of Asset Purchase Agreement to effectuate such an acquisition;
2. Approval to defer for future recovery the transaction costs Cinergy will incur as a result of such an acquisition;

3. Approval to enter into certain wholesale power agreements with CG&E to provide firm back-up service to the East Bend and Miami Fort 6 plants during periods of maintenance or forced outages and to provide for joint economic dispatch of the plants;
4. Approval to retain the profits from off-system sales of energy from the plants;
5. A deviation from the affiliate transaction pricing requirements embodied in Chapter 278 of the Kentucky Revised Statutes for certain fuel-related affiliate agreements;
6. Order that ULH&P's next IRP shall be due within three years of the Commission's final order in this proceeding;
7. Approval for ULH&P to transfer the plants back to CG&E if the proposed rate treatment described by Mr. Turner (embodied in the seven conditions) is not afforded ULH&P in future rate proceedings before the Commission, and
8. Authority for ULH&P to terminate its current Power Sale Agreement with CG&E.

Q. WHAT ARE YOUR RECOMMENDATIONS WITH RESPECT TO THESE EIGHT ITEMS?

A. In his testimony, David Brown Kinloch has recommended deferring the determination of whether to approve this Application in full or in part until such time as a full investigation has been made into the alternatives available to ULH&P. I join in that recommendation. But, should the Commission chose to approve item nos. 1, 3 and 8 of this application without further investigation into all available alternatives, then I recommend that item nos. 2 and 6 be accepted with modifications that I will describe and that item nos. 4 and 7 be rejected. I cannot make a recommendation on item no. 5 because it is not adequately explained in ULH&P's filing.

Q WHAT ARE THE SEVEN CONDITIONS THAT MR. TURNER CLAIMS THAT ULH&P REQUIRES IN ORDER TO IMPLEMENT THE PLANT TRANSFER?

A. At page 15-16 of his prefiled testimony, UHL&P witness Turner lists the following conditions for the transfer of asset ownership from CG&E to UHL&P:

1a. That the then current net book value of the plants be included in rate base in any future rate proceedings;

1b. That the transaction costs incurred by Cinergy and its subsidiaries for this transfer be deferred for recovery in ULH&P's future general rate proceedings;

2. That the monthly capacity charges in the Back-up Power Sale Agreement and other agreements between CG&E and ULH&P be included in base rates in any future general rate proceedings;

3. That energy charges under the Back-up Agreement be included in the Fuel Adjustment Clause ("FAC") beginning January 1, 2007;

4. That all energy transfer charges from CG&E assessed under the Purchase, Sale and Operation Agreement ("PSOA") be included in the FAC beginning January 1, 2007;

5. That the transferred accumulated deferred investment tax credit ("ADTIC") be amortized over the life of the plants below the line and excluded from retail ratemaking;

6. That the accumulated deferred federal and state income taxes transferred from GC&E to ULH&P not be considered for ratemaking in any future general rate proceedings; and

7. That ULH&P be allowed to retain all profits from off-system sales from the assets being transferred.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS CONCERNING THESE SEVEN CONDITIONS.

A. Again, I recommend further investigation of options available to ULH&P prior to acceptance of the proposal made in this Application. But, should the Commission choose to approve the Application in part or in full without further investigation, then I recommend that condition nos. 1a, 2, 3, 4 be accepted. I recommend that condition no. 1a be accepted with modifications that I will describe. In accompanying testimony, Michael J. Majoros, Jr. recommends that condition nos. 5 and 6 be rejected, and I recommend that condition no. 7 be rejected.

Q. ARE THE APPLICATION ITEMS AND MR. TURNER'S CONDITIONS MUTUALLY EXCLUSIVE?

A. No. Several of them are duplicative, that is, they are both Application items and conditions that Mr. Turner regards as necessary for the implementation of the asset transfer plan. In those cases, I will address them as Application items and note that they have already been considered when they come up as conditions of the transfer plan.

APPLICATION ITEM 1 – CNCP TO TRANSFER PLANTS

Q. WHAT EVIDENCE DOES THE COMPANY PROVIDE IN SUPPORT OF ITS REQUEST FOR A CPCN TO TRANSFER THREE PLANTS AND TO IMPLEMENT AN ASSET PURCHASE AGREEMENT WITH CG&E?

A. UHL&P witness Diane Jenner presents the results of a series of sensitivity analyses that she purports to demonstrate that the plant transfer program embodied in the Company's application is the most cost-effective relative to the best alternative plans. Her model compared up to 2800 resource expansion plans involving supply-side management combined with new coal, combustion turbine and gas-fired combined cycle plants, accompanied by limited power purchases.

The model ultimately selected three mixes of new plants and power purchases that would best serve UHL&P's load over the coming decades.

Ms. Jenner then compared the Present Value of Revenue Requirements ("PVRR") of these three expansion plans with the PVRR of the Company's proposed asset transfer plan and the PVRR of a full requirements purchased power agreement ("PPA"). Under this last PPA plan, every hour's load would be acquired at the then-applicable market price of power.

The results of Ms. Jenner's analysis are presented on page 26 of her prefiled testimony. They demonstrate that under the base assumptions of her analysis, the Company's proposed asset transfer plan has a PVRR that is $643.5 million, or over 16 percent lower than the next most favorable plan. Ms. Jenner then tested these plans against alternative assumptions as to the price of fuel, the market price of energy, and load growth. While the differences varied depending on the assumptions, the Company's asset transfer plan continued to be more favorable than either the all new construction plans or the full requirements PPA plan.

Q. DO MS. JENNER'S SENSITIVITY STUDIES DEMONSTRATE THAT THE COMPANY'S APPLICATION TO TRANSFER GENERATING ASSETS SHOULD BE APPROVED?

A. No. Ms. Jenner's studies are notable for what they did <u>not</u> study. Ms. Jenner compared the Company's proposal to only two very limited alternatives. The first alternative considers only newly constructed generating facilities. This alternative is almost certain to be less cost-effective than the Company's asset transfer plan because it surrenders the advantage of "sunk costs" in existing plants, even when the PVRR incorporates recovery of the undepreciated value of those plants. The other alternative is a PPA that prices power at the hour market price. This alternative surrenders the benefit of any long-term commitment of a generating resource and so exposes ULH&P to the risk of spot market prices.

Among the alternatives that Ms. Jenner did not analyze is a continuation of the present arrangement whereby CG&E supplies ULH&P's full power requirements at a fixed capacity and a fixed energy rate. While the current contract between ULH&P and CG&E is due to expire on December 31, 2006, no Company witness has suggested that it could not be renewed.

Q. DO YOU BELIEVE THAT CONTINUATION OF THE PRESENT PPA WOULD BE THE LEAST COST ALTERNATIVE FOR ULH&P'S POWER SUPPLY?

A. Not necessarily. It is possible that extension of the current contract arrangement would not yield the lowest PVRR were it compared with the Company's proposed asset transfer plan. That is because the fixed price full requirements plan passes back to CG&E the risks of market price fluctuations and of weather-driven load variations. CG&E would have to build allowances for these risks into its capacity and energy charges that might drive up the PVRR of this plan.

Q. ARE THERE ALTERNATIVES THAT MIGHT YIELD LOWER COSTS THAN EITHER THE PRESENT PPA OR THE COMPANY'S ASSET TRANSFER PLAN?

A. Possibly. ULH&P and CG&E might agree to a PPA that contains a fixed capacity charge that would reflect the optimal mix of CG&E's much larger fleet of generating assets serving UHL&P's load. This fixed capacity charge would be accompanied by a variable energy charge that would reflect the fuel and variable operating expenses of the hourly mix of plants and power purchases in CG&E/PSI power pool.

This alternative arrangement would avoid most of the weaker aspects of the energy transfer and the market price PPA plans, and yet still provide ULH&P

with reliable power at a price reflecting the underlying costs of the optimal mix of assets required to provide that power.

Compared to the asset transfer plan, this arrangement would avoid the "lumpiness" problem created by the fact that only three units, with capacities of 500, 414 and 163 MW respectively, would be committed to serving a peak load of only 800 MW. These units collectively provide 5 percent more capacity than ULH&P initially requires, and the two baseload units must be backed up by commitments from CG&E equivalent to their entire capacities. If CG&E were to commit capacity appropriate for ULH&P's load out of its much larger fleet of generating assets, there would be no need for ULH&P to overbuy capacity, nor would it be necessary for ULH&P to acquire fully redundant backup capacity .

Compared to a market price PPA, this arrangement would be less expensive and much less subject to price fluctuations. Rather than paying the market price of energy, which presumably equates to the hourly marginal cost of the CG&E/PSI power pool, ULH&P would pay energy charges reflecting the composite energy cost of all units in service in each hour: effectively the "embedded" energy cost. This is a much lower and more stable number than the market price of power.

Q. DO YOU THEREFORE RECOMMEND THAT THE COMMISSION REJECT THE ASSET TRANSFER PLAN IN FAVOR OF THE PPA ARRANGEMENT YOU HAVE JUST DESCRIBED?

A. Not necessarily. The Commission has previously expressed its preference for the "iron in the ground" alternative. There are certain advantages to this plan that are unrelated to cost. Specifically, the acquisition by ULH&P of specific generating assets brings back under the Commission jurisdiction the full provision of electric power to the Company's Kentucky ratepayers. The Commission would not have to rely on the Federal Energy Regulatory Commission ("FERC") to protect the interests of Kentucky ratepayers with respect to power supply.

This advantage applies not only to the regulation of electric rates but to the Commission's oversight of the Company's Integrated Resource Plan ("IRP"). Without the generation function under the Commission's authority, the Commission can oversee only the demand-side aspects of that plan. The supply-side aspects fall principally under FERC jurisdiction.

Q. WHAT, THEN, IS THE RELEVANCE OF YOUR DISCUSSION OF AN ALTERNTIVE PPA BETWEEN ULH&P AND CG&E?

A. The relevance goes to the Commission's response to the terms and conditions posed by the Company in its application. ULH&P's application purports to present an all-or-nothing choice between its asset transfer plan, complete with conditions, and the alternative of throwing its power supply open to the mercy of the competitive market for energy. This stark choice completely overlooks the fact that the source of market-based energy is ULH&P's own parent, CG&E. ULH&P purports to absolve its parent, CG&E, of any public utility responsibilities. If ULH&P does not generate electricity for its ratepayers, CG&E has no responsibility to do so, at least according to ULH&P.

Whether and how the Commission can force CG&E to provide power to ULH&P at cost-based rates is a legal issue which I am not qualified to address. The resolution of that issue determines the extent to which the Commission should or should not be intimidated by the terms and conditions in ULH&P's application. Assuming that the Commission need not believe that unless it accepts all of the conditions spelled out by ULH&P, the Company's Kentucky ratepayers will lose the protection of regulated power supply costs. The following review of these terms and conditions will identify several that should be rejected outright. Such rejection should not be considered as tantamount to rejection the entire asset transfer plan.

APPLICATION ITEM 2 – DEFERRAL OF TRANSACTION COSTS

Q. WHAT ARE THE TRANSACTION COSTS TO WHICH THIS ITEM REFERS?

A. ULH&P President Gregory Ficke states that transaction costs will be incurred by CG&E and ULH&P in order to effectuate the transfer of assets. CG&E will incur income and property taxes and financing-related costs related to the redemption of debt and release of certain assets from its mortgage. ULH&P has already incurred costs associated with the preparation of this filing, and it anticipates additional costs relating to tax matters and financing. Mr. Steffan's Attachment JPS-7 presents the Company's estimates of these costs. They come to $4,865,000.

Q. WHAT TREATMENT DOES THE COMPANY PROPOSE FOR THESE COSTS?

A. ULH&P proposes that these transaction costs, whatever they are, be deferred for recovery in the next rate case, which presumably would set rates for the period after January 1, 2007. Although the Company does not say so, I presume that it would expect to receive compensation for the deferral in the form of a compounding carrying charge.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THESE TRANSACTION COSTS?

A. I recommend that these costs be deferred and recovered, but not necessarily until the next rate case. During the interim between ULH&P's acquisition of the three plants and the January 1, 2007 resetting of retail rates, the Company will be free to earn as much from these three plants as it can under the frozen rates. If the plants generate profits in excess of a reasonable rate of return, then I recommend that the excess profits be applied against the recovery of transaction costs.

Hopefully, this approach will reduce, possibility eliminate the burden of these costs on ratepayers after January 1, 2007.

Q. HOW WOULD THIS PROPOSAL TO APPLY PLANT PROFITS TO TRANSACTIONS COSTS WORK?

A. The Company would book transaction costs in a deferred asset account exactly as it proposes. Between the transfer date and the January 1, 2007 rate proceeding (presumably conducted in 2006), there would be no reduction in this regulatory asset account. As part of the rate case, the Commission would conduct a retrospective analysis of the plants' sales and costs, inclusive of a reasonable rate of return and associated income taxes, to determine whether there were any excess profits earned during the three-year rate freeze period. The applicable revenue in this analysis would include <u>both</u> retail revenues and net revenues from off-system sales.

To the extent that the Commission finds that the plants generated excess revenue over their revenue requirement, that excess would be applied to offset the accumulated transaction costs. If excess profits do not offset the transaction costs, then the residual unrecovered balance would be amortized into rates over a reasonable period after January 1, 2007. If the excess profits exceed the transaction costs, then the deferred asset would be considered fully recovered, and the Company would be allowed to retain any further excess profits.

Hopefully, this procedure will minimize, and possibly eliminate the need to include transaction costs in the January 1, 2007 rates.

<u>APPLICATION ITEM 3 – WHOLESALE POWER AGREEMENTS</u>

Q. PLEASE DESCRIBE THE WHOLESALE POWER AGREEMENTS INCLUDED IN THIS ITEM.

A. There are two wholesale power agreements between ULH&P and CG&E. The first is the Back-up Power Sales Agreement ("Back-up PSA") that commits CG&E to provide back-up power to UHL&P whenever there are planned or unplanned outages at the East Bend or Miami Fort 6 plants. The second is the Purchase, Sales and Opēration Agreement ("PSOA") that accommodates joint economic dispatch of UHL&P's plants in conjunction with the fleet of plants operated by CG&E and PSI Energy.

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THIS ITEM?

A. These wholesale power agreements are necessary to ensure the reliability of power supply to UHL&P's Kentucky customers at the lowest cost possible within the construct of the transferred asset plan. Accordingly, they probably should be approved, although not necessarily by this Commission. The ultimate authority to approve these contracts lies with FERC, not this Commission. Unless the Commission and its staff can conduct an informed and expert examination of these contracts, their approval should probably be left to FERC, which has the necessary experience and expertise to evaluate wholesale contracts.

APPLICATION ITEM 4 – RETENTION OF PROFITS FROM OFF-SYSTEM SALES

Q. WHAT JUSTIFICATION DOES UHL&P OFFER FOR THIS ITEM?

A. Mr. Turner testifies that this item is appropriate "because of the significant value that ULH&P's customers are realizing in acquiring 'iron in the ground' at a net book value that is less than potential market value."

Q. IS THIS A VALID BASIS FOR ALLOWING ULH&P TO RETAIN OFF-SYSTEM PROFITS?

A. No, it is not. In return for surrendering these plants to regulation at net book value, CG&E gets something in return. That is the assurance provided by regulation that all expenses associated with these plants will be covered, that every cent of investment in them will be recaptured, and that in the meantime they will yield fair and reasonable after-tax return on all outstanding investment.

These are assurances that unregulated plants do not have, and they should not be taken lightly. In recent months, Mirant and NRG Energy have declared Chapter 11 bankruptcy, even though they both own "hard" generating assets. The much reduced risk of regulated generation relative to unregulated merchant generation justifies some apparent sacrifice on the part of CG&E. In this case, the sacrifice should take the form of foregone sale value from its UHL&P plants.

Q. SHOULD THIS ITEM OF THE APPLICATION BE APPROVED?

A. Absolutely not. UHL&P will be asking its retail customers to compensate it for all expenses associated with these plants, for the recovery of capital, and for a fair and reasonable post-tax rate of return. In short, ratepayers will fully support these plants. For this reason, ratepayers should be entitled to the earnings these plants generate. If ULH&P were to retain the profits from off-system sales from these plants, then ULH&P should be obliged to cover a portion of the fixed operating and capital costs of the plants. Otherwise, the arrangement is tantamount to granting the Company a supra-competitive rate of return.

Additionally, the arrangement would be asymmetrical. UHL&P expects ratepayers to absorb the cost of off-system purchases when CG&E's generating resources are short, but it proposes to pocket the profits from off-system sales when CG&E is long. This is clearly a one-sided, heads-I-win-tails-you-lose arrangement that the Commission should reject outright.

Q. SHOULD UHL&P RECEIVE NO PROFIT WHATEVER FROM OFF-SYSTEM SALES?

A. No. UHL&P should have some incentive to maximize the utilization of these plants, and to provide this incentive, it should be allowed to retain a percentage of the profits from off-system sales. However, given that retail ratepayers are covering all the costs of these plants, that percentage should be quite small, on the order of 10 percent.

APPLICATION ITEM 5 – DEVIATION FROM AFFILIATE TRANSACTION PRICING REQUIREMENTS

Q. WHAT IS THIS ITEM?

A. Mr. Ficke describes this item as a request for "a deviation from the affiliate transaction pricing requirements embodied in Chapter 278 of the Kentucky Revised Statutes for certain fuel- related affiliate agreements."

Q. DOES ANY UHL&P WITNESS DISCUSS THIS ITEM?

A. No. Mr. Mason describes CC&G's coal purchasing procedures and Mr. Roebel discusses the purchase of gas and propane. Neither these witnesses nor any other discuss the need to deviate from Kentucky's affiliate transaction requirements.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THIS ITEM?

A. I have none at this point. However, absent further explanation from the Company, the Commission should dismiss this item.

APPLICATION ITEM 6 – FILING OF IRP

Q. PLEASE DESCRIBE THIS ITEM.

A. UHL&P requests that the-Commission prescribe that the next Integrated Resource Plan ("IRP") be filed within three years of the Commission's final order in this proceeding.

Q. WHY IS THIS ITEM NECESSARY?

A. As a condition of its approval of ULH&P's current power sales agreement with CG&E, the Commission prescribed that the Company file a stand-alone IRP by June 2004. ULH&P now requests that this filing be deferred until three years after the Commission's decision in this case, which would be a deferral of about 2½ years.

Q. WHAT IS YOUR RECOMMEND WITH RESPECT TO THIS ITEM?

A. I agree that if ULH&P will commit to freezing its generation and transmission rates until 2007, the need for a revised IRP diminishes. However, the deferral requested by the Company is too long. A new IRP should be produced and reviewed by the Commission prior to the rate case that will commence in 2006 to set rates on January 1, 2007. That is because the IRP affects some elements in the rate case, such as the recovery of demand-side management and conservation costs. The Company's proposed deferral would have the IRP filed in late 2006, after the rate case is well under way. Not only would this filing be too late to be considered in the rate case, but it is unlikely that the Commission would be able to give the IRP the attention it deserves if it is simultaneously conducting a major ULH&P rate case.

Accordingly, I recommend that the new IRP be filed by June 30, 2005. That would allow it to be reviewed prior to the initiation of the rate case.

APPLICATION ITEM 7 – TRANSFER OF PLANTS BACK TO CG&E

Q. PLEASE DESCRIBE THIS ITEM.

A. UHL&P proposes that if it does not receive the rate treatment proposed by Mr. Turner in the 2006 rate case, the Company be permitted to transfer the plants back to CG&E.

Q. WHAT IS YOUR RESPONSE TO THIS PROPOSAL?

This proposal should be rejected. It appears that UHL&P does not trust the Commission to keep its word. Even if the Commission provides the requested assurances in this proceeding that the net book value of the plants, the costs of the power purchase agreements, and the transaction costs will all be incorporated into the revenue requirement in the next rate case, the Company apparently anticipates that the Commission will forsake those commitments when it comes to setting rates for January 1, 2007. Against that possibility. the Company would like the opportunity to transfer the plants back to CG&E.

This provision is altogether unnecessary. While it is true the current Commission cannot bind future Commissions, it is inconceivable that the 2006 Commission would disregard commitments made in this proceeding. The regulatory system is filled with commitments from one period to another. Many "regulatory assets" consist of expenses incurred by utilities in one period and recovered from ratepayers in another. All utility investment is essentially made in the expectation that regulators will permit recovery of and on the capital invested over the future life of the plant.

Moreover, the Company has not identified who should determine whether the Commission's commitments are fulfilled or broken. If this provision is adopted, then ULH&P could have effective veto power over the Commission's January 1, 2007 rate award. If the Company does not like the Commission's decision, it will switch its plants back to CG&E, and the Commission will have to live with whatever power purchase arrangement the two affiliated companies come up with.

The Company must make its judgment whether to proceed with the asset transfer based on the results of this proceeding. If it finds the Commission's commitments acceptable, then it should proceed with the transaction trusting that the Commission will keep its word. If the Commission's response in this case is not to the Company's liking, then it should withdraw its application. It should not be allowed to await the 2006 rate case to decide whether it wishes to change its mind.

I recommend that this provision be rejected.

APPLICATION ITEM 8 – TERMINATION OF THE EXISTING PPA

Q. PLEASE DESCRIBE THIS ITEM.

A. The existing power purchase agreement is based on the proposition that CG&E provides all power supply to ULH&P. This condition will not exist when the plants are transferred. For this reason the Company requests that the current PPA be terminated.

Q. DO YOU RECOMMEND THAT THIS ITEM BE ACCEPTED?

A. If the transfer of the pants is approved, I do.

CONDITION NO 1a – NET BOOK COST IN THE RATE BASE

Q. PLEASE DESCRIBE THIS CONDITION.

A. Mr. Turner states that as a condition for the transfer of the plants from CG&E to ULH&P, the net book value of those plants must be recognized and incorporated into the rate base in any future rate proceedings.

Q. WHAT IS YOUR RESPONSE TO THIS CONDITION?

A. As a general proposition, the Company's request is reasonable. The conventional regulatory treatment of generating plants -- indeed, all utility plant – is to incorporate them into the rate base at net book value. For this reason, I recommend that this condition be accepted.

In making this recommendation, I do not necessarily endorse the Company's perception of what constitutes net book value. In particular, there is a considerable difference of opinion as to whether unamortized investment tax credits and accumulated deferred income taxes should be netted against original investment in developing net book value. Acceptance of this condition should not be presumed to be a prejudgment of these issues.

CONDITION 1b – RECOVERY OF TRANSACTION COSTS

Q. PLEASE DESCRIBE THIS CONDITION.

A. Mr. Turner states that, as a condition of the transfer of the plants, the Company would like a commitment from the Commission that transaction costs associated with the transfer will be deferred for recovery in the next general rate case.

Q. HAVE YOU ALREADY ADDRESSED THIS ISSUE?

A. Yes, I have. I have recommended that this condition be accepted with the proviso that any excess profits generated by the plants during the rate freeze period be applied against the deferred transaction costs.

CONDITION NO. 2 – INCLUSION OF PPA CAPACITY CHARGES IN BASE RATES

Q. PLEASE DESCRIBE THIS CONDITION.

A. Mr. Turner states that, as a condition of the asset transfer, the Company would like a commitment from the Commission that the capacity charges contained in the FERC-approved back-up power agreement and the PSOA should be incorporated into base retail rates in the next rate proceeding.

Q. IS THIS CONDITION REASONABLE?

A. Yes, it is. Capacity charges represent resource commitments by the utility to ratepayers. They are fixed over a period of time and do not vary with market conditions. They are therefore appropriate for inclusion in base rates. It is my understanding that if they are approved by FERC, then this Commission has no authority to modify or reject them.

CONDITION NO. 3 – INCLUSION OF BACK-UP ENERGY IN THE FAC

Q. PLEASE DESCRIBE THIS CONDITION.

A. Mr. Turner would like a commitment from the Commission that the energy charges in the back-up purchase power agreement with CG&E will be incorporated into ULH&P's Fuel Adjustment Charge when the Commission sets rates for January 1, 2007.

Q. IS THIS A REASONABLE CONDITION?

A. Yes, it is. Back-up energy will be used when the ULH&P generating plants are unavailable. This energy is thus a substitute for that provided by ULH&P's own plants. Since the variable cost of ULH&P's energy will be collected through the Fuel Adjustment Charge, this substitute energy cost should be recovered in that charge as well.

CONDITION NO. 4 – INCLUSION OF PSOA ENERGY IN THE FAC

Q. PLEASE DESCRIBE THIS CONDITION.

A. Mr. Turner would like a commitment from the Commission that all costs of energy transfers from CG&E under the PSOA on a going forward basis from January 1, 2007 will be recovered in ULH&P's Fuel Adjustment Charge.

Q. IS THIS A REASONABLE CONDITION?

A. It is, provided that credits are passed through the Fuel Adjustment Charge as well. As described by Mr. McCarthy, the PSOA contains provisions that "settle" the cost of power among the various members of the CG&E/PSI power pool. When ULH&P is receiving power from the pool member at a cost less than that of its generating units, it is obliged to pay the supplier of that power the difference between its cost and that of the ULH&P unit that would have been dispatched were the alternative power not available. Conversely, if ULH&P's units are providing power to another pool member at a cost less than that member's next most efficient resource, then ULH&P receives compensation for the cost difference. If it is appropriate to recover ULH&P payments under this arrangement in the Fuel Adjustment Charge, then it is also appropriate to credit ULH&P's ratepayers for all receipts as well.

With this proviso, I find this condition to be reasonable.

CONDITION NO. 5 – EXLUSION OF ADTIC FROM RATEMAKING

Q. PLEASE DESCRIBE THIS CONDITION.

A. Mr. Turner would like a commitment from the Commission that the transferred Accumulated Deferred Income Tax Credit ("ADTIC") balance relating to the plants will be amortized on ULH&P's books "below the line" and excluded from ratemaking in all future rate cases.

Q. WILL YOU ADDRESS THIS CONDITION?

A. No. This condition is addressed in the accompanying testimony of Michael J. Majoros, Jr.

Q. WHAT DOES MR. MAJOROS RECOMMEND?

A. Mr. Majoros recommends that this condition be rejected.

CONDITION NO. 6 – EXLUSION OF DEFERRED TAXES FROM RATEMAKING

Q. PLEASE DESCRIBE THIS CONDITION.

A. Mr. Turner would like a commitment from the Commission that the transferred Accumulated Deferred Income Taxes relating to the plants will be excluded from ratemaking in all future rate cases.

Q. WILL YOU ADDRESS THIS CONDITION?

A. No. This condition is addressed in the accompanying testimony of Michael J. Majoros, Jr.

Q. WHAT DOES MR. MAJOROS RECOMMEND?

A. Mr. Majoros recommends that this condition be rejected.

CONDITION NO. 7 – RETENTION OF OFF-SYSTEM SALES PROFITS

Q. PLEASE DESCRIBE THIS CONDITION.

A. Mr. Turner would like a commitment from the Commission that ULH&P will be allowed to retain all profits from off-system sales of power generated by the ULH&P plants.

Q. HAVE YOU ALREADY ADDRESSED THIS CONDITION?

A. Yes, I have in connection with Application Item No. 4, which is the same request.

Q. WHAT WAS YOUR RECOMMENDATION?

A. I recommended that this condition be rejected.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

[redacted]

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In the Matter of :

APPLICATION OF THE GEORGIA)
POWER COMPANY TO INCREASE)
THE FUEL COST RECOVERY ALLOWANCE)
PURSUANT TO O.C.G.A. § 46-2-26)

DOCKET NO. 17066-U

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DIRECT TESTIMONY AND EXHIBITS

OF

CHARLES W. KING

ON BEHALF OF

THE COMMISSION ADVERSARY STAFF

JULY 21, 2003

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DIRECT TESTIMONY OF
CHARLES W. KING

I. Introduction

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

A. My name is Charles W. King. I am President of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. Please describe Snavely King.

A. Snavely King, formerly Snavely, King & Associates, Inc., was founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. The firm has a professional staff of 12 economists, accountants, engineers and cost analysts. Most of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 33-year history, members of the firm have participated in over 1,000 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Adversary Staff of the Georgia Public Service Commission ("Adversary Staff").

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

A. Yes. Attachment 1 is a summary of my qualifications and experience.

Q. Have you previously submitted testimony in regulatory proceedings?

A. Yes. Attachment 2 is a tabulation of my appearances as an expert witness before state and federal regulatory agencies.

Q. What is the objective of your testimony?

A. The objective of my testimony is to present the Adversary Staff's evaluation of the application of the Georgia Power Company ("Georgia Power" or "the Company") for a revision in its Fuel Cost Recovery ("FCR") rate and to recommend an alternative rate if it appears appropriate.

II. Summary

Q. What FCR rate does the Company propose?

A. Georgia Power proposes to increase the average FCR rate from its current (FCR-15) level of 1.6766 cents per kWh to a new (FCR-16) rate of 1.8348 cents per kWh.

Q. What are the components of this new rate?

A. There are two components. The first is 1.6376 cents per kWh to recover the costs of fuel and net purchased power that the Company projects it will incur during the 12-month period ending August 31, 2004. The second is the recovery, over a 12-month period, of $157,111,000 in fuel costs that the Company has claimed it will have under-recovered as of August 31, 2003. This recovery of deferred costs accounts for 0.1972 cents per kWh.

Q. What FCR rate does the Adversary Staff recommend?

A. The Adversary Staff recommends an average FCR rate of 1.8112 cents per kWh for the 12-month period ending August 31, 2004. This rate consists of 1.6338 cents for forecast fuel and purchase power costs and .1774 cents to recover prior period under-recoveries.

Q. What accounts for the .0236 cent per kWh difference between the average FCR rate sought by the Company and that recommended by the Adversary Staff?

A. The following elements account for the difference between the Company's and the Adversary Staff's recommended FCR rate:

- Disallowance of $13,436,679 plus carrying charges for the added costs imposed by a series of unplanned outages at Plant Vogtle in late November and early December 2002;
- Reduction of the equity portion of the composite cost of capital used as the carrying charge prior to August 2003 from 12.5 percent to 11.475 percent; and
- Reduction of the carrying charge rate going forward beginning September 2003 from the Company's composite cost of capital to its cost of short-term credit.

III. Plant Vogtle Outages

Q. What are the Vogtle plant outages to which you have referred?

A. On November 24, 2002, the two Vogtle nuclear units were shut down, and for the next three weeks they scarcely operated. Between November 24 and December 17, 2002, Unit 1 was totally out of service 179 hours and partially out of service another 78 hours. Unit 2 was totally out of service 435 hours and partially out of service another 123 hours. This means that Unit 1 was either totally or partially down 11 out of the 26 days during this period, and Unit 2 was out of service, either totally or partially, 24 out of the 26 days. Exhibit_____(CWK-1) is a summary of these outages.

Q. What was the cause of these outages?

A. I have attached two reports submitted by the Company in response to STF-5-7, Docket Number 13711-U, pertaining to these outages. The first, which I have labeled Exhibit_____(CWK-2), is an Event Report titled "Wrong Chemicals Added to Feedwater System Causes Dual Unit Shutdown." This report was submitted electronically on December 11, 2002 to the Institute of Nuclear Power Operations. The second page describes the cause:

> The root cause of this event was the failure of the supervisor to obtain the correct procedure for the evolution. The pre-job briefing focused on forklift safety and other safety aspects of the activity and not on the critical aspects of the task. The process of ensuring that the correct chemical was obtained was not discussed. Although a procedure specifying the correct chemical number and brand did exist, involved personnel stated that they were not aware of the procedure, nor did they question the need for a procedure to perform the activity.

The second report, labeled Exhibit_____(CWK-3), is the Nuclear Regulatory Commission's "Problem Identification and Resolution Report," dated January 3, 2003. Page 4 contains the following conclusion:

> The root causes for two unit trips and the dual unit shutdown were similar. This included procedural non compliances (not following the procedure or unaware of procedure existence) and weak supervisory oversight. The oversight weaknesses included missed or weak pre-job briefings, conducting risk significant activities in parallel, weak command and control, and poor communications. While some initiatives had been implemented, the licensee had not yet achieved positive results from their corrective actions.

Q. What is the relevance of these conclusions to the FCR?

A. The NRC concluded that poor management was the root cause of these outages. Georgia Power should not be permitted to pass through to ratepayers the added costs that result from the inadequacies of management. Due to management's clearly imprudent conduct in failing to properly manage Plant Vogtle to avoid the series of unplanned outages that occurred in late November and early December 2002, I recommend that Georgia Power bear the added fuel and purchased power costs to replace the energy that this plant could have produced.

Q. Have you calculated the added fuel and purchased power costs associated with the outages of the two Vogtle plants?

A. Yes. Nuclear units are very expensive to build but quite cheap to run. Indeed, the added cost to operate the Vogtle units is only about 0.4 cents per kWh, consisting entirely of nuclear fuel. For this reason, the Vogtle units should operate all of the time except when taken out of service for refueling or scheduled maintenance. When they are not operating, other more expensive generating plants must provide the power that the Vogtle plants would otherwise provide. Not just the substitute base load plants, but all plants in the system must move up on the economic dispatch schedule. When nuclear base load units are not operating, other low-cost base load units cannot handle the base load, so more expensive cycling plants fill in. When the cycling plants are not available, very expensive peaker plants must provide the cycling power. The entire chain of generating resources moves from less expensive to more expensive generation. Since Plant Vogtle has the lowest variable cost of any generating resource available to Georgia Power, when it goes out, every kWh on the system becomes more expensive to produce.

The measure of the cost of losing generating resources at any given time is the "system lambda." The system lambda reflects the most expensive generating resource required to serve the load on the system at any given hour. The measure of the cost of losing any generating resource is the difference between that resource's marginal operating cost and the system lambda.

To compute the cost of the lost Vogtle generating capability, I have multiplied the lost capacity of each Vogtle unit during its outage by the difference between the unit's hourly fuel cost and the system lambda during that hour. During off-peak hours, this differential is relatively low; during peak hours it is quite high. Fortunately, the Vogtle outages occurred in late November and early December when the system load was relatively moderate and the lambdas not particularly high.

I have set forth the cost of each outage in the final column of Exhibit _____(CWK-1). Total costs for the Vogtle Unit 1 outages came to $4,457,055; for Unit 2 outages they were $8,979,624. Total Vogtle outage costs for the period November 24 through December 17 were $13,436,679.

Q. Hasn't the Commission already instituted a Nuclear Performance Standard to reward or penalize Georgia Power for its outage performance?

Q. Yes. However, when the Commission adopted this plan in 1989, it explicitly retained the authority "to exclude any unit from consideration under the performance incentive program for the purpose of performing a separate prudence evaluation."[1] When an independent inspector, in this case the NRC, finds that outages were incurred due to poor management practices, the Commission can properly consider sanctions outside of the Nuclear Performance Standard. If it finds that imprudent management caused unusually high costs, it can override the Nuclear Performance Standard that otherwise would apply.

IV. <u>Carrying Charge – January 2002 through August 2003</u>

[1] Docket No. 3840-U, Second Supplemental Order, September 28, 1989, page 52.

Q. What carrying charge rate has the Company used for its deferred fuel and purchased power costs up to the present?

A. The Company has used a weighted average rate of return. This carrying cost was prescribed in the Commission's December 20, 2001 order in Docket No. 14000-U.

Q. Does the Company use the correct weighted average rate of return in its calculations?

A. No, it does not. The Company uses 12.5 percent as its authorized equity return. In Docket No. 14000-U, the Commission did not adopt a specific rate of return, but rather a range of 10.0 to 12.95 percent. The mid-point of this range is 11.475 percent, more than 100 basis points below that used by Georgia Power. If a point estimate of the equity return must be identified, it should be this mid-point, not 12.5 percent, close to the top of the authorized range.

Q. Have you computed the correct carrying charges?

A. Yes. Column E of Exhibit_____(CWK-5) presents the corrected carrying charges since the Commission's decision in Docket No. 14000-U, insofar as the data are available. I have the used the Company's capital structure, debt cost, and preferred securities and stock costs through February 2003. Since I do not have these data for the period March through August 2003, I have used the February return for these months.

V. Carrying Charge – September 2003 through August 2004

Q. Is the prospective carrying charge after August 2003 an issue in this case?

A. Yes. The Commission made it an issue in its Procedural and Scheduling Order of June 17, 2003 establishing this case.

Q. What principles should govern the determination of a carrying charge?

A. The carrying charge should reflect, as nearly as possible, the financial consequences of two opposite conditions. If there is an under-accrual from the FCR, the carrying charge should match the cost of the capital funds that the Company uses to acquire fuel and purchased power for which it is not immediately paid. If there is an over-accrual, the carrying charge should reflect the financial impact of providing the Company with supplemental funds for a relatively short period of time.

Q. What funds can the Company use to finance deferred fuel costs?

A. The primary source of funds is internally generated cash, which consists broadly, but not exclusively, of three elements: (1) depreciation and amortization expenses that are not accompanied by any corresponding outflows of cash; (2) deferred taxes, that is, the difference between the taxes the Company collects from ratepayers and the taxes it actually pays; and (3) retained earnings, that is, earnings that are not distributed as dividends to the Company's owners.

In Docket No. 15128-U, Georgia Power Company's Application to Issue New Securities, Georgia Power's then Assistant Comptroller Ron Hinson testified on May 28, 2002 that internally generated funds support about 70 percent of the Company's construction program.

After internally generated funds, the Company has access to short term debt. As described by Mr. Hinson in Docket No. 15128-U, Georgia Power borrows from three markets. The first is commercial paper, which is borrowed from dealers such as Merrill Lynch and Lehman Brothers, who in turn resell the paper to investors. The second is extendable commercial paper, a subset of the commercial paper market. Unlike conventional commercial paper, which has fixed maturities, the terms of these securities can be extended for up to a year. The final source of short term debt is variable rate pollution control bonds. These bonds are issued through public agencies, and the earnings are therefore tax-exempt, resulting in very low interest rates.

Finally, the Company has access to long-term capital. It can obtain equity capital infusions from its parent, Southern Company, which in turn can sell more stock in the public stock market, or it can sell additional long-term bonds in its own name.

Q. What is the mix of cash resources available to support the deferred fuel balances?

A. In Docket No 15128-U, the Company provided projected statements of cash flows for the years 2002, 2003 and 2004 as an exhibit to the testimony of Ron Hinson and David Brooks. I attach a copy of this exhibit as Exhibit_____(CWK-4). From this exhibit I calculate the following breakdown of the sources of funds to support the Company's capital additions:

Table 1
Georgia Power Company
Sources of Cash Flows

	2002	2003	2004
Internally Generated Capital			
Retained Earnings	4.2%	-0.9%	-0.6%
Other	66.5%	79.8%	64.2%
New Long-term Debt	30.9%	19.8%	36.8%
Other Financing	-1.6%	1.4%	-0.4%
Total	100.0%	100.0%	100.0%

Source: Exhibit_____(CWK-4)

The table supports Mr. Hinson's statement that about 70 percent of the Company's requirements for new capital are provided by internally generated funds. Those funds, however, are not provided by Georgia Power's parent, the Southern Company, in the form of retained earnings. Indeed, for two out of the three years retained earnings are negative. The detail of the "other financing" in Exhibit____(CWK-4) shows that the parent company was intending to make a negative contribution of new capital in 2002, about a 2.1 percent contribution in 2003, and it promises a 15 percent contribution in 2003.

Neither Exhibit_____(CWK-4) nor Table 1 displays the level of short-term debt, only the net change in that debt from the beginning to the end of the year. Schedule 5 to Georgia Power's June 11, 2003 application for refinancing (approved July 1) shows that on March 31, 2003, short term notes payable were $529,419,000. This amounts to 70 percent of the total new financing needs for the year.

Even this very large balance of short-term debt is only a fraction of the total credit available to the Company. Georgia Power has a "credit facility" with a consortium of about 20 banks from which it can draw up to $1.7 billion in short-term borrowing to back up the three other sources of short-term credit that I described earlier. This credit facility is the right to borrow at any time from a bank and to extend the loan for a two-year period.[2]

Q. What is the source of the funds that Georgia Power uses to cover the under-accruals from the FCR?

A. Except when there are specific uses designated for the funds raised, it is impossible to trace cash across the balance sheet from sources to uses. However, it seems highly improbable that Georgia Power would sell long-term debt or seek equity contributions from its parent to support the under-accrual of fuel costs that

[2] Docket No. 15128-U, Testimony of David Brooks, May 28, 2002, transcript page 29.

it plans to amortize within the next year. Moreover, as noted, the Southern Company is contributing very little in the way of equity capital in Georgia Power. Since this under-accrual is a short-term liability to the Company, it is likely covered either by internally generated funds or by short-term debt.

Q. What would be the financial impact of an over-accrual of FCR revenue relative to cost?

A. If there were an over-accrual from the FCR, the funds received by Georgia Power would offset the Company's need for short-term credit, effectively saving the Company the cost of that type of debt.

Q. What is the cost of short-term debt?

A. On May 28, 2002, David Brooks of Southern Company Services testified that current rates for the Georgia Power's commercial paper were about 1.85 percent and for its pollution control bonds about 1.45 percent.[3]

Q. What do you recommend as the carrying cost of the deferred fuel balances?

A. I recommend the cost of Georgia Power's short-term debt.

Q. Have you quantified this cost?

A. No. I do not have the current cost of Georgia Power's short-term debt, let alone forecasts of that cost over the coming year. For purposes of quantifying the FCR in this testimony, I have used the Federal Reserve's report of interest rates on three-month commercial paper. The average for this series of the most recent twelve months for which data are available (July 2002-June 2003) is 1.40 percent.

[3] Docket No. 15128-U, Transcript of May 28, 2002, page 29.

V. Conclusion

Q. Have you recomputed the deferred fuel and purchased power costs as of August 2003?

A. Yes. Exhibit_____(CWK-5) shows the build-up of the deferred fuel and purchase power balance from June 1, 2001 through August 2004. All of the data except the July and August 2003 figures are taken from the historical FCR reports of Georgia Power. The July and August data are Georgia Power's estimates. The August 31, 2003 deferred fuel balance is an under-recovery of $141,316,771. This figure is $15,793,780 lower than the Company's estimate of $157,110,551 in under-recovery. The difference is entirely due to my recommended disallowance of $13,436,679 for nuclear outage costs and my use of 11.475 percent as the cost of equity in the carrying charge.

Q. How did you compute the going-forward cost of fuel and purchased power from September 2003 through August 2004?

A. I substituted my alternative calculation of the prior period accumulated deferred fuel balance and my alternative carrying cost into the Company's costing model for the FCR. That model produced the 1.6338 cents that I recommend for recovery of prospective fuel and purchased power costs.

Q. How do the components of your recommended FCR compare with those proposed by the Company?

A. The components of the two FCRs can be compared as follows:

Table 2
Components of FCR-16

Component	Georgia Power	Staff
Future Fuel Cost Recovery	1.6376¢	1.6338¢
Prior Period Recovery	0.1972¢	0.1774¢
Total	1.8348¢	1.8112¢

Q. How long should this FCR rate remain in effect?

A. This rate, which is numbered FCR-16, should remain in effect only through August 2004. By the end of May 2004, the Company should be required to file for a new FCR-17 to take effect September 1, 2004.

Q. Why is it important that the Company file for a new FCR to replace FCR-16?

A. The Company has provided a projection of its costs through calendar year 2005. This projection indicates that if FCR-16 remains in effect beyond September 2004, the deferred fuel and purchased power account will grow to an over-recovery of over $100 million in early 2005 and remain above that level for most of the year. For this reason, I recommend that the Commission require, as a condition for approval of FCR-16, that the Company file for an FCR-17 to be effective September 1, 2004.

Q Does this complete your testimony?

A. Yes, it does.

Nuclear ages

Exhibit____(CWK-1)

Georgia Power Company
Nuclear Plant Outages November 24, 2002 - December 17, 2002

Unit	Type	Beginning Time	Ending Time	Calculated Duration	Percent Reduction	Distribution Cost of Closest Month	MWH LOST	Cost
VOGTLE 1	D1	11/24/02 5:15 PM	11/24/02 10:18 PM	5.1	53%	$0.0044	3,091	$56,210
VOGTLE 1	U1	11/24/02 10:18 PM	11/30/02 11:59 PM	145.7	100%	$0.0044	167,532	$2,588,946
VOGTLE 1	U1	12/1/02 12:00 AM	12/2/02 1:43 AM	25.7	100%	$0.0043	29,578	$457,217
VOGTLE 1	D1	12/2/02 1:43 AM	12/2/02 2:29 AM	0.8	97%	$0.0043	858	$18,100
VOGTLE 1	U1	12/2/02 2:29 AM	12/2/02 10:27 AM	8.0	100%	$0.0043	9,166	$189,239
VOGTLE 1	D1	12/2/02 10:27 AM	12/5/02 11:00 AM	72.6	68%	$0.0043	56,684	$1,147,343
				257.7			**266,909**	**$4,457,055**
VOGTLE 2	D1	11/24/02 3:56 PM	11/24/02 7:43 PM	3.8	54%	$0.0077	2,365	$27,856
VOGTLE 2	U1	11/24/02 7:43 PM	11/30/02 11:59 PM	148.3	100%	$0.0077	170,511	$2,078,491
VOGTLE 2	U1	12/1/02 12:00 AM	12/12/02 10:53 PM	286.9	100%	$0.0046	329,912	$5,701,372
VOGTLE 2	D1	12/12/02 10:53 PM	12/17/02 10:00 PM	119.1	55%	$0.0046	75,343	$1,171,906
				558.1			**578,131**	**$8,979,624**

Exhibit _____ (Cwk-2)

December 11, 2002

Vogtle Electric Generating Plant

Event Report Submitted to the Institute of Nuclear Power Operations (INPO) electronically via the Nuclear Network.

"**<u>Wrong Chemicals Added to Feedwater System Causes Dual Unit Shutdown</u>**"

Wrong Chemicals Added to Feedwater Systems Causes Dual Unit Shutdown

Abstract

On November 24, 2002, both Vogtle units were shutdown from 100% power due to high sodium levels detected in both units' feedwater systems. Investigation revealed that Chemistry personnel had mistakenly added sodium phosphate instead of Methoxypropylamine (MPA) to the condensate chemical injection systems for both units.

Reason for Message

To inform the industry of an event involving the introduction of incorrect chemicals to the steam generators.

Event Date:............11/24/2002
Unit Name:............Vogtle Units 1 & 2
NSSS/AE:..............Westinghouse/Bechtel-Southern Company Services
Turbine Manufacturer:.....General Electric

Maintenance Rule Applicability: N/A
Component Information (as applicable):

Description

On November 24, 2002, plant Chemistry Technicians were tasked with adding Methoxypropylamine (MPA) to the Condensate Chemical Injection Systems for both units. Approximately one hour after adding what was thought to be MPA to Unit 2, secondary plant chemistry experienced significantly elevated sodium levels resulting in mandatory shutdown of the unit in accordance with abnormal operating procedures for secondary plant chemistry. While Unit 2 was in the process of shutting down, Unit 1's secondary chemistry started to experience significantly elevated sodium levels resulting in a mandatory shutdown. Further investigation discovered that the chemical added was sodium phosphate.

The Chemistry personnel that added the incorrect chemical were performing the activity for the first time. Although the Chemistry supervisor that was involved in the event had participated in briefings associated with the activity, this individual had never performed the activity. The event started when a recently qualified secondary chemistry technician proceeded to the plant warehouse to obtain MPA. Upon seeing more than one similar looking container of chemicals from the same manufacturer, the technician questioned warehouse personnel concerning procurement documentation. The labeling on this container did not specify the actual chemical composition but did specify a manufacturer's chemical brand number. After reviewing the procurement documentation, the technician incorrectly assumed he had the correct chemical. Upon leaving the warehouse with the sodium phosphate, the technician was sure that he had obtained the correct chemical. The technician proceeded to the turbine building where he met a senior technician and the crew supervisor to add the chemical to the condensate chemical injection system for Unit 2. The chemical composition of the container was not questioned by the other technician or the crew supervisor and the chemical (sodium phosphate) was added. The senior technician and supervisor then added the chemical (sodium phosphate) to the second unit. Within an hour after adding the chemical, the secondary plant chemistry for both units began to experience significantly elevated sodium levels. The operating crew determined that the chemical injection system was the most likely cause and the injection was terminated immediately. Shutdown of both units commenced in accordance with plant procedures. Inspection of the empty chemical container revealed that sodium phosphate instead of MPA was added.

Both units were shutdown to mode 3 (hot standby) within six hours. Each unit was further cooled down to 110°F and placed in cold shutdown to flush the steam generators and minimize any potential damage.

Cause

The root cause of this event was the failure of the supervisor to obtain the correct procedure for the evolution. The pre-job briefing focused on forklift safety and other safety aspects of the activity and not on the critical aspects of the task. The process of ensuring that the correct chemical was obtained was not discussed. Although a procedure specifying the correct chemical number and brand did exist, involved personnel stated that they were not aware of the procedure, nor did they question the need for a procedure to perform the activity.

Corrective Actions

Shutdown of both units commenced in accordance with plant procedures. The following are the immediate corrective actions that were required to be implemented before the completion of the start-up of both units.

1) The secondary side of the steam generators for Unit 1 was drained and flushed two times to reduce sodium concentrations to 20 ppb level. Unit 2 required three drains and flushes to achieve the same sodium concentration level.

2) Limitations were established on the allowable concentrations for phosphates in the steam generators based on Reactor Coolant System temperature and reactor power during power ascension.

3) The chemical containers in the warehouse were more conspicuously labeled with chemical nomenclature, plant system, and procedure number.

4) A warehouse stock number will be assigned to the chemical containers such that pick-lists would be required to obtain them from the warehouse, thus requiring warehouse and chemistry personnel signatures.

5) Applicable chemistry procedures were revised to include the complete chemical nomenclature, signoffs for each step specifying the chemical, and an independent verification for the chemical.

6) Chemistry and warehouse personnel were briefed on the requirements specified in corrective actions 3-5.

Long term corrective actions for this event are under development. Additional information will be provided when it becomes available.

Safety Significance

Both units were shutdown in accordance with abnormal operating procedures for secondary plant chemistry. No problems were encountered with the shutdown. The actions taken of bringing both units off line and cooling down were to mitigate the potential damage to the steam generators and are consistent with recommendations found in the EPRI Secondary Water Chemistry Guidelines. An evaluation is being performed to consider potential long term impact to the steam generators.

Exhibit ____ (CWK-3)

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
61 FORSYTH STREET SW SUITE 23T85
ATLANTA, GEORGIA 30303-8931

January 3, 2003

Southern Nuclear Operating Company, Inc.
ATTN: Mr. J. Gasser, Vice President
P. O. Box 1295
Birmingham, AL 35201-1295

SUBJECT: VOGTLE ELECTRIC GENERATING PLANT - NRC PROBLEM IDENTIFICATION AND RESOLUTION INSPECTION REPORT NOS. 50-424/02-05 AND 50-425/02-05

Dear Mr. Gasser:

On December 6, 2002, the NRC completed a team inspection at the Vogtle Electric Generating Plant, the enclosed report documents the inspection findings, which were discussed with Mr. George Frederick and other members of your staff during an exit meeting December 5, 2002.

The inspection was an examination of activities conducted under your license as they relate to the identification and resolution of problems, and compliance with the Commission's rules and regulations and with the conditions of your operating license. Within these areas, the inspection involved examination of selected procedures and representative records, observations of activities, and interviews with personnel.

On the basis of the sample selected for review, there were no findings of significance identified. The team concluded that problems were properly identified, evaluated, and resolved within the problem identification and resolution programs. A very low threshold for entering problems into your corrective action program was observed. However, during the inspection, examples of minor problems were identified, including conditions adverse to quality that were not being entered into the corrective action program and narrowly focused corrective actions. Also, human performance errors contributed to two recent manual reactor trips and a dual unit shutdown.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS).

ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Brian R. Bonser, Chief
Reactor Projects Branch 2
Division of Reactor Projects

Docket Nos. 50-424 and 50-425
License Nos. NPF-68 and NPF-81

Enclosure: NRC Inspection Report 50-424/02-05 and 50-425/02-05

cc w/encl: (Seepage 3)

cc w/encl:
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Southern Nuclear Operating Company, Inc.
Electronic Mail Distribution

G. R. Frederick
General Manager, Plant Vogtle
Southern Nuclear Operating Company, Inc.
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<u>Distribution w/encl</u>:
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RIDSNRRDIPMLIPB
PUBLIC

PUBLIC DOCUMENT (circle one): YES

OFFICE	RII:DRP	RII:DRP	RII:DRS				
SIGNATURE	by e-mail	by e-mail	by e-mail				
NAME	TJohnson	TMorrissey	RMoore				
DATE	12/30/2002	12/26/2002	12/30/2002				
E-MAIL COPY?	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO

OFFICIAL RECORD COPY DOCUMENT NAME: C:\ORPCheckout\FileNET\ML030060145.wpd

U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.	50-424 and 50-425
License Nos.	NPF-68 and NPF-81
Report Nos:	50-424/02-05 and 50-425/02-05
Licensee:	Southern Nuclear Operating Company, Inc. (SNC)
Facility:	Vogtle Electric Generating Plant Units 1 and 2
Location:	7821 River Road Waynesboro, GA 30830
Dates:	November 12-15, December 2-6, 2002
Inspectors:	T. Johnson (Lead Inspector), Farley Senior Resident Inspector R. Moore, Reactor Inspector, Region II T. Morrissey, Vogtle Resident Inspector
Approved by:	Brian R. Bonser, Chief Reactor Projects Branch 2 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000424-02-05, IR 05000425-02-05, on November 12-15, and December 2-6, 2002, Southern Nuclear Operating Company; Vogtle Electric Generating Plant, Units 1 and 2, biennial baseline inspection of the identification and resolution of problems.

The inspection was conducted by a senior resident inspector, a resident inspector, and a regional reactor inspector. The inspection focused on corrective action program performance in the period since the previous inspection in January 2001. No findings of significance were identified.

Identification and Resolution of Problems

Overall, the licensee's Corrective Action Program (CAP) was effective at identifying, evaluating, and correcting problems. The threshold for entering problems into the CAP was low, resulting in a large number of Condition Reports (CRs). Problems entered into the CAP were adequately evaluated and appropriate actions were taken to resolve the problem. Recent events, including two reactor trips during low power feed water operations, and a dual unit shutdown due to secondary chemistry problems, were caused in part by human performance errors combined with weak supervisory oversight. The licensee is currently addressing these common root causes and developing corrective actions.

Some instances of missed problem identification were noted. System engineers were found to use the CAP effectively to address equipment issues. Quality Assurance organization audits were effective in identifying issues. Self-assessments were appropriate and findings were entered into the CAP. A safety conscious work environment was found where employees felt free to raise safety issues in CRs or the employee concerns program.

REPORT DETAILS

4. OTHER ACTIVITIES (OA)

4OA2 Problem Identification and Resolution (PI&R)

a. Effectiveness of Problem Identification

(1) Inspection Scope:

The inspectors reviewed issues and items selected across the seven cornerstones of safety that were either documented in NRC inspection reports or entered into the licensee's corrective action program (CAP) since the last performance of an NRC PI&R inspection in January 2001 (Inspection Report (IR) No. 50-424 and 425/2001-02). The inspectors assessed whether these items were being properly identified, characterized, and entered into the CAP for evaluation and resolution. The inspectors discussed PI&R observations from the baseline NRC inspection program with the resident inspectors.

The inspectors reviewed condition reports (CRs) for risk significant systems and discussed them with the responsible system engineer to determine whether problems were effectively identified and evaluated. The risk significant systems the inspectors reviewed included the following: Emergency Diesel Generator (EDG), electrical power, Residual Heat Removal (RHR), Safety Injection (SI), Component Cooling Water (CCW), Nuclear Service Cooling Water (NSCW), and Auxiliary Feedwater (AFW). A walkdown of each system was conducted to assess the material condition and determine if any unidentified degraded equipment conditions existed. The walkdowns were conducted with the system engineer or discussed with the system engineer after the walkdown. The condition of the system, past performance issues, and any planned modifications were discussed. System health reports were also reviewed.

The inspectors verified that problems in CRs were properly evaluated using the Maintenance Rule when appropriate. Selected maintenance work orders were reviewed to verify proper classification of deficiencies as either work orders or CRs.

The inspectors reviewed 15 licensee operating experience (OE) items to determine if they were appropriately evaluated for applicability and if identified problems were entered into the CAP.

During the inspection ongoing plant activities were reviewed including a review of the following: shift turnover meetings, plant status and plan of the day meetings, surveillance testing and maintenance, operational activities including unit trip recovery, startup, and power operation, a Safety Review Board (SRB) meeting, a Human Performance Review Board (HPRB) meeting, and a Plant Review Board (PRB) meeting; operating logs and the Major Problem Status Report (June 2002); and, discussion of issues with plant employees. The inspectors spot-checked completed technical specification surveillances for accuracy and timeliness. In addition, maintenance scheduling was reviewed to verify appropriate risk management was utilized. A sampling of maintenance work orders (MWOs) from calendar years 2001 and 2002 were reviewed to verify proper classification of deficiencies as either work orders or

CRs. The inspectors attended the daily work control meeting to evaluate the interfaces between the work control process and the CAP. Several equipment problems discussed during the plan of the day meetings were selected by the inspectors to verify the issues had been entered into the CAP, if necessary.

The inspectors reviewed self-assessment reports, audit reports, internal assessment reports, HPRB data, and minutes of the PRB and SRB meetings to determine if oversight activities were effective and if self-identified issues were appropriately entered into the CAP. Documents reviewed are listed in the attachment.

(2) Issues:

The licensee's program for identification of problems was effective and provided a suitable mechanism for the identification and documentation of plant problems. The threshold for entering issues was low and employees were encouraged to enter items. Initiators of CRs were from all plant groups which demonstrated the plant staff was familiar and involved with the corrective action program. However, the inspectors found several instances where minor housekeeping problems, fire protection deficiencies, and equipment material issues were not documented in the CAP. Examples included AFW system oil/water leaks, low oil bubbler level, valve position labeling, RHR Limitorque plastic cover, area housekeeping, and fire protection issues. When these issues were identified to the licensee, appropriate actions were taken.

Quality Assurance (QA) group audits were effective in identifying issues. The scope of PRB and SRB meetings was consistent with the documented charter for those activities and addressed CRs, procedure changes, license document changes and modifications in a thorough and questioning manner. The HPRB process provided valuable feedback for the selected human performance related CRs.

As documented in IR 50-424 and 425/2001-02, some issues from the assessments were not entered into the CAP. During this inspection, the inspectors found that self-assessments of the CAP were appropriately scoped and issues identified during the self-assessments were properly entered into the CAP. Self-assessments were performed by most departments.

The licensee was effective in identifying and placing OE issues into the CAP. The inspectors found several examples of actions necessary to address OE issues not entered and tracked in the CAP. In these cases, necessary actions were the responsibility of a cognizant individual, such as a system engineer.

b. Prioritization and Evaluation of Issues

(1) Inspection Scope

The inspectors reviewed the licensee's quarterly trend reports to determine whether identified trends were placed in the CAP. The inspectors also reviewed the Major Problem Status Report (June 2002) and selected completed CRs to determine whether the conditions identified had been resolved. The licensee classified CRs on safety significance ranging from Severity Level (SL) 1 (high significance) through SL 5 (little or no significance). All SL 3 and above CRs required a formal root cause determination.

During the period reviewed, several SL 2 CRs for plant trips were issued. The inspectors reviewed these SL 2 CRs and selected SL 3, SL 4, and SL 5 CRs. A sample of voided CRs was also reviewed to verify they were voided for appropriate reasons.

(2) Issues:

The licensee was generally effective in the use of trending, problem status reports, and SL classification of CRs to prioritize and evaluate issues. Quarterly trend report issues were entered into the CR program as SL 3 CRs and were appropriately evaluated. Classification levels were appropriate for the sample of CRs reviewed.

A concern with the licensee's resolution of configuration control problems was identified in IR 50-424 and 425/01-02. The effectiveness of corrective actions was limited and the condition of excessive mis-positions was not captured in an overall trend CR. Therefore, a scope analysis and comprehensive corrective action plan had not been developed. In response to this concern, the licensee initiated CR 2001000135 which resulted in the licensee performing a scope analysis and developing a comprehensive corrective action plan. The inspectors found that the corrective actions in this plan were extensive and included increased management oversight, training, individual evaluations of mis-position occurrences, benchmarking mis-positions at another nuclear station, a place-keeping policy for procedures which manipulate components, and post job briefings to specifically address configuration restoration. Additionally, "valve, breaker, switch mis-positions" were tracked as an area of interest in the Station Quarterly Trend Report.

The inspectors identified that CRs 2002002570 and 2002002796 did not address all the root causes. CR 2002002570, a SL 3 CR regarding a maintenance preventable functional failure, did not properly address the human performance root cause. The licensee documented this issue in the CAP as CR 2002003540. CR 2002002796 concerned a personnel error (wrong train event) during surveillance testing. During the HPRB, the licensee also identified that the root cause and corrective actions were narrowly focused. The licensee took actions for additional review of the CR.

c. Effectiveness of Corrective Actions

(1) Inspection Scope:

The inspectors reviewed root cause evaluations, corrective actions, the backlog of open items and actions items, and selected CRs to determine if appropriate corrective actions were documented, assigned, and implemented. This included verification of Action and Open Item Tracking activities and maintenance work orders or modification packages which implemented corrective actions. Where possible field verification of corrective actions was performed. The inspectors attended an HPRB meeting.

The inspectors reviewed licensee actions relative to two reactor trips, Unit 1 on April 20, 2002, and Unit 2 on November 13, 2002, caused partly by human error. The inspectors were also briefed by the licensee of an on-going event investigation of a forced dual unit shutdown on November 24, 2002, due to secondary chemistry problems. The inspectors reviewed the related CRs, event investigations, trends, and selected corrective actions to evaluate effectiveness. The inspectors also attended several event investigation meetings associated with the Unit 2 reactor trip.

(2) Issues:

In general, corrective actions were effective. System engineers were knowledgeable of equipment issues and effectively used the CAP to deal with equipment issues. The inspectors monitored the effectiveness of corrective actions and concluded the backlog of open items and action items were manageable.

The Open and Action Item Tracking processes were effective in verifying the completion of specified corrective actions in CRs and LERs. The inspectors were able to verify that the specified corrective actions were performed. With respect to configuration control issues discussed in the previous P&IR report, although mis-positioning continued to occur, the trending information showed improvement which indicated the corrective actions were having a positive effect on station activities.

The root causes for two unit trips and the dual unit shutdown were similar. This included procedural non compliances (not following the procedure or unaware of procedure existence) and weak supervisory oversight. The oversight weaknesses included missed or weak pre-job briefings, conducting risk significant activities in parallel, weak command and control, and poor communications. While some initiatives had been implemented, the licensee had not yet achieved positive results from their corrective actions.

The inspectors found the multi-discipline event team assembled for the most recent Unit 2 reactor trip was effective in developing corrective actions. The event team appropriately reviewed the effectiveness of the corrective actions associated with a similarly caused trip of Unit 1. The inspectors found the corrective actions associated with the Unit 1 trip were adequate. However, the corrective actions focused primarily on the specifics of the trip. Operator performance, including procedure use during startup and lower power feed water operations was not addressed. Also, there were no corrective actions relative to supervisory performance or command and control expectations. The inspectors characterized this as a missed opportunity.

d. Assessment of Safety-Conscious Work Environment

(1) Inspection Scope:

The inspectors assessed if any conditions existed causing employees' reluctance to raise safety issues. This included identifying deficient conditions through the CAP and the understanding and use of the employee concerns program (ECP) . The inspectors also reviewed the ECP procedure and a summary of employee concerns and interviewed the ECP supervisor to assess visibility of the program.

(2) Issues:

The inspectors determined the licensee had established and maintained a safety-conscious work environment as evidenced by the number of CRs written, a visible ECP, and the results of the NRC discussions during the course of the inspection.

All employees were aware of the process and the location and accessibility of the ECP coordinator. The inspectors concluded that employees felt free to raise issues.

4OA6 Management Meetings

Exit Meeting Summary

Inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on December 5, 2002. The licensee acknowledged the findings presented. No proprietary information was identified.

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

W. Bargeron, Plant Support Assistant General Manager
W. Burmeister, Manager Engineering Support
G. Frederick, Plant General Manager
T. Petrak, Maintenance Supervisor
P. Rushton, Plant Operations Assistant General Manager
M. Sheibani, NSAC Supervisor
T. Tynan, Operations Manager

LIST OF DOCUMENTS REVIEWED

Licensee Procedures:
00150-C, Condition Reporting and Tracking System
80014-C, Handling of Condition Reports for Deficient Conditions
80016-C, Trend Identification and Reporting
00040-C, Self Assessment Program
00414-C, Operating Experience Program
VSAER-WP-03, Safety Audit and Engineering Review Field Audits
VSAER-WP-05, Annual SAER Department Assessment
00058-C, Root Cause Determination
00409-C, Action Item, Open Item, and Commitment Tracking
VNS-AP-16, Condition Reporting and Tracking System
SNOC Concerns Program Procedure
00057-C, Event Investigation
50028-C, Engineering Maintenance Rule Implementation
50023-C, System Health and Monitoring Program
00354-C, Maintenance Scheduling
29540-C, Risk Assessment Monitoring
29542-C, Shutdown Risk Assessment
10000-C, Conduct of Operations
00002-C, Plant Review Board - Duties and Responsibilities
VSRB-05, Southern Nuclear Vogtle Project Support, Safety Review Board
00056-C, 10 CFR 50.59 Screening and Evaluations
28707-C, 480 Volt Air Circuit Breaker Maintenance and 60 Month Check
00404-C, Surveillance Test Program
00409-C, Action Item, Open Item, and Commitment Tracking
10024-C, Equipment Troubleshooting
81060-C, Open Item/Commitment Tracking Program Coordination
VSAER-WP-03, Safety Audit and Engineering Review Field Audits

Operating Experience:
IN 2001-09, Main Feedwater System Degradation in Safety-Related ASME Code Class 2 Piping inside the Containment of a Pressurized Water Reactor

IN 2002-09, Potential for Top Nozzle Separation and Dropping of a Certain Type of Westinghouse Fuel Assembly
IN 2002-24, Potential Problems with Heat Collectors on Fire Protection Sprinklers
IN 2002-25, Challenges to Licencees' Ability to Provide Prompt Public Notification and Information During an Emergency Preparedness Event
IN 2002-02, Supplement 1, Recent Experience with Plugged Steam Generator Tubes
IN 2002-18, Effect of Adding Gas into Water Storage Tanks on the Net Positive Suction Head for Pumps
SER 2-01, EDG Failure Resulting from Inadequate Performance Monitoring and Inadequate Response to Symptoms of Impending Failure
SER 3-02, Workers Exit Plant Site with Detectable External Radioactive Contamination
SER 5-01, 4-kV Breaker Failure, Switchgear Fire and Turbine Generator Damage
SEN 220, Pressure Boundary Leakage at Palisades
SEN 226, Stress Corrosion Cracking on a Portion of Safety Injection System Piping
SEN 230, Pressurizer Spray Valve Failure Resulting in Reactor Scram and Safety Injection
RIS 01-015, Performance of DC- Powered Motor-Operated Valve Actuators
RIS 01-009, Control of Hazard Barriers
OE 14513, Concern with Boron Concentration in Mode 3 below P-11 with SI Blocked

<u>Condition Reports</u>:

2001000203	2001002960	2001000162	2001001064	2001000434	2001001069
2001000468	2001001106	2001000598	2001001837	2001001460	2001001853
2001000727	2001002194	2001000529	2001002198	2001000533	2001002246
2001000970	2002000103	2001000971	2002001700	2001001443	2002002212
2001001444	2002002645	2001001514	2001003040	2001001516	2002000744
2001001582	2002000745	2001002097	2002000856	2001002951	2001000006
2001001580	2001001704	2001000165	2001000464	2001000581	2001002138
2001001907	2001002139	2001000960	2001002142	2002000319	2001002141
2001000681	2002000090	2001000178	2002000264	2002000301	2001000043
2001000132	2001000299	2001000307	2002002295	2001000310	2001000423
2001000519	2001003034	2001000723	2001002083	2002000723	2002001319
2000001563	2001000031	2001000113	2001000501	2001001022	2001002604
2002000107	2002000518	2002002281	2002001328	2001000361	2002002581
2002003295	2002002023	2002001647	2002001371	2002000589	2002002430
2002002685	2002001992	2002002302	2002002429	2002001841	2002002122
2002002224	2001000988	2001001061	2001001686	2001002177	2001002250
2001002570	2001002711	2001002771	2002000088	2002000431	2002000756
2002000859	2002001062	2002001088	2002001129	2002001299	2002001540
2002001655	2002001837	2002002385			

<u>Maintenance Work Orders</u>:
Maintenance Work Orders for SI, RHR, AFW, EDG, CCW, NSCW, AC power

10101119	20200276	20100832	20101733	20101413	20102735
10101119	20200276	20102735	20101413	20101733	10100044
10100539	10101390	10101430	10101639	10102299	10102307
10103500	10200764	10101084	20102150		

<u>Licensee Audits and Self-Assessments</u>:
SAER Audit of Corrective Actions, OP21-02/15, VSAER-2002-079
SAER Audit of Corrective Actions, OP21-01/01, VSAER-2001-013

SAER Audit of Corrective Actions, OP21-00/14, VSAER-2000-077
SAER Audit of Corrective Actions, OP21-02/01, VSAER-2002-019
SAER Audit of Corrective Actions, OP21-01/16, VSAER-2001-071
SAER Audit of Outage Activities, OP06/16/17/25/26-01/08,VSAER-2001-039
SAER Audit of Fire Protection Program, OP20-02/11, VSAER-2002-062
Count Room and Chemistry Self-Assessment, NOH-02449, July 2002
Maintenance Fire Protection Self-Assessment, NOM-02252, May 2002
Training Department Self-Assessment, February 2002
Health Physics Self-Assessment, NOH-02452, July 2002
Engineering Support Department Self-Assessment, NOE-03480, November 2001
Equipment Reliability Self-Assessment, NOE-03493, July 2002
2002 Operations Self Assessment, NOP 01357, June 2002

Safety Review Board (corporate) Meeting Minutes
Major Meetings: 02-02, 02-03, 02-05, 01-02, 01-04, 01-05, 01-08

Plant Safety Review Board (station) Minutes
9/11/02, 9/10/02, 8/30/02, 8/27/02, 8/20/02, 8/13/02

NRC Violations
NCV 50-424,425/00-05-02 (CR 2000001563)
NCV 50-424,425/00-06-01 (CR 2001000521)
NCV 50-424,425/01-03-01 (CR 2001000477)
NCV 50-424,425/01-03-02 (CR 2001000694)
NCV 50-424,425/01-08-01 (CR 2001002851)
NCV 50-424,425/02-02-01 (CR 2002001165, 2002001172, 2002001322)
NCV 50-424,425/02-02-02 (CR 2002001346, 2002001392, 2002001697)
NCV 50-424,425/02-02-03 (CR 2002001251)
NCV 50-424,425/02-02-04 (CR 20020000723, 2002001223)

Vogtle Quarterly Trend Reports
May - July, 2002
February - April, 2002
November, 2001 - January 2002
August - October, 2001
May - July, 2001

LERs, Event Investigation Reports (EIR)
LER 1-2001-001, Unit 1 Reactor Trip Due to Loss of Generator Excitation
EIR 1-2003-03, Reactor Trip due to Generator Excitation Loss
LER 1-2002-001, Improperly Wired Interlock Affects ECCS Re-circulation Valve
LER 2-2001-001, Reactor Trip While Testing Main Feedwater Pump Trip Signals
EIR 2-2001-01, Reactor Trip Due to Loss of Feedwater Flow
LER 1-2002-003, Loss of Main Feedwater ESF Actuation and Manual Reactor Trip
EIR 1-2002-001, Loss of Main Feedwater and Manual Reactor Trip
LER 1-2002-002, Containment Isolation Valve Rendered Inoperable
EIR 2-2002–002, Both Units Shutdown Due to Wrong Chemicals Added to Feed Systems
EIR 2-2002–001, Manual Reactor Trip Due to SG#3 HI-HI Level

Exhibit___ (CWK-4)(RH/DB 2)

GEORGIA POWER COMPANY
PROJECTED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2002, 2003 and 2004
($ in thousands)

	2002	2003	2004
Investing Activities:			
Gross property additions	(970,694)	(751,428)	(808,723)
Other	(34,287)	(6,393)	(5,513)
Net cash needed for investing activities	(1,004,981)	(757,821)	(814,236)
Operating Activities:			
Net income before preferred stock dividends	585,672	603,457	624,599
Adjustments to reconcile net income to net			
cash provided from operating activities --			
Depreciation and amortization	555,183	557,792	573,518
Amortization of Regulatory Liability	(112,132)	(112,132)	(112,132)
Deferred income taxes and investment tax credits, net	8,901	29,810	63,780
Other, net	(855)	(19,585)	(96,040)
Changes in certain current assets and liabilities --			
Receivables and payables, net	(1,478)	(29,528)	(14,669)
Fossil fuel stock	52,759	20,000	0
Materials and supplies	238	20,000	(3,670)
Collections of under recovered fuel cost	125,666	35,796	0
Other	40,242	57,680	60,523
Payment of preferred stock dividends	(672)	(672)	(672)
Payment of common stock dividends	(542,900)	(565,100)	(577,800)
Net cash provided from operating activities after dividends	710,624	597,518	517,437
Net cash shortfall before financing activities	(294,357)	(160,303)	(296,799)
Financing Activities:			
Proceeds from Security Sales			
Senior notes	450,000	500,000	400,000
Preferred securities	750,000	0	0
Total Proceeds	1,200,000	500,000	400,000
Security Retirements at Maturity or by Refunding			
Senior notes	(300,000)	(350,000)	(100,000)
Preferred securities	(589,250)	0	0
Total Redemptions	(889,250)	(350,000)	(100,000)
Net New Money Provided from Long Term Security Transactions	310,750	150,000	300,000
Other Financing Activities:			
Capital contributions from parent company	127,000	21,000	118,000
Capital distributions to parent company from Wansley CC sale	(200,000)	0	0
(Decrease) increase in notes payable, net	(349,592)	1,429	(110,898)
Sale of Plant Wansley Combined Cycles	415,498	0	0
Net Change in Cash and Cash Equivalents	16,661	0	0
Other	(25,960)	(12,126)	(10,303)
Net cash provided from financing activities	294,357	160,303	296,799

Exhibit______(CWK-5)

Georgia Power Company
Deferred Fuel and Purchased Power Costs, June 2001 - August 2003

	A	B	C	D		E	F	G
	Revenues	Expenses	Economy Credits	Adjustments		Carrying Cost Rate	Carrying Charge	Cumulative Under-Recovery
May-01								(91,680,904)
Jun-01	144,185,816	171,583,570						(119,078,658)
Jul-01	119,116,636	162,276,288						(162,238,309)
Aug-01	168,025,010	216,715,493		151,650	A			(211,080,443)
Sep-01	130,665,495	113,777,375						(194,192,323)
Oct-01	111,665,592	111,531,531						(194,058,262)
Nov-01	112,363,239	89,347,354						(171,042,377)
Dec-01	107,859,868	96,985,990	70	1,293,681	B			(161,462,111)
Jan-02	116,483,276	103,122,559	350.54			12.94%	1,067,825	(149,168,868)
Feb-02	107,209,682	86,657,187	37.52			12.52%	954,326	(129,570,661)
Mar-02	109,470,093	104,810,498	170.65			11.92%	789,231	(125,700,127)
Apr-02	117,593,943	115,827,176	102	852,804	C	11.85%	761,430	(125,547,492)
May-02	117,768,365	120,389,654	352			12.32%	790,334	(128,958,763)
Jun-02	135,284,868	129,173,596	164	597,250	D	12.28%	809,060	(124,253,637)
Jul-02	151,735,853	161,573,530	116			11.99%	761,061	(134,852,258)
Aug-02	147,861,696	152,117,554	204			12.10%	833,852	(139,941,763)
Sep-02	143,523,356	134,833,013	(16)			12.61%	901,693	(132,153,128)
Oct-02	125,071,270	126,541,548	433			12.58%	849,375	(134,472,347)
Nov-02	119,901,258	111,650,518	2,341			12.70%	872,521	(127,091,787)
Dec-02	130,323,587	119,307,007	884	(13,436,679)	E	12.33%	800,670	(103,438,315)
Jan-03	134,797,343	145,899,908	118			12.41%	655,722	(115,196,483)
Feb-03	128,947,249	112,281,330	61			12.58%	740,362	(99,270,865)
Mar-03	116,921,898	110,190,374	7			12.58%	638,009	(93,177,342)
Apr-03	116,518,422	127,824,389	41			12.58%	598,846	(105,082,114)
May-03	98,925,486	98,401,231				12.58%	675,357	(105,233,216)
Jun-03 e	110,423,438	114,016,747				12.58%	676,328	(109,502,853)
Jul-03 e	142,794,800	161,422,007	330,000			12.58%	703,769	(128,503,829)
Aug-03 e	148,418,143	160,625,198	220,000			12.58%	825,887	(141,316,771)

Source: Georgia Power Monthly Fuel Cost Recovery Reports

A Consists of the following adjustments reflected in August 2001 on the Report of Retail Fuel Cost Recovery:

Prior Period adjustment to CSS booked economy sales (booked 6/01).	158,078
Prior period adjustment to economy credit calculation (booked 8/01)	(6,323)
Correction to economy sales credit calculation (booked 7/01)	602
CSS booked economy credit (booked 11/01)	(709)
	151,648

B Consists of December 2001 reconciling items and prior period economy credits.
C Consists of April 2002 reconciling items and economy credits.
D Consists of June 2002 reconciling items and economy credits.
E Consists of disallowance for nuclear plant outages.

[redacted]

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In the Matter of :

APPLICATION OF THE GEORGIA	)	**DOCKET NO. 17066-U**
POWER COMPANY TO INCREASE	)	
THE FUEL COST RECOVERY ALLOWANCE	)	
PURSUANT TO O.C.G.A. § 46-2-26	)	

2 2 2004

DIRECT TESTIMONY AND EXHIBITS

OF

CHARLES W. KING

ON BEHALF OF

THE COMMISSION ADVERSARY STAFF

JULY 21, 2003

CONTENTS

Exhibits

DIRECT TESTIMONY OF
CHARLES W. KING

I. Introduction

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

A. My name is Charles W. King. I am President of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. Please describe Snavely King.

A. Snavely King, formerly Snavely, King & Associates, Inc., was founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. The firm has a professional staff of 12 economists, accountants, engineers and cost analysts. Most of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 33-year history, members of the firm have participated in over 1,000 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Adversary Staff of the Georgia Public Service Commission ("Adversary Staff").

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

A. Yes. Attachment 1 is a summary of my qualifications and experience.

Q. Have you previously submitted testimony in regulatory proceedings?

A. Yes. Attachment 2 is a tabulation of my appearances as an expert witness before state and federal regulatory agencies.

Q. What is the objective of your testimony?

A. The objective of my testimony is to present the Adversary Staff's evaluation of the application of the Georgia Power Company ("Georgia Power" or "the Company") for a revision in its Fuel Cost Recovery ("FCR") rate and to recommend an alternative rate if it appears appropriate.

II. Summary

Q. What FCR rate does the Company propose?

A. Georgia Power proposes to increase the average FCR rate from its current (FCR-15) level of 1.6766 cents per kWh to a new (FCR-16) rate of 1.8348 cents per kWh.

Q. What are the components of this new rate?

A. There are two components. The first is 1.6376 cents per kWh to recover the costs of fuel and net purchased power that the Company projects it will incur during the 12-month period ending August 31, 2004. The second is the recovery, over a 12-month period, of $157,111,000 in fuel costs that the Company has claimed it will have under-recovered as of August 31, 2003. This recovery of deferred costs accounts for 0.1972 cents per kWh.

Q. What FCR rate does the Adversary Staff recommend?

A. The Adversary Staff recommends an average FCR rate of 1.8112 cents per kWh for the 12-month period ending August 31, 2004. This rate consists of 1.6338 cents for forecast fuel and purchase power costs and .1774 cents to recover prior period under-recoveries.

Q. What accounts for the .0236 cent per kWh difference between the average FCR rate sought by the Company and that recommended by the Adversary Staff?

A. The following elements account for the difference between the Company's and the Adversary Staff's recommended FCR rate:

- Disallowance of $13,436,679 plus carrying charges for the added costs imposed by a series of unplanned outages at Plant Vogtle in late November and early December 2002;
- Reduction of the equity portion of the composite cost of capital used as the carrying charge prior to August 2003 from 12.5 percent to 11.475 percent; and
- Reduction of the carrying charge rate going forward beginning September 2003 from the Company's composite cost of capital to its cost of short-term credit.

III. Plant Vogtle Outages

Q. What are the Vogtle plant outages to which you have referred?

A. On November 24, 2002, the two Vogtle nuclear units were shut down, and for the next three weeks they scarcely operated. Between November 24 and December 17, 2002, Unit 1 was totally out of service 179 hours and partially out of service another 78 hours. Unit 2 was totally out of service 435 hours and partially out of service another 123 hours. This means that Unit 1 was either totally or partially down 11 out of the 26 days during this period, and Unit 2 was out of service, either totally or partially, 24 out of the 26 days. Exhibit____(CWK-1) is a summary of these outages.

Q. What was the cause of these outages?

A. I have attached two reports submitted by the Company in response to STF-5-7, Docket Number 13711-U, pertaining to these outages. The first, which I have labeled Exhibit_____(CWK-2), is an Event Report titled "Wrong Chemicals Added to Feedwater System Causes Dual Unit Shutdown." This report was submitted electronically on December 11, 2002 to the Institute of Nuclear Power Operations. The second page describes the cause:

> The root cause of this event was the failure of the supervisor to obtain the correct procedure for the evolution. The pre-job briefing focused on forklift safety and other safety aspects of the activity and not on the critical aspects of the task. The process of ensuring that the correct chemical was obtained was not discussed. Although a procedure specifying the correct chemical number and brand did exist, involved personnel stated that they were not aware of the procedure, nor did they question the need for a procedure to perform the activity.

The second report, labeled Exhibit_____(CWK-3), is the Nuclear Regulatory Commission's "Problem Identification and Resolution Report," dated January 3, 2003. Page 4 contains the following conclusion:

> The root causes for two unit trips and the dual unit shutdown were similar. This included procedural non compliances (not following the procedure or unaware of procedure existence) and weak supervisory oversight. The oversight weaknesses included missed or weak pre-job briefings, conducting risk significant activities in parallel, weak command and control, and poor communications. While some initiatives had been implemented, the licensee had not yet achieved positive results from their corrective actions.

Q. What is the relevance of these conclusions to the FCR?

A. The NRC concluded that poor management was the root cause of these outages. Georgia Power should not be permitted to pass through to ratepayers the added costs that result from the inadequacies of management. Due to management's clearly imprudent conduct in failing to properly manage Plant Vogtle to avoid the series of unplanned outages that occurred in late November and early December 2002, I recommend that Georgia Power bear the added fuel and purchased power costs to replace the energy that this plant could have produced.

Q. Have you calculated the added fuel and purchased power costs associated with the outages of the two Vogtle plants?

A. Yes. Nuclear units are very expensive to build but quite cheap to run. Indeed, the added cost to operate the Vogtle units is only about 0.4 cents per kWh, consisting entirely of nuclear fuel. For this reason, the Vogtle units should operate all of the time except when taken out of service for refueling or scheduled maintenance. When they are not operating, other more expensive generating plants must provide the power that the Vogtle plants would otherwise provide. Not just the substitute base load plants, but all plants in the system must move up on the economic dispatch schedule. When nuclear base load units are not operating, other low-cost base load units cannot handle the base load, so more expensive cycling plants fill in. When the cycling plants are not available, very expensive peaker plants must provide the cycling power. The entire chain of generating resources moves from less expensive to more expensive generation. Since Plant Vogtle has the lowest variable cost of any generating resource available to Georgia Power, when it goes out, every kWh on the system becomes more expensive to produce.

The measure of the cost of losing generating resources at any given time is the "system lambda." The system lambda reflects the most expensive generating resource required to serve the load on the system at any given hour. The measure of the cost of losing any generating resource is the difference between that resource's marginal operating cost and the system lambda.

To compute the cost of the lost Vogtle generating capability, I have multiplied the lost capacity of each Vogtle unit during its outage by the difference between the unit's hourly fuel cost and the system lambda during that hour. During off-peak hours, this differential is relatively low; during peak hours it is quite high. Fortunately, the Vogtle outages occurred in late November and early December when the system load was relatively moderate and the lambdas not particularly high.

I have set forth the cost of each outage in the final column of Exhibit _____(CWK-1). Total costs for the Vogtle Unit 1 outages came to $4,457,055; for Unit 2 outages they were $8,979,624. Total Vogtle outage costs for the period November 24 through December 17 were $13,436,679.

Q. Hasn't the Commission already instituted a Nuclear Performance Standard to reward or penalize Georgia Power for its outage performance?

Q. Yes. However, when the Commission adopted this plan in 1989, it explicitly retained the authority "to exclude any unit from consideration under the performance incentive program for the purpose of performing a separate prudence evaluation."[1] When an independent inspector, in this case the NRC, finds that outages were incurred due to poor management practices, the Commission can properly consider sanctions outside of the Nuclear Performance Standard. If it finds that imprudent management caused unusually high costs, it can override the Nuclear Performance Standard that otherwise would apply.

IV. Carrying Charge – January 2002 through August 2003

[1] Docket No. 3840-U, Second Supplemental Order, September 28, 1989, page 52.

Q. What carrying charge rate has the Company used for its deferred fuel and purchased power costs up to the present?

A. The Company has used a weighted average rate of return. This carrying cost was prescribed in the Commission's December 20, 2001 order in Docket No. 14000-U.

Q. Does the Company use the correct weighted average rate of return in its calculations?

A. No, it does not. The Company uses 12.5 percent as its authorized equity return. In Docket No. 14000-U, the Commission did not adopt a specific rate of return, but rather a range of 10.0 to 12.95 percent. The mid-point of this range is 11.475 percent, more than 100 basis points below that used by Georgia Power. If a point estimate of the equity return must be identified, it should be this mid-point, not 12.5 percent, close to the top of the authorized range.

Q. Have you computed the correct carrying charges?

A. Yes. Column E of Exhibit_____(CWK-5) presents the corrected carrying charges since the Commission's decision in Docket No. 14000-U, insofar as the data are available. I have the used the Company's capital structure, debt cost, and preferred securities and stock costs through February 2003. Since I do not have these data for the period March through August 2003, I have used the February return for these months.

V. <u>Carrying Charge – September 2003 through August 2004</u>

Q. Is the prospective carrying charge after August 2003 an issue in this case?

A. Yes. The Commission made it an issue in its Procedural and Scheduling Order of June 17, 2003 establishing this case.

Q. What principles should govern the determination of a carrying charge?

A. The carrying charge should reflect, as nearly as possible, the financial consequences of two opposite conditions. If there is an under-accrual from the FCR, the carrying charge should match the cost of the capital funds that the Company uses to acquire fuel and purchased power for which it is not immediately paid. If there is an over-accrual, the carrying charge should reflect the financial impact of providing the Company with supplemental funds for a relatively short period of time.

Q. What funds can the Company use to finance deferred fuel costs?

A. The primary source of funds is internally generated cash, which consists broadly, but not exclusively, of three elements: (1) depreciation and amortization expenses that are not accompanied by any corresponding outflows of cash; (2) deferred taxes, that is, the difference between the taxes the Company collects from ratepayers and the taxes it actually pays; and (3) retained earnings, that is, earnings that are not distributed as dividends to the Company's owners.

In Docket No. 15128-U, Georgia Power Company's Application to Issue New Securities, Georgia Power's then Assistant Comptroller Ron Hinson testified on May 28, 2002 that internally generated funds support about 70 percent of the Company's construction program.

After internally generated funds, the Company has access to short term debt. As described by Mr. Hinson in Docket No. 15128-U, Georgia Power borrows from three markets. The first is commercial paper, which is borrowed from dealers such as Merrill Lynch and Lehman Brothers, who in turn resell the paper to investors. The second is extendable commercial paper, a subset of the commercial paper market. Unlike conventional commercial paper, which has fixed maturities, the terms of these securities can be extended for up to a year. The final source of short term debt is variable rate pollution control bonds. These bonds are issued through public agencies, and the earnings are therefore tax-exempt, resulting in very low interest rates.

Finally, the Company has access to long-term capital. It can obtain equity capital infusions from its parent, Southern Company, which in turn can sell more stock in the public stock market, or it can sell additional long-term bonds in its own name.

Q. What is the mix of cash resources available to support the deferred fuel balances?

A. In Docket No 15128-U, the Company provided projected statements of cash flows for the years 2002, 2003 and 2004 as an exhibit to the testimony of Ron Hinson and David Brooks. I attach a copy of this exhibit as Exhibit_____(CWK-4). From this exhibit I calculate the following breakdown of the sources of funds to support the Company's capital additions:

Table 1
Georgia Power Company
Sources of Cash Flows

	2002	2003	2004
Internally Generated Capital			
Retained Earnings	4.2%	-0.9%	-0.6%
Other	66.5%	79.8%	64.2%
New Long-term Debt	30.9%	19.8%	36.8%
Other Financing	-1.6%	1.4%	-0.4%
Total	100.0%	100.0%	100.0%

Source: Exhibit_____(CWK-4)

The table supports Mr. Hinson's statement that about 70 percent of the Company's requirements for new capital are provided by internally generated funds. Those funds, however, are not provided by Georgia Power's parent, the Southern Company, in the form of retained earnings. Indeed, for two out of the three years retained earnings are negative. The detail of the "other financing" in Exhibit_____(CWK-4) shows that the parent company was intending to make a negative contribution of new capital in 2002, about a 2.1 percent contribution in 2003, and it promises a 15 percent contribution in 2003.

Neither Exhibit_____(CWK-4) nor Table 1 displays the level of short-term debt, only the net change in that debt from the beginning to the end of the year. Schedule 5 to Georgia Power's June 11, 2003 application for refinancing (approved July 1) shows that on March 31, 2003, short term notes payable were $529,419,000. This amounts to 70 percent of the total new financing needs for the year.

Even this very large balance of short-term debt is only a fraction of the total credit available to the Company. Georgia Power has a "credit facility" with a consortium of about 20 banks from which it can draw up to $1.7 billion in short-term borrowing to back up the three other sources of short-term credit that I described earlier. This credit facility is the right to borrow at any time from a bank and to extend the loan for a two-year period.[2]

Q. What is the source of the funds that Georgia Power uses to cover the under-accruals from the FCR?

A. Except when there are specific uses designated for the funds raised, it is impossible to trace cash across the balance sheet from sources to uses. However, it seems highly improbable that Georgia Power would sell long-term debt or seek equity contributions from its parent to support the under-accrual of fuel costs that

[2] Docket No. 15128-U, Testimony of David Brooks, May 28, 2002, transcript page 29.

it plans to amortize within the next year. Moreover, as noted, the Southern Company is contributing very little in the way of equity capital in Georgia Power. Since this under-accrual is a short-term liability to the Company, it is likely covered either by internally generated funds or by short-term debt.

Q. What would be the financial impact of an over-accrual of FCR revenue relative to cost?

A. If there were an over-accrual from the FCR, the funds received by Georgia Power would offset the Company's need for short-term credit, effectively saving the Company the cost of that type of debt.

Q. What is the cost of short-term debt?

A. On May 28, 2002, David Brooks of Southern Company Services testified that current rates for the Georgia Power's commercial paper were about 1.85 percent and for its pollution control bonds about 1.45 percent.[3]

Q. What do you recommend as the carrying cost of the deferred fuel balances?

A. I recommend the cost of Georgia Power's short-term debt.

Q. Have you quantified this cost?

A. No. I do not have the current cost of Georgia Power's short-term debt, let alone forecasts of that cost over the coming year. For purposes of quantifying the FCR in this testimony, I have used the Federal Reserve's report of interest rates on three-month commercial paper. The average for this series of the most recent twelve months for which data are available (July 2002-June 2003) is 1.40 percent.

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[3] Docket No. 15128-U, Transcript of May 28, 2002, page 29.

V. Conclusion

Q. Have you recomputed the deferred fuel and purchased power costs as of August 2003?

A. Yes. Exhibit_____(CWK-5) shows the build-up of the deferred fuel and purchase power balance from June 1, 2001 through August 2004. All of the data except the July and August 2003 figures are taken from the historical FCR reports of Georgia Power. The July and August data are Georgia Power's estimates. The August 31, 2003 deferred fuel balance is an under-recovery of $141,316,771. This figure is $15,793,780 lower than the Company's estimate of $157,110,551 in under-recovery. The difference is entirely due to my recommended disallowance of $13,436,679 for nuclear outage costs and my use of 11.475 percent as the cost of equity in the carrying charge.

Q. How did you compute the going-forward cost of fuel and purchased power from September 2003 through August 2004?

A. I substituted my alternative calculation of the prior period accumulated deferred fuel balance and my alternative carrying cost into the Company's costing model for the FCR. That model produced the 1.6338 cents that I recommend for recovery of prospective fuel and purchased power costs.

Q. How do the components of your recommended FCR compare with those proposed by the Company?

A. The components of the two FCRs can be compared as follows:

Table 2
Components of FCR-16

Component	Georgia Power	Staff
Future Fuel Cost Recovery	1.6376¢	1.6338¢
Prior Period Recovery	0.1972¢	0.1774¢
Total	1.8348¢	1.8112¢

Q. How long should this FCR rate remain in effect?

A. This rate, which is numbered FCR-16, should remain in effect only through August 2004. By the end of May 2004, the Company should be required to file for a new FCR-17 to take effect September 1, 2004.

Q. Why is it important that the Company file for a new FCR to replace FCR-16?

A. The Company has provided a projection of its costs through calendar year 2005. This projection indicates that if FCR-16 remains in effect beyond September 2004, the deferred fuel and purchased power account will grow to an <u>over</u>-recovery of over $100 million in early 2005 and remain above that level for most of the year. For this reason, I recommend that the Commission require, as a condition for approval of FCR-16, that the Company file for an FCR-17 to be effective September 1, 2004.

Q Does this complete your testimony?

A. Yes, it does.

Nuclear ages

Exhibit____(CWK-1)

Georgia Power Company
Nuclear Plant Outages November 24, 2002 - December 17, 2002

Unit	Type	Beginning Time	Ending Time	Calculated Duration	Percent Reduction	Distribution Cost of Closest Month	MWH LOST	Cost
VOGTLE 1	D1	11/24/02 5:15 PM	11/24/02 10:18 PM	5.1	53%	$0.0044	3,091	$56,210
VOGTLE 1	U1	11/24/02 10:18 PM	11/30/02 11:59 PM	145.7	100%	$0.0044	167,532	$2,588,946
VOGTLE 1	U1	12/1/02 12:00 AM	12/2/02 1:43 AM	25.7	100%	$0.0043	29,578	$457,217
VOGTLE 1	D1	12/2/02 1:43 AM	12/2/02 2:29 AM	0.8	97%	$0.0043	858	$18,100
VOGTLE 1	U1	12/2/02 2:29 AM	12/2/02 10:27 AM	8.0	100%	$0.0043	9,166	$189,239
VOGTLE 1	D1	12/2/02 10:27 AM	12/5/02 11:00 AM	72.6	68%	$0.0043	56,684	$1,147,343
				257.7			**266,909**	**$4,457,055**
VOGTLE 2	D1	11/24/02 3:56 PM	11/24/02 7:43 PM	3.8	54%	$0.0077	2,365	$27,856
VOGTLE 2	U1	11/24/02 7:43 PM	11/30/02 11:59 PM	148.3	100%	$0.0077	170,511	$2,078,491
VOGTLE 2	U1	12/1/02 12:00 AM	12/12/02 10:53 PM	286.9	100%	$0.0046	329,912	$5,701,372
VOGTLE 2	D1	12/12/02 10:53 PM	12/17/02 10:00 PM	119.1	55%	$0.0046	75,343	$1,171,906
				558.1			**578,131**	**$8,979,624**

Exhibit ______ (Cwk-2)

December 11, 2002

Vogtle Electric Generating Plant

Event Report Submitted to the Institute of Nuclear Power Operations (INPO) electronically via the Nuclear Network.

"**Wrong Chemicals Added to Feedwater System Causes Dual Unit Shutdown**"

Wrong Chemicals Added to Feedwater Systems Causes Dual Unit Shutdown

Abstract

On November 24, 2002, both Vogtle units were shutdown from 100% power due to high sodium levels detected in both units' feedwater systems. Investigation revealed that Chemistry personnel had mistakenly added sodium phosphate instead of Methoxypropylamine (MPA) to the condensate chemical injection systems for both units.

Reason for Message

To inform the industry of an event involving the introduction of incorrect chemicals to the steam generators.

Event Date:............11/24/2002
Unit Name:............Vogtle Units 1 & 2
NSSS/AE:..............Westinghouse/Bechtel-Southern Company Services
Turbine Manufacturer:.....General Electric

Maintenance Rule Applicability: N/A
Component Information (as applicable):

Description

On November 24, 2002, plant Chemistry Technicians were tasked with adding Methoxypropylamine (MPA) to the Condensate Chemical Injection Systems for both units. Approximately one hour after adding what was thought to be MPA to Unit 2, secondary plant chemistry experienced significantly elevated sodium levels resulting in mandatory shutdown of the unit in accordance with abnormal operating procedures for secondary plant chemistry. While Unit 2 was in the process of shutting down, Unit 1's secondary chemistry started to experience significantly elevated sodium levels resulting in a mandatory shutdown. Further investigation discovered that the chemical added was sodium phosphate.

The Chemistry personnel that added the incorrect chemical were performing the activity for the first time. Although the Chemistry supervisor that was involved in the event had participated in briefings associated with the activity, this individual had never performed the activity. The event started when a recently qualified secondary chemistry technician proceeded to the plant warehouse to obtain MPA. Upon seeing more than one similar looking container of chemicals from the same manufacturer, the technician questioned warehouse personnel concerning procurement documentation. The labeling on this container did not specify the actual chemical composition but did specify a manufacturer's chemical brand number. After reviewing the procurement documentation, the technician incorrectly assumed he had the correct chemical. Upon leaving the warehouse with the sodium phosphate, the technician was sure that he had obtained the correct chemical. The technician proceeded to the turbine building where he met a senior technician and the crew supervisor to add the chemical to the condensate chemical injection system for Unit 2. The chemical composition of the container was not questioned by the other technician or the crew supervisor and the chemical (sodium phosphate) was added. The senior technician and supervisor then added the chemical (sodium phosphate) to the second unit. Within an hour after adding the chemical, the secondary plant chemistry for both units began to experience significantly elevated sodium levels. The operating crew determined that the chemical injection system was the most likely cause and the injection was terminated immediately. Shutdown of both units commenced in accordance with plant procedures. Inspection of the empty chemical container revealed that sodium phosphate instead of MPA was added.

Both units were shutdown to mode 3 (hot standby) within six hours. Each unit was further cooled down to 110°F and placed in cold shutdown to flush the steam generators and minimize any potential damage.

Cause

The root cause of this event was the failure of the supervisor to obtain the correct procedure for the evolution. The pre-job briefing focused on forklift safety and other safety aspects of the activity and not on the critical aspects of the task. The process of ensuring that the correct chemical was obtained was not discussed. Although a procedure specifying the correct chemical number and brand did exist, involved personnel stated that they were not aware of the procedure, nor did they question the need for a procedure to perform the activity.

Corrective Actions

Shutdown of both units commenced in accordance with plant procedures. The following are the immediate corrective actions that were required to be implemented before the completion of the start-up of both units.

1) The secondary side of the steam generators for Unit 1 was drained and flushed two times to reduce sodium concentrations to 20 ppb level. Unit 2 required three drains and flushes to achieve the same sodium concentration level.

2) Limitations were established on the allowable concentrations for phosphates in the steam generators based on Reactor Coolant System temperature and reactor power during power ascension.

3) The chemical containers in the warehouse were more conspicuously labeled with chemical nomenclature, plant system, and procedure number.

4) A warehouse stock number will be assigned to the chemical containers such that pick-lists would be required to obtain them from the warehouse, thus requiring warehouse and chemistry personnel signatures.

5) Applicable chemistry procedures were revised to include the complete chemical nomenclature, signoffs for each step specifying the chemical, and an independent verification for the chemical.

6) Chemistry and warehouse personnel were briefed on the requirements specified in corrective actions 3-5.

Long term corrective actions for this event are under development. Additional information will be provided when it becomes available.

Safety Significance

Both units were shutdown in accordance with abnormal operating procedures for secondary plant chemistry. No problems were encountered with the shutdown. The actions taken of bringing both units off line and cooling down were to mitigate the potential damage to the steam generators and are consistent with recommendations found in the EPRI Secondary Water Chemistry Guidelines. An evaluation is being performed to consider potential long term impact to the steam generators.

Exhibit ____ (CWK-3)

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
61 FORSYTH STREET SW SUITE 23T85
ATLANTA, GEORGIA 30303-8931

January 3, 2003

Southern Nuclear Operating Company, Inc.
ATTN: Mr. J. Gasser, Vice President
P. O. Box 1295
Birmingham, AL 35201-1295

SUBJECT: VOGTLE ELECTRIC GENERATING PLANT - NRC PROBLEM IDENTIFICATION AND RESOLUTION INSPECTION REPORT NOS. 50-424/02-05 AND 50-425/02-05

Dear Mr. Gasser:

On December 6, 2002, the NRC completed a team inspection at the Vogtle Electric Generating Plant, the enclosed report documents the inspection findings, which were discussed with Mr. George Frederick and other members of your staff during an exit meeting December 5, 2002.

The inspection was an examination of activities conducted under your license as they relate to the identification and resolution of problems, and compliance with the Commission's rules and regulations and with the conditions of your operating license. Within these areas, the inspection involved examination of selected procedures and representative records, observations of activities, and interviews with personnel.

On the basis of the sample selected for review, there were no findings of significance identified. The team concluded that problems were properly identified, evaluated, and resolved within the problem identification and resolution programs. A very low threshold for entering problems into your corrective action program was observed. However, during the inspection, examples of minor problems were identified, including conditions adverse to quality that were not being entered into the corrective action program and narrowly focused corrective actions. Also, human performance errors contributed to two recent manual reactor trips and a dual unit shutdown.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS).

ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Brian R. Bonser, Chief
Reactor Projects Branch 2
Division of Reactor Projects

Docket Nos. 50-424 and 50-425
License Nos. NPF-68 and NPF-81

Enclosure: NRC Inspection Report 50-424/02-05 and 50-425/02-05

cc w/encl: (Seepage 3)

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Distribution w/encl:
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PUBLIC DOCUMENT (circle one): YES

OFFICE	RII:DRP	RII:DRP	RII:DRS				
SIGNATURE	by e-mail	by e-mail	by e-mail				
NAME	TJohnson	TMorrissey	RMoore				
DATE	12/30/2002	12/26/2002	12/30/2002				
E-MAIL COPY?	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO

OFFICIAL RECORD COPY DOCUMENT NAME: C:\ORPCheckout\FileNET\ML030060145.wpd

U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.	50-424 and 50-425
License Nos.	NPF-68 and NPF-81
Report Nos:	50-424/02-05 and 50-425/02-05
Licensee:	Southern Nuclear Operating Company, Inc. (SNC)
Facility:	Vogtle Electric Generating Plant Units 1 and 2
Location:	7821 River Road Waynesboro, GA 30830
Dates:	November 12-15, December 2-6, 2002
Inspectors:	T. Johnson (Lead Inspector), Farley Senior Resident Inspector R. Moore, Reactor Inspector, Region II T. Morrissey, Vogtle Resident Inspector
Approved by:	Brian R. Bonser, Chief Reactor Projects Branch 2 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000424-02-05, IR 05000425-02-05, on November 12-15, and December 2-6, 2002, Southern Nuclear Operating Company; Vogtle Electric Generating Plant, Units 1 and 2, biennial baseline inspection of the identification and resolution of problems.

The inspection was conducted by a senior resident inspector, a resident inspector, and a regional reactor inspector. The inspection focused on corrective action program performance in the period since the previous inspection in January 2001. No findings of significance were identified.

Identification and Resolution of Problems

Overall, the licensee's Corrective Action Program (CAP) was effective at identifying, evaluating, and correcting problems. The threshold for entering problems into the CAP was low, resulting in a large number of Condition Reports (CRs). Problems entered into the CAP were adequately evaluated and appropriate actions were taken to resolve the problem. Recent events, including two reactor trips during low power feed water operations, and a dual unit shutdown due to secondary chemistry problems, were caused in part by human performance errors combined with weak supervisory oversight. The licensee is currently addressing these common root causes and developing corrective actions.

Some instances of missed problem identification were noted. System engineers were found to use the CAP effectively to address equipment issues. Quality Assurance organization audits were effective in identifying issues. Self-assessments were appropriate and findings were entered into the CAP. A safety conscious work environment was found where employees felt free to raise safety issues in CRs or the employee concerns program.

REPORT DETAILS

4. OTHER ACTIVITIES (OA)

4OA2 Problem Identification and Resolution (PI&R)

a. Effectiveness of Problem Identification

(1) Inspection Scope:

The inspectors reviewed issues and items selected across the seven cornerstones of safety that were either documented in NRC inspection reports or entered into the licensee's corrective action program (CAP) since the last performance of an NRC PI&R inspection in January 2001 (Inspection Report (IR) No. 50-424 and 425/2001-02). The inspectors assessed whether these items were being properly identified, characterized, and entered into the CAP for evaluation and resolution. The inspectors discussed PI&R observations from the baseline NRC inspection program with the resident inspectors.

The inspectors reviewed condition reports (CRs) for risk significant systems and discussed them with the responsible system engineer to determine whether problems were effectively identified and evaluated. The risk significant systems the inspectors reviewed included the following: Emergency Diesel Generator (EDG), electrical power, Residual Heat Removal (RHR), Safety Injection (SI), Component Cooling Water (CCW), Nuclear Service Cooling Water (NSCW), and Auxiliary Feedwater (AFW). A walkdown of each system was conducted to assess the material condition and determine if any unidentified degraded equipment conditions existed. The walkdowns were conducted with the system engineer or discussed with the system engineer after the walkdown. The condition of the system, past performance issues, and any planned modifications were discussed. System health reports were also reviewed.

The inspectors verified that problems in CRs were properly evaluated using the Maintenance Rule when appropriate. Selected maintenance work orders were reviewed to verify proper classification of deficiencies as either work orders or CRs.

The inspectors reviewed 15 licensee operating experience (OE) items to determine if they were appropriately evaluated for applicability and if identified problems were entered into the CAP.

During the inspection ongoing plant activities were reviewed including a review of the following: shift turnover meetings, plant status and plan of the day meetings, surveillance testing and maintenance, operational activities including unit trip recovery, startup, and power operation, a Safety Review Board (SRB) meeting, a Human Performance Review Board (HPRB) meeting, and a Plant Review Board (PRB) meeting; operating logs and the Major Problem Status Report (June 2002); and, discussion of issues with plant employees. The inspectors spot-checked completed technical specification surveillances for accuracy and timeliness. In addition, maintenance scheduling was reviewed to verify appropriate risk management was utilized. A sampling of maintenance work orders (MWOs) from calendar years 2001 and 2002 were reviewed to verify proper classification of deficiencies as either work orders or

CRs. The inspectors attended the daily work control meeting to evaluate the interfaces between the work control process and the CAP. Several equipment problems discussed during the plan of the day meetings were selected by the inspectors to verify the issues had been entered into the CAP, if necessary.

The inspectors reviewed self-assessment reports, audit reports, internal assessment reports, HPRB data, and minutes of the PRB and SRB meetings to determine if oversight activities were effective and if self-identified issues were appropriately entered into the CAP. Documents reviewed are listed in the attachment.

(2) Issues:

The licensee's program for identification of problems was effective and provided a suitable mechanism for the identification and documentation of plant problems. The threshold for entering issues was low and employees were encouraged to enter items. Initiators of CRs were from all plant groups which demonstrated the plant staff was familiar and involved with the corrective action program. However, the inspectors found several instances where minor housekeeping problems, fire protection deficiencies, and equipment material issues were not documented in the CAP. Examples included AFW system oil/water leaks, low oil bubbler level, valve position labeling, RHR Limitorque plastic cover, area housekeeping, and fire protection issues. When these issues were identified to the licensee, appropriate actions were taken.

Quality Assurance (QA) group audits were effective in identifying issues. The scope of PRB and SRB meetings was consistent with the documented charter for those activities and addressed CRs, procedure changes, license document changes and modifications in a thorough and questioning manner. The HPRB process provided valuable feedback for the selected human performance related CRs.

As documented in IR 50-424 and 425/2001-02, some issues from the assessments were not entered into the CAP. During this inspection, the inspectors found that self-assessments of the CAP were appropriately scoped and issues identified during the self-assessments were properly entered into the CAP. Self-assessments were performed by most departments.

The licensee was effective in identifying and placing OE issues into the CAP. The inspectors found several examples of actions necessary to address OE issues not entered and tracked in the CAP. In these cases, necessary actions were the responsibility of a cognizant individual, such as a system engineer.

b. Prioritization and Evaluation of Issues

(1) Inspection Scope

The inspectors reviewed the licensee's quarterly trend reports to determine whether identified trends were placed in the CAP. The inspectors also reviewed the Major Problem Status Report (June 2002) and selected completed CRs to determine whether the conditions identified had been resolved. The licensee classified CRs on safety significance ranging from Severity Level (SL) 1 (high significance) through SL 5 (little or no significance). All SL 3 and above CRs required a formal root cause determination.

During the period reviewed, several SL 2 CRs for plant trips were issued. The inspectors reviewed these SL 2 CRs and selected SL 3, SL 4, and SL 5 CRs. A sample of voided CRs was also reviewed to verify they were voided for appropriate reasons.

(2) Issues:

The licensee was generally effective in the use of trending, problem status reports, and SL classification of CRs to prioritize and evaluate issues. Quarterly trend report issues were entered into the CR program as SL 3 CRs and were appropriately evaluated. Classification levels were appropriate for the sample of CRs reviewed.

A concern with the licensee's resolution of configuration control problems was identified in IR 50-424 and 425/01-02. The effectiveness of corrective actions was limited and the condition of excessive mis-positions was not captured in an overall trend CR. Therefore, a scope analysis and comprehensive corrective action plan had not been developed. In response to this concern, the licensee initiated CR 2001000135 which resulted in the licensee performing a scope analysis and developing a comprehensive corrective action plan. The inspectors found that the corrective actions in this plan were extensive and included increased management oversight, training, individual evaluations of mis-position occurrences, benchmarking mis-positions at another nuclear station, a place-keeping policy for procedures which manipulate components, and post job briefings to specifically address configuration restoration. Additionally, "valve, breaker, switch mis-positions" were tracked as an area of interest in the Station Quarterly Trend Report.

The inspectors identified that CRs 2002002570 and 2002002796 did not address all the root causes. CR 2002002570, a SL 3 CR regarding a maintenance preventable functional failure, did not properly address the human performance root cause. The licensee documented this issue in the CAP as CR 2002003540. CR 2002002796 concerned a personnel error (wrong train event) during surveillance testing. During the HPRB, the licensee also identified that the root cause and corrective actions were narrowly focused. The licensee took actions for additional review of the CR.

c. Effectiveness of Corrective Actions

(1) Inspection Scope:

The inspectors reviewed root cause evaluations, corrective actions, the backlog of open items and actions items, and selected CRs to determine if appropriate corrective actions were documented, assigned, and implemented. This included verification of Action and Open Item Tracking activities and maintenance work orders or modification packages which implemented corrective actions. Where possible field verification of corrective actions was performed. The inspectors attended an HPRB meeting.

The inspectors reviewed licensee actions relative to two reactor trips, Unit 1 on April 20, 2002, and Unit 2 on November 13, 2002, caused partly by human error. The inspectors were also briefed by the licensee of an on-going event investigation of a forced dual unit shutdown on November 24, 2002, due to secondary chemistry problems. The inspectors reviewed the related CRs, event investigations, trends, and selected corrective actions to evaluate effectiveness. The inspectors also attended several event investigation meetings associated with the Unit 2 reactor trip.

(2) Issues:

In general, corrective actions were effective. System engineers were knowledgeable of equipment issues and effectively used the CAP to deal with equipment issues. The inspectors monitored the effectiveness of corrective actions and concluded the backlog of open items and action items were manageable.

The Open and Action Item Tracking processes were effective in verifying the completion of specified corrective actions in CRs and LERs. The inspectors were able to verify that the specified corrective actions were performed. With respect to configuration control issues discussed in the previous P&IR report, although mis-positioning continued to occur, the trending information showed improvement which indicated the corrective actions were having a positive effect on station activities.

The root causes for two unit trips and the dual unit shutdown were similar. This included procedural non compliances (not following the procedure or unaware of procedure existence) and weak supervisory oversight. The oversight weaknesses included missed or weak pre-job briefings, conducting risk significant activities in parallel, weak command and control, and poor communications. While some initiatives had been implemented, the licensee had not yet achieved positive results from their corrective actions.

The inspectors found the multi-discipline event team assembled for the most recent Unit 2 reactor trip was effective in developing corrective actions. The event team appropriately reviewed the effectiveness of the corrective actions associated with a similarly caused trip of Unit 1. The inspectors found the corrective actions associated with the Unit 1 trip were adequate. However, the corrective actions focused primarily on the specifics of the trip. Operator performance, including procedure use during startup and lower power feed water operations was not addressed. Also, there were no corrective actions relative to supervisory performance or command and control expectations. The inspectors characterized this as a missed opportunity.

d. Assessment of Safety-Conscious Work Environment

(1) Inspection Scope:

The inspectors assessed if any conditions existed causing employees' reluctance to raise safety issues. This included identifying deficient conditions through the CAP and the understanding and use of the employee concerns program (ECP) . The inspectors also reviewed the ECP procedure and a summary of employee concerns and interviewed the ECP supervisor to assess visibility of the program.

(2) Issues:

The inspectors determined the licensee had established and maintained a safety-conscious work environment as evidenced by the number of CRs written, a visible ECP, and the results of the NRC discussions during the course of the inspection.

All employees were aware of the process and the location and accessibility of the ECP coordinator. The inspectors concluded that employees felt free to raise issues.

4OA6 Management Meetings

Exit Meeting Summary

Inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on December 5, 2002. The licensee acknowledged the findings presented. No proprietary information was identified.

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

W. Bargeron, Plant Support Assistant General Manager
W. Burmeister, Manager Engineering Support
G. Frederick, Plant General Manager
T. Petrak, Maintenance Supervisor
P. Rushton, Plant Operations Assistant General Manager
M. Sheibani, NSAC Supervisor
T. Tynan, Operations Manager

LIST OF DOCUMENTS REVIEWED

Licensee Procedures:
00150-C, Condition Reporting and Tracking System
80014-C, Handling of Condition Reports for Deficient Conditions
80016-C, Trend Identification and Reporting
00040-C, Self Assessment Program
00414-C, Operating Experience Program
VSAER-WP-03, Safety Audit and Engineering Review Field Audits
VSAER-WP-05, Annual SAER Department Assessment
00058-C, Root Cause Determination
00409-C, Action Item, Open Item, and Commitment Tracking
VNS-AP-16, Condition Reporting and Tracking System
SNOC Concerns Program Procedure
00057-C, Event Investigation
50028-C, Engineering Maintenance Rule Implementation
50023-C, System Health and Monitoring Program
00354-C, Maintenance Scheduling
29540-C, Risk Assessment Monitoring
29542-C, Shutdown Risk Assessment
10000-C, Conduct of Operations
00002-C, Plant Review Board - Duties and Responsibilities
VSRB-05, Southern Nuclear Vogtle Project Support, Safety Review Board
00056-C, 10 CFR 50.59 Screening and Evaluations
28707-C, 480 Volt Air Circuit Breaker Maintenance and 60 Month Check
00404-C, Surveillance Test Program
00409-C, Action Item, Open Item, and Commitment Tracking
10024-C, Equipment Troubleshooting
81060-C, Open Item/Commitment Tracking Program Coordination
VSAER-WP-03, Safety Audit and Engineering Review Field Audits

Operating Experience:
IN 2001-09, Main Feedwater System Degradation in Safety-Related ASME Code Class 2 Piping inside the Containment of a Pressurized Water Reactor

IN 2002-09, Potential for Top Nozzle Separation and Dropping of a Certain Type of Westinghouse Fuel Assembly
IN 2002-24, Potential Problems with Heat Collectors on Fire Protection Sprinklers
IN 2002-25, Challenges to Licencees' Ability to Provide Prompt Public Notification and Information During an Emergency Preparedness Event
IN 2002-02, Supplement 1, Recent Experience with Plugged Steam Generator Tubes
IN 2002-18, Effect of Adding Gas into Water Storage Tanks on the Net Positive Suction Head for Pumps
SER 2-01, EDG Failure Resulting from Inadequate Performance Monitoring and Inadequate Response to Symptoms of Impending Failure
SER 3-02, Workers Exit Plant Site with Detectable External Radioactive Contamination
SER 5-01, 4-kV Breaker Failure, Switchgear Fire and Turbine Generator Damage
SEN 220, Pressure Boundary Leakage at Palisades
SEN 226, Stress Corrosion Cracking on a Portion of Safety Injection System Piping
SEN 230, Pressurizer Spray Valve Failure Resulting in Reactor Scram and Safety Injection
RIS 01-015, Performance of DC- Powered Motor-Operated Valve Actuators
RIS 01-009, Control of Hazard Barriers
OE 14513, Concern with Boron Concentration in Mode 3 below P-11 with SI Blocked

Condition Reports:

2001000203	2001002960	2001000162	2001001064	2001000434	2001001069
2001000468	2001001106	2001000598	2001001837	2001001460	2001001853
2001000727	2001002194	2001000529	2001002198	2001000533	2001002246
2001000970	2002000103	2001000971	2002001700	2001001443	2002002212
2001001444	2002002645	2001001514	2001003040	2001001516	2002000744
2001001582	2002000745	2001002097	2002000856	2001002951	2001000006
2001001580	2001001704	2001000165	2001000464	2001000581	2001002138
2001001907	2001002139	2001000960	2001002142	2002000319	2001002141
2001000681	2002000090	2001000178	2002000264	2002000301	2001000043
2001000132	2001000299	2001000307	2002002295	2001000310	2001000423
2001000519	2001003034	2001000723	2001002083	2002000723	2002001319
2000001563	2001000031	2001000113	2001000501	2001001022	2001002604
2002000107	2002000518	2002002281	2002001328	2001000361	2002002581
2002003295	2002002023	2002001647	2002001371	2002000589	2002002430
2002002685	2002001992	2002002302	2002002429	2002001841	2002002122
2002002224	2001000988	2001001061	2001001686	2001002177	2001002250
2001002570	2001002711	2001002771	2002000088	2002000431	2002000756
2002000859	2002001062	2002001088	2002001129	2002001299	2002001540
2002001655	2002001837	2002002385			

Maintenance Work Orders:

Maintenance Work Orders for SI, RHR, AFW, EDG, CCW, NSCW, AC power

10101119	20200276	20100832	20101733	20101413	20102735
10101119	20200276	20102735	20101413	20101733	10100044
10100539	10101390	10101430	10101639	10102299	10102307
10103500	10200764	10101084	20102150		

Licensee Audits and Self-Assessments:

SAER Audit of Corrective Actions, OP21-02/15, VSAER-2002-079
SAER Audit of Corrective Actions, OP21-01/01, VSAER-2001-013

SAER Audit of Corrective Actions, OP21-00/14, VSAER-2000-077
SAER Audit of Corrective Actions, OP21-02/01, VSAER-2002-019
SAER Audit of Corrective Actions, OP21-01/16, VSAER-2001-071
SAER Audit of Outage Activities, OP06/16/17/25/26-01/08,VSAER-2001-039
SAER Audit of Fire Protection Program, OP20-02/11, VSAER-2002-062
Count Room and Chemistry Self-Assessment, NOH-02449, July 2002
Maintenance Fire Protection Self-Assessment, NOM-02252, May 2002
Training Department Self-Assessment, February 2002
Health Physics Self-Assessment, NOH-02452, July 2002
Engineering Support Department Self-Assessment, NOE-03480, November 2001
Equipment Reliability Self-Assessment, NOE-03493, July 2002
2002 Operations Self Assessment, NOP 01357, June 2002

Safety Review Board (corporate) Meeting Minutes
Major Meetings: 02-02, 02-03, 02-05, 01-02, 01-04, 01-05, 01-08

Plant Safety Review Board (station) Minutes
9/11/02, 9/10/02, 8/30/02, 8/27/02, 8/20/02, 8/13/02

NRC Violations
NCV 50-424,425/00-05-02 (CR 2000001563)
NCV 50-424,425/00-06-01 (CR 2001000521)
NCV 50-424,425/01-03-01 (CR 2001000477)
NCV 50-424,425/01-03-02 (CR 2001000694)
NCV 50-424,425/01-08-01 (CR 2001002851)
NCV 50-424,425/02-02-01 (CR 2002001165, 2002001172, 2002001322)
NCV 50-424,425/02-02-02 (CR 2002001346, 2002001392, 2002001697)
NCV 50-424,425/02-02-03 (CR 2002001251)
NCV 50-424,425/02-02-04 (CR 20020000723, 2002001223)

Vogtle Quarterly Trend Reports
May - July, 2002
February - April, 2002
November, 2001 - January 2002
August - October, 2001
May - July, 2001

LERs, Event Investigation Reports (EIR)
LER 1-2001-001, Unit 1 Reactor Trip Due to Loss of Generator Excitation
EIR 1-2003-03, Reactor Trip due to Generator Excitation Loss
LER 1-2002-001, Improperly Wired Interlock Affects ECCS Re-circulation Valve
LER 2-2001-001, Reactor Trip While Testing Main Feedwater Pump Trip Signals
EIR 2-2001-01, Reactor Trip Due to Loss of Feedwater Flow
LER 1-2002-003, Loss of Main Feedwater ESF Actuation and Manual Reactor Trip
EIR 1-2002-001, Loss of Main Feedwater and Manual Reactor Trip
LER 1-2002-002, Containment Isolation Valve Rendered Inoperable
EIR 2-2002–002, Both Units Shutdown Due to Wrong Chemicals Added to Feed Systems
EIR 2-2002–001, Manual Reactor Trip Due to SG#3 HI-HI Level

Exhibit___ (CWK-4)(RH/DB 2)

GEORGIA POWER COMPANY
PROJECTED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2002, 2003 and 2004
($ in thousands)

	2002	2003	2004
Investing Activities:			
Gross property additions	(970,694)	(751,428)	(808,723)
Other	(34,287)	(6,393)	(5,513)
Net cash needed for investing activities	(1,004,981)	(757,821)	(814,236)
Operating Activities:			
Net income before preferred stock dividends	585,672	603,457	624,599
Adjustments to reconcile net income to net			
cash provided from operating activities --			
Depreciation and amortization	555,183	557,792	573,518
Amortization of Regulatory Liability	(112,132)	(112,132)	(112,132)
Deferred income taxes and investment tax credits, net	8,901	29,810	63,780
Other, net	(855)	(19,585)	(96,040)
Changes in certain current assets and liabilities --			
Receivables and payables, net	(1,478)	(29,528)	(14,669)
Fossil fuel stock	52,759	20,000	0
Materials and supplies	238	20,000	(3,670)
Collections of under recovered fuel cost	125,666	35,796	0
Other	40,242	57,680	60,523
Payment of preferred stock dividends	(672)	(672)	(672)
Payment of common stock dividends	(542,900)	(565,100)	(577,800)
Net cash provided from operating activities after dividends	710,624	597,518	517,437
Net cash shortfall before financing activities	(294,357)	(160,303)	(296,799)
Financing Activities:			
Proceeds from Security Sales			
Senior notes	450,000	500,000	400,000
Preferred securities	750,000	0	0
Total Proceeds	1,200,000	500,000	400,000
Security Retirements at Maturity or by Refunding			
Senior notes	(300,000)	(350,000)	(100,000)
Preferred securities	(589,250)	0	0
Total Redemptions	(889,250)	(350,000)	(100,000)
Net New Money Provided from Long Term Security Transactions	310,750	150,000	300,000
Other Financing Activities:			
Capital contributions from parent company	127,000	21,000	118,000
Capital distributions to parent company from Wansley CC sale	(200,000)	0	0
(Decrease) increase in notes payable, net	(349,592)	1,429	(110,898)
Sale of Plant Wansley Combined Cycles	415,498	0	0
Net Change in Cash and Cash Equivalents	16,661	0	0
Other	(25,960)	(12,126)	(10,303)
Net cash provided from financing activities	294,357	160,303	296,799

Exhibit______(CWK-5)

Georgia Power Company
Deferred Fuel and Purchased Power Costs, June 2001 - August 2003

	A	B	C	D		E	F	G
	Revenues	Expenses	Economy Credits	Adjustments		Carrying Cost Rate	Carrying Charge	Cumulative Under-Recovery
May-01								(91,680,904)
Jun-01	144,185,816	171,583,570						(119,078,658)
Jul-01	119,116,636	162,276,288						(162,238,309)
Aug-01	168,025,010	216,715,493		151,650	A			(211,080,443)
Sep-01	130,665,495	113,777,375						(194,192,323)
Oct-01	111,665,592	111,531,531						(194,058,262)
Nov-01	112,363,239	89,347,354						(171,042,377)
Dec-01	107,859,868	96,985,990	70	1,293,681	B			(161,462,111)
Jan-02	116,483,276	103,122,559	350.54			12.94%	1,067,825	(149,168,868)
Feb-02	107,209,682	86,657,187	37.52			12.52%	954,326	(129,570,661)
Mar-02	109,470,093	104,810,498	170.65			11.92%	789,231	(125,700,127)
Apr-02	117,593,943	115,827,176	102	852,804	C	11.85%	761,430	(125,547,492)
May-02	117,768,365	120,389,654	352			12.32%	790,334	(128,958,763)
Jun-02	135,284,868	129,173,596	164	597,250	D	12.28%	809,060	(124,253,637)
Jul-02	151,735,853	161,573,530	116			11.99%	761,061	(134,852,258)
Aug-02	147,861,696	152,117,554	204			12.10%	833,852	(139,941,763)
Sep-02	143,523,356	134,833,013	(16)			12.61%	901,693	(132,153,128)
Oct-02	125,071,270	126,541,548	433			12.58%	849,375	(134,472,347)
Nov-02	119,901,258	111,650,518	2,341			12.70%	872,521	(127,091,787)
Dec-02	130,323,587	119,307,007	884	(13,436,679)	E	12.33%	800,670	(103,438,315)
Jan-03	134,797,343	145,899,908	118			12.41%	655,722	(115,196,483)
Feb-03	128,947,249	112,281,330	61			12.58%	740,362	(99,270,865)
Mar-03	116,921,898	110,190,374	7			12.58%	638,009	(93,177,342)
Apr-03	116,518,422	127,824,389	41			12.58%	598,846	(105,082,114)
May-03	98,925,486	98,401,231				12.58%	675,357	(105,233,216)
Jun-03 e	110,423,438	114,016,747				12.58%	676,328	(109,502,853)
Jul-03 e	142,794,800	161,422,007	330,000			12.58%	703,769	(128,503,829)
Aug-03 e	148,418,143	160,625,198	220,000			12.58%	825,887	(141,316,771)

Source: Georgia Power Monthly Fuel Cost Recovery Reports

A Consists of the following adjustments reflected in August 2001 on the Report of Retail Fuel Cost Recovery:

Prior Period adjustment to CSS booked economy sales (booked 6/01).	158,078
Prior period adjustment to economy credit calculation (booked 8/01)	(6,323)
Correction to economy sales credit calculation (booked 7/01)	602
CSS booked economy credit (booked 11/01)	(709)
	151,648

B Consists of December 2001 reconciling items and prior period economy credits.

C Consists of April 2002 reconciling items and economy credits.

D Consists of June 2002 reconciling items and economy credits.

E Consists of disallowance for nuclear plant outages.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of THE DETROIT EDISON COMPANY to increase rates, amend its rate schedules governing the distribution and supply of electric energy, implement Power Supply Cost Recovery plans, factors and reconciliations in its rate schedules for jurisdictional sales of electricity and for miscellaneous accounting authority and regulatory asset recovery.

MPSC Case No. U-13808

Direct Testimony of Charles W. King Concerning Final Rates

March 5, 2004

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

A. My name is Charles W. King. I am President of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. For whom are you testifying in this proceeding?

A. I am testifying on behalf of the Attorney General of Michigan.

Q. Are you the same Charles W. King who submitted prefiled testimony concerning interim rate relief on December 12, 2003?

A. Yes. I am.

Q. Did that testimony have attachments that described your qualifications and prior appearances before regulatory bodies?

A. Yes. Attachment A to that testimony is a resume of my experience and education. Attachment B is a list of my appearances before regulatory agencies as an expert witness. These attachments may be found at 10 T 1796 – 1810.

Q. What is the purpose of this testimony?

A. The purpose this testimony is to present the position of the Attorney General on a number of the issues that remain undecided following the issuance of the Commission's February 20, 2004 Order Granting Interim Rate Relief ("Interim Order"). In that Order, the Commission decided a number of issues for interim relief purposes, deferred others to the final rates phase, and did not address several other issues that were not raised in the interim relief phase.

Q. What issues not mentioned in the Interim Order must be considered in the final phase?

A. There are at least four:

- Class cost allocation and rate design
- Edison's capital structure and the authorized rate of return;
- Edison's proposed 2005 and 2006 rate increases; and
- Edison's proposed earnings sharing mechanism.

Q. What issues concerning final rates will you address in this testimony?

A. I will address the following issues:

- Statutory prohibition of rate increases and cost shifting;
- Stranded costs and the mitigation adjustment;
- Edison's proposed 2005 and 2006 rate increases;
- Pension cost recovery;
- Other Post-Employment Benefits ("OPEB") cost recovery;
- Management Retirement Benefit Plans;
- DTE's proposed merger control premium;
- The vehicle for recovering ITC and MISO transmission costs; and
- Edison's proposed earnings sharing mechanism

Q. Would you please summarize your conclusions regarding these issues.

A. First, as discussed in my earlier testimony, Act 141 prohibits rate increases for residential customers and small business customers until 2006 and 2005, respectively. While these rate caps are in effect, the Act prohibits cost shifting from customers with capped rates to customers without capped rates. This precludes implementation of most of Edison's rate increase. An analysis of class-by-class cost responsibility indicates that among the uncapped customer classes, only a small increase in the Primary Service class rates and a larger percentage increase in the Special Manufacturing Contract ("SMC") class could occur without shifting costs between capped and uncapped customers.

<u>Second,</u> my analysis of the costs and revenues related to the generation function indicates that there is a revenue sufficiency to this function. Based on the Commission's test of stranded costs, this sufficiency means that there are no stranded costs to be recovered in transition charges to Retail Open Access ("ROA") customers. However, if there are stranded costs, those costs should be mitigated by the application of net proceeds from off-system sales.

<u>Third</u>, the Commission should not in this case approve rate increases in 2005 and 2006 for customers whose rates are statutorily capped during 2004 and 2005.

<u>Fourth,</u> Edison's pension costs are spiking in 2004 and will decline in the subsequent years. For this reason, pension costs should be normalized based on the average of Edison's 2002-2004 pension costs ($74.4 million). The identical situation applies to Other Post-Employment Benefits ("OPEB") costs. The three-year average of these costs is $81.7 million.

<u>Fifth</u>, the Commission should disallow $4.1 million in Management Retirement Benefit Plans because these plans do not qualify under ERISA, because the same individuals who decide what benefits will be paid under these plans also receive those benefits, and because the recipients of these plans are the direct representatives of the Company's shareholders.

<u>Sixth</u>, the Commission should disallow Edison's proposed $85.3 million recovery for DTE's merger control premium because the premium costs were incurred by DTE, not Edison; because the premium does not represent costs of production, transmission and distribution; because the proposal would represent a double-recovery of the premium to previous MCN shareholders and, to some extent, to Edison shareholders; and because authorizing recovery would set an undesirable

precedent for future mergers and acquisitions not subject to Commission approval.

Seventh, the appropriate vehicle for recovering transmission costs is base rates, not Edison's PSCR factor, because transmission costs do not fit into the statutory definition of PSCR costs; because they are not variable and unpredictable; and because they are based on maximum demand, not on energy consumption, which is the measure by which PSCR costs are recovered.

Eighth, The Company's earnings sharing mechanism should be rejected because it is a device for retroactively recovering earnings lost due to statutory rate caps.

Statutory Prohibition of Rate Increases and Cost Shifting

Q. What are the statutory prohibitions that you are addressing in this part of your testimony?

A. I am addressing the prohibitions in Sections 10d(2) and 10d(5) of 2000 Public Act 141 ("Act 141"). These sections prohibit rate increases for residential customers during 2004 and 2005, and they prohibit rate increases for small business customers during 2004. They also forbid the shifting of costs among customer classes during the period when rate caps apply to any customer class. Section 10d(2) specifically prohibits cost shifting from capped to uncapped customers.

Q. Did you discuss class revenue requirements in your earlier testimony in the interim rate phase of this case?

A. Yes. That discussion is found in my earlier testimony at 10 T 1780 to 1789. The relevant Exhibits are I-52 through I-55.

Q. What did you conclude in that testimony?

A. I examined Edison's 2002 cost of service study that allocated all of the Company's costs among the respective customer classes. I objected to the current practice of allocating the costs of the generation function 75 percent on the basis of the classes' 12 monthly coincident peak demands and 25 percent on their relative consumption of energy. Instead, I proposed that generation costs be allocated on the basis of the distribution of investment among the three types of generating plant: base load, peaking and cycling. I found that 65.4 percent of Edison's generating plant investment is in base load plants, 29.2 percent is in cycling plants, and that the remaining 5.4 percent is in peaking plants. I therefore recommended that 65.4 percent of generating costs be allocated among customer classes on the basis of energy, 29.2 percent be allocated according to the classes' 12 monthly coincident peaks, and 5.4 percent be allocated on the basis of the average of four summer coincident peaks.

I reallocated Edison's 2002 costs based on these factors. I then trended the class revenue requirements from 2002 to 2004 according to Edison's predictions of the change in overall revenue requirement between the two years. A comparison of the projected 2004 revenue and class revenue requirements for customers whose rates are uncapped in 2004 reveals that, absent cost shifting, there is no justification for increasing rates for the General Service, Large General Service and Large Customer Contract ("LCC") classes. A small increase is justified for the Primary class, and a rather larger increase would appear appropriate for the Special Manufacturing Contract ("SMC") class.

Q. Did the Commission review this evidence in its Interim Order?

A. No. The Commission did not finally decide how the statutory prohibitions upon rate increases and cost shifting among customer classes should be implemented.

Q. How should the Commission implement the statutory prohibition on rate increases and cost shifting?

A. As my discussion of class revenue requirements indicates, the Act 141 prohibition against cost shifting precludes almost all of Edison's proposed rate increases to uncapped customers. The Commission may implement a small increase for Primary Service customers and a larger percentage increase for SMC customers after their contracts end.

Q. May the Company recover any additional revenue from its rate-capped customers?

A. That appears to be a legal question which I am not qualified to answer.

<u>Stranded Costs and Edison's Mitigation Adjustment</u>

Q. How does the Commission measure stranded costs?

A. In Case No. U-12639, the Commission adopted a procedure that compares the revenue requirement for the generation component of the Company's operations with the revenue that can be ascribed to power supply, as opposed to transmission, distribution and customer service. If generation-related revenues cover generation-related costs (including return), there are no stranded costs. If the generation-related revenue is less than the generation-related revenue requirement, then stranded costs are presumed to exist. Those stranded costs would then be recovered from ROA customers through non-bypassable transition charges. This procedure uses historical data to perform the separation of generation costs and revenues.[1]

[1] <u>Opinion and Order</u>, Case No. U-12639, December 20, 2001

Q. **Have you compared generation-related costs and revenues consistent with the Commission's approved methodology?**

A. Yes. On page 1 of Exhibit I-56, I have calculated the 2002 revenue requirement for the generation, transmission, distribution and other functional categories. On page 2, I calculated the distribution-related revenue by applying the Retail Access Service Tariff proposed by Edison to the total usage of all customers. I then subtracted that revenue from the Company's total revenue to arrive at the revenue that can be ascribed to the generation and transmission functions. When I compared the generation and transmission revenue requirement with the generation and transmission revenue, I found a revenue sufficiency of $279 million.

Q. **What did you conclude from this analysis?**

A. I concluded that there are no stranded costs and therefore that there should be no transition charge.

Q. **Does the Commission Staff agree with you?**

No. The Staff Report submitted by Staff witness William Aldrich simultaneously with my interim testimony asserts that there is a generation related revenue deficiency of $122 million. The report did not elaborate on how that number was derived.

Q. **If there are stranded costs, how should they be recovered?**

A. If the Commission concludes that there are stranded costs, then the Commission should allocate those costs to the ROA customers who caused them. This treatment is consistent with the Commission's original ruling in the first electric restructuring case (U-11290).

Q. Assuming there are stranded costs, should they by "mitigated" by means of Edison's proposed mitigation adjustment?

A. Yes. If the Commission finds that there are stranded costs, it would then be appropriate to apply the proceeds from off-system power sales as an offset to those costs. That is because the sales probably would not have been possible but for the generating capacity freed up by the transfer of ROA customers from Edison's generating system to that of other power providers. On the other hand, if there are no stranded costs, then the net proceeds from power sales should be applied to the PSCR and flowed through to Edison's retail customers.

<u>Edison's Proposed 2005 and 2006 Rate Increases</u>

Q. Why are rate increases in 2005 and 2006 being considered in this proceeding?

A. Edison has proposed 2005 and 2006 rate increases because the rates for residential customers are capped until January 1, 2006 and those for commercial or manufacturing customers with demands under 15 kW are capped until January 1, 2005. Edison requests approval now for increases in these customers' rates when their rate caps expire.

Q. Did the Commission address Edison's proposed 2005 and 2006 rate increases in its Interim Order?

A. No. The Interim Order dealt only with 2004 costs and the rates that should be set pending the finding of final rates in this case.

Q. Should the Commission address Edison's 2005 and 2006 rate increases in its final order?

A. No. As I pointed out in my earlier testimony, the Commission has received detailed evidence in this case only for Edison's costs and revenues in 2004. In addition, 2004 is the undisputed test year. There is insufficient reason to conclude that 2004 costs and revenues are appropriate for the years 2005 and 2006. Indeed, as I shall discuss shortly, there is reason to believe that pension and OPEB costs, in particular, will decline in 2005 and 2006.

Q. How should the 2005 and 2006 rates be set?

A. The Commission should inform Edison that if it wishes to increase the rates for small commercial customers in 2005, it should submit a rate case with 2005 cost and revenue data to support it. If Edison seeks an increase for 2006, it should submit a rate case based on 2006 revenue requirements. In no case should the Commission assume that 2004 costs are an appropriate basis for 2005 and 2006 rate increases.

Pension Cost Recovery

Q. What is Edison seeking to recover for employee pensions?

A. Edison originally sought to recover $111.7 million in pension costs for the year 2004. The Company has since updated this claim to $113.3 million

Q. What are the components of this $113.3 million?

A. The $113.3 million consists of the following components:[2]

[2] See Testimony of D.G. Brudzynski 7 T 901-903 and Exhibit A-16, Schedule F5-20.

- \$49.7 million in "service costs," which are the projected benefits earned by active employees during the current period on a present value basis,
- \$130.3 million in "interest costs," representing the year's accretion in the present value of the Projected Benefit Obligation ("PBO"),
- \$8.8 million in amortization of "prior service costs," that result from changes in the benefit plans that increase the PBO for existing employees and that are amortized over the remaining service years of the affected employees,
- \$50.0 million, described in Mr. Brudzynski's testimony as the amortization of the net loss in the value of the assets in the pension fund. More specifically, Mr. Brudzynski testified at the hearing that this is the amortization over 12 years of the difference between the current value of the fund assets and the present value of the Accumulated Benefit Obligation ("ABO"),[3]
- An offset of \$125.5 million for the expected return on the assets in the pension fund.

Q. What were the pension costs during the two previous years, 2002 and 2003?

A. In 2002, pension costs were \$31.4 million. In 2003 they were \$78.7 million.[4] This means that the 2004 pension cost is 44 percent greater than that for 2003 and 3.6 times the cost for 2002.

Q. What accounts for the apparent volatility of Edison's pension costs?

A. Two factors account for this volatility in pension costs. The first is the interest rate, and the second is the value of the assets in the pension fund.

Q. Why does the interest rate create volatility in pension costs?

[3] 8 T 1087

[4] Exhibit A-16, Schedule F-20.

A. Edison uses the December 31 yield on Moody's AA corporate bonds as the interest rate for discounting the PBO and the ABO to their present value for the next year. When the interest rate is lower, the present value is higher. When the present value of the PBO is higher, then the service costs are higher. When the present value of the ABO is higher, the more likely it is to exceed the asset value of the pension fund and require an amortization of any shortfall in pension funding. Also, a lower interest rate has the counter-intuitive effect of increasing the interest costs on the ABO. That is because as present value of the ABO increases, the annual accretion in that value is correspondingly larger.

Q. What has been the recent history of the interest rates used to calculate the present value of the PBO and the ABO?

A. During the January hearings, Edison witness Brudzynski testified that the 2002 interest rate was 7.25 percent, the interest rate used in his June 2003 filing was 6.75 percent, but that the expected 2004 interest rate is likely to be approximately 6.25 percent.[5] These declining values reflect the reduction in yields on Moody's AA corporate bonds.

Q. Why does the asset value of the pension fund create volatility in pension costs?

A. As the asset value of the pension fund changes, the differential between that value and the present value of the ABO changes correspondingly. If the asset value falls, that differential increases, and if it results in a shortfall, the pension fund is determined to be under-funded. The greater the under-funding is; the larger the annual amortization of that under-funding is.

Q. What has been the recent history of the asset value of the pension fund?

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[5] 7 T 893, 905.

A. According to Mr. Brudzynski, the pension fund lost $261 million in value in 2001 and another $222 million in 2002. Through November of 2003, it had gained $161 million in value.[6]

Q. How does the pension fund compare with the present value of the ABO as of the end of 2003?

A. Exhibit A-16, Schedule F5-22 indicates that, based on year-end 2002 factors, the value of the pension fund was $540 below the ABO as then calculated. During the January hearings, Mr. Brudzynski testified that updating the interest rate and the gain in the value of the pension find results in an increase in pension expense of $20 million. While the market value of the pension fund increased by $191 million, this increase had the effect of reducing expense by only $9 million. Meanwhile, the drop in interest rates to 6.25 percent resulted in an increase in the ABO of $221 million, which translates into an increase in pension expense of $29 million.[7]

Q. What is the likely future trend in interest rates?

A. Interest rates on high-grade corporate bonds are currently at a 37-year low.[8] Given the size of both the Federal budget deficit and the national trade deficit, it is unlikely that these very low interest rates can continue indefinitely into the future. On December 9, 2993, the economic research firm Macroeconomic Advisors released its 10-year forecasts of national product, income, inflation and interest rates. It forecasts a slow but steady increase in interest rates throughout the coming decade, as follows:[9]

[6] 7 T 1116, 1117.
[7] 7 T 892, 893.
[8] See http://www.federalreserve.gov/releases/h15/data/m/aaa.txt
[9] Macroeconomic Advisers, LLC, "Long-Term Economic Outlook", December 9, 2003.

	Bond Yields	
	10-year Treasury Bonds	Aaa Corporate Bonds
2003	4.01%	5.66%
2004	4.56%	5.74%
2005	5.27%	6.36%
2006	5.75%	6.84%
2007	5.86%	6.95%
2008	5.97%	7.06%
2009	6.01%	7.10%
2010	6.09%	7.18%
2011	6.11%	7.20%
2012	6.14%	7.23%

Q. What is the likely trend in the value of Edison's pension fund assets?

A. During the coming two years, that value will almost certainly increase. That is because Edison does not fully revalue its pension assets each year. Rather, it uses a "smoothing" technique in which only one-third of each year's gain or loss is recognized in the annual valuation of the pension fund. The remaining two-thirds are amortized into the revaluation over the next two years.

This smoothing process explains why, even though the fund increased in value by $161 million during 2003, the effect of that gain on pension costs is only $9 million. The revaluation at the end of 2003 will recognize only one-third of this increase, or $54 million. Meanwhile, it is still recognizing one third of the $222 million decline in value in 2002 and one-third of the $261 decline in 2003.

Even if there is no further increase in the value of the pension assets during 2004 and 2005, the valuation of the pension fund for purposes of computing pension expense will increase. At the end of 2004, the 2001 loss will have been fully amortized, and at the end of 2005, the 2002 loss will have been fully recognized. Meanwhile, the $54 million one-third of the 2003 gain will continue to be incorporated into the restated pension fund value.

Only if the securities markets decline to the same extent as they did during 2001 and 2002 will Edison's pension fund fail to display a gain for purposes of calculating pension expense at the end of 2004 and 2005.

Q. What do you conclude regarding the future of Edison's pension expense?

A. I conclude that if interest rates rise as predicted, the present value of Edison PBO and ABO will decline, reducing both service costs and interest costs and closing the gap between the ABO and the pension fund asset value. That gap will also reduce owing to the increase in the computed value of the asset value of the pension fund resulting from the full amortization of losses inherited from 2001 and 2002. It appears that the pension costs computed for 2004 are likely to be the peak pension costs that Edison has experienced and that it will experience in the immediate future.

Q. What is the relevance of these observations for this rate case?

A. In its Interim Order, the Commission approved the recovery of $113.5 million in pension expense on the condition that Edison contribute an equivalent amount into the pension fund each year for as long as these rates are in effect. By "these rates," it is not clear whether the Commission is referring to the interim rates or to the final rates that result from this case. However, in view of the reference to multiple year contributions, it would appear that the Commission means any rates that result from this case that include the $113.5 million pension expense. If so, then the Commission intends to lock $113.5 million in pension costs into Edison's revenue recovery.

Q. Is this a satisfactory solution, in your opinion?

A. No. As I have noted, the pension expense is almost certain to decline in the years subsequent to the test year in this case. The additional annual contributions that the Commission proposes will accelerate the decline in pension expense in the years following 2004. In only two or three years, the $113.5 million included in base rates will become a very large over-recovery of pension costs.

Q. What is the appropriate resolution of this problem?

A. The Commission should modify its $113.5 million quantification of pension costs to reflect a more "normalized" annual level.

Q. Can you recommend a normalized level of pension costs?

A. Yes. I recommend using an average of the three most recent years' pension costs as calculated by Edison:[10]

2002	$31,352,000
2003	78,691,000
2004	113,300,000
Total	$223,343,000
Average	$74,447,667

Other Post-Employment Benefits

Q. What are Other Post-Employment Benefits?

A. Other Post-Employment Benefits ("OPEBs") are principally the health insurance that the Company provides to its employees after they retire. In this regard they are very much like pensions.

Q. What is Edison seeking for OPEBs in its revenue requirement calculation?

A. Edison is seeking $105.7 million in OPEB costs.

[10] Exhibit A-16, Schedule F5-20.

Q. What are the elements of Edison claimed OPEB cost?

A. The elements are the same as those described for pensions, with one addition, as follows:[11]

Element	2004 Cost in Millions
Service Cost	$34.3
Interest Cost	75.1
Less Expected Return on Assets	(42.1)
Amortization	
Transition Costs	8.2
Prior Service Costs	.1
(Gain) Loss in Asset Value	30.1
Total	$105.7

The one addition is the amortization of "transition cost." This element arises because the treatment of OPEBs in similar manner as pensions began only in the early 1990s with the promulgation of Statement of Financial Accounting Standards No. 106 ("SFAS 106"). Prior to that time, these benefits were expensed as they were incurred. SFAS 106 required all companies to establish funded reserves against their future obligations to incur these costs. Since no company had such reserves, SFAS 106 allowed companies to amortize the present value of the required reserves over the estimated remaining service time of the affected employees. As employees retire, these transition costs should decline.

Q. Do the OPEBs present the same problems as pensions?

A. Yes. Since OPEB expense is calculated in virtually the same manner as pension expense, it faces the same volatility. Since the same drivers – interest rate and asset value – affect OPEB cost, this cost has shown a similar dramatic increase. The year 2002 OPEB cost of $58.2 million has almost doubled to $105.7 million in 2004.

[11] Exhibit A-16, Schedule F5-23 Revised.

Q. Do you recommend the same resolution of the OPEB expense issue as you recommended for pension expense?

Yes. If the rates set in this case are expected to remain in effect beyond 2004, then I recommend the same three-year historical average method I proposed for pension expense, but with two modification.. As noted earlier, the amortization of transition cost should decline over the years as the affected employees retire. For this reason, I recommend using the 2004 transition cost for this component of expense. Also, in 2002 there was a prior period adjustment of $3,037,000 that is not representative of any on-going quantification of OPEB expense. This element should be excluded from the expense calculation.

Q. Please quantify the three-year average OPEB expense that you recommend if there are to be no 2005 and 2006 rate cases?

A. I recommend $81.7 million, as follows:

2002	$42,208,000
2003	93,903,000
2004	97,500,000
Total	$223,611,000
Average	$74,537,000
Transition Amortization	8,200,000
Total Expense	$81,737,000

Management Retirement Benefit Plans

Q. What do you mean by "management retirement benefit plans?"

A. These are compensation plans that apply only to the Company's officers, managers and directors. They are "non-qualified" plans because they do not qualify under the Employee Retirement Income Security Act ("ERISA"). They are therefore not deductible as Company expenses for purposes of computing income taxes.[12]

Q. What are these plans?

A. Edison has five of these plans:[13]

Executive Supplemental Retirement Plan All Vice Presidents and a select group of Directors who are designated as participants by the Organization and Compensation Committee of the DTE Energy Company Board of Directors are eligible to participate in this plan.

Supplemental Retirement Plan Employees at the Director level and above or other highly compensated employees whose benefits under the DTE Energy Company Retirement Plan are limited by provisions of the Internal Revenue Code are eligible to participate in this Plan.

Supplemental Savings Plan All employees at the Director level or above are eligible to participate in this plan.

Executive Post-Employment Benefit Plan A select group of management or highly compensated employees are eligible to participate in this plan. This plan became effective January 1, 2003.

Deferred Stock Compensation Plan for Non-Employee Directors. Any Director of DTE Energy Company who is not a Company employee or an employee of any affiliate is eligible for this plan.

[12] It is my understanding that payments into these plans are not deductible for income tax purposes, but payments out of them to retired employees are deductible. The earnings of the retirement funds are also taxable to the Company.
[13] Response to Data Request AGDE 1.36/126.

Q. Has the Company included the cost of any of these plans in its revenue requirement in this case?

A. Yes. The Company has included costs for three of these plans in its claimed revenue requirement in this case, as follows:[14]

Executive Supplemental Retirement Plan	$3,000,000
Supplemental Retirement Plan	600,000
Non-Employee Directors Plan	500,000
Total	$4,100,000

Q. Should these costs be allowed in the Company's revenue requirement?

A. No. The Internal Revenue Service treats payments into the plans for these highly-paid senior executive managers and directors, most of whom are probably also stockholders, as taxable income of the Company. If these costs were deductible, the managers and directors would have an incentive to hide corporate income by paying benefits to themselves through these plans.

The same principle applies to the establishment of the regulated revenue requirement. The personnel who receive the benefits are the same personnel who receive them. If those benefits (along with associated income taxes) are incorporated into Edison's revenue requirement, then the incentive will be make them very, very generous. That generosity will be entirely at the expense of the ratepayers.

Even if the managers and directors exert self-control and avoid overly generous benefits, shareholders should still pay the benefits. That is because these senior personnel are direct representatives of the shareholders and are directly beholden to them. These are the employees who are entrusted with the obligation to maximize shareholder value. Shareholders should pay for at least some of their compensation.

[14] Response to Data Request No. 1.36/126.

Q. What is your recommendation?

A. I recommend excluding the $4.1 million represented by senior management and director retirement benefits from Edison's revenue requirements. This exclusion would also reduce the Company's income tax expense by about $2.35 million.[15]

<u>DTE's Merger Control Premium</u>

Q. What is the control premium?

A. The control premium refers to the acquisition by DTE Energy, Edison's parent company, of MCN Energy, the parent of Michigan Consolidated Gas Company. The control premium is the premium that DTE paid over the market value of MCN's stock. The market value of MCN's stock just prior to the announcement of the acquisition was $1,595.4 million, and DTE paid $2,488.1 million to acquire MCN. DTE's premium to obtain control of MCN was therefore $892.7 million.[16]

Q. What is Edison's proposal with respect to this control premium?

A. Edison argues that synergies resulting from combining the two companies more than outweigh the cost of the control premium. Specifically, Edison has estimated the operating and maintenance savings attributable to the merger at $80.5 million in 2002 and at $112.6 million in 2004.[17] Edison then computes a revenue requirement associated with the control premium totaling $85.2 million for 2004. Edison proposes to add this amount to its overall 2004 revenue requirement.[18]

Q. How does Edison calculate this $85.2 million in control premium revenue requirement?

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[15] Based on the income tax gross up factor of 1.573 from Exhibit A-3, Schedule C5.
[16] Exhibit F-16, Schedule F5-8 Revised.
[17] Exhibit A-16, Schedule F5-6 Revised.
[18] Exhibit A=16, Schedule F5-9 Revised.

A. Edison treats this control premium as a fully taxable regulatory asset to be amortized over 40 years. The 40-year recovery period is based on the assumption that the merger savings will continue for that period. The amortization is $14.7 million annually, but that is grossed up for income taxes to $23.2 million. The pre-tax return on the unamortized balance of the control premium begins at $62 million in 2004. By 2008, it will have declined to $55.7 million. These two elements, return-of and return-on the control premium, come to $85.2 million in 2004. [19]

Q. Is this control premium an appropriate adder to Edison's revenue requirement?

A. No. It is not. The revenue requirement is supposed to compensate the Company for costs incurred in providing the generation, transmission and distribution of electricity. The control premium has nothing to do with any of these functions. To the contrary, it was a cost DTE incurred to acquire MCN.

Q. Are there any other objections to including the recovery of the control premium in the revenue requirement?

A. Yes. First, there is an element of double recovery in this proposal, particularly for the previous stockholders of MCN. MCN stockholders enjoyed a substantial capital gain when they exchanged their MCN stock for that of DTE Energy. Now, Edison requests compensation again by means of a supra-competitive rate of return on the Edison component of DTE stock.

This double recovery arguably applies to Edison's original stockholders as well. The reason DTE was able to buy MCN is that it received $1.774 billion in cash when it securitized Edison's stranded costs in 2000. This $1.774 billion allowed Edison to retire debt that presumably was related to Edison's securitized assets.

[19] Exhibit A-16, Schedule F5-9.

The retirement of this debt provided financial headroom for DTE to issue new debt to acquire MCN. In effect, Edison's ratepayers are currently paying for MCN through their securitization charges. The Company now proposes that its ratepayers should again pay for the use of cash to acquire MCN.

Additionally, I question whether the merger of the gas distribution and electric utilities represents an unalloyed benefit to consumers in the Detroit area. Gas and electricity are competing energy sources for space heating, water heating and cooking. To the extent that this competition encourages the respective gas and electric utilities to minimize costs, enhance service, and encourage the efficient use of their energy, those circumstances represent a public benefit. The loss of this benefit offsets savings that Edison claims it has achieved from the merger of competing utilities.

Finally, Edison's proposal, if approved, would set a very undesirable precedent. The Commission played no part whatever in the initiation, negotiation and consummation of the merger. It was never asked to weigh the public benefits and costs of the merger or to approve its price and terms. If the Commission accepts Edison's proposal in this case, then it will create precedent to approve similar merger premium compensation arrangements in the future. These arrangements shift the entire cost of acquisition from shareholders to ratepayers. All that would be required is for the utility to project future savings from a merger that exceed the cost of any merger premium. The Commission will then be cast in the role of passing on to ratepayers a cost incurred entirely outside of the regulatory purview. This also constructively allows a utility to recover avoided costs as though it actually incurred those costs.

The Vehicle for Recovering ITC and MISO Costs

Q. What are ITC and MISO costs?

A. The ITC (Independent Transmission Company) and the MISO (Midwest Independent System Operator) are the two entities that provide transmission services to Edison. The ITC had been part of Edison, but it has been spun off as an independent entity. The MISO is the regional organization that operates the upper Midwest power grid and sells transmission services to Edison and other "Load Service Entities" in the region.

Edison estimates that it will incur $126.9 million of costs related to these entities, as shown in Exhibit A-13, Schedule E-6.1.

Q. What is the issue with respect to ITC and MISO costs?

A. The issue is whether these costs should be recovered in base rates or whether they should be incorporated into the PSCR factor.

Q. Have you already addressed this issue in your testimony in the interim phase?

Yes. At 10 T 1790 and 1790, I pointed out that including transmission costs in Edison's PSCR factor is not appropriate because (1) transmission charges do not fall within the definitions of Section 6j(1) of 1982 PA 304, (2) the MISO transmission charges do not fit the unpredictable characteristics of costs that are conventionally recovered through periodic cost adjustment clauses, and (3) the MISO charges are based on aggregate demand, that is, maximum consumption in any one hour. They are not based on energy consumption, which is the basis for the PSCR factors.

Earnings Sharing Mechanism

Q. What does Edison propose as an earnings sharing mechanism?

A. Edison proposes an earnings sharing mechanism ("ESM") that would establish a "deadband" of 100 basis points (one percent) around its authorized rate of return on common equity. Using Edison's currently approved rate of return of 11.5 percent, the deadband would be from 10.5 percent to 12.5 percent. If the Company's earned return on equity falls within that deadband, there would be no adjustments to the rates. As the earned returns depart from that deadband, ratepayers would make up part of the shortfall or receive part of the surplus in increasing proportions as the departure from the deadband increases. Again using 11.5 percent as the approved return to equity, Edison proposes that the division between ratepayers and shareholders would be as follows:

Under-earnings			Over-earnings		
ROE Range	To Shareholders	To Ratepayers	ROE Range	To Shareholders	To Ratepayers
10.5%-11.5%	100%	0%	11.5%-12.5%	100%	0%
10.0%-10.5%	80%	20%	12.5%-13.0%	80%	20%
9.5%-10.0%	60%	40%	13.0%-13.5%	60%	40%
9.0%-9.5%	40%	60%	13.5%-14.0%	40%	60%
Below 9.0%	20%	80%	Over 14.0%	20%	80%

Edison proposes that this mechanism operate for the remaining years of the rate caps established by Act 141, that is, until the end of 2005 when residential rates will be uncapped.

Q. What is your recommendation with regard to Edison's earnings sharing mechanism?

A. The mechanism should be rejected. First, it is probably unnecessary. Second, it is a device to recapture the earnings otherwise lost due to the rate freeze.

Q. Why is the ESM probably unnecessary?

As I have already testified, rates should be reset after the rate caps expire. Specifically, there should be a rate case based on 2005 revenue requirements to be effective when the cap on rates to small commercial and manufacturing customers expires at the end of 2004. Then, there should be another rate case based on 2006 costs when the residential rate cap expires at the end of 2005. Thus, there is no need for an ESM to capture departures from the authorized rate of return during those years.

Q. Why is the ESM a device for recapturing earnings otherwise lost during the rate freeze?

A. The ESM proposed by Edison compares actual return on equity with authorized return on equity. Obviously, Edison will not know its actual return on equity until after the end of the year, so the mechanism will operate retroactively. This means that if the rate caps on residential and small commercial and manufacturing customers during 2004 result in a rate of return below the authorized rate of return – which will happen if Edison's revenue requirement claim has any merit – then Edison will be able to recover a portion of the lost earnings the next year, 2005. By then, of course, the small commercial and manufacturing customers' rates will have been uncapped, so a portion of this recapture will be from the very customers whose frozen rates gave rise to the earnings shortfall. The same thing will happen in 2006. Edison will be able to recover a portion of the lost earnings in 2005 due to the continued freeze on residential customers, and those residential customers will contribute to that recovery.

Q. Does this conclude your testimony?

A. Yes. It does.

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

JUL 2 2 2004

IN THE MATTER OF THE OFFICE OF THE PEOPLE'S COUNSEL'S COMPLAINT FOR A COMMISSION-ORDERED INVESTIGATION INTO THE REASONABLENESS OF WASHINGTON GAS LIGHT COMPANY'S EXISTING RATES	) FORMAL CASE NO. 989
IN THE MATTER OF THE APPLICATION OF WASHINGTON GAS LIGHT COMPANY, DISTRICT OF COLUMBIA DIVISION, FOR AUTHORITY TO INCREASE EXISTING RATES AND CHARGES FOR GAS SERVICE	)

DIRECT TESTIMONY AND EXHIBITS OF
THE OFFICE OF THE PEOPLE'S COUNSEL

OF
CHARLES W. KING
EXHIBIT OPC (H)

ON BEHALF OF
THE OFFICE OF THE PEOPLE'S COUNSEL

March 8, 2002

**DIRECT TESTIMONY OF
CHARLES W. KING**

Q PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Charles W. King. I am President of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. PLEASE DESCRIBE SNAVELY KING.

A. Snavely King, formerly Snavely, King & Associates, Inc., was founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. The firm has a professional staff of 12 economists, accountants, engineers and cost analysts. Most of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 32-year history, members of the firm have participated in over 500 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. Attachment 1 is a summary of my qualifications and experience. I should add to the educational portion of that resume that I received my primary and secondary education in the public schools of the District of Columbia.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. Attachment 2 is a tabulation of my appearances as an expert witness before state and federal regulatory agencies. Based on that tabulation, this is my 28th appearance before this Commission since 1978.

Q. FOR WHOM ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the District of Columbia Office of the People's Counsel ("OPC").

Q. WHAT IS THE OBJECTIVE OF YOUR TESTIMONY?

A. The objective of my testimony is to present OPC's position on the following Issues:

Issue 6: Are the Company's cost of service, rate design proposals and tariff changes reasonable?

g. Is the Company's proposal to increase the maximum amount for customer deposits to guarantee payment of bills reasonable?

i. Is the Company's proposal to apply carrying costs to over or under collected ACA balances appropriate?

l. Is the Company's application of its jurisdictional cost allocation methodology reasonable?

m. Should the method of pricing service to interruptible service customers change? If so, how are the resultant impacts handled?

Issue 7: Is the Company's proposed distribution among customer classes reasonable and appropriate? If the Commission decides on a revenue requirement decrease, what is an appropriate and reasonable distribution?

Issue 12: Are WGL's D.C. rates reasonable and appropriate in comparison to other WGL service territory base rates?

a. Are the Company's costs of operations higher in the District of Columbia than in Maryland or Virginia and, if so, describe all the assumptions and other factors that would explain the differences?

b. Are the distribution rates to District ratepayers higher than rates charged to Maryland or Virginia ratepayers, and, if so, describe all the assumptions and other factors that would explain the differences?

Q. HOW HAVE YOU STRUCTURED YOUR TESTIMONY?

A. I first consider Issues No. 7, pertaining to the appropriate and reasonsable distribution of OPC's proposed rate decrease or the Company's proposed rate increase among customer classes and sub-classes. In the course of this discussion, I will discuss WGL's proposal to increase customer charges much more than commodity charges.

I then move on to Issue No. 6, rate design, and the various sub-issues under that major heading.

I conclude by discussing Issue 12, which concerns the relative costs of and rates for gas distribution service in the District of Columbia vis-a-vis the suburban jurisdictions.

Q, WHAT ARE YOUR FINDINGS AND RECOMMENDATIONS REGARDING THE ISSUES YOUR ARE ADDRESSING IN YOUR TESTIMONY?

A. Issue No. 7: With regard to the allocation of the revenue change, whether upward or downward, among customer classes, I recommend that residential and commercial class rates should receive the same percentage rate change

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Washington Gas' proposal to impose a 100 percent increase in the annual revenues derived from customer charges to heating customers and its proposal to increase all monthly customer charges by 50% violates the Commission's rate design criteria. Changes in both customer and commodity charges should mirror the overall changes in classes' revenue recovery. This approach will preserve the historical relationship between customer and commodity charges.

The peak usage charge in the commercial rate schedules should change by the same percentage as the other rate elements.

Issue No. 6 (g): The Commission should not approve either the Company's proposed increase in the ceiling on customer deposits or the requested increase in reconnection charges because both of these proposals would aggravate the difficulty that low income households experience in maintaining access to gas service.

Issue No. 6 (i): The Commission should not approve the Company's request to apply carrying costs to the Actual Cost Adjustment ("ACA") balances.

Issue No. 6 (l): While Washington Gas' application of the jurisdictional cost allocation methodology is reasonable, the Commission should be aware that after an allocation of common corporate costs is established in this rate case, the actual amount of such costs appropriately allocated to the D.C. jurisdiction will continuously decline in subsequent years. This decline will lead to accretion of earnings in the D.C. jurisdiction.

Issue No. 6 (m): Washington Gas should maintain the current method of pricing service to interruptible customers.

Issue No. 12 and 12(a): The District imposes higher taxes on its utilities than do the suburban jurisdictions. This difference reflects the problem that a very high proportion real estate of the District is exempt from property taxes. The District is therefore forced to use indirect taxes, such as the Gross Receipts Taxes on utilities, to derive at least some revenue from the governmental and non-profit organizations that occupy so much property in the City.

A relevant distinction between the District and the suburbs is the greater proportion of meters located inside customers' premises in the District. This difference causes higher meter reading costs, more services on customer premises, and more customer service calls. Additionally, the data do not support the Company's assertion that there are fewer therm sales in the District than in the suburbs. Finally, depreciation rates are higher in D.C. than in the suburban jurisdictions.

Issue No. 12(b) Distribution charges in Maryland and Virginia differ from those in the District in both level and structure. Customer charges are higher in the suburbs, but the commodity charges are lower. Of great importance is the fact that both Maryland and Virginia maintain declining block rates, so that the more gas a customer uses, the less he/she pays per therm. These rate structures increase the guaranteed portion of the Company's revenue recovery by enlarging the unavoidable component of the customer's bill. They also send the wrong price signal by encouraging gas consumption and discouraging conservation and energy efficiency.

ISSUE NO. 7: **IS THE COMPANY'S PROPOSED DISTRIBUTION AMONG CUSTOMER CLASSES REASONABLE AND APPROPRIATE? IF THE COMMISSION DECIDES ON A REVENUE REQUIREMENT DECREASE, WHAT IS AN APPROPRIATE AND REASONABLE DISTRIBUTION?**

Q. WHAT IS YOUR SUMMARY ANSWER TO THESE QUESTIONS?

A. The Company's proposed distribution among customer classes is not reasonable or appropriate. The proposed disproportionate increases to the residential customer class are not justified under the Commission's stated rate design criteria, which include historical continuity, like charges for like services, ability to pay, as well as cost considerations.

Additionally, the proposed increases in customer charges, which disproportionately affect residential customers, increase the unavoidable component of customers, thereby sending the wrong price signal to customers who conserve gas and employ energy efficiency appliances.

Rates for the respective customer classes and sub-classes should be adjusted by a common percentage consistent with the Commission's finding as the Company's revenue requirement.

This recommendation applies regardless of whether the Commission finds that Washington Gas' rates should be increased or decreased. Therefore, if the Commission finds that rates should be reduced, all classes should receive the same percentage rate reduction.

Q. WHAT CHANGES IN THE DISTRIBUTION OF REVENUES AMONG CUSTOMER CLASSES HAS THE COMPANY PROPOSED?

A. The Company proposes to increase the monthly customer charges for all customers in all classes by 50 percent. Additionally, it proposes to apply the customer charge to heating customers during all 12 months, rather than the nine months during which it currently applies. The combined effect of these changes is to double the annual customer charge revenue collected from heating service customers. Exhibit OPC (F)-1 shows that because heating customers make up the overwhelming majority of the Company's D.C. customer base, the Company's proposals result in an average effective increase in customer charges of 90 percent.

Assuming that all commodity charges remain the same, an increase in the customer charge has a much greater impact on the residential class than on the commercial classes. That is because there are far more residential customers than commercial customers and because individual residential customers consume less gas than most commercial customers. This is true notwithstanding that commercial customer charges are somewhat higher than residential customer charges.

Additionally, the Company proposes to recover 80 percent of the remaining revenue requirement increase from the residential class, even though residential customers currently generate 55 percent of the Company's retail distribution service revenue in the District of Columbia.[1] The resultant class distribution of the Company's 16.3 percent revenue increase request is as follows:[2]

Residential Heating and Cooling	22.0%
Non-heating and Non-cooling	
Individually Metered Apartments	36.1%
Other	23.0%

[1] Computed from data on Exhibit WG (2F)-1, Schedule C.
[2] Exhibit WG (2F)-1, Schedule C

Commercial and Industrial	
Heating and Cooling under 3,075 therms	11.0%
Heating and Cooling over 3,075 therms	6.6%
Non-heating and non-cooling	6.6%
Group Metered Apartments	
Heating and/or Cooling under 3,075 therms	9.9%
Heating and/or Cooling over 3,075 therms	6.5%
Non-heating and Non-cooling	6.3%
Other (non-recurring) charges	40.2%

Q. HOW DO THESE CHANGES AFFECT THE DISTRIBUTION OF THE COMPANY'S REVENUE BY SOURCE?

A. Exhibit OPC (F)-1 shows that the proposed rate structure will increase the proportion of revenue generated from customer charges from 10.9 percent to 17.7 percent. This shift would increase revenue generated from the fixed and inelastic customer charges relative to the revenue derived from the variable and price-elastic commodity charges. By this device, Washington Gas would guarantee the recovery of a substantially greater portion of its revenue, reducing its risk exposure to variations in weather, increases in appliance efficiency, and the efforts of its customers to conserve energy.

Q. HOW DOES THE COMPANY JUSTIFY THESE HIGHLY UNEQUAL RATE INCREASES AMONG CLASSES?

A. Company witnesses Chapman[3] and Raab[4] both claim that in Formal Case No. 715, the Commission established five basic requirements that must be satisfied to justify a rate design change:

1. The modifications must provide sufficient revenues,

[3] WG (2F), page 6.

2. The rate design "attempt[s] to approximate the effects of free market in establishing prices which promote economically justifiable uses and discourage wasteful uses...,"
3. A multiplicity of rate designs is avoided,
4. A fair distribution of the revenue burden by customer class is promoted, and
5. The customer groups' ability to pay is considered.

Mr. Chapman invokes criterion No. 1 to justify the overall rate increase of 16.3 percent. The unequal distribution among customer classes is supported by witness Raab. Mr. Raab relies on a marginal cost study that purports to show that the current customer charges are not compensatory relative to the cost of adding a new customer and that overall the residential class does not recover its collective marginal costs. Invoking the principal of inverse elasticity, Mr. Raab claims that these findings justify a significant increase in the customer charge, indeed, one larger than that proposed by the Company.

Mr. Raab then cites to Mr. Touriniemi's embedded cost of service study, which purports to demonstrate that residential customers generate below-average rates of return and non-residential customers provide above-average rates of return. According to Mr. Raab, these results imply that non-residential customers are subsidizing residential customers.

Citing the ratemaking attributes listed by Dr. James Bonbright, Mr. Raab concludes that efficiency, fairness, and avoidance of undue discrimination argue against unequal class rates of return and for the Company's proposal to impose very unequal rate increases among the respective classes.

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[4] WG (G), page 5.

Q. HAVE MESSRS. CHAPMAN AND RAAB ACCURATELY DESCRIBED THE COMMISSION'S CRITERIA FOR EVALUATING RATE DESIGNS?

A. Their description is decidedly incomplete. In particular, the fourth criterion, fairness, should be more fully described. The implication of Mr. Raab's testimony is that "fairness" means correspondence with cost, whether embedded cost or reconciled marginal costs. This implication is not at all accurate, as demonstrated by the following complete quotation from Commission Order No. 7135 in Formal Case No. 715:[5]

> Another major objective of rate design is to strive for a fair distribution of revenue burden among various customer classes. In determining what is fair, the Commission is faced with the extremely difficult task of applying numerous criteria and measures of fairness. The criteria advocated by a particular party will be dictated by the rate benefits received by that party from application of the criteria. As Staff witness Reiser notes, three not wholly compatible standards of fairness are generally urged by various parties. Fairness may depend on the reasonable expectations of the customer and is therefore tied to historical patterns and trends. Thus radical shifts in the allocation of revenue burdens disappoints [sic] historically held expectations and produces unfairness. However, it is also argued that uniform rates for the same kind of service are fair even through there are real differences in cost of delivery of the service. Third, fairness also must be considered in terms of compensation to the supplier in that rates should offset or match PEPCO's costs for a particular service.

The fifth criterion, ability to pay, likewise needs some greater elaboration. Here is what the Commission had to say about that criterion:

> Finally, general notions of social equity call for a complex evaluation of groups of customers' ability to pay. The goal of the application of this criterion is to distribute cost burdens among various customer groups in keeping with generally held social goals. This criterion is often in conflict with the goal of matching price to cost of production and delivery of electric service, and is particularly vexing in application because customer classifications

[5] Order No. 7135, 2 D.C.P.S.C. 15, 61 (1980)

> in terms of a utility perspective do not necessarily coincide with, or help identify, the economic groups which must be identified for rational cost burden distribution goals.[6]

The Commission concluded as follows:

> It is clear that any one of a number of reasonable rate structures could result from the application of these criteria. The Commission is faced with the need to balance competing considerations to minimize conflicts among various objectives in order to ensure a reasonable and sound rate structure.[7]

Q. HOW WELL DOES THE COMPANY'S PROPOSED RATE STRUCTURE CONFORM TO THE FIRST OF THE COMMISSION'S CRITERIA, THE RECOVERY OF REQUIRED REVENUE?

A. The Company's rate structure conforms to the Company's perception of its required revenue. However, the Company's perception is clouded by its exaggerated view of its revenue needs, as described by OPC witnesses Smiley-Smith and Bright. Those witnesses demonstrate that the Company needs considerably less revenue than it has claimed.

In any event, the current rate design can continue to provide Washington Gas with a reasonable opportunity to recover whatever revenue requirement the Commission ultimately approves in this proceeding.

Q. HOW WELL DOES THE COMPANY'S PROPOSED RATE DESIGN CONFORM TO THE COMMISSION'S SECOND CRITERION, THAT IT SHOULD "APPROXIMATE THE EFFECTS OF THE FREE MARKET IN ESTABLISHING PRICES WHICH PROMOTE ECONOMICALLY JUSTIFIABLE USES AND DISCOURAGE WASTEFUL USES...?"

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[6] Id.

[7] Id. at 62.

A. The Company has failed to demonstrate that its proposed rate structure "approximates the effects of the free market." Specifically, the proposal to inflate the customer charges is one that could only be made by a monopoly. In almost every free market, prices are set based on the number of units sold, even when there are very substantial fixed costs associated with that production. No one has to pay admission to enter a shopping mall, nor is there a charge to visit any of the stores within it. Only when the shopper actually buys goods does he/she incur a cost. This is true even though there are very considerable fixed costs in operating retail malls and their constituent stores.

As regards discouraging wasteful uses, the effect of the Company's customer charge proposal is to increase the cost of gas service but reduce the cost of the gas itself. Obviously, this shift in price signals reduces customers' incentive to conserve gas and eliminate wasteful uses.

Q. DOES THE COMPANY'S PROPOSED RATE STRUCTURE AVOID A MULTIPLICITY OF RATES?

A. Yes. The Company does not propose to change the current structure of retail rates in the District, which is relatively simple.

Q. DO THE COMPANY'S RATE PROPOSALS CONFORM TO THE COMMISSION'S CONCEPTION OF FAIRNESS?

A. No. In the language quoted earlier from Formal Case No. 715, the Commission has found that there are three "not wholly compatible" standards of fairness. The first is customers' reasonable expectations that historical patterns will continue. Neither the dramatic increases in customer charges nor the highly disproportionate residential rate increases conform to this standard. They are exactly the sort of radical shifts in the allocation of revenue burdens that disappoint historically held expectations and produce unfairness.

Second, the Commission noted the argument that uniform rates for the same kind of service are fair even though there are real differences in cost. Since the delivery service provided to residential customers is virtually identical to that provided commercial and industrial customers, this argument suggests that similar delivery charges per therm may be fair notwithstanding the cost differences asserted by Messrs. Touriniemi and Raab.

The final standard of fairness, i.e. that rates should offset or match the utility's cost for a particular service, is "not wholly consistent" with the other two. There is no indication that the Commission intended that this standard of fairness should override the other two. Yet witness Raab apparently interprets fairness as "equity," and equity as requiring the matching of rates with cost. This interpretation is flatly contrary to the explicit conclusion of the Commission in its landmark order in Formal Case 715:

> We conclude that to the extent that PEPCO's rate design may result in some inter-class rate of return differentials, it has ample justification in historical and equitable considerations.[[8]]

The analogous situation exists today with respect to Washington Gas inter-class rate of return differentials. Until the most recent rate case, Formal Case No. 934, the commodity charge for all customers, residential and commercial, was identical. This identity reflected the argument cited in the Commission's Formal Case 715 order that uniform rates for the same kind of service are fair even though there are real differences in the cost of delivering that service. The present difference in commodity rates

[8] Id. at 67.

for the two classes flows from the creation of the peak usage charge in Settlement and Stipulation in Formal Case No. 934. This charge applies only to commercial customers.[9] Until this change in rate structure, the only differences among the classes' rates were in the customer charges. Thus, historical considerations would argue for the minimum distinction in commodity rates between the residential and commercial rate schedules, even when there are demonstrable differences in costs.

Q. ASSUMING, <u>ARGUENDO</u>, THAT COSTS ARE AN IMPORTANT DETERMINANT OF THE COMMISSION'S STANDARD OF FAIRNESS, DO COSTS JUSTIFY THE COMPANY'S PROPOSED INCREASES IN CUSTOMER CHARGES?

A. No. The evidence presented by the Company does not support the dramatic increases in customer charges proposed by Washington Gas. Company witness Raab claims to provide this support by calculating an annual marginal distribution cost per customer of $450.50.[10] Finding that aggregate residential marginal costs exceed residential revenue generation, he applies the inverse elasticity principle to justify inflating the "reconciled" residential heating and/or cooling customer cost to $33.64 per month,[11] a multiple of both the present and the Company's proposed customer charge.

Mr. Raab's marginal cost calculation is incorrect and inappropriate because it uses the single independent variable of customers as the driver of distribution costs. In accompanying testimony, OPC (E), Mr. George Donkin points out that the cost of distribution mains is not driven by the number of customers, but rather by a combination of peak day usage and annual gas throughput. He also observes that the other major component

[9] <u>See</u> Settlement and Stipulation, Formal Case No. 934, page 9.
[10] Exhibit WG (G)-2, Schedule 5

of distribution costs, customer services, is driven not only by the number of customers but by peak day demand and by annual gas consumption.

Q. BUT DOESN'T MR. RAAB ESTABLISH THAT THERE IS A MATHEMATICAL RELATIONSHIP BETWEEN DISTRIBUTION COSTS AND THE NUMBER OF CUSTOMERS?

A. Not exactly. Mr. Raab has established that as the number of customers increases, the aggregate cost of the distribution system increases as well. The reason for this relationship is obvious. As Washington Gas extends its distribution system to reach more previously unserved customers, its distribution costs increase. The marginal distribution cost of adding new customers, as measured by Mr. Raab, is $450.50 per customer per year.

But this observation emphatically does not apply to the District of Columbia. It is a suburban phenomenon, where gas service is being extended to new customers in new developments that previously were beyond the reach of the gas distribution system. In the District of Columbia, the distribution system is fully built out, and has been for decades. A new customer in the District of Columbia attaches to an existing main, likely one that has been in place for years. Any new expenditures for distribution mains in the District are likely to be for replacement due to wear and tear or as in the case of Georgetown, as part of a multi-utility renovation program. Variations in the number of customers served in the District have nothing to do with these expenditures.

Moreover, the D.C. customer base is shrinking. In the year 2000, there were 1,430 new meters added in the District, but there were 6,689 meters

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[11] Exhibit WG (G)-2, Schedule 4, page 1

removed. This compares with the suburbs, where 28,289 meters were added and only 16,648 removed.[12]

Q. ASSUMING, ARGUENDO, THAT COSTS ARE AN IMPORTANT DETERMINANT OF THE COMMISSION'S STANDARD OF FAIRNESS, DO COST DIFFERENCES JUSTIFY THE COMPANY'S PROPOSED UNEQUAL DISTRIBUTION OF THE RATE INCREASE AMONG CLASSES?

A. The Company relies principally on the class cost of service study presented by witness Touriniemi as Exhibit WG (2E)-4. That study shows much lower rates of return for the residential classes than for the commercial classes. However, as discussed in the testimony of OPC witness George Donkin, the allocation procedures used by the Company are seriously flawed and tend to overstate the costs assigned to the residential classes. When those costs are restated, the differences in the rates of return among the classes are as follows:

System average	6.65%
Residential Heating	8.40%
Residential Non-heating	
Individually metered apartments	-16.43%
Other	0.01
Non-residential	
Small	10.77%
Large	12.21%
Non-heating, non-cooling	17.65%
Group Metered Apartments	
Small	11.21%
Large	12.44%
Non-heating	15.26%
Interruptible	-13.27%

[12] WG Response to OPC Date Request No. 11-178(b).

As I will discuss shortly, the differences in rates of return among the classes are not so great as to justify a different percentage class rate adjustments, particularly between to the two largest classes, the residential and the commercial heating classes. They certainly do not justly the Company's proposal to increase rates to the residential heating class by two to three times the increase applicable to the commercial heating class. While the non-heating residential class shows very poor embedded cost results, I question the advisability of increasing the rates to these customers. I will discuss this issue in more detail later in my testimony. It is also addressed by Mr. Donkin in his testimony, Exhibit OPC (E).

Q. DO THE COMPANY'S RATE DESIGN PROPOSALS REFLECT THE COMMISSION'S FINAL CRITERION, THAT OF GROUPS' ABILITY TO PAY?

A. No. First of all, the proposed doubling of annual customer charges to residential heating/cooling customers would impose a substantial fixed and unavoidable increase in the burden borne by every customer in this class without regard to his/her ability to pay. Percentage-wise, this increase falls hardest on the residential customers using the least amount of gas. It also sends the wrong price signal by reducing the reward to those customers who reduce their gas bills through conservation.

Additionally, the disproportionate increase in residential rates relative to commercial rates solely for the purpose of equalizing rates of return ignores the irrefutable evidence that there are many residential customers who already have experienced difficulty in paying their gas bills. That evidence was presented to the Commission in Formal Case No. 1007, where it was found that as of September 2001, 6000 District customers had their gas service terminated because they had been unable to pay the extraordinarily high gas bills incurred the previous winter.

Washington Gas apparently regards that it has discharged its obligation to assist low-income District residents through the Residential Essential Service ("RES") discounts. These are a fairly complex set of discounts from the winter gas bills of heating service customers who pass low-income qualifications established by the Federal Government and certified by the District of Columbia Energy Office. As discussed in the testimony of Dr. Thurston, Exhibit OPC (G), this program appears has been less than a total success. It has apparently failed to reach a large portion of those qualifying for it, and it does nothing for low-income customers who are just above the threshold income qualifications.

Specific actions to deal with this problem have been developed and articulated by the Office of People's Counsel in Formal Case No. 1007, and I will not repeat them here. The relevant issue in this proceeding is whether the overall rate design proposed by Washington Gas contains any recognition of the difficulties that many D.C. residential customers have experienced in paying their gas bills. The clear answer is no.

Q. WILL THE COMPANY'S PROPOSALS HELP FINANCIALLY STRAPPED D.C. CONSUMERS?

A. No. Quite to the contrary, most of the Company's rate design proposals will aggravate the problems of households having difficulty in paying their bills. The Company proposes to double the unavoidable customer charges paid by heating customers; it recommends a disproportionate increase in residential rates, it asks for an increase in the customer deposit ceiling, and it proposes a trebling of the reconnection fee that disconnected customers must pay to restore their gas service.

Q. WHAT ARE YOUR RECOMMENDATIONS WITH REGARD TO THE COMPANY'S PROPOSED TREATMENT OF THE CUSTOMER CHARGES?

A. The Company's proposal to increase all customer charges by 50 percent and to impose a 100 percent annual customer charge revenue increase on heating customers (by extending payment of the charge from the current nine to twelve months per year) is clearly in violation of the Commission's rate design criteria. It represents a radical shift in the allocation of revenue burdens that disappoints historically held expectations and produces unfairness. It is not supported by the Company's own cost studies once the particular characteristics of the District of Columbia are recognized. Finally, it contravenes the social equity objective of recognizing customers' ability to pay by doubling the burden of fixed monthly payments which a heating customer cannot avoid no matter how intensively he/she conserves gas.

On the basis of the foregoing, I recommend that, with the exception discussed below, changes in the customer charges should mirror the overall changes in classes' revenue recovery. This approach will preserve the historical relationship between customer and commodity charges.

Q. WHAT ARE YOUR RECOMMENDATIONS WITH REGARD TO THE ALLOCATION OF THE REVENUE CHANGE AMONG CUSTOMER CLASSES?

A As noted, the Commission has identified non-cost factors, such as historical continuity, ability to pay, and like charges for like services, as justifying differences in rates of return among customer classes. All of these considerations support the acceptance of a somewhat lower rate of return for the residential class relative to the commercial classes.

The Commission has not articulated the differential in class returns that might justify disproportionate rate changes. We may reasonably conclude that there is a band of reasonableness around a common rate of return where variations among returns are permitted. In this case the band at issue is that identified by OPC witness Donkin. The principal differential is between the 8.40 percent of the residential heating class and the 10.77 and 12.21 percent returns shown for the non-residential small and large heating classes, respectively.

As the Commission noted in the language from Formal Case 715 quoted earlier, it needs "to balance competing considerations to minimize conflicts among various objectives..." in determining whether to apply different percentage rate adjustments to different classes. The only consideration in favor of such differentials is the embedded cost study, which indicates higher returns for the commercial class than the residential class. On the other hand, there are a number of other factors that militate in favor of applying an equal percentage change to these customer classes.

Q. WHAT OTHER FACTORS SUPPORT AN EQUAL PERCENTAGE CHANGE FOR THE RESIDENTIAL AND COMMERCIAL CLASSES?

A. Such factors include the following:

- The residential class already pays more than the system average rate of return,
- A sizable number of residential customers had difficulty paying for their gas last winter (winter 2000-2001). A disproportionate gas rate increase combined with another cold winter could further aggravate the

problems of those residential customers at the lower end of the income scale who do not qualify for RES discounts.

- The historical pattern has been for residential and commercial customers to pay the same commodity rate.
- The gas distribution service provided to commercial customers is identical to that provided to residential customers.
- Only 8 percent of the residential class uses Delivery Service vs. 29 percent of the commercial class,[13] which means that the residential class poses a lower risk of stranded costs for pipeline and storage capacity commitments.
- Only two suppliers serve the residential delivery service customers vs. 11 serving commercial customers,[14] which means that the residential class poses a lower risk of default due to failure of suppliers to perform on their commitments.
- Many of the commercial customers are exempt from D.C. property and income taxes. All residential customers pay D.C. property and income taxes
- All commercial customers can deduct gas bills from their income taxes. No residential customer can deduct gas costs from income taxes.

For the foregoing reasons, I recommend that the residential and the commercial classes rates receive the same percentage rate change, whether upward or downward.

Q. HAVE YOU IDENTIFIED ANY CLASS OF CUSTOMERS WHOSE REVENUES ARE NOT COVERING EXPENSES?

[13] Formal Case No. 874, June 27, 2001 Hearing, Washington Gas PowerPoint Presentation, Slide no. 12.
[14] Id.

A. The only sub-classes that are decidedly out of a range of reasonableness are the non-heating and non-cooling residential customer classes. The Individually Metered Apartment ("IMA") subclass has a negative rate of return and the "Other" subclass (presumably single-family homes) exactly recovers its allocated expenses, with no contribution to capital costs. Arguably, these classes should be required to contribute more revenue. However, I recommend that the Commission not apply a disproportionate rate change to these sub-classes.

Q. WHY DO YOU OPPOSE A DISPROPORTIONATE RATE CHANGE FOR THE NON-HEATING RESIDENTIAL CLASSES?

A. As noted, there are two sub-classes, IMA and "other." The "other" class uses gas for cooking and hot water heating. IMA customers probably use gas only for cooking, since most apartment houses have central hot water heating.

Customers who use gas only for cooking have very little commitment to the gas company. For a fairly limited expenditure, they can buy electric ranges and dismiss the gas utility altogether. For this reason, the 13,685 IMA customers must be considered very price-elastic. Only a small increase in the cost of gas could cause them to switch to electricity.

Mr. Donkin's study indicates that it would take a doubling of revenue to raise the IMA class above a negative rate of return. The question is whether it is worth it to the Company and to other gas customers to retain these customers. The answer to that question is the same as it is with respect to interruptible customers: These customers contribute if they generate revenue that exceeds the incremental cost of serving them. They most likely would not be willing to pay rates that generate a full return before they would leave the system, but they can reduce the costs to other ratepayers if they contribute some revenue to offset the fixed costs of the system.

IMA customers pay the same commodity rate as residential heating customers. To create a separate commodity rate for this relatively small class would violate the Commission criterion of avoiding a multiplicity of rates. It would be of questionable value anyway, since these customers consume, on average only 63 therms of gas annually, or about five therms monthly.

The only way to achieve a disproportionate adjustment in the IMA rates is to change the customer charge. That charge is currently $3.79 monthly, or $45.48 annually. Mr. Donkin indicates that the monthly billing and collecting expense for non-heating customers is approximately $3.00, which means that the current charge is compensatory. It is not necessary to increase this rate to extract a contribution from these customers. On the other hand, it makes no sense to reduce this rate if the Commission finds that an overall rate reduction is in order. Accordingly, I recommend that the customer charge for this sub-class be increased by the system-wide percentage revenue increase if an increase is warranted, but that it be held at $3.79 if there is a rate reduction.

Q. WHAT IS YOUR RECOMMENDATION FOR THE "OTHER" NON-HEATING RESIDENTIAL CUSTOMERS?

A. Since the relatively few (5,065) "other" non-heating residential customers already pay a customer charge of $4.47, and Mr. Donkin quantifies the out-of-pocket cost of serving these customers as $3.00, With a $1.47 margin over monthly incremental cost, it is not is necessary to make a special adjustment to this rate. These customers, like the residential heating customers, should receive the system-average change in recurring rates, whether upward or downward.

Q. WHAT CHANGES SHOULD BE MADE TO THE STRUCTURE OF THE COMMERCIAL RATES?

A. In marked contrast with its proposal to double the customer charges for commercial customers, the Company proposes to hold the peak usage charge at its present level. I recommend that the peak usage charge receive the same percentage rate change as the other commercial rate elements.

Q. WHAT IS THE REASON YOU BELIEVE THE PEAK USAGE CHARGE SHOULD CHANGE WITH THE OTHER RATE ELEMENTS?

A. The peak usage charge is described in the Company's tariff as follows:

> "Peak usage" is a measure of the amount of gas delivered to a customer on the coldest days of the year for which the Company must incurred substantial costs for investment, operation and maintenance of gas production facilities and additional distribution facilities to accommodate customers' increased gas usage on those days. Increased usage or decreased usage by a customer on the coldest days has a corresponding increase or decrease on the Company's costs and, therefore, on the level of the "peak usage charge" the Company must bill the customer.[15]

According to Mr. Raab, peak day sendout is a major cost driver. He uses it as the independent variable that drives all transmission and customer accounts costs. While the relationship of peak day sendout to customer accounting costs seems questionable, its impact on transmission costs is undeniable. Furthermore, as Mr. Donkin notes, peak day usage is a driver of distribution mains and services costs as well. Yet, the peak usage rate,

[15] Washington Gas Light Company P.S.C. of D.C. No. 3, First Revised Page No. 10 (Rate Schedule No. 2)

which more closely reflects peak day sendout than any other rate element, is only 2.39¢ per therm, and it accounts for only six percent of the non-gas revenue of the commercial customer class. This important price signal generates less revenue than do the current, let alone the proposed commercial customer charges[16]

WG witness Chapman asserts that the reason for holding the peak usage charge at its present level is "to mitigate further high winter bills for this [commercial] class."[17] This explanation is contrary to the purpose of the charge. It is also flatly wrong. It is contrary to the purpose of the charge because the objective of the peak usage charge is to signal to these customers the cost consequences of their usage patterns. If commercial customers use more gas during the peak winter days, they are driving up the Company's costs, and that effect needs to be conveyed to those customers. If the impact is high winter bills, then that impact is appropriate.

But the impact is not high winter bills, and that is why Mr. Chapman is wrong. While the peak usage charge is set by the customer's peak winter usage, and so conveys an important price signal, it is paid all year long. It is a "ratchet" that is established by peak winter demand but does not even come into play until the next November.

For the foregoing reasons, I recommend that the peak winter usage charge be adjusted up or down to the same extent as the other elements in the commercial rate schedules.

ISSUE NO. 6: ARE THE COMPANY'S...RATE DESIGN PROPOSALS AND TARIFF CHANGES REASONABLE?

[16] Source: Attachment A, Witness Chapman Exhibit WG (F)-1, Source sheet 7.
[17] WG (F), page 14.

G. IS THE COMPANY'S PROPOSAL TO INCREASE THE MAXIMUM AMOUNT FOR CUSTOMER DEPOSITS TO GUARANTEE PAYMENT OF BILLS REASONABLE?

Q. WHAT IS YOUR SUMMARY ANSWER TO THIS ISSUE?

A. OPC is opposed to any tariff changes that increase the obstacles to access to gas service by financially strapped residential customers. Two of the Company's rate design proposals have this effect. The Company's proposed increase in the maximum customer deposit from $100 to $325 not only increases the obstacles to access to gas service, but it violates the D.C. Consumer Bill of Rights. The increase in the reconnection charge to $90 also raises the barrier to resumption of gas service. Both of these proposals should be denied.

Q. WHAT OTHER RATE DESIGN AND TARIFF CHANGES HAS WASHINGTON GAS PROPOSED?

A. In addition to its proposed increases in the recurring rates discussed earlier, the Company proposes the following additional changes:[18]

- Establish a maximum customer deposit amount of $325,
- Increase the charge for customer-initiated meter relocations from $27.09 to $75,
- Eliminate the $40.64 minimum charge for appliance adjustments and permit competitive rates to apply,
- Increase the current four-tiered charges for reconnecting a disconnected customer to a common $90,
- Increase the charge by direct payment to a Company representative at the customer's premise from $6.32 to $25,
- Increase the charge for dishonored checks from $7.22 to $15, and

[18] Exhibits WG (F), pages 43-54 and WG (2F)-1, Schedule C, page 4.

- Bifurcate and increase the current $35.22 service initiation charge to become $55 if gas is still flowing and $115 if physical initiation of new service is required.

Q. WHAT IS THE REVENUE EFFECT OF THESE OTHER TARIFF CHANGES?

A. The Company estimates that collectively, these tariff changes will increase revenue by $1,646,762. The average percentage increase in these tariff items is 124 percent.

Q. WHAT IS YOUR REACTION TO THESE PROPOSALS?

A. The extraordinarily large increases proposed for these charges require extraordinarily explicit and quantified justification. Even where there is an arguable cost justification, there has to be a recognition that some of the proposed increases aggravate the difficulty that low income households experience in maintaining access to gas service. OPC has opposed and will continue to oppose all such increases.

Q. WHAT SPECIFIC INCREASES PROPOSED BY THE COMPANY AGGRAVATE THE DIFFICULTY THAT LOW INCOME HOUSEHOLDS EXPERIENCE IN MAINTAINING ACCESS TO GAS SERVICE?

A. The Company's proposed increase in the ceiling on customer deposits and its proposed 121 percent increase in reconnection charges[19] both add to the obstacles that low-income households experience in maintaining access to gas service. The increase in the customer deposit ceiling has the added objection that it violates the Consumer Bill of Rights, which

[19] Computed from Exhibit WG (2F)-1, Schedule B, page 5, line 9.

limits customer deposits to the lesser of $100 or twice the estimated maximum monthly bill of the customer over 12 months.[20]

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE PROPOSED INCREASE FOR CUSTOMER DEPOSITS?

A. At page 47 of his original prefiled testimony (Exhibit WG (F)), Mr. Chapman acknowledges that the existing tariff provision is inconsistent with the Consumer Bill of Rights, and he requests to the Commission to make an exemption to this rule to allow a $325 ceiling to be imposed. The immediate solution is not to ask the Commission to override the Consumer Bill of Rights, but rather to change the present tariff language to conform to the regulation. Then, if Washington Gas believes that the ceiling is too low, it should go through the proper legislative channels to raise that ceiling.

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE PROPOSED INCREASE IN RECONNECTION FEES?

A. The proposed increase to $90 in reconnection fees raises a further financial obstacle on top of increased gas costs to any customer whose service has been disconnected by reason of non-payment. This charge is likely to deprive yet more low-income D.C. households of access to gas service. I question whether it is even in the best interests of the Company, as its effect is likely to increase the already large volume of uncollectible bills that the Company has accumulated in the District of Columbia.

The current reconnection charges distinguish between multi-family (4 or more) apartments and other dwellings, and among weekday working hours, non-working hours, and Sunday and holidays. Since these rates

[20] 15 DCMR §307.7 (1991)

are clearly more cost-based than the flat $90 that the Company now proposes for all forms of reconnection, their structure should be retained.

As for the level of the reconnection charges, the Company has not provided adequate cost information by which the Commission can determine which, if any, of the current reconnection charges should be raised.[21] Both the magnitude of the proposed increase and the economic and social damage of any possible overcharge require persuasive and well-documented justification. The Company has not provided such justification. It has failed its burden of proof. Accordingly, I recommend that the existing charges be adjusted by the overall percentage rate adjustment of the recurring residential service rates.

Q. IS THE COMPANY'S PROPOSED INCREASE IN THE DISCONNECTION FEE REASONABLE?

A. No. The only increase related to disconnection for which the Company has provided any cost detail is the proposed jump from $6.32 to $25 for on-premise payments to avoid disconnection. This increase discourages customers from making payments at the time of disconnection, an action that saves the added costs of a subsequent reconnection visit. As an incentive, this charge should be kept low to encourage reconnection to the system. I recommend a rate no greater than $10 for this charge.

<u>ISSUE NO. 6.I.</u> IS THE COMPANY'S PROPOSAL TO APPLY CARRYING COSTS TO OVER OR UNDER COLLECTED ACA BALANCES APPROPRIATE?

Q. WHAT IS YOUR SUMMARY ANSWER TO THIS QUESTION?

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[21] See Attachment A, Volume 3 to Washington Gas' June 29, 2001 filing, Chapman workpapers, note 34.

A. No. As explained below, the Company's proposal to apply carry charges to the ACA balances is not appropriate.

Q. PLEASE DESCRIBE THE ACA MECHANISM.

A. The Actual Cost Adjustment ("ACA") is the true-up mechanism for the Purchased Gas Charge ("PGC"). Each August, the Company submits to the Commission a reconciliation between what it has collected in the PGC during the previous year and its actual gas acquisition, storage and transportation costs. Since the PGC is based on a quarterly forecast of gas prices and consumption, the forecasted PGC costs may differ from the actual costs by reason of unpredictable changes in gas prices or consumption. The principal unpredictable consumption variable is weather. This reconciliation may go either way, with the Company owing customers or customers owing the Company. The balance is then divided by the estimated firm sales for the coming year, and the resultant ACA surcharge or surcredit is applied on a per-therm basis to all firm sales customers for the ensuing September through August period. [22]

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO CARRYING CHARGES FOR THE ACA BALANCES?

Hitherto, there has been no carrying charge for the ACA balances. The Company now proposes that its pre-tax rate of return be applied each month to the ACA balance, whether positive or negative to the Company, from the month the balance is created to the month it is fully repaid (August of the following year).[23] This procedure would remove any ACA balance from the calculation of working capital for purposes of finding the overall revenue requirement.

[22] See P.S.C. of D.C. No. 3, General Service Provision No. 16.

The Company's claimed justification for this proposal is that gas prices have become so volatile that the ACA balances, previously relatively small, have recently become quite large. What used to be a relatively minor carrying cost has become quite major. If approved, the carrying charges would begin to apply the month following Commission approval.

Q. DO YOU SUPPORT THE COMPANY'S REQUEST FOR AN ACA CARRYING CHARGE?

A. No. First of all, the proposal adds a further level of complexity to what is already a fairly complex process. Specifically, it adds a requirement to reconstruct the ACA balance each month through the past year and to predict the ACA recovery each month in the coming year. This added complexity increases the likelihood of confusion, misunderstanding, and error.

Second, the effect of this proposal will be to increase the absolute size of the ACA surcharge or surcredit, further compounding the already volatile nature of the gas acquisition charges imposed on ratepayers. Anything that adds to the instability of gas rates is damaging to both ratepayers and the Company.

Third, the long-term effect of this change should be zero. While the ACA may swing from positive to negative from year to year, over time it should wash out. The ACA surcredits should offset ACA surcharges over the years. If they do not, then there is something generically wrong with the Company's PGC forecasting mechanism.

Finally, this proposal is symptomatic of a Company viewpoint that OPC strongly opposes. It is the mentality that gas acquisition, storage and

[23] Exhibit WG (F), pages 29-31.

transportation costs are beyond the Company's control, and that Washington Gas has a right to full recovery of every cent of these costs, no matter what their level. OPC has consistently advocated shifting some of the risk of gas procurement to the Company. To the extent that today the Company bears the carrying cost burden when prices turn out to be higher than predicted, that will focus the Company's attention on minimizing its exposure to high prices. Conversely, if the Company can realize some carrying cost benefit by reducing actual gas costs below those predicted, then that, too, will be a beneficial incentive.

Q. ARE THERE ANY FURTHER PROBLEMS WITH THIS PROPOSAL?

A. Yes. There is the further question of the carrying charge rate. The Company proposes to apply its full pre-tax rate of return. I question whether purchased gas is financed by equity and long-term capital. To the contrary, the 2001 Annual Report to Stockholders of Washington Gas' parent, WGL Holdings, Inc., indicates that it is financed by short-term bank credit:

> Long-term debt was principally used to fund the utility segment's [Washington Gas] ongoing construction program to support customer growth and replace facilities of existing customers. Additional short-term debt issued during fiscal year 2001 was used to fund a higher volume and cost of storage gas balances, increased customers accounts receivable, and higher levels of unrecovered gas cost as compared with fiscal year 2000.[24]

It appears from this quotation that a gas cost carrying charge that includes all the components of capital would result in an over-recovery. Assuming, *arguendo*, that a carrying charge is appropriate, it should be one that reflects the cost of the Company's short-term debt.

[24] WGL Holdings, Inc. Annual Report to Stockholders, 2001, page 20.

ISSUE NO. 6M: **SHOULD THE METHOD OF PRICING SERVICE TO INTERRUPTIBLE CUSTOMERS CHANGE? IF SO, HOW ARE THE RESULTANT IMPACTS HANDLED?**

Q. WHAT IS THE METHOD OF PRICING SERVICE TO INTERRUPTIBLE CUSTOMERS?

A. Interruptible service is available only to large customers who have an alternative source of energy, usually fuel oil, which can substitute for gas during interruptions. Aside from a customer charge, interruptible customer rates are essentially negotiated between the Company and the customer on an individual basis. The basis of these negotiated rates is the cost of the alternative fuel that the customer would use in lieu of gas.

There are two types of interruptible service, sales and delivery service. Under sales service (Schedule 3), where the Company buys the gas, the per-therm commodity rate must be greater than the weighted average cost of gas, so that it contributes to the provision of delivery service. Under delivery service (Schedule 3A), where the customer buys its own gas, the commodity rate just needs to be a positive number.

As the name implies, interruptible customers are subject to interruptions at the sole discretion of the Company on notice as short as an hour. Failure to interrupt results in a penalty of $2.25 per therm for any gas consumed during the interruption period.[25]

The contributions of the interruptible service over the cost of gas, along with any penalty receipts, are tallied up each November and are split between the Company and firm service customers. Ninety percent of the net (after gas acquisition costs) interruptible revenue is converted into a Distribution Charge Adjustment ("DCA"), which is an offset to the per-

[25] P.S.C. of D.C. No. 3, 3rd revised page 17.

therm charges of all firm service customers. The remaining 10 percent of net interruptible service revenue is retained by the Company as "below-the-line" revenue as an incentive to market of this service and to maintain the largest possible margins.

Q. HOW IMPORTANT IS INTERRUPTIBLE SERVICE IN THE DISTRICT OF COLUMBIA?

A. Interruptible service is quite important in the District of Columbia. It accounts for 33 percent of all D.C. gas sendout, but only 18 percent in Virginia and 13 percent in Maryland.[26] The overwhelming majority of interruptible gas uses Delivery Service.[27] As a result, District customers benefit from a fairly sizable DCA, currently amounting to 5.6¢ per therm, for an offset of more than 10 percent against the PGC.[28] Of course, Washington Gas benefits as well. Currently, it enjoys a below-the-line profit of .32¢ on every therm it bills under the DCA rider in the District of Columbia.

Q. ARE THERE ANY PROBLEMS WITH THIS METHOD OF PRICING INTERRUPTIBLE SERVICE?

A. In the past, there have been some problems with the implementation of the terms of the interruptible service tariff schedules, but I not aware of any problems recently. The current pricing arrangement benefits both the Company and its customers, whether interruptible or firm.

Q. DOESN'T MR. DONKIN'S ANALYSIS SHOW THAT INTERRUPTIBLE SERVICE GENERATES A NEGATIVE RATE OF RETURN?

[26] Calendar year Jurisdictional Cost Allocation Study, Schedule AL, page 1.
[27] Based on data in the Washington Gas' 2000 Gas Procurement Report.
[28] Washington Gas: Firm Purchased Gas charge Statement, Billing Month of February 2002.

A. Yes. But Mr. Donkin's analysis is on a purely embedded cost basis. For purposes of allocating revenue requirement by customer class, Mr. Donkin's study appropriately does not consider the effect of losing the revenue from the very price-elastic interruptible customers. The justification for the present arrangement is that interruptible service provides a contribution toward the fixed cost of the distribution system that could not be obtained if interruptible rates were set at fully allocated costs. It would be infeasible and counter-productive to attempt to generate a full return from this service.

Q. DO YOU THEREFORE RECOMMEND THAT THE PRESENT PRICING PROCEDURES BE MAINTAINED?

A. Yes. I do.

<u>ISSUE 6.L:</u> IS THE COMPANY'S APPLICATION OF ITS JURISDICTIONAL COST ALLOCATION METHODOLOGY REASONABLE?

Q. HAVE YOU EXAMINED THE COMPANY'S JURISDICTIONAL COST ALLOCATIONS?

A.. Yes. I have examined the Company's 2000, 1999 and 1998 jurisdictional cost allocations. I have also compared those allocations with the corresponding allocations submitted to the Maryland Public Service Commission and to the Virginia State Corporation Commission.

Q. WHAT WAS THE RESULT OF YOUR EXAMINATION?

A. The Company's D.C. jurisdictional allocation studies are identical to those submitted in Maryland. They differ from those submitted in Virginia due to the fact that Virginia apparently uses end of year, rather than average year plant balances.

Q. WERE THESE ALLOCATIONS APPROPRIATE?

A. One could always quibble with the details of any cost allocation program. However, OPC has no objections to the Company's application of its jurisdictional cost allocation methodologies in this proceeding. I therefore have no recommendations with respect to the jurisdictional allocation of costs other than that they be accepted by the Commission.

Q. DO YOU HAVE ANY OTHER COMMENTS WITH REGARD TO JURISDICTIONAL ALLOCATIONS?

A. Yes. The Commission should be alert to the fact that the D.C. allocators are declining each year, as demonstrated in the following table:

Washington Gas Light Co.
D.C. Jurisdictional Allocators

	1998	1999	2000
Annual Therm Sales	.237222	.236105	.231356
Peak Day Therms	.195148	.197323	.196940
Gas Plant In Service exl.General	.205176	.204142	.202797
General Gas Plant	.196248	.195594	.194783
Direct Labor	.246198	.242196	.207955
Administrative and General	.232101	.223804	.213722

The significance of these declining allocators relates to the trend in D.C. jurisdictional costs over time. When the Commission establishes a revenue requirement based on adjusted year 2000 D.C. jurisdictional results, the revenue recovery that it sets will have a tendency to become excessive relative to the jurisdictional costs for subsequent years. That is because many company-wide costs, such as administrative overheads, transmission mains, and general plant become less and less the responsibility of D.C. ratepayers. Those costs may grow, but the proportion of them allocated to the District declines. Once the D.C. rates are fixed, the revenue they generate cover a declining proportion of the system costs, and the result is earnings accretion. This trend, which has been the pattern of many years, may partially account for the evidence of excessive D.C. earnings that stimulated OPC to file the complaint that persuaded the Commission to initiate this proceeding. It may also explain why Washington Gas has not itself initiated a rate case in the District of Columbia since 1994.

ISSUE 12: ARE WGL'S D.C. RATES REASONABLE AND APPROPRIATE IN COMPARISON TO OTHER WGL SERVICE TERRITORY BASE RATES?

A. ARE THE COMPANY'S COSTS OF OPERATIONS HIGHER IN THE DISTRICT OF COLUMBIA THAN IN MARYLAND OR VIRGINIA AND, IF SO, DESCRIBE ALL THE ASSUMPTIONS AND OTHER FACTORS THAT WOULD EXPLAIN THE DIFFERENCES?

Q. WHAT EVIDENCE HAS THE COMPANY PRESENTED IN RESPONSE TO THIS ISSUE?

A. Mr. Touriniemi's Exhibit WG(2E)-5 compares the cost per therm allocated to D.C., Maryland and Virginia for most of the principal expense items Overall, the exhibit shows total D.C. distribution cost per therm to be 50.587¢, compared with 35.655¢ per therm in Maryland and 36.750¢ in Virginia. The exhibit displays only some of the detail for these disparities. It shows that operations expense in the District is 19.468¢, versus 11.663¢ and 12.144¢ for Maryland and Virginia, respectively. The largest component of this differential is 11.313¢ for "Administrative and General" in the District, relative to only 6.341¢ in Maryland and 6.792¢ in Virginia. The only other item on Exhibit WG (2E)-5 of major importance is gross receipts taxes, which are 4.599¢ in the District but only .757¢ and .865¢ in Maryland and Virginia, respectively.

Unaccountably, the Exhibit WG (2E)-5 does not show the per-therm values for the largest single element of cost within the overall per-therm distribution cost total, and that is return on rate base. Those costs are as follows:.

	DC	MD	VA
Firm Term Sales	214,901,529	493,104,017	416,035,730
Return on Rate Base	$29,948,914	$55,718,835	$ 52,717,315
Cents per Firm Therm	13.9	11.3	12.7

Q. DOES THE INCLUSION OF INTERRUPTIBLE SERVICE IMPROVE THIS COMPARISON?

Yes, it does, because actual interruptible deliveries (either sales or delivery service) account for 33 percent of D.C. sendout in 2000, but only 18 percent in Maryland and 13 percent in Virginia. A comparison of total distribution costs with and without interruptible sales is as follows[29]

Cents per Therm

	DC	MD	VA
Distribution Cost per Total Therms	33.5	.29.4	32.1
Distribution cost per Firm Therms	50.4	35.6	.36.8

Of course, interruptible customers do not pay the full embedded cost of their delivery service, so the inclusion of their therms in the foregoing comparison does not translate proportionately into lower per therm revenue requirements. Nevertheless, as noted earlier, D.C. firm service customers do benefit from a Distribution Cost Adjustment ("DCA") that is netted out of the PGC they pay each month. The current value of the DCA is 5.6¢. The offsets corresponding to the DCA in Maryland and Virginia are probably much lower.

[29] Term data: 2000 jurisdictional allocation study. Schedule AL, page 1.. Distribution Costs from Exhibit WG (2E)-5.

Q. WHAT EXPLANATION DOES THE COMPANY OFFER FOR THESE DISPARITIES IN THE COST OF SERVICE AMONG THE THREE JURISDICTIONS?

A. At page 30 of his Supplemental Testimony (Exhibit WG (2E)), Mr. Touriniemi cites three principal factos that account for the somewhat higher costs in the District of Columbia. The first is governmental policies, which include higher costs for the amortization of regulatory assets, least cost planning expense and post-retirement benefits. This category would also include the higher D.C. gross receipts taxes, income taxes and right-of-way fees.

The second factor cited by Mr. Touriniemi for higher D.C. costs is the greater volume of uncollectible accounts expense: 1.57¢ per therm in the District as compared to 0.37¢ and 0.12¢ per therm in Maryland and Virginia, respectively.

The third cause, according to Mr. Touriniemi, is the lower number of therms sold in the District of Columbia which requires fixed costs to be spread over a fewer number of therms.

Mr. Touriniemi also cites dramatic differences in depreciation expense per therm: 6.67¢ in D.C., versus 2.4¢ and 1.3¢ in Maryland and Virginia, respectively.

Q. HAVE YOU ANY COMMENTS ON THESE RESPECTIVE CAUSES?

A. Mr. Touriniemi is correct that D.C. imposes higher taxes on its utilities than do the suburban jurisdictions. This difference reflects the problem that has confounded the District government ever since I can remember (and I have lived in the Washington area all my life), which is that a very high proportion of the real estate in the District is exempt from property taxes. The District is therefore forced to use indirect taxes, such as the Gross Receipts Taxes on utilities, to derive at least some revenue from the governmental and non-profit organizations that occupy so much property in the City. The amortization of regulatory assets are addressed in the testimony of OPC Witness Nancy Bright, Exhibit OPC (D).

A distinction of the District not mentioned in Mr. Touriniemi's testimony is the much greater number of meters located inside customers' premises in the District relative to the suburbs.[30] This difference would like cause higher meter reading costs, more services on customer premises, and more customer service calls.

The data do not support Mr. Touriniemi's assertion that there are fewer therm deliveries in the District than in the suburbs. To the contrary, the average therm consumption per meter in the District during 2000 was 2,228, versus 1,638 in Maryland and 1,350 in Virginia. Even if the measurement is limited to firm service therms, the per-meter consumption was 1,479 therms in the District, but only 1,349 in Maryland and 1,179 in Virginia.[31]

Finally, the very significant differences in depreciation rates account for OPC's insistence that the Company produce an updated depreciation study. Although differences in the mix of plant might account for some of the higher depreciation cost in the District, the D.C. depreciation rates are significantly higher for corresponding types of plant, as demonstrated for the five largest depreciable categories of plant:

[30] Washington Gas response to OPC Data Request No; 11-178(a)
[31] Based on data in the 2000 Jurisdictional Cost Allocation Study, Schedule AL, pages 1 and 4.

Depreciation Rates, 2000[32]

Description	System Plant Balance ($000)	D.C Rate	Maryland Rate	Virginia Rate
Distribution Mains- Plastic	529,676	2.962	2.363	2.503
Services – Plastic	524,806	4.491	3.222	3.123
Distribution Mains – Steel	254,289	3.089	2.363	2.503
Meters – Hard Case	102,334	2.921	2.142	2.148
Meter Installations	95,831	4.287	2.500	4.464

This issue of these very unequal depreciation rates will be examined in Phase II of this proceeding.

<u>ISSUE NO. 12.B:</u> ARE THE DISTRIBUTION RATES TO DISTRICT RATEPAYERS HIGHER THAN RATES CHARGED TO MARYLAND OR VIRGINIA RATEPAYERS, AND, IF SO, DESCRIBE ALL THE ASSUMPTIONS AND OTHER FACTORS THAT WOULD EXPLAIN THE DIFFERENCES?

Q. DID THE COMPANY ADDRESS THIS SUBISSUE IN ITS PREPARED TESTIMONY?

A. No. There are no comparisons of distribution rates in the District with corresponding rates in Maryland or Virginia in any other Company's prefiled testimony or exhibits.

Q. HOW DO DISTRIBUTION CHARGES IN THE DISTRICT OF COLUMBIA COMPARE WITH THOSE IN MARYLAND AND VIRGINIA?

A. Distribution charges in Maryland and Virginia differ from those in the District in both structure and level. Possibly the structural differences are the most significant.

In both Maryland and Virginia, heating customers receive bills 12 month of the year, versus nine months in the District. This means that although the customer charges appear quite similar, \$7.49 in the District versus \$7.10 in Maryland and \$7.81 (\$8.78 for customers with over 1000 therms) in Virginia for residential service, they are in fact one third higher in the suburban jurisdictions by reason of the added three months of billing.

More important, both suburban jurisdictions have declining block rates. For residential customers these blocks are as follows:

<u>District of Columbia</u>	38.89¢ per therm
<u>Maryland</u>	
First 45 therms	35.57¢ per therm
Next 135 therms	25.57¢ per therm
Over 180 therms	19.25¢ per therm
<u>Virginia</u>	
First 25 therms	43.63¢ per therm
Next 100 therms	27.92¢ per therm
Over 125 therms	23.36¢ per therm

The D.C. residential commodity rate is higher than those in the suburbs. However, against this rate must be applied a 5.6¢ DCA credit, which shows up in the PGC (all jurisdictions have what appears to be a similar PGC), and is probably higher in the D.C. than the corresponding credits in the suburban jurisdictions. This factor would reduce the disparity.

The same declining block rate structure is found in the commercial rates of both suburban jurisdictions, but with very different blocks and much different rates:

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[32] Washington Gas Light Company 2000 FERC Form 2, page 338b

District of Columbia

All therms	37.68¢ per therm

Maryland

First 300 therms	30.85¢ per therm
Next 6,700 therms	21.26¢ per therm
Over 7000 therms	15.81¢ per therm

Virginia

First 125 therms	28.37¢ per therm
Next 875 therms	22.81¢ per therm
Over 1000 therms	17.69¢ per therm

Again, these rates are not altogether comparable. First, the District has as different, and higher, DCA credit. Second, the D.C. has a peak usage rate of 2.39¢ per therm based on the customer's highest monthly consumption during the previous winter.

Finally. both suburban jurisdictions have a separate rate for Group Metered Apartments. The commodity rates in these rate schedules are identical to those in the commercial schedules. The only distinction is in the customer charges, where the GMA schedules distinguish between heating/cooling and non-heating/non-cooling, with a customer charge for heating/cooling customers ($42.25 in Maryland and $44.60 in Virginia) much higher than for any other schedule.

Q. CAN YOU DESCRIBE THE ASSUMPTIONS THAT EXPLAIN THE DIFFERENCES AMONG THESE RATES BY JURISDICTION?

A. The higher D.C. rates presumably reflect higher D.C. costs, which I discussed earlier. I can only speculate as to the assumptions that underlie

Exhibit OPC (H)-1
(Revised)

Washington Gas Light Company
Customer Charge Revenue

		Present Customer Charges	Proposed Customer Charges	Current Customer Rate	Proposed Customer Rate	Present Customer Revenue	Proposed Customer Revenue	Percent Increase
	Residential							
1	Heating and/or cooling	$ 1,032,064	$ 1,352,880	$ 7.49	$ 11.25	$ 7,730,159	$ 15,219,900	97%
2	Non-heating and non-cooling	164,217	164,217	3.79	5.70	622,382	936,037	50%
3	Other	60,782	60,782	4.47	6.70	271,696	407,239	50%
	Non-residential							
	Heating and/or Cooling							
4	Less than 3075 therms	46,772	57,463	10.02	15.05	468,655	864,818	85%
5	More than 3075 therms	45,147	58,823	25.19	37.80	1,137,253	2,223,509	96%
6	Non-heating and non-cooling	42,253	42,253	10.70	16.05	452,107	678,161	50%
7	Total					$10,682,253	$ 20,329,665	90%
8	Customer Charge Correction Factor					0.985322759	0.985322759	
9	Corrected Customer Charge Revenues					10,525,467	20,031,281	
10	Net Firm Non-Gas Revenues					$96,676,664	$ 112,960,806	
11	Percent Revenues from Customer Charges					10.9%	17.7%	

Sources:
Lines 1-9 - Exhibit WG (2F)-1, Schedule B, page 4
Line 10 - Exhibit WG (2F)-1, Schedule B, page 1, line 10 and line 22

Washington Gas Light Company
Present and OPC Recommended Rates

	Present Rate	OPC Recommended Rate
Rate Schedule Nos 1 and 1A		
Heating and/or Cooling		
Customer Charge	$ 7.49	$ 6.49
Initial RES Discount	$ (0.1895)	$ (0.1895)
Non-heating and Non-cooling		
Customer Charge IMA	$ 3.79	$ 3.79
Customer Charge Other	$ 4.47	$ 3.87
Commodity per therm	$ 0.3989	$ 0.3456
Rate Schedule Nos 2 and 2A		
Heating/Cooling		
Customer Charge under 3,075 therms	$ 10.02	$ 8.68
Customer Charge over 3,075 therms	$ 25.16	$ 21.80
Non-heating/non-cooling		
Customer Charge	$ 10.70	$ 9.27
Commodity Charge	$ 0.3768	$ 0.3265
Peak Usage Charge	$ 0.0239	$ 0.0207
Non-Recurring Charges		
Meter Relocations		
Meter actually relocated	$ 27.09	$ 75.00
Meter not relocated	$ 27.09	$ 75.00
Dishonored Checks	$ 7.22	$ 15.00
Reconnect Fees		
Individual		
7 am to 5 pm	$ 40.64	$ 35.21
All other times	$ 63.21	$ 54.77
Multi-family		
7 am to 5 pm	$ 16.25	$ 14.08
All other times	$ 22.57	$ 19.56
Service Initiation Charge		
Gas Flowing	$ 35.22	$55.00
Gas not flowing	$ 35.22	$115.00

Washington Gas Light Company
OPC Rate Adjustment Factor

	Rate Elements not subject to average reduction:	**Source**	A Present Revenue	B Proposed Revenue	C Difference
1	IMA Customer Charge	WG (2F)-1,Sch B, p 4, 4C*4D	622,382	622,382	
2	RES Credits	Note: Line 20 below	-	(305,344)	
	Non-Recurring Charges				
	Late payment Charge				
	Meter Relocations				
3	Meter actually relocated	WG (2F)-1, Sch B, p 5, 4D, 4F	1,598	4,425	
4	Meter not relocated	WG (2F)-1, Sch B, p 5, 5D, 5F	542	1,500	
5	Dishonored Checks	WG (2F)-1, Sch B, p 5, 6D, 6F	37,479	77,805	
	Service Initiation Charge				
6	Gas Flowing	WG (2F)-1, Sch B, p 5, 15D, 15F	554,257	865,535	
7	Gas not flowing	WG (2F)-1, Sch B, p 5, 16D, 16F	385,589	1,259,020	
8	Watergate	WG (2F)-1, Sch C, 22F	1,802,000	1,802,000	
9	Natural Gas Vehicles	WG (2F)-1, Sch C, 23F	130,000	130,000	
10	Total Not Subject to Average Reduction	Sum, Lines 1-9	3,533,847	4,457,323	923,476
	Revenue Subject To Average Reduction:				
11	Present Revenue	WG (2F)-1, Sch C, 28F	99,637,000		
12	Add: Conservation Adjustment	OPC (D)-1, 15(2)	800,962		
13	Total Revenue	L11+L12; OPC (D)-1, 15(4)	100,437,962	88,421,070	(12,016,892)
14	Revenue Subject to Uniform Reduction	Line 13-Line110	96,904,115	83,963,747	(12,940,368)
15	Uniform Rate Adjustment Factor	B14/A14		0.866462	
	Note:				
16	RES Customers, November 2001	F.C. No. 1007, Resp to OPC 1-13	5,283		
17	Average Discounted Therms	WG (2F)-1, Sch B, p3, 3B	305		
18	Total Discounted Therms	Line 16*Line17	1,611,315		
19	Current Tariff Discount Rate	WG (2F)-1, Sch B, p3, 9B	$ (0.1895)		
20	Current Value of RES Discounts	Line 18*Line 19	$ (305,344)		