FirstEnergy

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FILE

February 20, 2008

VIA HAND DELIVERY

Ms. Reneé J. Jenkins
Director of Administration
Docketing Department
The Public Utilities Commission of Ohio
180 East Broad Street, 13th Floor
Columbus, Ohio 43215

Re: Case Nos. 07-551-EL-AIR, 07-552-EL-ATA, 07-553-EL-AAM, 07-554-EL-UNC, In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Increase Rates For Distribution Service, Modify Certain Accounting Practices and for Tariff Approval.

Dear Ms. Jenkins:

Enclosed for filing on behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company are an original and twenty copies of the Rebuttal Testimony in the above-captioned cases. The witnesses are as follows, and are listed in the order in which they will be presented:

Friday, February 22, 2008
Harvey L. Wagner
Susan Lettrich
Gregory F. Hussing
Kevin L. Norris
Steven E. Ouellette

Monday, February 25, 2008
Michael J. Vilbert
Jeffrey R. Kalata
William R. Ridmann

The Companies assume that other parties' rebuttal witness(es) will appear on Monday as well.

Copies have been served on all parties on the attached certificate of service, Please contact me if you have any questions.

Respectfully submitted,

Stephen L. Feld / JTS

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Attorneys for Applicants, Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company

CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing Rebuttal Testimony was this 20th day of February, 2008 served electronically on the parties of record reflected on the attached service list. Additionally, a copy was served on Joseph P. Meissner via UPS Next Day Air.

Ebony L. Miller /JRB

Ebony L. Miller
An Attorney for Applicants

Case No. 07-551-EL-AIR, et al.
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Case No. 07-551-EL-AIR
Case No. 07-552-EL-ATA
Case No. 07-553-EL-AAM
Case No. 07-554-EL-UNC

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

IN THE MATTER OF THE APPLICATION

OHIO EDISON COMPANY
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
THE TOLEDO EDISON COMPANY

FOR AUTHORITY TO INCREASE RATES FOR DISTRIBUTION SERVICE, MODIFY CERTAIN ACCOUNTING PRACTICES AND FOR TARIFF APPROVAL

Rebuttal Testimony

February 20, 2008

W. Ridmann	Company Exhibit 1-C
H. Wagner	Company Exhibit 3-C
J. Kalata	Company Exhibit 4-C
M. Vilbert	Company Exhibit 8-C
G. Hussing	Company Exhibit 13-C
K. Norris	Company Exhibit 15-C
S. Ouellette	Company Exhibit 16-C
S. Lettrich	Company Exhibit 17-C

[Company Exhibit 1-C]

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio	)	
Edison Company, The Cleveland Electric	)	
Illuminating Company, and The Toledo	)	Case No. 07-551-EL-AIR
Edison Company for Authority to	)	Case No. 07-552-EL-ATA
Increase Rates for Distribution Service,	)	Case No. 07-553-EL-AAM
Modify Certain Accounting Practices	)	Case No. 07-554-EL-UNC
and for Tariff Approvals	)	

REBUTTAL TESTIMONY OF

WILLIAM R. RIDMANN

ON BEHALF OF

OHIO EDISON COMPANY
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
THE TOLEDO EDISON COMPANY

___ Management policies, practices, and organization

___ Operating income

___ Rate base

___ Allocations

___ Rate of return

___ Rates and tariffs

_X_ Other –Case Overview,
Revenue Requirements
Gross Rev. Conversion Factor

Q. PLEASE STATE YOUR NAME FOR THE RECORD.

A. My name is William R. Ridmann.

Q. ARE YOU THE SAME WILLIAM R. RIDMANN THAT PROVIDED INITIAL, UPDATE AND SUPPLEMENTAL TESTIMONY THAT WAS FILED IN THIS PROCEEDING ON JUNE 7, 2007, AUGUST 6, 2007, AND JANUARY 10, 2008, RESPECTIVELY?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to address several issues raised by Staff witnesses regarding distribution related general plant and uncollectible expense adjustments. Further I address the Staff's failure to affirmatively act upon the Companies' requests for means to recover deferred fuel costs and non-distribution related uncollectible expense and customer deposits.

<u>FirstEnergy Service Company General Plant</u>

Q. STAFF WITNESS BUCKLEY REASONS IN HIS PREFILED TESTIMONY THAT THE ALLOCATED PORTION OF THE FIRSTENERGY SERVICE COMPANY GENERAL PLANT SHOULD NOT BE INCLUDED IN THE COMPANIES' REVENUE REQUIREMENTS BECAUSE THE STAFF DID NOT HAVE THE OPPORTUNITY TO REVIEW THE ASSETS DURING THE "STAFF'S TYPICAL RATE BASE REVIEW." DO YOU AGREE WITH THAT ARGUMENT?

A. No. The Staff's rate base investigation was ongoing at the time it was made aware of the Service Company general plant omission and it had an adequate opportunity to review the assets.

Q. WHEN DID THE COMPANIES FIRST LEARN OF THE INADVERTENT OMISSION?

A. We became aware of the omission in late October 2007.

Q. WHEN WAS STAFF NOTIFIED?

A. Staff was notified immediately through phone calls. The issue was formally brought to the attention of Staff on November 1, 2007, in a Company response to a data request Staff had issued as part of its ongoing rate base investigation.

Q. HAD THE STAFF COMPLETED ITS RATE BASE INVESTIGATION AT THE TIME IT WAS MADE AWARE OF THIS ISSUE?

A. To the best of my knowledge, Staff had not completed its investigation. First, the Staff was formally made aware of the issue through another rate base related data request response, PUCO DR-87. Second, the Companies responded to a different rate base related data request after the notice of this issue was made, PUCO DR-88. Finally, the Staff Reports were issued December 4, 2007, more than one month after the issue was raised. In the Reports, the Staff noted that its rate base investigation was not yet completed, and that final Staff decisions on General Plant would "be provided prior to making a final determination of the appropriate level of plant in service for purposes of this proceeding" (CEI/OE/TE Staff Reports, pg. 5).

Q. DID THE COMPANIES PROVIDE STAFF THE OPPORTUNITY TO REVIEW THE NATURE OF THE ASSETS IN QUESTION?

A. Yes. Staff was provided the opportunity to review a detailed list of the assets and their associated values as of December 2000 and date certain. Additionally, Staff issued several requests for discovery in which it asked for, among other things, (1) detail behind selected asset balances, (2) account balance activity between December 2000, and May 2007, (3) the estimated amount of the total asset transfer, (4) the FERC accounting guidelines governing the transfer of such assets between a service company and an operating subsidiary, and (5) reasons why the assets were on the Service Company books, why they should be transferred back to the Operating Companies, and why it is appropriate to include them now as rate base in this proceeding. All these requests for discovery were responded to quickly, and the information requested was provided.

Q. WHY WERE THESE GENERAL PLANT ASSETS ON FIRSTENERGY SERVICE COMPANY'S BOOKS?

A. In December 2000, general plant assets (such as office equipment and furniture, communications equipment, and certain software, among other things) were transferred from the Operating Companies to the Service Company to capture the "Value Center" concept. Value Centers were "department cost centers" within the Value Based Management (VBM) System. The VBM system, which interfaced with the Oracle accounting system, generated monthly reports that were used by the Service Company and utility company employees to analyze on-going cost levels such as labor and depreciation expense as well as capital expenditures. The Value Centers were required to have "complete costs" associated with the services that were provided by the Value Center. This would include depreciation expense associated with the assets they had responsibility for. This is the reason the general plant assets were transferred to these Value Centers that resided in the Service Company.

Q. WHY NOW ARE CERTAIN OF THESE ASSETS BEING TRANFERRED BACK TO THE OPERATING COMPANIES?

A. First, the Service Company adopted the SAP accounting system in June 2003. SAP provides a different reporting mechanism that does not require assets to be categorized in value centers. The Oracle systems are now no longer in use. Second, the assets in question are used by Service Company employees to support the distribution function. Despite the Companies' inadvertent omission of these general plant assets in their filings, these assets are in fact used by employees in support of the distribution function. If these assets were not distribution related, the Companies would not now be completing the transfer of certain balances to their respective accounting books. Furthermore, as I indicate above, these assets were not transferred to the Service Company until December 2000. Notwithstanding additions, retirements and accumulated depreciation, these same assets were on the books of the respective Operating Companies at the time of their last rate cases, were included in the rate base in those cases, and were obviously in service as of date certain in this case. Staff's decision not to recognize the costs associated with these assets in the Companies' revenue requirements in this proceeding amounts to an unreasonable confiscation of property utilized to serve distribution customers.

Q. COMPANY WITNESS CHATMAN INDICATED IN HER SUPPLEMENTAL TESTIMONY (COMPANY EXHIBIT 5-B) THAT THE

FINALIZED TRANSFER OF CERTAIN OF THESE ASSETS TO THE OPERATING COMPANIES WOULD BE COMPLETED IN JANUARY 2008. HAS THIS TRANSFER BEEN FINALIZED?

A. Yes. The final Designated Assets were transferred with the January 2008 accounting close. The total transfer now sums to $17,377,469 for the three Operating Companies, which compares to the $15,099,631 transferred at the time Company Witness Chatman submitted Supplemental Exhibit PRC-2.

Q. ARE THERE ANY OTHER ASSETS TO CONSIDER CONCERNING THIS ISSUE?

A. Yes. In addition to the $17,377,469 of general plant assets actually transferred to the Operating Companies, another $54,101,922 of assets still reside on the Service Company books. These additional assets are used in support of distribution operations and will be recognized as such going forward through the allocation of their associated depreciation expense, property tax expense, and carrying costs to each of the Operating Companies.

Q. SINCE THE TRANSFERRED ASSETS ARE NOT INCLUDED, NOR ARE THE CARRYING CHARGES ON THE REMAINING ASSETS BEING ALLOCATED TO THE COMPANIES, IN EITHER THE COMPANIES' FILINGS OR THE STAFF REPORTS, HOW WOULD YOU SUGGEST THEY BE RECOGNIZED IN THE OVERALL REVENUE REQUIREMENT?

A. Rather than adding the net plant in service to each of the Companies' rate base, I have calculated the revenue requirement associated with these assets, which can be found on Rebuttal Exhibit WRR-1 (Line No. 20). The Companies are requesting that the Commission approve an additional $2,564,920, $1,120,882 and $2,063,191 be added to the revenue requirements of OE, TE and CEI, respectively.

Q. THE SUM OF THOSE ADDITIONAL REVENUE REQUIREMENTS IS APPROXIMATELY $5.7 MILLION. HOW DOES THIS DIFFER FROM COMPANY WITNESS FERNANDEZ'S PRIOR CALCULATION?

A. Company Witness Fernandez represented that the additional revenue requirement associated with the net plant in service was $8.9 million (The $8.9 million is presented on Rebuttal Exhibit WRR-1, Line No. 16). The amount presented here and in Rebuttal Exhibit WRR-1 nets accumulated deferred income tax liabilities against the net plant to determine the amount of additional revenue requirement.

Q. PLEASE DESCRIBE REBUTTAL EXHIBIT WRR-2.

A. Rebuttal Exhibit WRR-2 calculates the tax-adjusted rate of return the Companies are requesting be applied to the net amount of transferred assets. The tax-adjusted rates of return shown in this exhibit, which are ultimately multiplied by the net rate base shown in Rebuttal Exhibit WRR-1, are calculated using the following determinants: (1) The 51% debt, 49% equity capital structure requested by the Companies and supported by Staff Witness Cahaan, (2) the embedded cost of debt (as revised by Company Witness Pearson in his Supplemental Testimony, Company Exhibit 7-B) and return on equity requested by the Companies, (3) the state, local and federal income tax rates used on the C-4 Tax Schedules in the Staff Report, and (4) the uncollectible and CAT tax factors as identified in the Companies' Update C-

10 Schedules. Any of these variables can easily be changed to reflect the Commission's decision on such inputs.

Q. ARE THERE ANY OTHER CONSIDERATIONS YOU ACCOUNTED FOR WHEN DETERMINING THE REVENUE REQUIREMENTS ASSOCIATED WITH THE ASSET TRANSFER?

A. Yes. As indicated by Company Witness Fernandez during his direct oral examination on January 31, 2008, a small amount of carrying charges associated with the assets in question was already being billed to the Operating Companies and was included in the Companies' respective revenue requirements. These charges should reduce the additional revenue requirements being requested; otherwise, the expense would be double counted. This adjustment is made on Line No. 19 in Rebuttal Exhibit WRR-1.

Q. IS YOUR ADJUSTMENT DIFFERENT FROM THE AMOUNT INDICATED BY COMPANY WITNESS FERNANDEZ?

A. Yes. Company Witness Fernandez noted that the amount of carrying charge was $197,000 for the three Operating Companies. That amount represents the 2007 budget. The total carrying charge of $153,797 presented in Rebuttal Exhibit WRR-3 is the amount for the updated test-year, which includes three months of actual and nine months of budget. Rebuttal Exhibit WRR-4 show the entries on the Companies' books for March, April and May 2007.

Q. DID YOU ACCOUNT FOR THE DEFERRED TAX LIABILITIES ASSOCIATED WITH THESE ASSETS WHEN CALCULATING THE IMPACT TO REVENUE REQUIREMENTS?

A. Yes. Deferred tax liabilities associated with these assets are included on Line No. 13 of Rebuttal Exhibit WRR-1 and serve to reduce the rate base to which the tax-adjusted rate of return is applied. The deferred taxes on the $17,377,469 of transferred assets were developed by determining where a book/tax depreciation timing difference existed for the specific assets transferred to the Operating Companies. The total of the book/tax timing difference was multiplied by the effective Federal, State and Local deferred tax rates Company Witness Young identifies in his Exhibit GDY-1 to his Supplemental Testimony (Co. Exhibit 6-B), and the resulting value represents the accumulated deferred tax liability associated with the assets as of date certain. The deferred taxes on the $54,101,922 of assets remaining at the Service Company represent a value applied to this net plant based on the ratio of the total book/tax timing difference of the net transferred assets to the total net plant of the assets transferred to the Operating Companies. The current FirstEnergy Service Company effective deferred tax rates are then applied to the resulting book/tax timing calculation to determine the deferred tax liabilities.

Q. SHOULD THE COMMISSION MAKE ANY RECOGNITION OF THE DEPRECIATION EXPENSE OR PROPERTY TAX EXPENSE ASSOCIATED WITH THESE ASSETS?

A. No. The depreciation and property tax expenses associated with these assets were already being billed to each respective Operating Company at the time of the filings and are included in the test year expenses. Going forward, the transfer of certain of these assets will now cause the Operating Companies directly to incur these expenses rather than incur them through allocation of Service Company expenses.

For the assets remaining at the Service Company, the allocation of such expenses will continue.

Q. SHOULD THE COMMISSION BE CONCERNED THAT ITS APPROVAL OF THE COMPANIES' REQUEST TO INCLUDE THESE ASSETS IN REVENUE REQUIREMENTS IS CONTRARY TO THE STANDARD FILING REQUIREMENTS?

A. No. As previously stated, these assets are used to serve the distribution function at issue in this proceeding. The appropriate distribution related assets have been transferred to the Operating Companies within the test period. Furthermore, the value of the assets being considered here are the values as of date certain, which is no different from any other plant in service item also considered in this proceeding.

Rate Certainty Plan Deferred Fuel Costs

Q. AS WITH THE STAFF REPORT, HAS STAFF AGAIN FAILED TO ADDRESS IN TESTIMONY AND REVISED SCHEDULES THE COMPANIES' CONCERN OVER A MECHANISM TO RECOVER RCP FUEL DEFERRALS?

A. Yes. The Staff has failed to address the Companies' Objections I.c.3, I.c.5 and II.16 in testimony. All three of these objections deal with the Companies' request that Staff address a recovery mechanism for the fuel deferrals the Companies presented in this proceeding.

Q. DO YOU FEEL THAT STAFF HAS EXPLORED ALL AVENUES AVAILABLE WHEN CONSIDERING THIS ISSUE?

A. No, I do not.

Q. DO THE REVENUE REQUIREMENTS FILED BY THE COMPANIES IN THIS PROCEEDING INCLUDE RECOVERY OF ANY DEFERRED FUEL BALANCES?

A. Yes, the Companies proposed that the estimated 12/31/2008 deferred fuel balance, net of accumulated deferred income tax balances, be included as part of rate base. The requested distribution revenue requirement inherently includes a portion related to recovery of the deferred balance over 25 years with a return on the net balance at the cost of debt. However, the Staff removed both the deferred balance and amortization expense in its Staff Report.

Q. DO YOU BELIEVE STAFF MISSED AN OPPORTUNITY TO CHANGE THE METHODOLOGY THROUGH WHICH FUEL DEFERRALS ARE ADDRESSED IN THIS PROCEEDING?

A. Yes, I do.

Q. HOW DO YOU PROPOSE TO REVISE THE METHODOLOGY?

A. I propose removing the revenue requirements associated with the estimated fuel deferrals that are currently included in the Companies' proposed overall distribution revenue requirements and replacing them with separate revenue requirements based upon appropriate actual data. I also propose recovering these revenue requirements via a Rider in the Companies' tariffs and not through distribution rates.

Q. WHY DO THE COMPANIES NOW PROPOSE THIS METHODOLOGY?

A. At the time of the update filing, the Supreme Court had yet to rule on the recovery mechanism for deferred fuel costs and the Companies' proposed recovery was consistent with the RCP Stipulation and Recommendation. After the Court's decision, however, the Staff Report was issued with fuel costs removed from the revenue requirements and the Companies objected to the Staff's failure to recommend a method by which recovery of the deferred fuel costs could be accomplished. Subsequently, in its Order in Case No. 07-1003-EL-ATA, the Commission granted the Companies the opportunity to recover the 2008 actual incremental fuel costs contemporaneously through a rider ("Fuel Cost Recovery Rider"), but did not approve a mechanism to address the 2006-2007 deferred fuel costs and related carrying charges. The methodology presented here is the Companies' proposed solution to recover the remaining costs in a manner consistent with the Commission's treatment of the 2008 fuel costs addressed in PUCO Case No. 07-1003-EL-ATA. The proposed Rider ("Deferred Fuel Cost Rider") also avoids the issue posed by the Supreme Court decision since the deferred fuel costs are removed from the distribution revenue requirement and placed in a rider that is specifically related to fuel recovery.

Q. HAVE YOU QUANTIFIED THE PORTION OF THE COMPANIES' PROPOSED REVENUE REQUIREMENT FROM THE UPDATE FILING ASSOCIATED WITH RECOVERY OF DEFERRED FUEL?

A. Attached Rebuttal Exhibit WRR-5(a) does just that. From this Exhibit, I recommend reducing the Companies' proposed revenue requirements as follows: CE = $16,945,383, OE = $11,632,049, and TE = $4,782,141. The Staff Report, of course, has already accounted for this reduction by removing the fuel related rate base and amortization expense from the calculation of revenue requirements.

Q. HAVE YOU CALCULATED THE REVENUE REQUIREMENTS THAT WOULD BE INCLUDED IN THE PROPOSED DEFERRED FUEL COST RIDER?

A. Yes, I have. These amounts are shown on the attached Rebuttal Exhibits WRR-5(b-d). I have presented multiple recovery periods from which the Commission may choose.

Q. PLEASE EXPLAIN THE BASIS FOR THE REPLACEMENT REVENUE REQUIREMENTS THAT YOU ARE PROPOSING TO BE RECOVERED THROUGH THE RIDER.

A. The Commission approved Fuel Cost Recovery Rider became effective January 11, 2008 to recover ongoing incremental fuel costs contemporaneously in 2008, therefore, there are no 2008 fuel costs in the rate base nor associated amortization expense in this proposed Deferred Fuel Cost Rider. Rather, the proposed Rider only includes recovery of the actual December 31, 2007 deferred fuel balances increased by the carrying costs through May 2008, plus a return at the cost of debt, amortization expense, uncollectible expenses, and the Commercial Activity Tax.

Q. FOR WHAT PERIOD DO THE COMPANIES PROPOSE THE DEFERRED FUEL COST RIDER BE EFFECTIVE?

A. The Companies propose that the Deferred Fuel Cost Rider (see Rebuttal Exhibit WRR-6(a-c)) become effective June 1, 2008, but no later than January 1, 2009, and continue until the deferred balance is fully recovered. If recovery does not begin on June 1, 2008, the Commission must recognize the additional carrying charges on the deferred fuel balances through the date on which recovery begins.

Q. ARE THE COMPANIES FILING A SIMILAR MECHANISM IN PUCO CASE NO. 08-0124-EL-ATA?

A. Yes, a similar recovery mechanism was filed in that Case.

Q. SO WHY ADDRESS THE ISSUE IN THIS PROCEEDING?

A. At this time, the Companies are unsure of where the Commission will address the 2006-2007 deferred fuel costs. We are asking in this case that the Commission state which proceeding the issue will be addressed, and rule accordingly. The Companies are certain that the RCP Stipulation and Recommendation, as approved by the Commission, specifically allows for the deferral and recovery of such costs. The question before us now is how and where the recovery will be addressed.

<u>**Uncollectible Expense and Customer Deposits**</u>

Q. IN STAFF WITNESS CHOUDHURY'S CORRECTED ATTACHMENTS TO PREFILED TESTIMONY, ADDITIONAL CHANGES WERE MADE TO THE COMPANIES' TEST YEAR UNCOLLECTIBLE EXPENSE THROUGH HER SCHEDULE C-3.12 ADJUSTMENTS. DO YOU AGREE WITH THESE ADJUSTMENTS?

A. No. I believe the C-3.12 adjustments made by Staff Witness Choudhury are in error.

Q. PLEASE EXPLAIN.

A. Staff witness Choudhury indicates in her Prefiled Testimony (page 2 at line 15) that the ratio used to develop the amount of jurisdictional uncollectible expense includes recognition of sales for resale revenue. The inclusion of this revenue in her calculation is erroneous for two reasons. First, the Companies did not incur uncollectible expense on this type of revenue during the test year. Except for a very small portion of the Toledo Edison revenue - (approximately 4.6% of total sales for resale revenue recognized in the test year), the near entirety of the sale for resale revenue included in the test year is associated with inter-company sales (For OE and CEI, the entire amount of sales for resale revenue was associated with inter-company sales). There is no reason for an uncollectible expense to be incurred by the Companies for a wholesale transaction that takes place between affiliated subsidiaries of FirstEnergy Corp. Second, when developing jurisdictional uncollectible expense for which the retail customer will be responsible, there should be no recognition of a wholesale transaction to which the retail customer is not a party. Including the sales for resale revenue in this calculation essentially makes retail customers bear the obligation for uncollectible expense attributable to other FirstEnergy subsidiaries. Therefore, these sales for resale revenues should not be included in the calculation to determine jurisdictional uncollectible expense.

Q. WHAT EFFECT DOES THE INCLUSION OF SALE FOR RESALE REVENUE IN THE CALCULATION OF THE UNCOLLECTIBLE EXPENSE RATIO HAVE ON THE AMOUNT OF JURISDICTIONAL UNCOLLECTIBLE EXPENSE?

A. Including the sales for resale revenue in the ratio used to determine jurisdictional uncollectible expense increases the denominator of the ratio calculation, thereby reducing the ratio and inappropriately reducing the amount of jurisdictional uncollectible expense.

Q. **HAVE YOU QUANTIFIED THE CORRECT ADJUSTMENT NECESSARY TO IDENTIFY JURISDICTIONAL UNCOLLECTIBLE EXPENSE?**

A. Yes. Attached Rebuttal Exhibit WRR-7 includes the corrected calculation of jurisdictional uncollectible expense the Companies are seeking recovery of in this case. The corrected expense adjustments are \$(7,687,898), \$(11,856,506) and \$(4,929,762) for CEI, OE and TE, respectively.

Q. **STAFF WITNESS CHOUDHURY ALSO RESPONDS TO THE COMPANIES' OBJECTION NO. II.2, RELATED TO THE STAFF'S FAILURE TO RECOMMEND A MEANS BY WHICH THE REMAINING PORTION OF UNCOLLECTIBLE EXPENSE (NOW REMOVED THROUGH STAFF'S C-3.12 ADJUSTMENT, AS CORRECTED ABOVE) SHOULD BE ADDRESSED. HAS STAFF ADDRESSED THE ISSUE ADEQUATELY IN THIS PROCEEDING?**

A. No. The Companies acknowledge Staff's attempt to recognize in base distribution rates only that portion of uncollectible expense that is distribution related. However, I feel that the remainder of the uncollectible expense could be addressed in this proceeding through a non-distribution related Rider ("Rider UNCD").

Q. **SIMILAR TO WITNESS CHOUDHURY'S COMMENTS ON THE NON-DISTIRBUTION RELATED UNCOLLECTIBLE EXPENSE, STAFF WITNESS CASTLE FAILS TO ADDRESS A METHODOLOGY IN WHICH THE NON-DISTRIBTUION RELATED CUSTOMER DEPOSITS AND INTEREST THEREON SHOULD BE HANDLED. COULD CUSTOMER**

DEPOSITS AND THE RELATED INTEREST THEREON BE INCLUDED IN RIDER UNCD AS WELL?

A. Yes, they could. Uncollectible expense and customer deposits are both a function of the level of revenue the Companies receive. The non-distribution related portions of these items could both be handled similarly through this one rider.

Q. COULD YOU PLEASE EXPLAIN THE MECHANICS OF THE PROPOSED RIDER UNCD?

A. The proposed Rider UNCD is structured so that an uncollectible/customer deposit percentage is applied to all billing components exclusive of the distribution related billing components addressed in this proceeding, transformer charges, and the list of all applicable riders shown on Rebuttal Exhibits WRR-9(a-c). The value calculated by applying such percentage will be added to the customer bill as a non-bypassable charge for non-distribution related uncollectibles and customer deposits.

Q. HOW WAS THIS UNCOLLECTIBLE / CUSTOMER DEPOSITS PERCENTAGE DEVELOPED?

A. The portion of the percentage associated with uncollectible expense is no different than the percentage used to calculate the above distribution related uncollectible expense. It is simply the ratio of total company test year uncollectible expense to total company revenue, exclusive of sales for resale revenue. The portion of the percentage associated with customer deposits and the related interest expense is calculated similarly, however, the revenue used in the denominator of the percentage calculation excludes both sales for resale and other operating revenues (the Companies only collect customer deposits on retail electric sales). The sum of the uncollectible portion, customer deposits portion and interest on customer deposits portion collectively determine the Rider UNCD Percentage, which is 0.5465%, 0.6912% and 0.7510% for CEI, OE and TE, respectively (see attached Rebuttal Exhibit WRR-8(a)). The calculation of the individual percentages for each component can be reviewed throughout Rebuttal Exhibits WRR-8(b-d).

Q. THE RIDERS, ATTACHED AS REBUTTAL EXHIBITS WRR-9(a-c), INDICATE THAT THE DISTRIBUTION CHARGES AND CHARGES/CREDITS RELATED TO CERTAIN RIDERS WILL BE EXCLUDED FROM THE RIDER UNCD CALCULATION. ARE THERE ANY OTHER CHARGES THAT SHOULD BE EXLCUDED?

A. If any other rate mechanisms account for recovery of a portion of the total uncollectible expense, then yes, the charges incurred through those mechanisms should be excluded from the calculation of Rider UNCD.

Q. WHEN WILL THESE RIDERS BECOME EFFECTIVE?

A. Rider UNCD will become effective January 1, 2009, for each Operating Company.

<u>Stipulation on Revenue Distribution</u>

Q. COULD YOU PLEASE DESCRIBE THE STIPULATION ENTERED IN THIS PROCEEDING ON FEBRUARY 11, 2008?

A. Yes. The stipulation resolves among the signatory parties the revenue distribution coming out of this case and the rate design associated with the GS, GP, GSUB and GT schedules.

It also withdraws all Objections to the Staff Reports submitted by the Ohio Energy Group (OEG) and Kroger. The testimony of Mr. Baron, Mr. Baudino and Mr. Kollen on behalf of OEG will not be offered in this proceeding. The testimony of Mr. Higgins on behalf of Kroger Co. will also not be offered in this proceeding.

The stipulation also provides for the withdrawal of certain Objection to the Staff Report filed by the Industrial Energy Users – Ohio, and the testimony of Mr. Murray on behalf of IEU will not be offered in this proceeding.

Q. DO YOU CONSIDER THIS STIPULATION A RESONABLE AGREEMENT IN LIGHT OF THE ENTIRETY OF ISSUES IN THIS CASE?

A. Yes, I do.

Q. DO YOU CONSIDER THIS STIPULATION AGREEMENT TO BE IN THE BEST INTEREST OF THE PUBLIC?

A. Yes, I do.

Q. IS THE STIPULATION SUPPORTED BY THE MAJORITY OF THE PARTIES TO THIS PROCEEDING?

A. Yes, it is.

Q. DOES THIS STIPULATION VIOLATE ANY REGULATORY PRINCIPLES?

A. No, it does not.

Percent of Income Payment Plan

Q. IS IT THE INTENT OF CEI AND TE THAT WITH THE ELIMINATION OF THE PIPP DISCOUNT RATE, THOSE COMPANIES WILL USE THE STANDARD 3% (ELECTRIC AS SECONDARY HEAT SOURCE) AND 13% (ELECTRIC AS PRIMARY HEAT SOURCE) INCOME CRITERIA FOR PIPP CUSTOMERS AT OR BELOW 50% OF THE POVERTY LEVEL?

A. Yes, it is.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

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Rebuttal Exhibit WRR-1

FirstEnergy Service Co
Net Plant Value as of May 2007 (By Asset Category)

Line No.	Category	FERC Allocator	FE Service Company General Plant: Gross Plant	Reserve	Net Plant	Net General Plant Supporting Ohio Distribution Operations: OE *	TE *	CEI *	Total
1	Adminstr Services Total	Multi Factor - All	5,865,040	1,920,890	3,944,150	679,183	298,967	560,464	1,538,613
2	Corporate Administration Total	Multi Factor - All	27,862,481	10,065,053	17,797,428	3,064,717	1,349,045	2,529,015	6,942,777
3	Distribution Division Total	Multi Factor - Op Cos	-	-	-	-	-	-	-
4	Finance Admin Total	Multi Factor - All	8,865,836	6,887,581	1,978,255	340,656	149,952	281,110	771,717
5	Generation Total		1,014,757	307,027	707,730	-	-	-	-
6	Governmental Affairs Total		54,641	16,820	37,821	-	-	-	-
7	Information Systems Total	Multi Factor - All	153,933,058	39,159,993	114,773,064	19,763,922	8,699,798	16,309,252	44,772,972
8	Legal Total	Multi Factor - All	282,780	88,361	194,419	33,479	14,737	27,627	75,843
9	Total **		197,878,593	58,445,725	139,432,868	23,881,956	10,512,499	19,707,468	54,101,922
10	Net Plant Transferred in December 2007 and January 2008 ***		116,585,085	83,466,706	33,118,379	7,998,608	3,177,622	6,201,239	17,377,469
11	Grand Total		314,463,678	141,912,431	172,551,247	**31,880,564**	**13,690,121**	**25,908,707**	**71,479,391**

	Additional Revenue Requirement Calculation	OE	TE	CEI	Total
12	Net Plant in Service (11)	31,880,564	13,690,121	25,908,707	71,479,391
13	Accumulated Deferred Tax Liabilities	(10,885,274)	(4,557,058)	(9,049,395)	(24,491,727)
14	Rate Base (12 + 13)	20,995,290	9,133,063	16,859,312	46,987,664
15	Tax-adjusted ROR ****	12.54%	12.60%	12.57%	
16	Carrying Charge on Net Plant (12 x 15)	3,997,823	1,724,955	3,256,724	8,979,502
17	Carrying Charge on Deferred Taxes (13 x 15)	(1,365,013)	(574,189)	(1,137,509)	(3,076,712)
18	Total Carrying Charge (16 + 17)	**2,632,809**	**1,150,766**	**2,119,215**	**5,902,791**
19	Portion of Carrying Charge included in Revenue Requirement *****	67,889	29,884	56,024	153,797
20	Total Additional Revenue Requirement (18 - 19)	**2,564,920**	**1,120,882**	**2,063,191**	**5,748,994**

* FERC Allocators applied to Net Plant	Multi Factor - All	Multi Factor-Op Cos
OE	17.22%	20.81%
TE	7.58%	9.16%
CEI	14.21%	17.18%

** $54,101,922 represents the date certain amount of assets residing on FE Service Company's books, the associated costs of which are now allocated to the Operating Companies (e.g. Depreciation Expense, Property Tax Expense, Carrying Cost).

*** $17,377,469 of date certain assets had been transferred to the Operating Companies in December 2007 and January 2008 and now reside on each Companies' respective books. This value updates the $15,099,631 provided on Company Witness Chatman's Supplemental Exhibit PRC-2.

**** Rebuttal Exhibit WRR-2

***** Rebuttal Exhibit WRR-3

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Rebuttal Exhibit WRR-2

Calculation of Tax-adjusted Rate of Return

OE (a)			ROR	Tax Rates (b)	Tax-adjusted ROR	
	Capitalization %	% Cost (c)	Weighted Cost %			
Long-Term Debt	51.0%	6.54%	3.34%		3.34%	
Common Equity	49.0%	11.75%	5.76%	36.6847%	9.09%	= Equity Return / (1 - Tax Rate)
Total Capitalization	100.0%		9.09%		12.43%	
				0.8996%	12.54%	= 12.43% / (1 - Rate)

CEI (a)						
	Capitalization %	% Cost (c)	Weighted Cost %			
Long-Term Debt	51.0%	6.54%	3.34%		3.34%	
Common Equity	49.0%	11.75%	5.76%	37.0100%	9.14%	= Equity Return / (1 - Tax Rate)
Total Capitalization	100.0%		9.09%		12.48%	
				0.7497%	12.57%	= 12.48% / (1 - Rate)

TE (a)						
	Capitalization %	% Cost (c)	Weighted Cost %			
Long-Term Debt	51.0%	6.54%	3.34%		3.34%	
Common Equity	49.0%	11.75%	5.76%	37.0307%	9.14%	= Equity Return / (1 - Tax Rate)
Total Capitalization	100.0%		9.09%		12.48%	
				0.9477%	12.60%	= 12.48% / (1 - Rate)

(a) Capital structure and equity/debt costs per Companies' Update Filing
(b) 2007 Income Tax rates per Staff Schedule C-4. Commercial Activities Tax rate of 0.156% and Uncollectible Percentages per Company Schedules C-10.

	Income Taxes	OE	CEI	TE
(1)	OH State	1.62944%	1.61469%	1.55953%
(2)	Muni	0.65086%	1.09660%	0.92230%
(3)	PA State	0.31150%	0.38100%	0.64240%
(4)		2.59180%	3.09229%	3.12423%
(5)		100.0%	100.0%	100.0%
(6)	State/Muni deduction for Fed Tax (5 - 4)	97.40820%	96.90771%	96.87577%
(7)	Federal Tax	35.0%	35.0%	35.0%
(8)	Effective Federal (6 x 7)	34.09287%	33.91770%	33.90652%
(9)	Total Effective Tax Rate (4 + 8)	36.68467%	37.00999%	37.03075%
	Revenue Factors			
	Uncollectible Accounts	0.7436%	0.5937%	0.7917%
	CAT Tax	0.1560%	0.1560%	0.1560%
		0.8996%	0.7497%	0.9477%

(c) Embedded Cost of Long-Term Debt revised from the Companies' Original and Updated filings to reflect the Supplemental Testimony of Jim Pearson (Co. Exh. 7-B, pg. 12, line 22)

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Rebuttal Exhibit WRR-3

FE Corp/Service Co. Loan Interest
Included in Test Year Expense

2007 Multi Factors		2008 Multi Factors	
OE	17.22%	OE	16.97%
TE	7.58%	TE	7.47%
CE	14.21%	CE	14.01%
	39.01%		38.45%

		2007 Budget	Ohio Edison Multi Factors	Ohio Edison Allocated Expense	Toledo Edison Multi Factors	Toledo Edison Allocated Expense	Cleveland Elec. Illum. Multi Factors	Cleveland Elec. Illum. Allocated Expense	TOTAL Allocated Expense
budget	January	69,851	17.22%	12,028	7.58%	5,295	14.21%	9,926	27,249
budget	February	66,481	17.22%	11,448	7.58%	5,039	14.21%	9,447	25,934
budget	March	63,111	17.22%	10,868	7.58%	4,784	14.21%	8,968	24,620
budget	April	59,741	17.22%	10,287	7.58%	4,528	14.21%	8,489	23,304
budget	May	56,372	17.22%	9,707	7.58%	4,273	14.21%	8,010	21,990
budget	June	53,002	17.22%	9,127	7.58%	4,018	14.21%	7,532	20,677
budget	July	30,761	17.22%	5,297	7.58%	2,332	14.21%	4,371	12,000
budget	August	27,579	17.22%	4,749	7.58%	2,091	14.21%	3,919	10,759
budget	September	24,398	17.22%	4,201	7.58%	1,849	14.21%	3,467	9,517
budget	October	21,217	17.22%	3,654	7.58%	1,608	14.21%	3,015	8,277
budget	November	18,036	17.22%	3,106	7.58%	1,367	14.21%	2,563	7,036
budget	December	14,855	17.22%	2,558	7.58%	1,126	14.21%	2,111	5,795
		505,405		87,030		38,310		71,818	197,158

		Test Year 3mo. Actual / 9mo. Budget	Ohio Edison Multi Factors	Ohio Edison Allocated Expense	Toledo Edison Multi Factors	Toledo Edison Allocated Expense	Cleveland Elec. Illum. Multi Factors	Cleveland Elec. Illum. Allocated Expense	TOTAL Allocated Expense
actual	March 2007 (a)	64,998	17.22%	11,193	7.58%	4,927	14.21%	9,236	25,356
actual	April 2007 (a)	59,523	17.22%	10,250	7.58%	4,512	14.21%	8,458	23,220
actual	May 2007 (a)	58,016	17.22%	9,990	7.58%	4,398	14.21%	8,244	22,632
budget	June 2007	53,002	17.22%	9,127	7.58%	4,018	14.21%	7,532	20,677
budget	July 2007	30,761	17.22%	5,297	7.58%	2,332	14.21%	4,371	12,000
budget	August 2007	27,579	17.22%	4,749	7.58%	2,091	14.21%	3,919	10,759
budget	September 2007	24,398	17.22%	4,201	7.58%	1,849	14.21%	3,467	9,517
budget	October 2007	21,217	17.22%	3,654	7.58%	1,608	14.21%	3,015	8,277
budget	November 2007	18,036	17.22%	3,106	7.58%	1,367	14.21%	2,563	7,036
budget	December 2007	14,855	17.22%	2,558	7.58%	1,126	14.21%	2,111	5,795
budget	January 2008	11,090	16.97%	1,882	7.47%	828	14.01%	1,554	4,264
budget	February 2008	11,090	16.97%	1,882	7.47%	828	14.01%	1,554	4,264
		394,564		$\boxed{67,889}$		$\boxed{29,884}$		$\boxed{56,024}$	$\boxed{153,797}$

(a) Totals tie to actual entries shown on Rebuttal Exhibit WRR-4 (pg. 2 of 2). Operating Company amounts are reconciled to charges assessed for March on Rebuttal Exhibit WRR-4 (pg. 2 of 2).

Entries to record the income/expense on the inter-company loan between FE Corp and FE Service Company for the purchase of certain General Plant Assets (debit FE Svc. Co expense / credit FE Corp income).

March 2007 Entry:

JE-Intercompany
Overall no. 0100060493SC0007 Doc.currency USD

CoCd / Itm	DocumentNo / PK	Year / Account	Type / Account short text	Doc. Date	Pstng Date	Reference	Crcy / Amount	Text
1000	100000308	2007	JI	03/28/2007	03/31/2007	16360942217	USD	
1	50	419399	Int&DivIncAssocCos				64,997.75-	INTERESTGNPLTADVANCE
2	40	146190	ARAssocFESC				64,997.75	
SC00	100060493	2007	JI	03/28/2007	03/31/2007	16360942217	USD	
1	40	430000	IntExpPrefSecAssocCo				64,997.75	INTERESTGNPLTADVANCE
2	50	234668	A/PASSCCO-1000				64,997.75-	

April 2007 Entry:

JE-Intercompany
Overall no. 0100076073SC0007 Doc.currency USD

CoCd / Itm	DocumentNo / PK	Year / Account	Type / Account short text	Doc. Date	Pstng Date	Reference	Crcy / Amount	Text
1000	100000467	2007	JI	04/25/2007	04/30/2007	16360942217	USD	
1	50	419399	Int&DivIncAssocCos				59,522.65-	INTERESTGNPLTADVANCE
2	40	146190	ARAssocFESC				59,522.65	
SC00	100076073	2007	JI	04/25/2007	04/30/2007	16360942217	USD	
1	40	430000	IntExpPrefSecAssocCo				59,522.65	INTERESTGNPLTADVANCE
2	50	234668	A/PASSCCO-1000				59,522.65-	

May 2007 Entry:

JE-Intercompany
Overall no. 0100101076SC0007 Doc.currency USD

CoCd / Itm	DocumentNo / PK	Year / Account	Type / Account short text	Doc. Date	Pstng Date	Reference	Crcy / Amount	Text
1000	100000661	2007	JI	05/30/2007	05/31/2007	16360942217	USD	
1	50	419399	Int&DivIncAssocCos				58,015.72-	INTERESTGNPLTADVANCE
2	40	146190	ARAssocFESC				58,015.72	
SC00	100101076	2007	JI	05/30/2007	05/31/2007	16360942217	USD	
1	40	430000	IntExpPrefSecAssocCo				58,015.72	INTERESTGNPLTADVANCE
2	50	234668	A/PASSCCO-1000				58,015.72-	

March 2007 charges to FE Service Company cost center 502633:

Cost Centers: Actual/Plan/Variance	Date: 02/08/2008	Page: 2 / 3
		Column: 1 / 2
Cost Center/Group	502633	Spc Itms GenAct-SC00
Person responsible:	Bob Cantwell	
Reporting period:	3 to 3 2007	

Cost elements	Act. costs	Plan costs	Abs. var.	Var. (%)
426502 MiscIncomDedctOther				
430000 IntExpPrefSecAssocC	64,997.75	63,111.31	1,886.44	2.99
550100 OutContrctProNonLeg				
692000 LostVendorDiscounts	14,779.67		14,779.67	
692100 DiscountMngrProg	543.57-		543.57-	
* Debit	79,233.85	63,111.31	16,122.54	25.55
** Over/underabsorption	79,233.85	63,111.31	16,122.54	25.55

March 2007 Assessments (Multi-factored to all companies) (credit FE Svc. Co expense):

Breakdown by Partner	Date: 02/08/2008	Page: 2 / 2
		Column: 1 / 2
Cost Center/Group	502633	Spc Itms GenAct-SC00
Person responsible	Bob Cantwell	
Reporting period	3 to 3 2007	

Cost Elements/Partner Object	Act. Costs	Plan Costs	Var. (Abs.)	Var. (%)
CTR 300263 SC00Alloc-ATSI	3,811.15-	2,997.79-	813.36-	27.13
CTR 404063 SC00Alloc-OE-Oth	13,644.07-	10,709.99-	2,934.08-	27.40
CTR 414063 SC00Alloc-TE-Oth	6,005.93-	4,714.41-	1,291.52-	27.40
CTR 424063 SC00Alloc-CE-Oth	11,259.13-	8,841.89-	2,417.24-	27.34
CTR 434063 SC00Alloc-PP-Oth	1,980.85-	1,552.54-	428.31-	27.59
CTR 444063 SC00Alloc-ME-Oth	7,400.44-	5,812.55-	1,587.89-	27.32
CTR 454063 SC00Alloc-PN-Oth	7,281.59-	5,717.88-	1,563.71-	27.35
CTR 464063 SC00Alloc-JC-Oth	14,167.01-	11,126.52-	3,040.49-	27.33
CTR 600271 SC00Alloc-FE SOL	1,529.21-	233.51-	1,295.70-	554.88
CTR 615359 SC00Alloc-GENCO	3,541.75-	3,559.48-	17.73	0.50-
CTR 626079 ExecbilltoFENOC	39.62-	75.73-	36.11	47.68-
CTR 640021 SC00Allocatns-FENGCO	4,413.33-	4,266.32-	147.01-	3.45
CTR 700043 SC00Alloc-FEVentures	110.93-	265.07-	154.14	58.15-
CTR 700303 SC00Alloc-FEProperty	23.77-	18.93-	4.84-	25.57
CTR 700338 SC00Alloc-GPUTel	39.62-	37.87-	1.75-	4.62
CTR 700405 SC00Alloc-MarbelEner	15.85-	18.93-	3.08	16.27-
CTR 700642 SC00Alloc-DivHolding	7.92-	6.31-	1.61-	25.52
CTR 700726 SC00Alloc-FEHldg	3,961.68-	3,155.59-	806.09-	25.54
* 872008 ExAsSC00 OTL Allocat	79,233.85-	63,111.31-	16,122.54-	25.55
** Credit	79,233.85-	63,111.31-	16,122.54-	25.55
*** Over/Underabsorption	79,233.85-	63,111.31-	16,122.54-	25.55

Reconcile March 2007 Journal Entry Assessments to Rebuttal Exhibit WRR-3:

	OE	TE	CEI
(1) Total March Assessment	13,644.07	6,005.93	11,259.13
	14,779.67	14,779.67	14,779.67
	(543.57)	(543.57)	(543.57)
(2) Portion of Assessment not related to General Plant interest	14,236.10	14,236.10	14,236.10
(3) Multi-Factor Assessment Ratio	17.22%	7.58%	14.21%
(4) Total Reduction (2 x 3)	2,451.46	1,079.10	2,022.95
(5) March Assessment related to General Plant interest (ties to Rebuttal Exhibit WRR-3, March values) (1 – 4)	11,192.61	4,926.83	9,236.18

Revenue Requirement for Fuel Deferral Recovery Included in Update Filing

	Category	OE	CEI	TE	TOTAL
(1)	Deferral Balance	$206,630,453	$139,867,602	$59,271,411	$405,769,466
(2)	ADIT	$74,826,441	$50,391,894	$21,476,450	$146,694,785
(3)	Rate Base	$131,804,012	$89,475,708	$37,794,961	$259,074,681
(4)	Return	$8,527,720	$5,950,135	$2,365,965	$16,843,820
(5)	Amortization	$8,265,218	$5,594,704	$2,370,856	$16,230,778
(6)	Total Return + Amortization	$16,792,938	$11,544,839	$4,736,821	$33,074,598
(7)	Uncollectible Accounts	0.743628%	0.593743%	0.791695%	
(8)	CATT Tax	0.156000%	0.156000%	0.156000%	
(9)		0.899628%	0.749743%	0.947695%	
(10)	Revenue Requirement	$16,945,383	$11,632,049	$4,782,141	$33,359,573

(1) Actual fuel deferral balances as of date certain 5/31/07, including actual carrying charges, plus estimated deferral amounts and associated carrying charges from 6/1/07 through 12/31/08.
(2) Accumulated deferred income taxes associated with row 1.
(3) Calculation: Row 1 - Row 2.
(4) Calculation: Cost of Debt x Row 3, where the Costs of Debt for OE, CEI, and TE are 6.47%, 6.65%, and 6.26%. Source: Schedule A-1 from the Update Filing.
(5) Straight-line amortization of deferral balances in Row 1 based on a 25-year recovery period. Calculation: Row 1 / 25.
(6) Calculation: Row 4 + Row 5.
(7) Estimated rate for uncollectible expense applicable to the amounts in Row 6. Source: Schedule C-10 from the Update Filing.
(8) Current CATT Tax rate applicable to the amounts in Row 6. Source: Schedule C-10 from the Update Filing.
(9) Calculation: Row 7 + Row 8.
(10) Calculation: Row 6 / (1 - Row 9).

Ohio Edison Company
Deferred Fuel Cost Rider Calculation

	Category	5 Years	10 Years	15 Years	20 Years	25 Years
(1)	Deferral Balance	$114,328,841	$114,328,841	$114,328,841	$114,328,841	$114,328,841
(2)	ADIT	$40,728,395	$40,728,395	$40,728,395	$40,728,395	$40,728,395
(3)	Rate Base	$73,600,446	$73,600,446	$73,600,446	$73,600,446	$73,600,446
(4)	Return	$4,761,949	$4,761,949	$4,761,949	$4,761,949	$4,761,949
(5)	Amortization	$22,865,768	$11,432,884	$7,621,923	$5,716,442	$4,573,154
(6)	Total Return + Amortization	$27,627,717	$16,194,833	$12,383,872	$10,478,391	$9,335,103
(7)	Uncollectible Accounts	0.743628%	0.743628%	0.743628%	0.743628%	0.743628%
(8)	CATT Tax	0.260000%	0.260000%	0.260000%	0.260000%	0.260000%
(9)		1.003628%	1.003628%	1.003628%	1.003628%	1.003628%
(10)	Revenue Requirement	$27,907,808	$16,359,017	$12,509,420	$10,584,621	$9,429,742
(11)	Forecasted MWH Sales	25,937,134	25,937,134	25,937,134	25,937,134	25,937,134
(12)	Rate per KWH (cents/KWH)	0.10760	0.06307	0.04823	0.04081	0.03636

(1) Actual fuel deferral balances as of 12/31/07, including actual carrying charges, plus estimated associated carrying charges from 1/1/08 through 5/31/08.
(2) Accumulated deferred income taxes associated with row 1.
(3) Calculation: Row 1 - Row 2.
(4) Calculation: Cost of Debt x Row 3, where the Costs of Debt for OE is 6.47%.
Source: Schedule A-1 from the Update Filing.
(5) Straight-line amortization of deferral balances in Row 1 based on a 25-year recovery period.
Calculation: Row 1 / 25.
(6) Calculation: Row 4 + Row 5.
(7) Estimated rate for uncollectible expense applicable to the amounts in Row 6.
Source: Schedule C-10 from the Update Filing.
(8) CATT Tax rate to be effective 4/1/09 applicable to the amounts in Row 6.
(9) Calculation: Row 7 + Row 8.
(10) Calculation: Row 6 / (1 - Row 9).
(11) Applicable forecasted MWH sales for the twelve months ended 5/31/09.
(12) Calculation: (Row 10 / Row 11) / 10.

The Cleveland Electric Illuminating Company
Deferred Fuel Cost Rider Calculation

	Category	5 Years	10 Years	15 Years	20 Years	25 Years
(1)	Deferral Balance	$78,546,940	$78,546,940	$78,546,940	$78,546,940	$78,546,940
(2)	ADIT	$28,228,331	$28,228,331	$28,228,331	$28,228,331	$28,228,331
(3)	Rate Base	$50,318,609	$50,318,609	$50,318,609	$50,318,609	$50,318,609
(4)	Return	$3,346,188	$3,346,188	$3,346,188	$3,346,188	$3,346,188
(5)	Amortization	$15,709,388	$7,854,694	$5,236,463	$3,927,347	$3,141,878
(6)	Total Return + Amortization	$19,055,576	$11,200,882	$8,582,650	$7,273,535	$6,488,065
(7)	Uncollectible Accounts	0.593743%	0.593743%	0.593743%	0.593743%	0.593743%
(8)	CATT Tax	0.260000%	0.260000%	0.260000%	0.260000%	0.260000%
(9)		0.853743%	0.853743%	0.853743%	0.853743%	0.853743%
(10)	Revenue Requirement	$19,219,662	$11,297,332	$8,656,555	$7,336,167	$6,543,934
(11)	Forecasted MWH Sales	17,840,404	17,840,404	17,840,404	17,840,404	17,840,404
(12)	Rate per KWH (cents/KWH)	0.10773	0.06332	0.04852	0.04112	0.03668

(1) Actual fuel deferral balances as of 12/31/07, including actual carrying charges, plus estimated associated carrying charges from 1/1/08 through 5/31/08.
(2) Accumulated deferred income taxes associated with row 1.
(3) Calculation: Row 1 - Row 2.
(4) Calculation: Cost of Debt x Row 3, where the Costs of Debt for CEI is 6.65%.
Source: Schedule A-1 from the Update Filing.
(5) Straight-line amortization of deferral balances in Row 1 based on a 25-year recovery period.
Calculation: Row 1 / 25.
(6) Calculation: Row 4 + Row 5.
(7) Estimated rate for uncollectible expense applicable to the amounts in Row 6.
Source: Schedule C-10 from the Update Filing.
(8) CATT Tax rate to be effective 4/1/09 applicable to the amounts in Row 6.
(9) Calculation: Row 7 + Row 8.
(10) Calculation: Row 6 / (1 - Row 9).
(11) Applicable forecasted MWH sales for the twelve months ended 5/31/09.
(12) Calculation: (Row 10 / Row 11) / 10.

The Toledo Edison Company
Deferred Fuel Cost Rider Calculation

	Category	5 Years	10 Years	15 Years	20 Years	25 Years
(1)	Deferral Balance	$33,400,428	$33,400,428	$33,400,428	$33,400,428	$33,400,428
(2)	ADIT	$12,066,221	$12,066,221	$12,066,221	$12,066,221	$12,066,221
(3)	Rate Base	$21,334,207	$21,334,207	$21,334,207	$21,334,207	$21,334,207
(4)	Return	$1,335,521	$1,335,521	$1,335,521	$1,335,521	$1,335,521
(5)	Amortization	$6,680,086	$3,340,043	$2,226,695	$1,670,021	$1,336,017
(6)	Total Return + Amortization	$8,015,607	$4,675,564	$3,562,217	$3,005,543	$2,671,538
(7)	Uncollectible Accounts	0.791695%	0.791695%	0.791695%	0.791695%	0.791695%
(8)	CATT Tax	0.260000%	0.260000%	0.260000%	0.260000%	0.260000%
(9)		1.051695%	1.051695%	1.051695%	1.051695%	1.051695%
(10)	Revenue Requirement	$8,100,803	$4,725,259	$3,600,078	$3,037,488	$2,699,934
(11)	Forecasted MWH Sales	8,739,223	8,739,223	8,739,223	8,739,223	8,739,223
(12)	Rate per KWH (cents/KWH)	0.09269	0.05407	0.04119	0.03476	0.03089

(1) Actual fuel deferral balances as of 12/31/07, including actual carrying charges, plus estimated associated carrying charges from 1/1/08 through 5/31/08.
(2) Accumulated deferred income taxes associated with row 1.
(3) Calculation: Row 1 - Row 2.
(4) Calculation: Cost of Debt x Row 3, where the Costs of Debt for TE is 6.26%.
Source: Schedule A-1 from the Update Filing.
(5) Straight-line amortization of deferral balances in Row 1 based on a 25-year recovery period.
Calculation: Row 1 / 25.
(6) Calculation: Row 4 + Row 5.
(7) Estimated rate for uncollectible expense applicable to the amounts in Row 6.
Source: Schedule C-10 from the Update Filing.
(8) CATT Tax rate to be effective 4/1/09 applicable to the amounts in Row 6.
(9) Calculation: Row 7 + Row 8.
(10) Calculation: Row 6 / (1 - Row 9).
(11) Applicable forecasted MWH sales for the twelve months ended 5/31/09.
(12) Calculation: (Row 10 / Row 11) / 10.

DEFERRED FUEL COST RIDER

This Deferred Fuel Cost Rider is effective for bills rendered beginning on the first billing portion of June 2008 and applies to all customers on tariffs and to all contracts that permit the inclusion of this Rider.

The amount of this Rider reflects eligible fuel costs deferred from January 2006 through December 2007, plus the associated Commission-approved carrying costs on the unrecovered deferred cost balance, in accordance with Case 05-1125-EL-ATA, et al. The Rider also includes carrying charges incurred after 2007 based on the annual embedded cost of long-term debt at 6.47%, applicable uncollectible expenses, and Commercial Activity Tax (CAT).

The Deferred Fuel Cost Rider Charge shall equal XXXXX ¢ per kWh.

DEFERRED FUEL COST RIDER

This Deferred Fuel Cost Rider is effective for bills rendered beginning on the first billing portion of June 2008 and applies to all customers on tariffs and to all contracts that permit the inclusion of this Rider.

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The Deferred Fuel Cost Rider Charge shall equal XXXXX ¢ per kWh.

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The Deferred Fuel Cost Rider Charge shall equal XXXXX ¢ per kWh.

Rebuttal Exhibit WRR-7

UNCOLLECTIBLE EXPENSE ADJUSTMENT

	Line Item Description	CEI	OE	TE	TOTAL
1	Staff's Adjusted Total Operating Revenue	$435,968,968	$508,093,367	$156,930,031	$1,100,992,366
2	Company Uncollectible Rate	0.5937%	0.7436%	0.7917%	0.6955%
3	Adjusted Uncollectible Expense	$2,588,534	$3,778,326	$1,242,407	$7,609,267
4	Unadjusted Total Company Uncollectible Expense	$10,276,431	$15,634,832	$6,172,169	$32,083,432
5	Corrected Uncollectible Expense Adjustment	($7,687,898)	($11,856,506)	($4,929,762)	($24,474,165)
6	Staff's Uncollectible Expense Adjustment	($7,856,183)	($11,981,321)	($5,174,859)	($25,012,363)
7	Difference	$168,285	$124,815	$245,097	$538,198

1 Staff Witness Choudhury Corrected Attachment Schedule C-3.12
2 Company Schedule C-10
3 Line 1 * Line 2
4 Company Schedule C-2.1
5 Line 3 - Line 4
6 Staff Witness Choudhury Corrected Attachment Schedule C-3.12
7 Line 5 - Line 6

Ohio Edison Company
The Toledo Edison Company
The Cleveland Electric Illuminating Company
Case No. 07-551-EL-AIR, et al.

Rebuttal Exhibit WRR-8(a)

Calculation of Rider UNCD Percentage

		CEI	OE	TE
1	Uncollectible Portion (a)	0.5937%	0.7436%	0.7917%
2	Return on Customer Deposits Balance Portion (b)	-0.0620%	-0.0689%	-0.0675%
3	Interest on Customer Deposits Portion (b)	0.0148%	0.0165%	0.0268%
4	**RIDER UNCD Percentage (1 + 2 + 3)**	**0.5465%**	**0.6912%**	**0.7510%**

NOTES:
(a) *See Rebuttal Exhibit WRR-8(b)*
(b) *See Rebuttal Exhibit WRR-8(c)*

Ohio Edison Company
The Toledo Edison Company
The Cleveland Electric Illuminating Company
Case No. 07-551-EL-AIR, et al.

Rebuttal Exhibit WRR-8(b)

Calculation of Uncollectbile portion of Rider UNCD Percentage and related amount of expense recovery

		CEI	OE	TE
1	Total Company Revenue (a)	$ 1,851,134,797	$ 2,174,334,304	$ 971,211,688
2	Sales for Resale [FERC Acct. 447] (b)	$ 120,346,017	$ 71,828,049	$ 191,597,129
3	Total Revenue associated with Uncollectible (1 - 2)	$ 1,730,788,780	$ 2,102,506,255	$ 779,614,559
4	Total Company Provision for Uncollectible (b)	$ 10,276,431	$ 15,634,832	$ 6,172,169
5	Percentage of Total (4 / 3)	0.5937%	0.7436%	0.7917%
6	Staff Adjusted Jurisdictional Distribution Revenue (a)	$ 435,968,968	$ 508,093,367	$ 156,930,031
7	Uncollectible Provision accounted for in Base Distribution Rates (5 x 6) (c)	**$ 2,588,534**	**$ 3,778,326**	**$ 1,242,407**
8	Remaining Revenue [excluding Sales for Resale, Acct. 447] (1 - 2 - 6)	$ 1,294,819,812	$ 1,594,412,888	$ 622,684,528
9	Uncollectible Provision to be recovered in RIDER UNCD (5 x 8)	**$ 7,687,898**	**$ 11,856,506**	**$ 4,929,762**
10	Uncollectible portion of RIDER UNCD Percentage (9 / 8)	**0.5937%**	**0.7436%**	**0.7917%**

NOTES:

		CEI	OE	TE
(a)	Staff Report Adjustment C-3.1	$ (669,324)	$ 1,112,830	$ 1,221,254
	Revised Staff Report Adjustment C-3.15 (d)	$ (6,948,582)	$ (10,626,457)	$ (1,735,332)
	Staff Report Adjustment C-3.18 (CEI), C-3.17 (TE, OE)	$ (8,522)	$ 19,477	$ 22,311
	Total Staff Revenue Adjustments	$ (7,626,428)	$ (9,494,150)	$ (491,767)
	Unadjusted Jurisdictional Revenue per application (b)	$ 443,595,396	$ 517,587,517	$ 157,421,798
	Staff Adjusted Jurisdictional Distribution Revenue	$ 435,968,968	$ 508,093,367	$ 156,930,031
	Total Company Revenue per application (b)	$ 1,851,134,797	$ 2,174,334,304	$ 971,211,688

(b) *Applicant Schedule C-2.1*
(c) *See Rebuttal Exhibit WRR-7*
(d) *Schedule C-3.15, Corrected Attachments to Prefiled Testimony of Syeda Choudhury*

Ohio Edison Company
The Toledo Edison Company
The Cleveland Electric Illuminating Company
Case No. 07-551-EL-AIR, et al.

Rebuttal Exhibit WRR-8(c)

Calculation of Customer Deposit portion of Rider UNCD Percentage

		CEI	OE	TE
1	Total Company Revenue (a)	$ 1,851,134,797	$ 2,174,334,304	$ 971,211,688
2	Sales for Resale [FERC Acct. 447] (a)	$ 120,346,017	$ 71,828,049	$ 191,597,129
3	Other Operating Revenue [FERC Accts. 450-456] (a)	$ 31,407,055	$ 41,266,559	$ 16,099,732
4	Total Revenue not associated with customer deposits (2 + 3)	$ 151,753,072	$ 113,094,608	$ 207,696,861
5	Total Revenue associated with Customer Deposits (1 - 4)	$ 1,699,381,724	$ 2,061,239,696	$ 763,514,827
6	Total Customer Deposits (related expense) (b)	$ (1,053,685)	$ (1,419,633)	$ (515,394)
7	Percentage of Total (6 / 5)	-0.0620%	-0.0689%	-0.0675%

Calculation of Interest on Customer Deposit portion of Rider UNCD Percentage

		CEI	OE	TE
8	Total Company Revenue (a)	$ 1,851,134,797	$ 2,174,334,304	$ 971,211,688
9	Sales for Resale [FERC Acct. 447] (a)	$ 120,346,017	$ 71,828,049	$ 191,597,129
10	Other Operating Revenue [FERC Accts. 450-456] (a)	$ 31,407,055	$ 41,266,559	$ 16,099,732
11	Total Revenue not associated with customer deposits (9 + 10)	$ 151,753,072	$ 113,094,608	$ 207,696,861
12	Total Revenue associated with Customer Deposits (8 - 11)	$ 1,699,381,724	$ 2,061,239,696	$ 763,514,827
13	Total Interest on Customer Deposits (c)	$ 251,476	$ 339,625	$ 204,522
14	Percentage of Total (13 / 12)	0.0148%	0.0165%	0.0268%

NOTES:
(a) *Applicant Schedule C-2.1*
(b) *See Rebuttal Exhibit WRR-8(d)*
(c) *See Staff Report Schedule C-3.16*

Ohio Edison Company
The Toledo Edison Company
The Cleveland Electric Illuminating Company
Case No. 07-551-EL-AIR, et al.

Rebuttal Exhibit WRR-8(d)

Calculation of Return on Customer Deposits

		CEI	OE	TE
1	Total Customer Deposits Balance (a)	$ (8,382,539)	$ (11,320,834)	$ (4,090,431)
2	Tax Impacted Rate of Return (b)	12.57%	12.54%	12.60%
4	Required Return on Customer Deposits Balance	$ (1,053,685)	$ (1,419,633)	$ (515,394)

NOTES:
(a) *Staff Report Schedule B-6*
(b) *See Rebuttal Exhibit WRR-2*

RIDER UNCD
UNCOLLECTIBLE / CUSTOMER DEPOSITS RIDER

APPLICABILITY:

Applicable to any customer receiving generation service either from the Company through its RIDER GEN, Original Sheet No. 88, or from a Certified Supplier.

RATES:

The charges in this RIDER UNCD shall be added to the customer's bill by applying the below percentage to the Net Charges, exclusive of all of the following three charges: 1) Distribution Charges; 2) Transformer Charge; and 3) the charges included in the applicable Riders listed below. The Net Charges for a customer receiving service from a Certified Supplier will include those charges billed from the supplier for all services rendered.

RIDER UNCD percentage: 0.6912%

The RIDER UNCD Charge is calculated as follows:

$$\frac{\text{Net Charges}}{(1 - 0.6912\%)} - \text{Net Charges}$$

Where the Net Charges are all charges billed to a customer less Distribution Charges and the charges from the following applicable Riders:

Residential Distribution Credit Rider, Sheet No. 81
Business Distribution Credit Rider, Sheet No. 86
Universal Service Rider, Sheet No. 90
Deferred Fuel Cost Rider, Sheet No. 108

RIDER UNCD
UNCOLLECTIBLE / CUSTOMER DEPOSITS RIDER

APPLICABILITY:

Applicable to any customer receiving generation service either from the Company through its RIDER GEN, Original Sheet No. 88, or from a Certified Supplier.

RATES:

The charges in this RIDER UNCD shall be added to the customer's bill by applying the below percentage to the Net Charges, exclusive of all of the following three charges: 1) Distribution Charges; 2) Transformer Charge; and 3) the charges included in the applicable Riders listed below. The Net Charges for a customer receiving service from a Certified Supplier will include those charges billed from the supplier for all services rendered.

RIDER UNCD percentage: 0.5465%

The RIDER UNCD Charge is calculated as follows:

$$\frac{\text{Net Charges}}{(1 - 0.5465\%)} - \text{Net Charges}$$

Where the Net Charges are all charges billed to a customer less Distribution Charges and the charges from the following applicable Riders:

Residential Distribution Credit Rider, Sheet No. 81
Business Distribution Credit Rider, Sheet No. 86
Universal Service Rider, Sheet No. 90
Deferred Fuel Cost Rider, Sheet No. 108

RIDER UNCD
UNCOLLECTIBLE / CUSTOMER DEPOSITS RIDER

APPLICABILITY:

Applicable to any customer receiving generation service either from the Company through its RIDER GEN, Original Sheet No. 88, or from a Certified Supplier.

RATES:

The charges in this RIDER UNCD shall be added to the customer's bill by applying the below percentage to the Net Charges, exclusive of all of the following three charges: 1) Distribution Charges; 2) Transformer Charge; and 3) the charges included in the applicable Riders listed below. The Net Charges for a customer receiving service from a Certified Supplier will include those charges billed from the supplier for all services rendered.

RIDER UNCD percentage: 0.7510%

The RIDER UNCD Charge is calculated as follows:

$$\frac{\text{Net Charges}}{(1 - 0.7510\%)} - \text{Net Charges}$$

Where the Net Charges are all charges billed to a customer less Distribution Charges and the charges from the following applicable Riders:

Residential Distribution Credit Rider, Sheet No. 81
Economic Development Rider (4a), Sheet No. 84
Business Distribution Credit Rider, Sheet No. 86
Universal Service Rider, Sheet No. 90
Deferred Fuel Cost Rider, Sheet No. 108

[Company Exhibit 3-C]

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio	)	
Edison Company, The Cleveland Electric	)	
Illuminating Company, and The Toledo	)	Case No. 07-551-EL-AIR
Edison Company for Authority to	)	Case No. 07-552-EL-ATA
Increase Rates for Distribution Service,	)	Case No. 07-553-EL-AAM
Modify Certain Accounting Practices	)	Case No. 07-554-EL-UNC
and for Tariff Approvals	)	

REBUTTAL TESTIMONY OF

HARVEY L. WAGNER

ON BEHALF OF

OHIO EDISON COMPANY
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
THE TOLEDO EDISON COMPANY

___ Management policies, practices, and organization

_X_ Operating income

_X_ Rate base

___ Allocations

___ Rate of return

___ Rates and tariffs

___ Other –Case Overview,
Revenue Requirements
Gross Rev. Conversion Factor

Q. PLEASE STATE YOUR NAME FOR THE RECORD.

A. My name is Harvey L. Wagner.

Q. ARE YOU THE SAME HARVEY L. WAGNER THAT PROVIDED INITIAL AND SUPPLEMENTAL TESTIMONY THAT WAS FILED IN THIS PROCEEDING ON JUNE 7, 2007 AND JANUARY 10, 2008, RESPECTIVELY?

A. Yes, I am.

Q. HAVE YOU REVIEWED THE TESTIMONY OF OCC WITNESS EFFRON AND STAFF WITNESS CASTLE?

A. Yes I have.

Q. WILL YOU PLEASE SUMMARIZE THE ISSUES EACH HAS TAKEN WITH REGARD TO ISSUES YOU ADDRESSED IN YOUR INITIAL AND SUPPLEMENTAL TESTIMONY WITH WHICH YOU DISAGREE?

A. Yes, the issues to which I take exception, as they relate to my testimony, are summarized below.

Mr. Effron's Issues:

- Exclusion from rate base of the regulatory asset for other postretirement benefit costs (OPEB);
- Methodology for quantifying Rate Certainty Plan (RCP) distribution deferrals;
- Limiting rate base inclusion for RCP distribution deferrals to the date certain balances;

- Calculation of carrying charges on RCP deferrals and transition tax deferrals net of accumulated deferred income taxes;
- Exclusion from rate base of transition tax deferrals, or in the alternative to include in rate base using only the embedded cost of debt;
- Exclusion of a portion of incentive compensation.

Mr. Castle's Issues:

- Limiting rate base inclusion for RCP distribution deferrals, Ohio Line Extension deferrals, and transition tax deferrals to the date certain balances;
- Methodology for quantifying RCP distribution deferrals; and
- Calculation of carrying charges on RCP deferrals, transition tax, and Ohio line extension deferrals net of accumulated deferred income taxes.

Q. WHY DO YOU DISAGREE WITH MR. EFFRON'S RECOMMENDATION TO EXCLUDE THE REGULATORY ASSET FOR OPEB COSTS FROM RATE BASE FOR CEI AND TE?

A. Mr. Effron's conclusion is based on the incorrect assumption that the regulatory asset balances for OPEB have not required the expenditure of funds by CEI and TE. Accounting for postretirement benefits under Statement of Financial Accounting Standards No. 106 is admittedly complicated and I can understand how Mr. Effron may have reached his faulty conclusion. At the time that the OPEB transition obligations were initially recorded upon adoption in 1993, recognition of the obligation was represented by non-cash accounting entries. However, 15 years later, in 2008, the liabilities resulting from those non-cash accounting entries have indeed been reduced by payments for retiree health care costs applicable to the obligations initially recognized in 1993. In fact, actual expenditures for the year 2006 related to the transition obligation balances as of January 1, 1993, were computed to be approximately $9.5 million for CEI retirees and $5.8 million for TE retirees. Estimates for payments for the years encompassing the test year in this case are shown on Attachment HLW-1, with estimates for such payments for 2007 and 2008 set forth below:

	2007	2008
Toledo Edison	$4.8 million	$4.7 million
CEI	$8.4 million	$8.0 million

It is clear that both CEI and TE have expended and will continue to expend cash that exceeds the balances of their OPEB regulatory assets as of the date certain in the amounts of $8.2 million for CEI and $3.5 million for TE, and those balances are appropriately includable in rate base.

Q. WHAT IS YOUR DISAGREEMENT REGARDING THE METHODOLOGIES FOR QUANTIFYING THE RCP DISTRIBUTION DEFERRALS PUT FORTH BY MR. EFFRON?

A. My overarching disagreement relates to the apparent lack of understanding that Mr. Effron has in regard to the methodology to calculate distribution deferrals that arose from the RCP case, Case Nos. 05-1125-EL-ATA et al., to compute the level of costs the Companies incur in each year 2006, 2007 and 2008 that exceed the level of costs that are embedded in the Companies' present rates. OCC did not file a Memorandum Contra or otherwise object at the time to the Companies' methodology to compute distribution deferrals as contained in their Motion for

Clarification filed in the RCP case. In fact, the OCC signed the Supplemental Stipulation in the RCP case that bound them to not challenge the reasonableness of the deferral process or the types of expenditures deferred. The PUCO Staff, through the testimony of Mr. Castle, also rejects Mr. Effron's adjustment. The Companies have applied this unopposed methodology consistently in 2006 and 2007, determining that the level of costs they incurred in each of those years exceeded the cap imposed by the revised stipulation of $150 million in the aggregate for each year.

Mr. Effron has identified various mechanical applications all of which reduce the distribution deferral balance for the Companies without regard to the intent or plain language of the revised stipulation and Orders and Entries in the RCP case, or the potential adverse financial impacts that could result if the Commission were to adopt any of his positions. Mr. Effron's most egregious attempt to minimize the distribution deferrals by imputing accumulated depreciation on embedded plant since January 1, 2001 demonstrates his total disregard of the Commission's directive in its January 25, 2006 Entry on Rehearing "...to substantiate that they have spent more than the distribution O&M expense embedded in current rates...".

Q. DO YOU AGREE WITH THE POSITION TAKEN BY MR. EFFRON AND MR. CASTLE THAT THE CARRYING CHARGES ACCRUED ON THE RCP DISTRIBUTION DEFERRALS SHOULD BE BASED ON THE BALANCE OF THE REGULATORY ASSET NET OF ACCUMULATED DEFERRED INCOME TAXES?

A. Absolutely not. That is not what was agreed to in the RCP Stipulation by the Companies. Nothing in the language of the RCP stipulation requires or contemplates that such a calculation should take place or that the authorized carrying charges were to be applied against the RCP deferral balance net of accumulated deferred income taxes. In fact, while testifying in the RCP case, Case Nos. 05-1125-EL-ATA et seq., I was directed during cross-examination to describe information contained in a Form 8-K that the Companies filed with the Securities and Exchange Commission regarding their application in those cases before the PUCO. It was clear in those materials that carrying charges capitalized on the fuel deferrals and distribution deferrals would be computed on those balances – there was no reference to reductions for accumulated deferred income taxes, because it was not part of the Stipulated agreement or Orders or Entries in that case. Such a provision would have changed the economics of the Stipulation for the Companies such that the terms of the Stipulation would have been different if the economic value of the carrying charge on the full amount of the deferrals was reduced. At the time of the RCP Order, the Companies filed a Motion for Clarification setting out the methodology that was to be used in calculating the deferrals. My understanding is that discussions were held with Staff that showed that carrying charges would be applied to the deferral balances gross of taxes, without objection from the Staff. Nothing in the RCP Order or Entries did anything to change the methodology to be followed as set forth by the Companies. This methodology has been followed since January 2006 in accruing the deferrals on the Companies' books of account. The same methodology was contained in the detailed breakdown of how the distribution deferrals and carrying charges were being recorded by the Companies that was provided to the Staff both in the first half of 2007 and then again in August 2007. Staff did not advise the Companies at any time that the methodology and calculations that the Companies had been following since 2006 were objectionable in any way. It would be unreasonable for the Commission to now change its finding and retroactively order the Companies to change the methodology they have been following for over the past two years, thereby adversely affecting the economics underlying the RCP Stipulation.

Q. HAS THE COMMISSION COMPUTED CARRYING CHARGES ON ANY OF THE COMPANIES' REGULATORY ASSET BALANCES NET OF ACCUMULATED DEFERRED INCOME TAXES IN THE PAST?

A. The Commission has not to my knowledge, since the implementation of Statement of Financial Accounting Standards No. 92 (SFAS 92), required any of the Companies' regulatory asset balances to be reduced by accumulated deferred income taxes in order to compute the additional interest charges to be deferred under any of the Companies' rate plans, and no justification has been offered in this case to support such a change in Commission precedent -- accumulated deferred income taxes have existed throughout the entire period.

Q. IF A REGULATORY ASSET BALANCE WOULD BE REDUCED BY THE ACCUMULATED DEFERRED INCOME TAXES FOR RATE BASE TREATMENT WHEN THE REGULATORY ASSET IS INCLUDED IN RATE BASE, WHY SHOULDN'T A SIMILAR ADJUSTMENT BE MADE FOR CAPITALIZING CARRYING CHARGES ON THE REGULATORY ASSET BALANCES BEFORE INCLUSION IN RATE BASE?

A. First of all, that is not what the Companies agreed to in the RCP Stipulation and not what the RCP Order and Entries required. Before the Financial Accounting Standards Board issued SFAS 92, in 1987 (effective for the Companies in 1988), regulated enterprises were permitted to capitalize an equity return as a regulatory asset (e.g., post-in-service allowance for funds used during construction, including equity). With the issuance of SFAS 92, the Financial Accounting Standards Board recognized that an equity return was not an incurred cost. Accordingly, regulated enterprises were specifically precluded from capitalizing an equity return on regulatory assets, except under a qualifying phase-in plan in connection with the completion of a major generating unit. Carrying charges on other regulatory assets, however, could continue to represent interest expense associated with debt, which is defined under generally accepted accounting principles as an incurred cost that may be capitalized pursuant to an order of a regulatory commission. Since capitalizing interest costs only does not reflect an equity return, not reducing the base for capitalizing the carrying charge by the accumulated deferred income taxes mitigates a portion of the lost equity return. That is precisely why the Companies have requested and received authorization from the Commission to capitalize carrying charges on the regulatory asset balances without reduction for accumulated deferred income taxes. Capitalizing a return (including an authorized equity return) on regulatory asset balances that have been reduced by accumulated deferred income taxes would yield a regulatory asset balance that is larger than the regulatory asset balance that results from capitalizing interest at the long-term debt rate on the regulatory asset balance with no reduction for accumulated deferred income taxes. This phenomenon is illustrated on Attachment HLW-2.

Q. WOULD THERE BE ANY ADVERSE FINANCIAL IMPLICATIONS TO THE COMPANIES IF THE COMMISSION WERE TO REQUIRE THE COMPANIES TO REDUCE THE CARRYING CHARGES CAPITALIZED ON THEIR RCP DISTRIBUTION DEFERRALS AS RECOMMENDED BY MR. EFFRON?

A. Yes, the Companies would be immediately required to write-off a portion of the carrying charges that the Commission previously authorized the Companies to accrue. Through December 31, 2008, the write-offs would amount to \$15 million for OE, \$12 million for CEI and \$6 million for TE – a total of \$33 million for FirstEnergy's Ohio utilities. Recording losses of this magnitude would jeopardize the Companies' financial integrity with negative credit metric implications. Further, such a result could potentially compromise the Commission's longstanding credibility with the financial community by not following through with providing recovery of prudently incurred costs that were authorized for deferral in prior regulatory proceedings. The Commission should not adopt the position of Mr. Effron on this issue. Such a change in policy by the Commission should not be implemented on an ad hoc basis, and the Commission should reject Mr. Effron's suggestion that such a change in policy be applied retroactively to deferrals that were authorized years ago.

Q. DOES THE DEFINITION OF DISTRIBUTION EXPENSES IN TERMS OF THE FERC ACCOUNTS REFERENCED BY MR. EFFRON DIFFER FROM THE DEFINITION OF DISTRIBUTION EXPENSES ON ATTACHMENT 2 TO THE RCP SUPPLEMENTAL STIPULATION?

A. Yes, it does. Distribution expenses on Attachment 2 to the RCP Supplemental Stipulation, attached as Attachment HLW-3, encompass more than just the particular distribution FERC accounts referenced by Mr. Effron. The distribution expenses set forth therein include costs recoverable through distribution rates such as sub-transmission expenses, administrative and general expenses, customer accounts expenses, and customer service expenses. The Companies' position is consistent with Mr. Castle's conclusion that Mr. Effron was in error by stating the RCP distribution deferrals must be limited to amounts in FERC Accounts 580-598.

Q. Did the Companies defer any amounts from Account 561.4 or include any amounts from Account 561.4 in the revenue requirements of this case?

A. No.

Q. If the amounts set forth in Account 561.4 were excluded from the calculation of the maximum deferral, would the amount that the Companies deferred be any different?

A. No. The amounts deferred by the Companies in 2006 and 2007 would not be impacted by excluding amounts set forth in Account 561.4 from the calculation of the maximum deferral amount. The Companies would still defer $150 million of distribution deferrals in each of those years.

Q. DO YOU AGREE WITH MR. CASTLE AND MR. EFFRON THAT THE RCP DISTRIBUTION DEFERRAL BALANCES INCLUDED IN RATE BASE AND THEIR SUBSEQUENT AMORTIZATION SHOULD BE BASED ON THE DATE CERTAIN INSTEAD OF DECEMBER 31, 2008?

A. No, I do not. For all of the reasons set forth in my previous testimonies, I believe the most appropriate date is December 31, 2008, not the date certain.

Q. HAVE YOU REVIEWED THE RECOMMENDED TREATMENT RELATING TO THE TRANSITION TAX DEFERRAL PUT FORTH BY MR. EFFRON?

A. Yes, I have.

Q. DO YOU AGREE WITH MR. EFFRON'S SUGGESTIONS REGARDING THE TRANSITION TAX DEFERRAL?

A. No, I do not.

Q. WHAT DOES MR. EFFRON RECOMMEND REGARDING THE TRANSITION TAX DEFERRAL?

A. Mr. Effron recommends removing the Transition Tax deferral from rate base because the Stipulation and Recommendation in Case No. 99-1212-EL-ETP did not explicitly state that the transition tax deferrals could be included in rate base during the recovery period. In addition, he also states that the transition tax deferral should be removed from rate base due to what he has defined as a "short" (5 year) recovery period.

Q. DOES THE LACK OF SPECIFIC LANGUAGE IN THE ETP STIPULATION STATING THAT THE REGULATORY ASSET ARISING FROM THE TRANSITION TAX DEFERRAL MAY BE INCLUDED IN DISTRIBUTION RATE BASE MEAN THAT INCLUSION OF THAT REGULATORY ASSET IN RATE BASE IS PROHIBITED IN THIS PROCEEDING OR CONTRARY TO THE COMMISSION'S INTENT?

A. Of course not. Based on my experience reviewing Commission accounting orders for many years, the Commission would not authorize the creation of deferrals, including capitalized carrying charges on those deferrals, without the intent to permit recovery of the cost and a return on investment (through inclusion in rate base) in a future rate proceeding. To do otherwise would undermine the Commission's credibility to follow through with appropriate rate making treatment following authorization of deferral accounting.

Q. SHOULD THE FACT THAT, IN MR. EFFRON'S WORDS, "THERE IS A RELATIVELY SHORT AMORTIZATION PERIOD" HAVE ANY IMPACT REGARDING WHETHER DEFERRED COSTS (REGULATORY ASSETS) SHOULD BE EXCLUDED FROM RATE BASE?

A. Certainly not. The amortization, or recovery period, is irrelevant and doesn't change the fact that investors' funds were expended to finance the deferrals. The fact remains that the Companies did pay the taxes giving rise to the Transition Tax Deferrals, and they were paid years ago, and those will not be fully recovered for years into the future. The Companies received authority from the Commission to recover these costs as part of the ETP Stipulation, and full recovery, including a return on the deferrals, should not now be denied.

Q. DID MR. EFFRON RECOMMEND THAT CARRYING CHARGES ON THE TRANSITION TAX DEFERRALS ALSO BE REDUCED TO REFLECT INCLUSION OF ACCUMULATED DEFERRED INCOME TAXES AS A REDUCTION TO THE CAPITALIZATION BASE?

A. Yes and I disagree with his position for the same reasons as described above for the RCP deferrals.

Q. DO YOU HAVE A CONCERN WITH THE LONG-TERM DEBT RATE ON THE TRANSITION TAX DEFERRALS EMPLOYED BY MR. EFFRON?

A. Yes. Mr. Effron mentions that the embedded cost of long-term debt should be consistent with the rate used to capitalize interest from the time of deferral until the commencement of recovery. The Stipulation in Case No. 99-1212-EL-ETP Section VIII.5 states: "The changes in taxes as a result of Am. Sub. S.B. No. 3 will be addressed such that rates will be frozen at current levels as provided below: (a)...the embedded cost of debt for the applicable company will be used to capitalize interest on such balances;...." The ETP Stipulation only specified the embedded cost of debt be used on regulatory asset balances before they were included in rate base. Therefore, because the ETP Stipulation did not specify a return different from the overall return, it is most appropriate to use the rate of return approved from each Company's last rate case. However, at a minimum, the approved cost of long-term debt existing at the time should be used. These approved cost of long-term debt rates would remain constant at 9.83% for OE and

9.01% for CEI and TE. Staff agreed that the embedded long term debt rate for each of the Companies as authorized in the previous rate case should be utilized. Tr. Vol. VII, pp. 37-39.

Q. IN THOSE INSTANCES WHERE MR. CASTLE SIMPLY AGREED WITH AN ADJUSTMENT MADE BY MR. EFFRON, WOULD YOUR ARGUMENTS AGAINST THAT POSITION REMAIN THE SAME AS SET FORTH ABOVE?

A. Yes they would.

Q. WOULD YOU PLEASE DESCRIBE YOUR DISAGREEMENT WITH MR. CASTLE'S APPROACH TO QUANTIFYING THE RCP DISTRIBUTION DEFERRALS?

A. Mr. Castle referred to my supplemental testimony with regard to one of the "whichever is less" calculations applied by the Staff in quantifying the RCP distribution deferrals. Apparently my points were not as clear in the supplemental testimony as they could have been, leading to Mr. Castle's reference. The first issue I have with the Staff's minimizing calculation is the way the Staff applied the $150 million maximum relating to the first five months of 2007. The Staff chose a straight-line projection of the $150 million calendar year maximum by limiting the total deferrals for the first five months of 2007 to $62.5 million (5/12 of $150 million), without regard to the level of eligible expenditures incurred during that five-month period that were permitted to be deferred under the RCP Order and Entries. The stipulation and Order and Entries were very clear that the $150 million cap on the RCP distribution deferrals was to be applied on an individual calendar year basis – i.e., for each calendar year ending on December 31, 2006, 2007 and 2008. During cross-examination, even Mr. Castle agreed that there was nothing in the RCP Orders and Entries other than an annual amount. Tr. Vol. VII, p. 49. The actual eligible distribution deferral amount for 2007 for all three Companies combined was $182,749,923, so the actual deferral amount for 2007 was $150 million, demonstrating that on an actual basis in 2007 no further restriction on the level of deferrals below the cap was applicable. Imposing a partial year restriction as of May 31st based on partial year results is inappropriate and inconsistent with the RCP Orders and Entries.

Q. WOULD YOUR ISSUE WITH MR. CASTLE'S PARTIAL YEAR APPROACH BE RECTIFIED BY USING THE ESTIMATED RCP DISTRIBUTION DEFERRAL BALANCES AS PROPOSED BY THE COMPANIES AS OF DECEMBER 31, 2008, OR EVEN USING END OF TEST YEAR BALANCES?

A. Yes, it would. My previous testimony sets out the reasons why the Commission should authorize distribution rates in this case based on the estimated December 31, 2008 balances, and for those reasons as well as the discussion set forth above, the Companies continue to request the Commission to do so. But in any event, the Companies should be permitted to include the actual level of eligible deferred expenses for the January through May 2007 period in the amount of $71,917,186, as shown in the Total column of Mr. Castle's Exhibit MAC-1, page 1 of 19, Line 7.

Q. DO YOU AGREE WITH THE APPROACH MR. CASTLE USES TO CALCULATE THE DISTRIBUTION PLANT DEPRECIATION EXPENSE AND PROPERTY TAX?

A. No, I do not. The Companies establish the maximum amount eligible to defer for all costs being recovered through distribution rates, including depreciation expense and property taxes. The Motion for Clarification described the methodology the Companies used to calculate those costs with respect to eligible property additions as long as the aggregate deferral amounts did not exceed the lesser of $150 million or the total of costs incurred during the year in excess of costs embedded in rates in Case No. 99-1212-EL-ETP. Mr. Castle inappropriately attempts to exclude these amounts for distribution plant depreciation expense and property tax in developing the aggregate maximum potential deferral amount.

Q. HAVE YOU ANY RECOMMENDATIONS RELATED TO MR. CASTLE'S ANALYSIS RELATED TO 2006 ON HIS EXHIBIT MAC-1?

A. Yes. First the Companies' distribution deferral principal balance amount for 2006 as filed is appropriate. Even using Mr. Castle's numbers, as shown on Company Exhibit 26, yields the result that the Companies should be permitted to include $150 million in rate base for distribution deferrals. The RCP Order and Entries were clear that the $150 million was an aggregate number for all three companies. There is nothing in that Order or those Entries that authorizes or even suggests otherwise. Consistent with the language of the RCP Order and Entries, the $150 million cap on distribution deferrals is applicable to the aggregate of the three Companies, and on that basis the Commission should include $150 million in rate base.

Q. WOULD A SIMILAR ISSUE ARISE RELATED TO DETERMINING THE CAP FOR DISTRIBUTION DEFERRALS FOR 2007?

A. No. Whether utilizing the Companies' methodology or the Staff's approach, for 2007 the Companies may defer $150 million of distribution deferrals because under either approach the maximum deferral exceeds $150 million.

Q. HAVE YOU REVIEWED MR. CASTLE'S POSITION REGARDING THE OHIO LINE EXTENSION DEFERRAL?

A. Yes. In addition to my supplemental testimony on this topic, I have an additional area of concern associated with Mr. Castle's testimony at page10, lines 5 through 10. He states that should the Commission accept the company's view relative to the treatment of carrying charges and monthly customer payments that one should rely on Exhibit MAC-2, pages 1-3, for the calculation of the deferrals. I disagree. The carrying charges computed on that schedule are reduced by the deferred income taxes. For the same reasons stated earlier in my rebuttal testimony the carrying charges should not be computed net of accumulated deferred income tax. For this reason if the Commission adopts the Companies' position, it should rely on Workpaper WPC3.5c for each Company that was submitted with the Update Filing.

Q. PLEASE DESCRIBE THE POSITIONS TAKEN BY OCC AND STAFF RELATED TO INCENTIVE COMPENSATION EXPENSE.

A. Generally, both OCC and Staff argue against the inclusion of certain incentive compensation expense in the revenue requirements for each of the Operating Companies, namely the portion of incentive compensation expense that is attributable to financial goals such as earnings per share and stock performance, because the achievement of such goals, in their opinion, benefits shareholders only. As such, OCC and Staff contend that the costs they identify as being associated with these incentives should not be borne by customers.

Q. DOES THE ACHIEVEMENT OF FINANCIAL GOALS IN THE COMPANIES' INCENTIVE COMPENSATION PROGRAMS BENEFIT SHAREHOLDERS ONLY, AS SUGGESTED BY OCC AND STAFF?

A. No. I believe it is unreasonable to conclude that achievement of financial goals provides benefits exclusively to shareholders because these goals are designed to maximize profitability, increase cash flow, decrease interest expense, and increase earnings, which are common goals that benefit customers as well.

Q. CAN YOU PROVIDE ANY EXAMPLES OF CUSTOMERS BENEFITING FROM THE ACHIEVEMENT OF SUCH FINANCIAL GOALS?

A. Yes, I can. First, the achievement of certain financial goals results in greater cash inflows to the Companies, which tends to defer the need for the next rate case and provides more funds to reinvest in their infrastructure. Customers would see the benefits of this reinvestment through maintaining and improving operational performance such as higher quality of service and better reliability, and as OCC Witness Effron noted in his Direct Testimony, incentives related to the achievement of such operational goals should be recoverable from customers. Second, having a company-wide focus on financial goals such as profit maximization facilitates a common focus on efficiency across each of the Companies, which leads to cost reductions and other efficiency enhancements. All interested parties, especially customers, benefit by delivery of energy to the customers in the most cost efficient, reliable and safe manner. Third, improved financial performance creates the opportunity for the Companies to achieve better credit ratings, resulting in lower borrowing costs. This reduction to the Companies' respective costs of debt will benefit customers in future rate proceedings. In fact, today's customers have already seen all of these benefits mentioned above as evidenced by the Companies having refrained from seeking distribution related rate increases over a number of years – 19 years for OE customers and 12 years for customers of CEI and TE.

Q. OVERALL, WHAT IS THE PURPOSE OF THE COMPANIES' INCENTIVE COMPENSATION PLANS?

A. First, competitive pressures in the utility industry have created a more significant need for a tool such as incentive compensation for the Companies to compete with their peers for the best available talent. As such, the Companies' total compensation packages allow them to better attract and retain employees because the marketplace recognizes incentive pay, including financial incentives, as a standard practice among well-regarded companies. More than 90% of larger companies provide at least one type of variable pay program to employees. Elimination of incentive compensation in today's environment would place the Companies at a severe competitive disadvantage for which I believe the ratepayers would suffer the consequences. The Companies must be able to compete for and retain talent in order to continue to deliver safe and reliable electric service. Second, the incentive compensation plans seek to shift a more significant portion of compensation expense from fixed to variable – putting more of employees' compensation at risk. Having more talented, motivated employees provides enhanced performance that creates direct benefits to the customers of the Companies.

Q. DO YOU BELIEVE THAT RECOVERY OF FINANCIAL INCENTIVE COMPENSATION EXPENSES SHOULD BE ALLOWED IN RATE CASES?

A. Yes. For the reasons and examples stated above, I believe that overall, a successful company is based on achieving financial and operational goals, both of which are aligned to the interests of customers and therefore, the associated financial incentive compensation expense should be fully supported by the customers.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does at this time.

FAS 106-Estimated Benefit Payments for employees hired prior to 1/1/93 and EARNED prior to 1/1/93

	Cleveland Electric			Toledo Edison		
Year	Active Employees as of 1/1/2007	Retirees as of 1/1/2007	Total	Active Employees as of 1/1/2007	Retirees as of 1/1/2007	Total
(A) 2006	$ -	$ 9,500,000	$ 9,500,000	$ -	$ 5,800,000	$ 5,800,000
(E) 2007	$ 41,070	$ 8,403,416	$ 8,444,486	$ 518,092	$ 4,787,249	$ 5,305,341
2008	139,765	8,006,308	8,146,073	594,710	4,740,745	5,335,455
2009	277,629	7,678,652	7,956,281	686,792	4,666,128	5,352,920
2010	458,146	7,303,297	7,761,443	795,576	4,601,756	5,397,332
2011	667,181	7,001,335	7,668,516	922,397	4,403,090	5,325,486
2012	870,200	6,251,194	7,121,395	1,030,808	4,155,613	5,186,421
2013	1,085,008	5,725,924	6,810,932	1,142,468	3,910,339	5,052,807
2014	1,256,919	5,249,169	6,506,088	1,229,394	3,708,356	4,937,751
2015	1,280,232	4,799,980	6,080,212	1,271,220	3,549,372	4,820,592
2016	1,358,851	4,401,525	5,760,377	1,305,895	3,328,024	4,633,919
2017	1,397,683	4,065,007	5,462,690	1,305,784	3,107,943	4,413,727
2018	1,342,354	3,738,043	5,080,396	1,277,157	2,875,136	4,152,293
2019	1,323,400	3,436,356	4,759,756	1,249,777	2,643,050	3,892,826
2020	1,318,201	3,118,348	4,436,549	1,228,074	2,426,247	3,654,321

(A) - Actual
(E) - Estimate

Illustration of Gross vs. Net Balances for Carrying Charge

Capital Structure Assumption:

	Weight	Cost	Weighted Cost	Pre-Tax Weighted Cost*
Equity	49%	11%	5.39%	8.29%
Debt	51%	6%	3.06%	3.06%
	100%		8.45%	11.35%

* Assumes 35% income tax rate.

Assume Base:

Gross Deferral	$ 100
Deferred Taxes	35
Net of Taxes	$ 65

Carrying Charge:

		Revenue Requirement
Debt -- Gross Basis =	$100 * 6% =	**$ 6.00**
Overall -- Net Basis =	$65 * 11.35% =	**$ 7.38**

Reduced Capitalized Carrying Charge on Gross = $ 1.38

Check:

Balance Sheet -- Capital and Liabilities

Equity	$ 31.85	(a)
Debt	33.15	
Deferred Taxes	35.00	
	$ 100.00	

After-Tax Return on Equity

Carrying Charge Income	$ 7.38	
Interest Expense	1.99	
Pre-Tax Income	$ 5.39	
Income Taxes @ 35%	1.89	
Net Income	$ 3.50	(b)

Return on Equity **11.00%** (b) / (a)

Attachment 2

Distribution Deferral Categories

Operation and Maintenance (O&M) Expenses

Obsolete Equipment
Costs associated with replacements of equipment due to inability to get parts, or outdated equipment. Remote terminal unit replacements, full line rehabilitation, transformer replacement, breaker replacement, substation spare equipment, line rebuilds, carrier set replacements, batteries/charger replacements, oscillograph digital fault recorder replacements and other distribution equipment.

Failures, Relocations, Storms
Costs associated with replacement of equipment and devices; Costs associated with relocation of facilities for which the Companies do not receive reimbursement; Costs associated with restoration activity in response to storms.

IT Services
Costs associated with Information Technology services such as hardware and software programs used to support customer service, operating and regional support, and regional dispatching personnel. The programs are used for improvements with customer service reliability or any other need for supporting the Companies' electric service.

Corrective Maintenance
O&M costs associated with the unplanned repair and maintenance of the system.

Operations
O&M costs associated with the activities related to managing and directing the distribution operations of the company.

Preventive Maintenance
O&M costs associated with the planned repair and maintenance of the system.

Vegetation Management
Costs associated with tree trimming and vegetation management program.

Other
Costs associated with the installation or removal of meters; Expenses incurred to improve/reinforce the reliability of the infrastructure assets. Examples include, but are not limited to, system control and data acquisitions and motor operated air break switch additions, recloser addition to distribution lines, relaying replacements, transrupters, CRI improvements, etc. Costs associated with street lighting and lighting services. O&M expenses associated with the purchase and upkeep of tools and work equipment. This also includes transportation tools and equipment; Costs associated with projects required to improve relieve or correct an existing or projected voltage or thermal condition. Also includes line terminal upgrades, line/wave traps, line reconductoring, line upgrades.

Capital

System Reinforcement
Costs associated with reinforcing our infrastructure. Examples include, but are not limited to, line terminal upgrades, line/wave traps, line reconductoring, line upgrades, replacement of a breaker due to load or interrupting current limitations, rebuilds to improve capacity.

Obsolete Equipment
Costs associated with replacements of equipment due to inability to get parts, or outdated equipment. Remote terminal unit replacements, full line rehabilitation, transformer replacement, breaker replacement, substation spare equipment, line rebuilds, carrier set replacements, batteries/charger replacements, oscillograph digital fault recorder replacements and other distribution equipment.

Failures, Relocations, Storms
Costs associated with replacement of equipment and devices; Costs associated with relocation of facilities for which the Companies do not receive reimbursement. .

IT Services
Costs associated with Information Technology services such as hardware and software programs used to support customer service, operating and regional support, and regional dispatching personnel. The programs are used for improvements with customer service reliability or any other need for supporting the Companies' electric service.

Corrective Maintenance
Capital costs associated with the unplanned repair and maintenance of the system.

Reliability
Capital costs incurred to improve/reinforce the reliability of the infrastructure assets. Examples include, but are not limited to, system control and data acquisition and motor operated air break switch additions, recloser addition to distribution lines, relaying replacements, transrupters, circuit reliability index improvements, etc.

Other
Capital costs associated with projects required to improve relieve or correct an existing or projected voltage or thermal condition. Some specific examples include, but are not limited to, new substations, transformer additions, transformer replacement, substation capacitor installation, line capacitor installation, and feeder/exit additions; Costs associated with the installation or removal of meters; Costs associated with street lighting and lighting services. Capital associated with the purchase and upkeep of tools and work equipment. This also includes transportation tools and equipment. Costs associated with tree trimming and vegetation management program.

[Company Exhibit 4-C]

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Increase Rates for Distribution Service, Modify Certain Accounting Practices and for Tariff Approvals	)))))))	Case No. 07-551-EL-AIR Case No. 07-552-EL-ATA Case No. 07-553-EL-AAM Case No. 07-554-EL-UNC

REBUTTAL TESTIMONY OF

JEFFREY R. KALATA

ON BEHALF OF

OHIO EDISON COMPANY
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
THE TOLEDO EDISON COMPANY

___ Management policies, practices, and organization

_X_ Operating income

___ Rate base

___ Allocations

___ Rate of return

___ Rates and tariffs

___ Other –Case Overview,
Revenue Requirements
Gross Rev. Conversion Factor

I. Background

Q. PLEASE STATE YOUR NAME FOR THE RECORD.

A. My name is Jeffrey R. Kalata.

Q. ARE YOU THE SAME JEFFREY R. KALATA THAT PROVIDED INITIAL, UPDATE AND SUPPLEMENTAL TESTIMONY THAT WAS FILED IN THIS PROCEEDING ON JUNE 7, 2007, AUGUST 6, 2007, AND JANUARY 10, 2008, RESPECTIVELY?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal testimony is to address assertions related to Pension and Other Post-Employment Benefits ("OPEB") costs made by witnesses for the Ohio Office of Consumers' Counsel ("OCC") and Industrial Energy Users - Ohio ("IEU"), and to address the position taken by the PUCO Staff with respect to test year employee levels for full-time employees. I will also quantify the impacts of the positions taken by Ohio Edison Company, The Cleveland Electric Illuminating Company ("CEI"), and The Toledo Edison Company (collectively, "Operating Companies") regarding full-time employee levels and incentive compensation expense, the latter of which is described in the Rebuttal Testimony of the Operating Companies' Witness Harvey L. Wagner.

Q. DOES YOUR REBUTTAL TESTIMONY EQUALLY APPLY TO EACH OF THE OPERATING COMPANIES?

A. Yes, it does.

II. Pension and OPEB Expense

Q. PLEASE SUMMARIZE THE POSITION TAKEN BY OCC and IEU CONCERNING PENSION AND OPEB EXPENSES.

A. Generally, each of these parties takes issue with the fact that the Operating Companies determined pension and OPEB expense based on test year service costs, rather than net periodic costs for the same period. They argue either individually or collectively that the Operating Companies' methodology fails to recognize that customers allegedly funded the relevant trust funds and/or that methodology does not conform to Generally Accepted Accounting Principles ("GAAP"). As I will explain, each of these assertions is flawed in its logic.

Q. DID CUSTOMERS SUFFICIENTLY FUND THE RELEVANT PENSION AND OPEB TRUST FUNDS?

A. No. Based on a review of the Operating Companies' last individual rate cases, which occurred in 1989 for Ohio Edison and 1995 for CEI and Toledo Edison, pension expense was reflected as a credit to test year expenses and, therefore, there could be no component of current base rates that funds or has funded these trust funds. In fact, cash contributions totaling approximately $450 million were made to the Operating Companies' respective pension trust funds during 2004, 2005 and 2007. These were voluntary cash contributions and were not made to satisfy IRS minimum funding requirements. Further, the vast majority of OPEB costs are attributed to health care and prescription drug benefits. Inasmuch as costs for these benefits have escalated significantly beyond those assumed in the Operating Companies' last rate cases, any customer funding from the current base rates would be insufficient to pay for the actual prescription drug costs incurred by the Operating Companies.

Q. IS THE OPERATING COMPANIES' CALCULATION OF OPEB AND PENSION COSTS CONSISTENT WITH GAAP?

A. Yes, it is. Each of the components used to determine both the OPEB and Pension costs were calculated in accordance with GAAP. However, GAAP does not dictate ratemaking treatment in this instance and the Operating Companies believe that the use of current year service costs is appropriate. Therefore, the Operating Companies excluded (i) the expected return on plan assets; (ii) the interest on the unfunded liability; and (iii) the amortization of prior unrecognized costs. Further, it is not unusual that costs included for purposes of ratemaking are not identical to those included for financial reporting purposes. For example, under GAAP, capital leases are treated as assets whereas for purposes of ratemaking, these leases are not included in rate base and the entire payment is included as an operating cost. Also, when developing the recommended capital structure for each of the Operating Companies in this proceeding, debt due within one year has been included in the debt component even though under GAAP it would be treated as a current liability.

Q. WHY DID THE OPERATING COMPANIES EXCLUDE THE EXPECTED RETURN ON PLAN ASSETS COMPONENT WHEN DETERMINING PENSION/OPEB COSTS?

A. The voluntary cash contributions made to the Operating Companies' pension trust funds over the past several years have played a significant role in increasing the expected return on plan assets. Inasmuch as the rates paid by customers did not include a provision for pension expense in the Operating Companies' respective test year revenue requirements upon which the current base rates were developed, customers did not fund the voluntary payments made by the Operating Companies. By accepting the intervenors' position, the Commission would be penalizing the Company for voluntarily making contributions to its pension trust funds. The Company could have decided not to make the contribution which would have increased the test year net periodic pension expense for GAAP purposes. Similarly, due to the significant increases in OPEB costs since the time the Operating Companies' current base rates were established, customers have not sufficiently funded the Operating Companies' OPEB obligation. Therefore, the benefits of the expected return on the Operating Companies' investments should not flow back to customers.

Q. WHY DID THE OPERATING COMPANIES EXCLUDE THE INTEREST EXPENSE ON THE UNFUNDED LIABILITY COMPONENT?

A. The interest expense represents the growth in the future liability in the current year necessary to increase the net present value of the liability from the end of the prior year to the end of the current year. It is the Operating Companies' position that the return on plan investments should be relatively equal to this interest expense -- especially over a period of years -- and, therefore, this expense should be offset by the interest earned on the investments. Because the Operating Companies are excluding the return on investment, they are also excluding this interest expense.

Q. WHY DID THE OPERATING COMPANIES EXCLUDE THE AMORTIZATION OF PRIOR UNRECOGNIZED COSTS WHEN DETERMINING TEST YEAR PENSION AND OPEB EXPENSE?

A. The amortization of unrecognized costs is based on prior activity that is not reflective of the costs incurred by today's employees as participants in the Operating Companies' current pension and OPEB plans. Thus, inclusion of these costs should not be borne by today's ratepayers.

III. Employee Levels for Full-Time Employees

Q. PLEASE DESCRIBE THE POSITION TAKEN BY STAFF WITNESS SMITH REGARDING TEST YEAR EMPLOYEE LEVELS FOR FULL-TIME EMPLOYEES.

A. Staff Witness Smith contends that "only actual employee levels may be used when calculating labor expense" and that the Operating Companies' proposal to include budgeted employee levels for full-time employees as of the end of the test year is inappropriate because these budgeted levels are "neither known nor measurable." As such, Staff recommends using average employee levels for full-time employees over the first six months of the test year when determining test year payroll expense, in part, because taking the average would "smooth out any variances" that may exist during this time period.

Q. DO YOU AGREE WITH STAFF'S POSITION THAT THE OPERATING COMPANIES SHOULD USE EMPLOYEE LEVELS FOR FULL-TIME EMPLOYEES THAT ARE KNOWN AND MEASURABLE WHEN DETERMINING TEST YEAR PAYROLL EXPENSE?

A. While the Operating Companies still assert that budgeted employee levels as of the end of the test year are best representative of the period that rates will be in effect, I do not disagree, conceptually, with Staff's reliance on using employee levels that are known and measurable. However, I do not believe that the Staff's method of taking an average of the actual employee levels for full-time employees over the first six months of the test year is appropriate for calculating test year payroll expense.

Q. WHY IS STAFF'S METHODOLOGY INAPPROPRIATE?

A. Exhibit JRK-7 provides a graphic depiction of the actual employee levels for full-time employees over the first eleven months of the test year, as compared to the average employee levels used by Staff. As you can see from this graph, actual employee levels for full-time employees have steadily increased each month. This trend, when coupled with FirstEnergy's publicly stated intent to hire approximately 3,000 employees over the next few years, suggests that Staff's methodology is inappropriate because it does not reflect the most <u>current</u> known and measurable employee levels for full-time employees. Further, it is not necessary to use an average because there is no upward and downward volatility associated with the upward trend of the actual monthly employee levels presented in Exhibit JRK-7. Thus, the most appropriate known and measurable employee levels for full-time employees to be included in the determination of test year payroll expense are the actual employee levels as of January 2008. Given the actual test year history to date, these employee levels are most reflective of the period in which the rates proposed in this proceeding will be in effect.

Q. IN YOUR SUPPLEMENTAL TESTIMONY, YOU OBJECTED TO STAFF'S EXCLUSION OF SFAS 123(R) EXPENSE IN THE DETERMINATION OF TEST YEAR PAYROLL EXPENSE. DID STAFF ADDRESS THIS PART OF THE OPERATING COMPANIES' OBJECTION IN ITS PREFILED TESTIMONY?

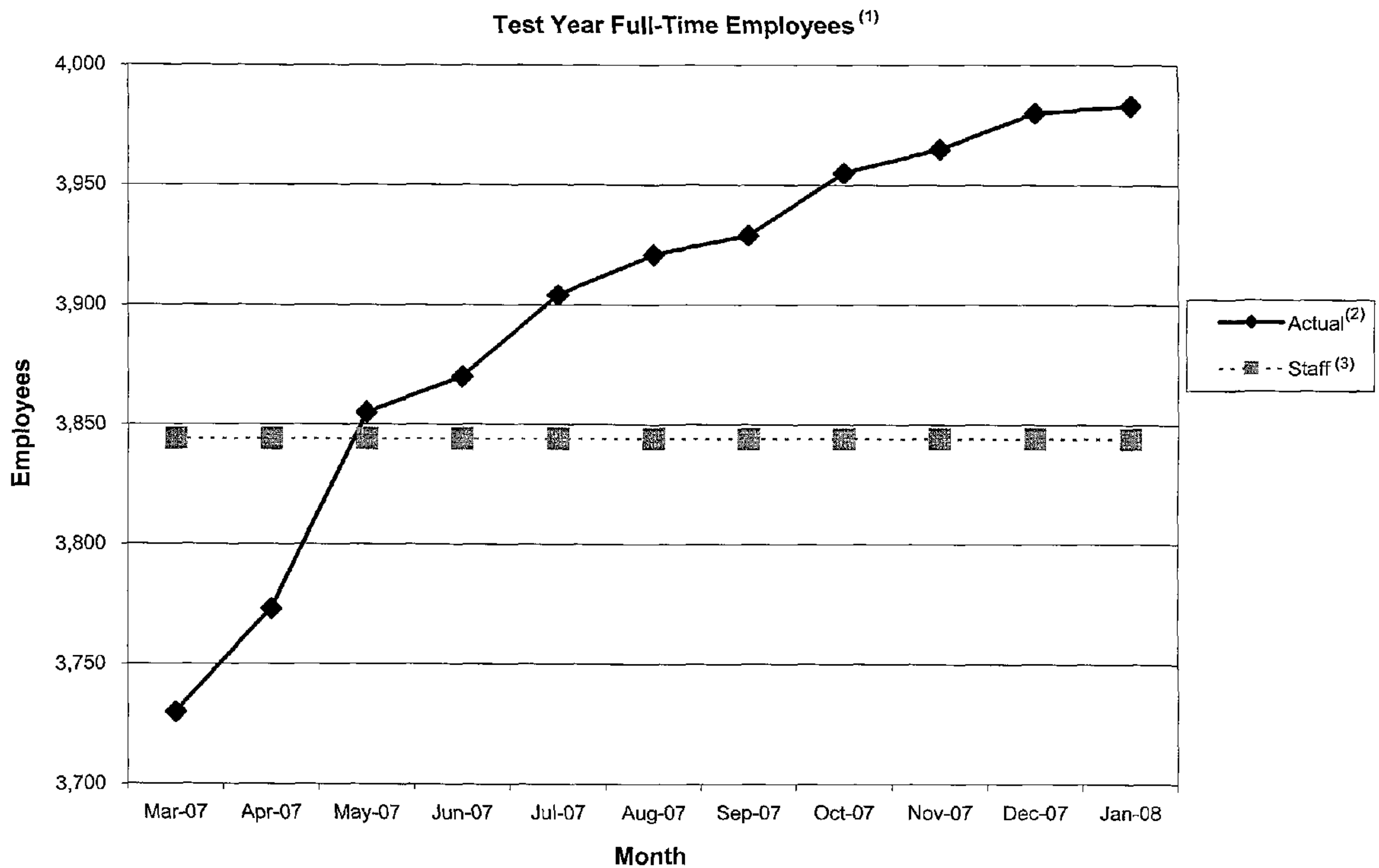
A. No, Staff did not address this issue in Prefiled Testimony. As evidenced by TJS Exhibit OE 1, TJS Exhibit CEI 1, and TJS Exhibit TE 1 attached to the Prefiled Testimony of Staff Witness Smith, SFAS 123(R) expense is not included in Staff's revised test year payroll expense calculation. No rationale for excluding this compensation expense, however, has been provided by Staff. This expense should be included in the Operating Companies' revenue requirements because it reflects the amortization of costs that have already been incurred to compensate employees for performance that provides benefits to ratepayers.

Q. WHAT IMPACT DO THE OPERATING COMPANIES' PROPOSED CHANGES DESCRIBED IN THIS TESTIMONY HAVE ON THE STAFF'S RECOMMENDED TEST YEAR PAYROLL EXPENSE AND FICA TAX EXPENSE?

A. The attached Exhibit JRK-8 provides the test year payroll expense calculated by incorporating actual employee levels for full-time employees as of January 2008 into the Staff's payroll methodology. Please note that this Exhibit also reflects the Operating Companies' inclusion of SFAS 123(R) expense, (which is described in more detail in my Supplemental Testimony), and the Operating Companies' recommended changes to test year incentive compensation expense as described in the Supplemental Testimony of Harvey L. Wagner. These changes to test year payroll expense also impact the calculation of test year FICA Tax expense for each of the Operating Companies, which is reflected on the attached Exhibit JRK-9.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.



(1) Includes employees of the Operating Companies and allocated FE Service Company employees.
(2) Actual employee levels for the first 11 months of the test year.
(3) Average actual employee levels during the first 6 months of the test year.

Ohio Edison Company
Case No. 07-551-EL-AIR
Adjustment for Labor Expense Annualization For the Twelve Months Ended February 29, 2008
PUCO Revised Staff Report vs. FirstEnergy

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
					Reconciliation of Delta Amounts			
Line No.	Line Item Description	PUCO	FE	Delta	Head Count	SFAS 123(R)	ICP %	Total
(1)	Annualized Test-Year Labor Expense	$92,709,869	$98,143,843	$5,433,974	$3,795,503	$0	$1,638,471	$5,433,974
(2)	Average Annual Bonus Dollars	$654,147	$654,147	$0	$0	$0	$0	$0
(3)	Average Annual Severance Dollars	$2,883,528	$2,883,528	$0	$0	$0	$0	$0
(4)	Test-Year Employee Discount	$0	$0	$0	$0	$0	$0	$0
(5)	Total Direct Labor (1) through (4)	$96,247,544	$101,681,518	$5,433,974	$3,795,503	$0	$1,638,471	$5,433,974
(6)	O&M Expense Ratio	58.64%	58.64%	0.00%	58.64%	58.64%	58.64%	
(7)	O&M Labor Expense (5) x (6)	$56,439,560	$59,626,042	$3,186,482	$2,225,683	$0	$960,799	$3,186,482
(8)	Jurisdictional Allocation Factor	87.97%	87.97%	0.00%	87.97%	87.97%	87.97%	
(9)	Jurisdictional O&M Labor Expense (7) x (8)	$49,649,881	$52,453,029	$2,803,148	$1,957,933	$0	$845,215	$2,803,148
(10)	O&M Labor Expense Allocated from FE Service Company	$32,280,180	$34,592,065	$2,311,885	$1,202,897	$313,188	$795,800	$2,311,885
(11)	Total O&M Labor Expense (9) + (10)	$81,930,061	$87,045,094	$5,115,033	$3,160,830	$313,188	$1,641,015	$5,115,033
(12)	Test-year Labor Expense	$82,606,482	$82,606,482	$0	$0	$0	$0	$0
(13)	Adjustment (11) - (12)	($676,421)	$4,438,612	$5,115,033	$3,160,830	$313,188	$1,641,015	$5,115,033

(C) Source: TJS Exhibit OE 1 from the Prefiled Testimony of Staff Witness Smith.
(D) Test year labor expense calculated by incorporating the changes described in Jeffrey R. Kalata's Rebuttal Testimony into the Staff's labor annualization methodology provided in the Staff reports.
(E) Calculation: column D - column C.
(F) Portion of the amount in column E that is attributable to the inclusion of actual employees for full-time employees as of January 2008, as opposed to average employee levels from March 2007 through August 2007, as proposed by Staff.
(G) Portion of the amount in column E that is attributable exclusively to the inclusion of SFAS 123(R) expense, which was excluded from the Staff's labor annualization methodology in the Staff Report. The amounts included in column I are based on a historical annual average from 2004 through 2006. Please see Exhibit JRK-5 from Jeffrey R. Kalata's Supplemental Testimony for more details.
(H) Portion of the amount in column E that is attributable to the inclusion of 100% of incentive compensation expense, as opposed to the 80% recommended by Staff and OCC. Please see the Rebuttal Testimony of Harvey L. Wagner for more details.
(I) Calculation: column F + column G + column H.

The Cleveland Electric Illuminating Company
Case No. 07-551-EL-AIR
Adjustment for Labor Expense Annualization For the Twelve Months Ended February 29, 2008
PUCO Revised Staff Report vs. FirstEnergy

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
					Reconciliation of Delta Amounts			
Line No.	Line Item Description	PUCO	FE	Delta	Head Count	SFAS 123(R)	ICP %	Total
(1)	Annualized Test-Year Labor Expense	$77,198,580	$80,424,277	$3,225,697	$2,040,789	$0	$1,184,908	$3,225,697
(2)	Average Annual Bonus Dollars	$337,682	$337,682	$0	$0	$0	$0	$0
(3)	Average Annual Severance Dollars	$649,730	$649,730	$0	$0	$0	$0	$0
(4)	Test-Year Employee Discount	$527,697	$527,697	$0	$0	$0	$0	$0
(5)	Total Direct Labor (1) through (4)	$78,713,689	$81,939,386	$3,225,697	$2,040,789	$0	$1,184,908	$3,225,697
(6)	O&M Expense Ratio	51.20%	51.20%	0.00%	51.20%	51.20%	51.20%	
(7)	O&M Labor Expense (5) x (6)	$40,301,409	$41,952,966	$1,651,557	$1,044,884	$0	$606,673	$1,651,557
(8)	Jurisdictional Allocation Factor	95.15%	95.15%	0.00%	95.15%	95.15%	95.15%	
(9)	Jurisdictional O&M Labor Expense (7) x (8)	$38,346,791	$39,918,247	$1,571,456	$994,207	$0	$577,249	$1,571,456
(10)	O&M Labor Expense Allocated from FE Service Company	$26,637,709	$28,545,485	$1,907,776	$992,636	$258,444	$656,697	$1,907,776
(11)	Total O&M Labor Expense (9) + (10)	$64,984,500	$68,463,732	$3,479,232	$1,986,843	$258,444	$1,233,946	$3,479,232
(12)	Test-year Labor Expense	$62,887,639	$62,887,639	$0	$0	$0	$0	$0
(13)	Adjustment (11) - (12)	$2,096,861	$5,576,093	$3,479,232	$1,986,843	$258,444	$1,233,946	$3,479,232

(C) Source: TJS Exhibit CEI 1 from the Prefiled Testimony of Staff Witness Smith.
(D) Test year labor expense calculated by incorporating the changes described in Jeffrey R. Kalata's Rebuttal Testimony into the Staff's labor annualization methodology provided in the Staff reports.
(E) Calculation: column D - column C.
(F) Portion of the amount in column E that is attributable to the inclusion of actual employees for full-time employees as of January 2008, as opposed to average employee levels from March 2007 through August 2007, as proposed by Staff.
(G) Portion of the amount in column E that is attributable exclusively to the inclusion of SFAS 123(R) expense, which was excluded from the Staff's labor annualization methodology in the Staff Report. The amounts included in column I are based on a historical annual average from 2004 through 2006. Please see Exhibit JRK-5 from Jeffrey R. Kalata's Supplemental Testimony for more details.
(H) Portion of the amount in column E that is attributable to the inclusion of 100% of incentive compensation expense, as opposed to the 80% recommended by Staff and OCC. Please see the Rebuttal Testimony of Harvey L. Wagner for more details.
(I) Calculation: column F + column G + column H.

The Toledo Edison Company
Case No. 07-551-EL-AIR
Adjustment for Labor Expense Annualization For the Twelve Months Ended February 29, 2008
PUCO Revised Staff Report vs. FirstEnergy

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line No.	Line Item Description	PUCO	FE	Delta	Reconciliation of Delta Amounts			
					Head Count	SFAS 123(R)	ICP %	Total
(1)	Annualized Test-Year Labor Expense	$33,640,569	$35,258,804	$1,618,235	$1,075,706	$0	$542,529	$1,618,235
(2)	Average Annual Bonus Dollars	$101,166	$101,166	$0	$0	$0	$0	$0
(3)	Average Annual Severance Dollars	$339,721	$339,721	$0	$0	$0	$0	$0
(4)	Test-Year Employee Discount	$122,127	$122,127	$0	$0	$0	$0	$0
(5)	Total Direct Labor (1) through (4)	$34,203,583	$35,821,818	$1,618,235	$1,075,706	$0	$542,529	$1,618,235
(6)	O&M Expense Ratio	53.24%	53.24%	0.00%	53.24%	53.24%	53.24%	
(7)	O&M Labor Expense (5) x (6)	$18,209,987	$19,071,536	$861,549	$572,706	$0	$288,843	$861,549
(8)	Jurisdictional Allocation Factor	95.87%	95.87%	0.00%	95.87%	95.87%	95.87%	
(9)	Jurisdictional O&M Labor Expense (7) x (8)	$17,457,915	$18,283,882	$825,967	$549,053	$0	$276,914	$825,967
(10)	O&M Labor Expense Allocated from FE Service Company	$14,209,278	$15,226,937	$1,017,659	$529,498	$137,861	$350,300	$1,017,659
(11)	Total O&M Labor Expense (9) + (10)	$31,667,193	$33,510,819	$1,843,626	$1,078,551	$137,861	$627,214	$1,843,626
(12)	Test-year Labor Expense	$31,877,113	$31,877,113	$0	$0	$0	$0	$0
(13)	Adjustment (11) - (12)	($209,920)	$1,633,706	$1,843,626	$1,078,551	$137,861	$627,214	$1,843,626

(C) Source: TJS Exhibit TE 1 from the Prefiled Testimony of Staff Witness Smith.
(D) Test year labor expense calculated by incorporating the changes described in Jeffrey R. Kalata's Rebuttal Testimony into the Staff's labor annualization methodology provided in the Staff reports.
(E) Calculation: column D - column C.
(F) Portion of the amount in column E that is attributable to the inclusion of actual employees for full-time employees as of January 2008, as opposed to average employee levels from March 2007 through August 2007, as proposed by Staff.
(G) Portion of the amount in column E that is attributable exclusively to the inclusion of SFAS 123(R) expense, which was excluded from the Staff's labor annualization methodology in the Staff Report. The amounts included in column I are based on a historical annual average from 2004 through 2006. Please see Exhibit JRK-5 from Jeffrey R. Kalata's Supplemental Testimony for more details.
(H) Portion of the amount in column E that is attributable to the inclusion of 100% of incentive compensation expense, as opposed to the 80% recommended by Staff and OCC. Please see the Rebuttal Testimony of Harvey L. Wagner for more details.
(I) Calculation: column F + column G + column H.

Ohio Edison Company
Case No. 07-551-EL-AIR
Calculation of Test Year FICA Tax Expense
Revised Staff Report vs. FirstEnergy

TJS Exhibit FICA (FE Revised)

(A)	(B)	(C)	(D)	(E)
		Jurisdictional Amount		
Line No.	Description	PUCO	FE	Delta
1	Annualized O&M Labor Expense	$81,930,061	$87,045,094	$5,115,033
2	Percentage of OASDI Taxable Wages	97.19%	97.19%	0.00%
3	OASDI Taxable Wages (1 x 2)	$79,627,826	$84,599,127	$4,971,301
4	Effective Tax Rate	6.20%	6.20%	0.00%
5	Old Age, Survivors and Disability Insurance (OASDI) Portion of FICA Tax (3 x 4)	$4,936,925	$5,245,146	$308,221
6	Medicare Effective Tax Rate	1.45%	1.45%	0.00%
7	Medicare Expense Portion of FICA Tax (6 x 1)	$1,187,986	$1,262,154	$74,168
8	Test-Year FICA Tax Expense (5 + 7)	$6,124,911	$6,507,300	$382,389

(C) Source: TJS Exhibit FICA from the Prefiled Testimony of Staff Witness Smith.
(D) Test year FICA Tax expense calculated by incorporating Ohio Edison's revised test year labor expense into the Staff's methodology in TJS Exhibit FICA. Source of annualized O&M labor expense: Row 11, column D of Exhibit JRK-8 (page 1 of 3)
(E) Calculation: column D - column C.

The Cleveland Electric Illuminating Company
Case No. 07-551-EL-AIR
Calculation of Test Year FICA Tax Expense
Revised Staff Report vs. FirstEnergy

TJS Exhibit FICA (FE Revised)

(A)	(B)	(C)	(D)	(E)
Line No.	Description	Jurisdictional Amount PUCO	Jurisdictional Amount FE	Jurisdictional Amount Delta
1	Annualized O&M Labor Expense	$64,984,500	$68,463,732	$3,479,232
2	Percentage of OASDI Taxable Wages	96.38%	96.38%	0.00%
3	OASDI Taxable Wages (1 x 2)	$62,632,061	$65,985,345	$3,353,284
4	Effective Tax Rate	6.20%	6.20%	0.00%
5	Old Age, Survivors and Disability Insurance (OASDI) Portion of FICA Tax (3 x 4)	$3,883,188	$4,091,091	$207,903
6	Medicare Effective Tax Rate	1.45%	1.45%	0.00%
7	Medicare Expense Portion of FICA Tax (6 x 1)	$942,275	$992,724	$50,449
8	Test-Year FICA Tax Expense (5 + 7)	$4,825,463	$5,083,815	$258,352

(C) Source: TJS Exhibit FICA from the Prefiled Testimony of Staff Witness Smith.
(D) Test year FICA Tax expense calculated by incorporating CEI's revised test year labor expense into the Staff's methodology in TJS Exhibit FICA. Source of annualized O&M labor expense: Row 11, column D of Exhibit JRK-8 (page 2 of 3).
(E) Calculation: column D - column C.

The Toledo Edison Company
Case No. 07-551-EL-AIR
Calculation of Test Year FICA Tax Expense
Revised Staff Report vs. FirstEnergy

TJS Exhibit FICA (FE Revised)

(A)	(B)	(C)	(D)	(E)
Line No.	Description	Jurisdictional Amount		
		PUCO	FE	Delta
1	Annualized O&M Labor Expense	$31,667,193	$33,510,819	$1,843,626
2	Percentage of OASDI Taxable Wages	97.11%	97.11%	0.00%
3	OASDI Taxable Wages (1 x 2)	$30,752,011	$32,542,356	$1,790,345
4	Effective Tax Rate	6.20%	6.20%	0.00%
5	Old Age, Survivors and Disability Insurance (OASDI) Portion of FICA Tax (3 x 4)	$1,906,625	$2,017,626	$111,001
6	Medicare Effective Tax Rate	1.45%	1.45%	0.00%
7	Medicare Expense Portion of FICA Tax (6 x 1)	$459,174	$485,907	$26,733
8	Test-Year FICA Tax Expense (5 + 7)	$2,365,799	$2,503,533	$137,734

(C) Source: TJS Exhibit FICA from the Prefiled Testimony of Staff Witness Smith.
(D) Test year FICA Tax expense calculated by incorporating Toledo Edison's revised test year labor expense into the Staff's methodology in TJS Exhibit FICA. Source of annualized O&M labor expense: Row 11, column D of Exhibit JRK-8 (page 3 of 3).
(E) Calculation: column D - column C.

[Company Exhibit 8-C]

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio	)	
Edison Company, The Cleveland Electric	)	
Illuminating Company, and The Toledo	)	**Case No. 07-551-EL-AIR**
Edison Company for Authority to	)	**Case No. 07-552-EL-ATA**
Increase Rates for Distribution Service,	)	**Case No. 07-553-EL-AAM**
Modify Certain Accounting Practice	)	**Case No. 07-554-EL-UNC**
And for Tariff Approvals		

REBUTTAL TESTIMONY OF

MICHAEL J. VILBERT

ON BEHALF OF

OHIO EDISON COMPANY
THE TOLEDO EDISON COMPANY, AND
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

__ Management policies, practice, and organization

__ Operating income

__ Rate base

__ Allocations

X Rate of return

__ Rates and tariffs

__ Other – Cost of Service

TABLE OF CONTENTS

I. INTRODUCTION AND SUMMARY

Q1. Please state your name and address for the record.

A1. My name is Michael J. Vilbert. My business address is The Brattle Group, 44 Brattle Street, Cambridge, MA 02138, USA.

Q2. Did you previously file testimony in this proceeding?

A2. Yes, I filed Direct Testimony[1] ("Vilbert Direct") on behalf of Ohio Edison Company ("OE"), The Cleveland Electric Illuminating Company ("CEI") and The Toledo Electric Company ("TE"), (collectively, the "Companies" or the Ohio Electric Distribution Utilities ("Ohio EDUs")) in June 2007 regarding the return on equity that the Ohio EDUs should be allowed an opportunity to earn on the equity financed portion of their rate bases. I filed Supplemental Testimony ("Vilbert Supplemental") on behalf of the Companies in January 2008. Please see the detailed resume in Appendix A attached to my Direct Testimony for my professional qualifications.

Q3. What is the purpose of your rebuttal testimony?

A3. I have been asked by the Companies to comment on the testimonies of Mr. Aster R. Adams ("Adams Direct") on behalf of the Office of the Ohio Consumers' Counsel, of Mr. Richard C. Cahaan as Staff Witness ("Cahaan Direct"), and of Mr. Howard Sogalnick on behalf of the Ohio School Council ("Sogalnick Direct") with regard to the appropriate return on equity.

II. FINANCIAL RISK AND CAPITAL STRUCTURE

Q4. What are the issues in the Adams Direct regarding capital structure?

A4. The Adams Direct recommends using FirstEnergy's capital structure,[2] but that capital structure is not necessarily representative for the Ohio EDUs. Although financial risk is acknowledged as a component of a firm's risk[3], the Adams Direct does not consider the

[1] Company Exhibit 8.

[2] Adams Direct, pp. 5-6 and Attachment ARA-2.

[3] Adams Direct, p. 16.

impact on the required return on equity due to any difference in financial leverage between the sample and the regulated companies.

Q5. Please address the financial risk issue in the Adams Direct.

A5. The estimated costs of equity reflect *both* the business risk and the financial risk of the sample companies based upon the sample companies' *market value* capital structures.[4] If the market value capital structures of the sample firms were different, the estimated costs of equity would be different as well. As noted in the Vilbert Supplemental and the Vilbert Direct in Section II.C, "the ATWACC (After Tax Weighted Average Cost of Capital) – a company's overall cost of capital -- is constant over a broad range of capital structures. However, the cost of equity is not. The cost of equity for the Companies should reflect the risk of their underlying assets and be comparable to the return that is achievable on investments of comparable risk."[5] In other words, the Adams Direct does not adjust for the differences in the sample's capital structure nor for the fact that FirstEnergy's capital structure has greater financial risk than the regulatory capital structure filed by the Companies. Therefore a cost of equity recommendation that relied on the parent's capital structure would be higher than one that relies on the Companies' filed capital structure.

A. ATWACC AND MARKET-TO-BOOK ISSUES

Q6. Is it appropriate to estimate the cost of equity for the sample companies using market data?

A6. Yes. The Adams Direct, the Staff Reports and the Vilbert Direct all estimate the cost of equity for the sample companies using market information. The Discounted Cash Flow Model ("DCF" model) and the risk positioning model (i.e., the CAPM and ECAPM) rely upon market information, and the cost of equity estimates derived from those estimation models reflect the business risk and financial risk of the sample companies at their *market*

[4] Vilbert Supplemental, pp. 2-4.

[5] Vilbert Supplemental, pp. 4-7.

value capital structures.[6] The returns on equity recommended by the Adams Direct as well as by the Cahaan Direct and the Vilbert Direct are derived from these models.

B. THE ADAMS DIRECT'S CRITIQUE OF THE ATWACC METHOD

Q7. The Adams Direct claims that the ATWACC "method is flawed in that it tends to overstate the true cost of equity" and that "the underlying flawed assumption is that the Commission is obligated to maintain current stock price levels..."[7] Are these statements an accurate assessment of the ATWACC approach?

A7. No. The comments in the Adams Direct testimony demonstrate a misunderstanding of the ATWACC approach and its adjustment for financial risk. The Adams Direct claims that the ATWACC approach is an attempt to maintain a particular ratio of the market value of equity to the book value of equity (the "market-to-book value"), but this is incorrect. The market-to-book value is irrelevant to the ATWACC approach.

Q8. Please explain why the market-to-book ratio is irrelevant to the ATWACC approach?

A8. Note that in the formula (1) for the ATWACC displayed on p. 14 of the Vilbert Direct, book values do not appear in the calculation; therefore, there is no way that the ATWACC can anchor the market-to-book ratio. Regardless of the market-to-book ratio, what matters is the percentage of the market value capital structure that is equity relative to the percentage that is debt.

Q9. Please explain the apparent source of the misunderstanding of the ATWACC approach.

A9. One source of the misunderstanding is that the ATWACC is a *rate of return* not a dollar amount of return. The flaw in reasoning can be illustrated in the following simplified example. Suppose that the cost of equity estimated using the DCF or the risk positioning method is 10 percent for a regulated company with a market value capital structure with 67 percent equity and 33 percent debt. (See Step 1 in Figure 1 below.) Suppose that the

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[6] This is well accepted financial theory. See, for example, Richard A. Brealey, Stewart C. Myers, and Franklin Allen, *Principles of Corporate Finance*, New York: McGraw-Hill/Irwin 8th ed. (2006) pp. 503-06.

[7] Adams Direct, pp. 18-19.

book value regulatory capital structure is 50 percent equity and 50 percent debt and that the ATWACC adjusted rate of return on equity is 12.1 percent. (See Step 2 in Figure 1 below.) Does this mean that if the Commission allows a 12.1 percent return on equity that the return on the market value of equity will be 12.1 percent? The answer, of course, is no.

Q10. Please illustrate why allowing an ATWACC adjusted return on rate base will not provide a rate of return on the market value of equity equal to 12.1 percent in the example.

A10. The reason is that the ATWACC adjusted return on equity is applied to the *book value* of equity in the rate base not the market value of equity. In this example, the market-to-book ratio is 2.0, so that the market value of equity is $1000 but the book value is only $500. A 12.1 percent rate of return on equity times a $500 book value of equity gives a return of about $60.70 which would be about 6 percent (i.e., 60.70/1000) on the $1000 of market value of equity. In other words, although the return on the book value rate base would be 12.1 percent in the example, the return on the market value of equity would be about 6 percent, ½ of the allowed return on the equity financed portion of the rate base. A 6 percent return on the market value of equity is likely to be less than the company's current market cost of debt. (See Step 3 in Figure 1 below.)

Figure 1: Example of ATWACC approach, and the resulting return on the market value of equity.

Step 1: Compute ATWACC using market values

	Market Values		Return	Tax Rate	Wt. Average
Equity	1000	67%	10.0%		0.067
Debt	500	33%	6.0%	40%	0.012
	1500	100%		ATWACC	$\boxed{0.079}$

Step 2: Using book value capital structure, compute allowed return on equity that yields the ATWACC determined in Step 1

	Book Values		Return	Tax Rate	Wt. Average
Equity	500	50%	12.1%		0.061
Debt	500	50%	6.0%	40%	0.018
	1000	100%		ATWACC	$\boxed{0.079}$

Step 3: Implied allowed equity return on market value of equity

	Dollar Amount	Rate of Return
Equity Return	60.7	6.07%

The example in Figure 1 illustrates an additional advantage of the ATWACC approach: rate payers are indifferent to the regulatory capital structure. The cost to customers would be unaffected by a different regulatory capital structure because the return on equity would change as capital structure changes in order to maintain a constant ATWACC, but the capital costs (i.e., the sum of interest expense, equity return and income taxes) paid by customers would not be affected by changes in capital structure.

Q11. If the allowed return on equity is 12.1 percent instead of 10 percent are you saying that this will or will not maintain the current market-to-book ratio?

A11. The ATWACC approach does not say anything about this. Instead, the ATWACC approach simply says that the estimated return on investments of comparable business risk to the regulated company is equal to the ATWACC. Therefore the regulated company should be allowed an overall *rate of return* equal to the ATWACC on the *book value* rate base.

Q12. Is the ATWACC method incompatible with the use of a book value rate base?

A12. No. The use of book value rate base is perfectly consistent with the use of a rate of return calculated from market data using the ATWACC method. The book value rate base is merely a historical record of the costs of assets purchased by investors to provide service to customers. All rate-of-return analysts estimate a market cost of capital to apply to that investment, and as noted above, all three testimonies use market data to estimate the cost of equity for the sample companies. The only difference is that the Vilbert Direct calculates the overall market rate of return on all of the sources of capital for the sample firms and applies that overall rate of return to the rate base. Because the regulated capital structure differs from the market value capital structures of the sample companies, the allowed return on equity must be adjusted so that the weighted-average cost of capital used to set rates is equal to the market-determined overall cost of capital from the sample of companies with comparable business risk.

Q13. Do you have any comments on Table 3 in the Adams Direct?

A13. Yes. Table 3 is misleading. In Table 3, p. 21 the Adams Direct presents the average of Vilbert Direct's cost of equity estimates before any financial risk adjustment which he calls the "traditional methods". Mr. Adams then calculates what he characterizes as the "overstatement" of cost of equity as the average difference between the Vilbert Direct's cost of equity estimates before and after financial risk considerations. The differences average about 1.4 percent. The table goes on to calculate the adjusted ROE as my recommended cost of equity of 11¾ percent minus the 1.4 percent. This fails to take into consideration that the average of the Vilbert Direct's DCF and risk positioning estimates is 10.7 percent not the 10.3 percent that results from subtracting 1.4 percent from 11.75 percent. The Adams Direct simply misrepresents the Vilbert Direct's results. If the Adams Direct wants to refer to an average of the "traditional" cost of equity estimates in the Vilbert Direct, the proper figure is 10.7 percent shown in Table 3, not the 10.3 percent cited, but in any event this value ignores the financial risk and would not be correct for the Companies.

C. The Cahaan Direct's Critique of the ATWACC Method

Q14. How does the Cahaan Direct address financial risk?

A14. The Cahaan Direct also accepts the importance of financial risk and evaluates the ATWACC approach. The Cahaan Direct concludes that because the market value capital structure of FirstEnergy is not substantially different from the average market capital structure of the sample companies, there is no need for an adjustment for differences in financial risk.[8]

Q15. Is the Cahaan Direct correct that the financial risk of FirstEnergy, the parent company, is comparable to the sample compared on a market value basis?

A15. Yes, but that is not the right question. This proceeding is directed toward setting the appropriate return on equity on the rate base for the Ohio EDUs not FirstEnergy. The appropriate comparison is between the regulatory capital structure of the Ohio EDUs and the (market value) capital structure of the sample companies because the costs of equity estimated by the models (i.e., the DCF and the CAPM) reflect the business and financial risk of the sample companies at their market value capital structures.

Q16. Please continue.

A16. The Cahaan Direct's concern seems to stem from the relatively high market-to-book value ratios of the sample companies, but that issue is a distraction from the point being made by the ATWACC approach. The market-to-book ratios are irrelevant to the ATWACC approach. This was discussed above but another way to think about this is to consider a world in which the market-to-book ratios are always equal to one for all of the sample companies. If the sample companies' average capital structure was one with 67 percent equity and the regulated company's capital structure was one with 50 percent equity, there would seem to be little disagreement that the financial risk of the sample was lower than for the regulated company, but it would have absolutely nothing to do with the market-to-book ratio. In particular, the ATWACC method is not a method to introduce the market-to-book ratio through the "backdoor" as is of concern in the Cahaan Direct.[9]

Q17. Do the cost of equity estimates from the DCF model and the CAPM depend upon the market value or book value capital structures of the sample companies?

A17. The market value capital structure is the relevant measure of financial risk. The market determined cost-of-equity estimates from the sample depend upon both the business and the financial risk of the sample. The financial risk of the sample companies depends

[8] Cahaan Direct, pp. 26-28.

[9] Cahaan Direct, p. 28.

upon the market value not the book value capital structures. There is no debate in financial theory that financial risk is a function of market value capital structures.

Q18. Please continue with the example.

A18. In the example, the average capital structure of the sample companies is 67 percent equity even though the market-to-book ratios are all equal to one, but the regulated company's capital structure has only 50 percent equity. Applying the cost of equity from the sample in this situation without consideration of the differences in financial risk would clearly be wrong. Anyone disagreeing with the last statement should consider whether their answer would change if the regulatory capital structure had 80 percent equity or 90 percent equity instead of 50 percent.

Q19. But the sample companies and FirstEnergy's market-to-book ratios are not equal to one. Doesn't that change the example?

A19. No. First, again note that the market-to-book ratio does not enter the calculation of the ATWACC for the sample companies. It is all based upon the market value capital structures and the market costs of debt, preferred stock and equity. Second, the cost of equity estimated from the market models still reflects the business and financial risk of the sample companies at their market value capital structures not their book value capital structures. Third, applying the cost of equity estimated from the market models to the regulated entity still requires consideration of the differences in capital structures between the sample and the regulated company just as when the market-to-book ratios were all equal to one. Nothing of consequence has changed for application of the ATWACC to the regulated entity due to the market-to-book ratios. Finally, note that there is nothing inconsistent with applying the ATWACC to a book value capital structure. Nothing I am recommending would change the way the Ohio EDUs are regulated or would change the reliance on a rate base established on a book value basis. What the ATWACC approach does do is change the way that the information from the market models is interpreted for application to the book value rate base. Specifically, the ATWACC approach recognizes that as the capital structure changes, the return on equity must change as well in order to be consistent with the market determined cost of equity estimates from the sample.

III. ESTIMATING THE SAMPLE COMPANIES' COSTS OF EQUITY

Q20. Do you have any comments on the cost of equity methodologies relied upon by the Adams Direct and the Cahaan Direct?

A20. Yes. My comments in this section are primarily addressed to the Adams Direct because the methodologies used by the Staff were addressed in my Supplemental Testimony. I do note several places, however, that the Cahaan Direct agrees with my approach and rejects several aspects of the way the Adams Direct implements the models. With regard to the Adams Direct, I first address the implementation of the DCF method. Next, I address the implementation of the CAPM, and finally, I discuss the Adams Direct's critique of the Empirical Capital Asset Pricing Model ("ECAPM").

A. THE DCF MODEL

Q21. What comments do you have regarding the Adams Direct's implementation of the DCF model?

A21. The Adams Direct implements the DCF model in a manner very similar to the Staff's implementation, so the comments in my Supplemental Testimony apply equally to the Adams Direct's implementation.[10] Specifically, there are two problems with the DCF model in the Adams Direct. The first is that the Adams Direct relies on stock prices that are up to a year old. Because the DCF model is intended to be a forward-looking model, it is important that the stock prices in the model reflect current information. The calculation of the dividend yield in the Adams Direct with reference to a yearly average price destroys one of the primary advantages of the DCF model in that it is a forward looking model. Stock prices averaged over an entire year reflect stale and out of date information. One need only consider the developments in the credit markets due to the subprime mortgage crisis to realize how out of date information from a year ago truly is. A year is simply too long a time period to rely on for the purpose of calculating the current price and yield.

[10] Vilbert Supplemental, pp. 13-14.

Q22. What is the second problem in the Adams Direct implementation of the DCF model?

A22. The Adams Direct summarizes the dividend payments over the last four quarters rather than annualizing the most recent dividend, i.e., multiplying the most recent dividend by four. This procedure will definitely *underestimate* the cost of equity using the DCF model. As noted above the DCF model assumes that dividends growth each period by the assumed constant growth rate. Using historical dividends from as much as a year ago violates the constant growth assumption and in general will underestimate future dividends to the extent that dividends paid have increased over the last four quarters. As with using historical prices from a year ago, this procedure weakens the forward looking nature of the model.

Q23. Do you have any other comments on the Adams Direct's reliance on the DCF model

A23. The Adams Direct seems to believe that the DCF model provides more reliable estimates of the cost of capital for the sample companies than the risk positioning model does at this time, but that belief is highly debatable at best.[11] As noted in the Vilbert Direct,[12] the DCF model can be a useful model if its assumptions are fully met, but those assumptions are so unlikely to be satisfied and also have such a large effect on the estimated cost of equity it produces that it is unusual for the conditions necessary for the completely reliable implementation of the model to be present. In other words, changing the "assumed" terminal growth rate as well as when the terminal growth rate will be achieved in the non-constant growth formulation of the model changes the DCF estimates substantially, but there is literally no information upon which to base those assumptions.

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[11] The Surface Transportation Board recently decided to switch from using the constant growth DCF to the CAPM to determine the cost of capital for railroads citing among other factors, the assumption of a constant growth rate and a constant dividend payout ratio not being generally true. See *Surface Transportation Board* Decision STB Ex Parte No. 664, "Methodology To Be Employed In Determining The Railroad Industry's Cost Of Capital," January 17, 2008.

[12] Vilbert Direct, p. 23.

B. The CAPM

Q24. Do you have a general comment on the Adams Direct's implementation of the CAPM?

A24. Yes. In general, most of the procedures used in the Adams Direct have the effect of an unwarranted reduction in the estimated return on equity, a point with which the Cahaan Direct agrees when it says that "[c]onsidering the current yields on FirstEnergy operating companies' long-term bonds, and bonds of similar quality, the risk premium implied by the [Adams Direct's] 8.61% or the 8.33% estimates are simply too low to be credible."[13]

Q25. Do you have any comment on the method that the Adams Direct uses to estimate the parameters for use in the CAPM?

A25. Yes. The Adams Direct estimates all of the parameters in the model by taking averages of different information sources irrespective of whether it is appropriate to do so. For example, Mr. Adams calculated the sample companies' betas as the average of the betas estimated by *Value Line*, Bloomberg's, and Reuters,[14] two of which adjust betas and one of which does not. Rather than make a judgment whether betas should be adjusted or not, the Adams Direct simply averages different estimates. A similar approach is used for the risk-free rate where the Adams Direct relied on the average of yield on 10-year and 30-year Treasury bonds for a full year ending in November 2007. This is a problem because the MRP should be matched with the measure of the risk-free being used. The average yields on 10-year Treasury bonds are generally lower than the yields on 30-year Treasury bonds, so the MRP used with the yields on 10-year Treasury bonds compared to 30-year Treasury bonds should be different as well. Moreover, interest rates that are as much as a year old are stale and out of date which destroys the forward looking aspect of the CAPM. Similarly, the Adams Direct averages many estimates of the MRP including geometric and arithmetic from many sources to determine the MRP for use in the models. While

[13] Cahaan Direct, p. 25.

[14] *Value Line* betas are estimated using five years of weekly returns and the New York Stock Exchange Composite Index as the market proxy. *Value Line* betas are adjusted. Reuter's betas are estimated using five years of monthly returns and the S&P 500 as the market proxy. Reuter betas are not adjusted. Bloomberg allows its user to determine the frequency as well as the time horizon over which betas are estimated. However, the standard is two years of weekly data. Bloomberg generally uses the S&P 500 index and allows its user to determine whether the betas are adjusted. In this case, the Bloomberg betas are quite similar to those obtained from *Value Line.*

such an approach reduces the effect of the analyst's judgment, it also has the effect of making the analyst more of a calculating machine than an expert making judgments about the weight of the evidence. The point is that simply averaging many values for a parameter does not improve the estimate if the values being averaged are not appropriate.

Q26. The Adam Direct relies on estimates of the MRP based upon the geometric mean. Is this appropriate for use in the CAPM?

A26. No. Although the Adams Direct cites a few sources in favor of relying on the geometric average in some circumstances to determine the market risk premium, this is not currently standard practice in finance and is specifically recommended against by nearly every academic source. The Cahaan Direct agrees that the arithmetic average is correct for use in the CAPM.[15] The inappropriate use of the geometric estimate of the MRP accounts, in part, for the exceptionally low CAPM cost of equity estimates in the Adams Direct.

Q27. Do you have other comments on the Adams Direct's estimation of the MRP for use in the CAPM?

A27. Yes. The Adams Direct's discussion of the literature on the market risk premium does not include any articles more recent than 2005. Many of the more recent articles support a higher estimate of the MRP. In addition, the Adams Direct goes through substantial effort to calculate the ex ante risk premium based upon an original article by Ibbotson and Chen and subsequently relied upon by Professor Randall Woolridge in a different proceeding, but these calculations are unnecessary because Morningstar publishes the Ibbotson and Chen ex ante risk premium in their *Valuation Edition* yearbook.

Q28. Please elaborate on the market risk premium issue.

A28. As discussed in the Vilbert Direct, there is currently no consensus on the market risk premium. However, the Adams Direct does not cite a full spectrum of the literature that focuses on this issue. For example, the Adams Direct cites a 2003 publication of Dimson, March and Staunton in support of a relatively low market risk premium.[16] However, in

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[15] Cahaan Direct, p. 12 cites p. 77 in the Ibbotson SBBI Valuation Edition Yearbook 2007 which states that the arithmetic mean is the appropriate measure of the MRP for use in the CAPM.

[16] Adams Direct, p. 40.

their most recent publication, Dimson March and Stauton (2007) estimate the arithmetic mean historical market risk premium at 6.6 percent relative to Treasury bonds for the U.S.[17] It is also noteworthy that another regulator, the Surface Transportation Board, in its recent decision to rely on the CAPM decided after extensive review that the Morningstar/Ibbotson historical arithmetic average from 1926 to today was the most appropriate estimate of the MRP.

> We are now persuaded that basing the equity-risk premium on returns dating from 1926 is the superior and more standard approach. We are cognizant of the literature, cited by several parties, indicating that some experts believe that the forward-looking equity-risk premium should be lowered to reflect the impact of higher price/earnings ratios. For example, the expert for the AAR directed the agency to an adjusted equity-risk premium published by Morningstar/Ibbotson that seeks to reflect the upward trend in price-earnings ratios and reduces the forward-looking equity-risk premium. We acquired the cost-of-capital book published by Morningstar/Ibbotson so that we might carefully review that alternative figure. But while Morningstar/Ibbotson does report such a figure, which falls in the 6% range, the company itself continues to rely on returns dating from 1926 in its own CAPM calculations. Moreover, WCTL submitted evidence showing that most commercial vendors of cost-of-capital information use this same figure in their CAPM calculation. Accordingly, we will follow the standard approach and use the historical average from 1926. [footnotes omitted][18]

Q29. Earlier you noted that the Morningstar publishes its forecast of the Ibbotson and Chen ex ante risk premium in its Valuation Edition Yearbook so that there was no need to calculate the value. What is the forecast in the 2007 Yearbook?

A29. The arithmetic forecast is 6.35 percent over Treasury bonds, which is very similar to the 6.5 percent MRP used by both the Vilbert Direct and the Staff Reports. The geometric mean ex ante MRP is 4.33 percent.[19] Note that the Adams Direct calculates the ex ante geometric risk premium to be 4.64 percent, which is equal to 6.66 percent on an arithmetic basis. As noted in the Morningstar *Valuation Edition*, for "use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic

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[17] Elroy Dimson, Paul Marsh, and Mike Stauton (2007), *Global Investment Returns Yearbook 2007*, London Business School and ABN-AMRO, March 2007, p. 48.

[18] *Surface Transportation Board*, "Methodology to Be Employed in Determining the Railroad Industry's Cost of Capital," Decision, STB Ex Parte No. 664, November 27, 2007, p. 13.

[19] Morningstar, SBBI Valuation Edition, 2007 Yearbook, p. 96.

calculation is the relevant number."[20] In other words, the Adams Direct ex ante MRP should be about 200 basis points higher than the 4.64 percent geometric average used in the calculations.

Q30. The Adams Direct also argues that survivorship bias leads to an overstatement of the historical market risk premium by as much a 1.50 percent.[21] Does this represent the most recent view in the academic literature?

A30. No. There are newer academic articles that find the survivorship bias to be very minor. As noted in the Vilbert Direct, Jorion and Goetzmann (1999) found the survivorship bias to be only 29 basis points.[22] The 2006 version of the Dimson, Marsh and Staunton article cited by the Adams Direct calculates that the survivorship bias is de minimus, about 1/10th of 1 percent, i.e., 0.1 percent not 1.50 percent referenced in the Adams Direct.[23] Dimson et al note that higher estimates of the survivorship bias requires implausibly low probabilities of the long-term market survival, but such low probabilities contradict the history of world equity markets.

Q31. The Adams Direct relies on the geometric market risk premium which is inconsistent with standard financial economics. Please explain why the geometric market risk premium is inappropriate for cost of capital estimation.

A31. While the Adams Direct cites a few sources in support of the geometric market risk premium, it is not standard practice in finance. In general, those articles rely on serial correlation in market returns as justification of use of the geometric average, but those articles also suggest weighting the arithmetic and geometric means with by far the greatest weight on the arithmetic mean. Although the geometric mean return is appropriate for consideration of achieved returns over a period of time, it is well established that the geometric mean is not correct for estimating the expected return. Based on current academic and other literature, the geometric average based MRP is not

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[20] *Ibid.*, p. 96.

[21] Adams Direct p. 39.

[22] Jorion, P., and W. Goetzmann (1999), "Global Stock Markets in the Twentieth Century," *Journal of Finance* 54:953-980. See also the Vilbert Direct, pp. B-6 to B-7.

[23] *The Worldwide Equity Premium: A Smaller Puzzle*, Revised 7 April 2006, by Elroy Dimson, Paul Marsh, and Mike Staunton, London Business School, p. 22.

appropriate for estimating cost of capital in a regulatory setting because the CAPM requires a forward looking perspective. This is well understood in the broader finance community. A few examples of current publications stating that the arithmetic mean not the geometric mean is correct are Ibbotson Associates, *Stock, Bonds, Bills and Inflation, Valuation Edition*, 2007 Yearbook, p. 77, Roger A. Morin (2006), *New Regulatory Finance*, Public Utilities Reports, Inc., pp. 116-117, the *Investments* text by Professors Bodie, Kane, and Marcus (2005) Zvi Bodie, Alex Kane, and Alan J. Marcus (2005), *Investments*, 6th Edition, McGraw-Hill, p. 865, and *Principles of Corporate Finance*, 8th Edition, McGraw-Hill, by Richard A. Brealey, Stewart C. Myers, and Franklin Allen (2006), pp. 150-151.

Q32. The Adams Direct also claims that the *Value Line* betas are over estimated because they are calculated with regard to the NYSE Index as opposed to the S&P 500 Index for the market proxy.[24] Is this a valid concern?

A32. No, not in my opinion. In fact, I have never heard anyone claim that the choice of either the S&P 500 Index or the NYSE Index has a significant effect on the estimation of beta. Moreover, I am highly skeptical of this assertion because the correlation between the NYSE Index and the S&P 500 Index is very high, on the order of 0.98 depending upon time period,[25] so that betas estimated against one index are likely to be very similar to betas against the other index. Recall that beta is a measure of the correlation of a company's stock returns with the returns on the market.

[24] Adams Direct, p. 35.

[25] The correlation is 0.98 for the period January 1988 to September 2007.

C. THE ECAPM

Q33. The Adams Direct claims that "an ECAPM analysis using adjusted betas rather than raw betas double-counts the empirical effect of historical Betas"[26] and that "The use of Value Line betas in Dr. Vilbert's ECAPM analysis results in an overstatement of the cost of equity."[27] Do you understand the nature of the Adams Direct's concern?

A33. Yes. The Adams Direct does not dispute the fact that the security market line is flatter than predicted by the CAPM nor does it dispute that this can be captured by the ECAPM as modeled in the Vilbert Direct. Indeed, the Adams Direct states the belief that: "If one is going to use the results of the ECAPM to adjust a CAPM result, one must begin in the same place that the ECAPM begins – with raw Betas."[28] This explicitly acknowledges the Adams Direct's acceptance of the validity of the ECAPM relationship. The Adams Direct does dispute, however, the use of *Value Line* betas in conjunction with the ECAPM framework. Specifically, Mr. Adams believes that *Value Line's* adjustment of the estimated betas towards one already captures the ECAPM relationship.

Q34. Is this true?

A34. No. The interpretation of the literature on the ECAPM contained in the Adams Direct is not accurate. Mr. Adams makes the unsubstantiated claim that "the use of a Value Line Beta in a CAPM equation more than adequately compensates for the empirical evidence relied upon by Dr. Vilbert."[29] The argument relies upon the faulty premise that the ECAPM empirical results are formed with "raw betas" and *Value Line* betas are something else. The important point to remember is that the *Value Line* adjustment is made to an *estimated* beta, not the actual underlying beta.[30] If the actual beta were known, adjustment would not be necessary – indeed, there would be no need for

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[26] Adams Direct, p. 22.

[27] *Ibid.*, p. 22.

[28] *Ibid.*, p. 22.

[29] Adams Direct, p. 23, ll. 9-11.

[30] It should be noted that this adjustment is a common one in the industry (e.g., Merill-Lynch, Bloomberg).

estimation at all.[31,32] The purpose of *Value Line* beta adjustment is to compensate for beta estimation error in order to produce as accurate an estimate of the actual (unobservable) beta as possible. Contrary to the claims in the Adams Direct, the empirical research underlying the ECAPM does not describe a relationship between estimated betas (i.e., "raw betas") and expected returns.[33] Instead, these studies typically use an alternative method to correct for sampling errors in order to form unbiased estimates of actual betas.[34] Specifically, they typically employ a sophisticated methodology relying on specially designed portfolios to remove the sampling error. These studies therefore tell us that after adjusting for sampling error as much as possible, there is still a flattening of the security market line relative to the CAPM relationship. So whether one uses an adjustment as done in these studies, or one uses a (2/3, 1/3) weighting as done by *Value Line* to transform raw beta estimates into unbiased estimates of true betas, an adjustment is still unaccounted for in the security market line. This point is particularly clear from the results in the article by Litzenberger, Ramaswamy, and Sosin (1980), which explicitly uses both "raw" and "adjusted" betas to map the empirical market line. With "raw" betas, the results support the use of a 3.912 percent alpha factor, whereas with adjusted betas, this alpha factor is about 1.932 percent.[35] In other words, even if the actual beta of a stock were known, an "alpha" term of almost 2 percent would still be necessary to capture the empirical relationship between individual security excess

[31] If the actual beta were unchanging, then an over-estimate of beta in one time period will make it more likely that an underestimate will be observed in the next – which results in the regression towards mean phenomenon. There is also evidence that betas of continuing firms tend to trend towards one. Together, these suggest that historical betas are biased estimators of true betas – using the *Value Line* type adjustment has been shown to be a very good estimator of true betas in this circumstance.

[32] Professor Blume first documented the need for the *Value Line* style adjustment. See Blume, Marshall E. (1971), "On the Assessment of Risk," *The Journal of Finance*, 26(1), pp. 785-795. The empirical fact has been replicated and widely acknowledged ever since.

[33] A representative list of articles that support the ECAPM approach is included in Appendix C, Table No. MJV-C1 included in the Vilbert Direct. See also "The Capital Asset Pricing Model: Theory and Evidence," Eugene F. Fama and Kenneth R. French, *The Journal of Economic Perspectives*, Vol. 18, No. 3 (Summer, 2004), pp. 25-46.

[34] Litzenberger, Robert H. and Krishna Ramaswamy and Howard Sosin. (1980), "On the CAPM Approach to Estimation of a Public Utility's Cost of Equity Capital," *The Journal of Finance* 35 (2), pp. 369-387.

[35] Although one might suggest that one should use the same portfolio methodology as in the papers instead of the *Value Line* adjustment, this is cannot be used to provide an unbiased estimate of an individual company's beta without excessive complication (i.e., it is designed for portfolios).

returns and market excess returns. This is precisely what I have done in the Vilbert Direct.

IV. DETERMINING THE OHIO EDUs' COSTS OF EQUITY

Q35. Mr. Adams claims that his recommended return on equity and resulting overall weighted-average cost of capital is reasonable because it is consistent with historical returns on total capital earned by a group of electric utilities covered by *Value Line.* Are the returns reported by *Value Line* a relevant comparison for this rate case?

A35. No. There are several problems with the return comparisons in Tables 6 and 7 of the Adams Direct. First, the realized returns listed are those of FirstEnergy and not those of the Companies. Second, the historical returns are not necessarily compatible with those required going forward, and third, the method of calculating these returns makes them meaningless for comparison to the required returns for the regulated companies.

Q36. Do you have any comments on the level of the recommended return on equity?

A36. Yes. The Adams Direct recommends a cost of equity below what is the norm for investment grade rated public utilities which in and of itself indicates that the recommendation is too low. The 9.26 percent return on equity that Adams Direct recommends is well below the median return on equity for utilities that have a BBB credit rating as determined by Standard & Poor's.[36] This is an indication that the recommendation is likely to be viewed as very low by the investment community which is troublesome given the planned capital expenditure by the Ohio EDUs of almost $1.8 billion through 2011.[37] In this regard it is noteworthy that while Moody's Investors Services, Inc. ("Moody's) rates Ohio Edison Company Baa2, both The Toledo Edison Company and The Cleveland Electric Illuminating Company have Baa3 credit ratings by Moody's. The Baa3 rating corresponds to the lowest investment grade rating from Moody's.[38] In the current environment of substantial need for infrastructure expenditure

[36] Standard & Poor's, Corporate Ratings Criteria 2007, p. 43.

[37] Actual and forecast for the period 2006 to 2011, FirstEnergy 2006 10-K, p. 12.

[38] Direct Testimony of James F. Pearson on behalf of the Ohio EDUs ("Pearson Direct"), pp. 6-7.

and "[m]ore-expensive and less-available credit",[39] setting the allowed rate of return below what investors expect is likely to hurt not only the Companies but in the long run consumers as well, because the funds for needed investments may be more costly, more difficult to obtain, or both in today's credit markets. Given that two of the three Ohio EDUs are at the bottom at the investment grade credit ratings scale, it is essential that the Ohio EDUs' credit ratings remain investment grade in order to maintain full access to capital markets.

Q37. Please elaborate on need to access capital markets.

A37. The September 28, 2007 *Value Line* report points to the need for substantial investment in generation and transmission,[40] a point also mentioned in several reports commissioned by the *Edison Electric Institute,*[41,42] but the industry is in a period of great uncertainty. For example, the prices of fossil fuels have increased dramatically and have become much more volatile over the last few years. Construction prices for all facilities have recently increased rapidly, and uncertainties exist about how the rise in prices will affect the infrastructure investment strategy:

> However, rising construction costs will put additional upward pressure on retail rates over time, and may alter the pace and composition of investments going forward. The overall impact on the industry and on customers, however, will be borne out in various ways, depending on how utilities, markets and regulators respond to these cost increases.[43]

Second, public concern with environmental sustainability and the need for renewable sources of energy has led to the adoption in many states of renewable generation requirements.[44] It seems certain that environmental concerns will increase in the future and may lead to new restrictions on emissions from power plants, but the impact of these

[39] Testimony of Chairman Ben S. Bernanke, "The Economic Outlook," before the Committee on the Budget, U.S. House of Representatives, January 17, 2008.

[40] Electric Utility Industry Report, *Value Line Investment Survey*, Plus Edition, as of September 28, 2007.

[41] Basheda, Gregory et al., "*Why Are Electricity Prices Increasing: An Industry-Wide Perspective*", report prepared for *The Edison Foundation* (June 2006).

[42] Chupka, Mark and Gregory Basheda, *Rising Utility Construction Costs: Sources and Impacts*, report prepared for *The Edison Foundation* (September 2007).

[43] *Ibid.*, p. 31.

[44] "The Impact of a Federal Renewable Portfolio Standard," North American Power Service Insight, Wood Mackenzie, February 2007.

concerns on renewable energy requirements and restrictions on green house gases is uncertain. These uncertainties are a clear source of risks for electric utility investors. For example, at the Federal level, the House passed a bill this summer proposing a 15 percent renewable energy requirement by 2020, while an earlier Senate bill on energy did not include a similar requirement.[45] Clearly, environmental issues are an important source of uncertainty about future costs and regulation, and increase the risk of regulated electric utilities.

Q38. Please summarize your conclusions regarding the stability of the electric utility industry at this time.

A38. The future development of the electric industry is uncertain at this time, and the natural gas industry must deal with rapidly increasing commodity prices and decreasing average consumption so the stable conditions necessary for the reliable implementation of the DCF model are not present at this time for either industry. The future structure of the electric utility industry is far from certain, and the uncertainty regarding the future direction of the electric industry makes access to capital markets more difficult. The industry faces the need for substantial capital investment going forward to meet the challenges of new environmental and safety standards as well as the need for conservation. Acquiring the capital necessary for the required investments will require a supportive regulatory environment including an adequate return on equity.

Q39. Aren't most of the factors leading to instability in the electric industry factors that affect generation or transmission only and as such would not be relevant to the risk of the Ohio EDUs?

A39. No. While many of the risks specifically affect generation, the risks are not restricted to that portion of the industry, and investors are well aware of the turmoil and uncertainty in the electric industry. Although generation is not part of the Ohio EDUs rate base, the Companies have a Provider of Last Resort ("POLR") obligation which is accompanied by a great deal of uncertainty at this time. To the extent that the mechanisms for the recovery of the costs of procuring power for customers have not been resolved, the

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[45] These pieces of legislation have been widely reported in the national press. For a specific reference, see *Edison Electric Institute* press release of August 4, 2007, available at http://www.eei.org/newsroom/press_releases/070804.htm.

uncertainty throughout the electric industry and particularly in the cost of power will increase the risk and uncertainty of the Ohio EDUs.

Q40. Are there other issues with how the Adams Direct arrived at its cost of equity recommendation?

A40. Yes. Mr. Adams does not address Ohio specific risk factors in his testimony. As I explained in my Supplemental Testimony, the fact that the Ohio legislature is considering legislation that may affect competition in Ohio adds uncertainty to the Ohio EDUs operating environment. In the Vilbert Supplemental, I discussed the potential impact of the legislation and concluded that not considering these factors will likely lead to an underestimation of the cost of equity. Details are provided in the Vilbert Supplemental at pp. 15-17.

Q41. Are these risk concerns similar to the POLR concerns you noted in the Vilbert Direct.

A41. Yes. POLR obligations may also impose an asymmetric risk on the company which must be recognized and evaluated when drawing cost of capital conclusions from the benchmark samples.

Q42. Mr. Adams also testified about the risk arising from the Ohio EDUs' POLR obligations and whether the pending legislation in Ohio increased the Ohio EDUs' risks.[46] What is your response?

A42. The Ohio EDUs' POLR obligations increase the risk of the Ohio EDUs relative to the sample companies in the Vilbert Direct because the precise mechanisms by which the recovery of the costs of acquiring power for the Companies' customers has not been resolved. The outcome of the pending legislation in Ohio may or may not increase the risk of the Ohio EDUs' POLR obligations, but my point is that the outcome of the legislation as well as the mechanism for acquiring power for customers and recovering the costs of the power have not been finalized. As a result, there is a great deal of uncertainty facing the Ohio EDUs with regard to their POLR obligations. As a general observation, investors dislike uncertainty and demand higher returns in compensation.

[46] Hearing Transcript, February 12, 2008, pp. 70-74.

Q43. Do you have any evidence that POLR risk has been a problem in other jurisdictions?

A43. Yes. The experience of distribution utilities in some other states has not been favorable. Note that the point in the following examples is not whether the regulatory environment in Ohio is similar to that in other states, but rather that investors are well aware of the kinds of things that can go wrong. Investors must make judgments as to the ultimate resolution of the issues in Ohio and will recognize and price the uncertainty of the outcome. For example, in Illinois the legislation arbitrarily renewed a price cap in spite of the fact that the cost of power had increased substantially. As a result, the rating agencies immediately downgraded some of the state's utilities' credit ratings.[47] In Maryland, similar uncertainty occurred regarding the full recovery of the costs of acquiring power as the prices of power increased dramatically.[48] As with a policy of reducing the cost of equity only in an era of declining performance, POLR obligations typically impose significant asymmetric risks on a company's equity returns. All else equal, investors respond to this by lowering the value they place on equity which has a direct impact on the company's cost of capital. To ignore this fact and treat the Companies as if they are of the same business risk (and have the same cost of capital) as the benchmark samples risks a material error in the cost of capital for the Companies.

Q44. But is the risk of the Companies' POLR obligations a topic that should be considered here given the notion that the Commission and/or the legislature will take care of things and not leave the Companies in a bind?

A44. In my opinion, this proceeding should consider the uncertainty and corresponding risk of the Companies' POLR obligations because it is a risk that is relevant to the Companies at this time and will continue to be a risk until the uncertainty is resolved. Although some parties here may have confidence that the POLR issue will be adequately dealt with by the Commission, this confidence does not set the cost of capital – investor expectations and uncertainty does. Since there has been no settlement of this issue as yet, investors

[47] See for example, Moody's Investors Service, Rating Action, "Union Electric Company," 12 March 2007 and "Fitch Downgrades ComEd's Ratings; Remains on Rating Watch Negative," Fitch Ratings, 9 March 2007.

[48] See for example, Fitch Ratings, "U.S. Power and Gas 2007 Outlook for Key Credits," Corporate Finance, December 16, 2006 and "BGE: Cap on Rates May Force Bankruptcy," *Baltimore Business Journal*, February 17, 2006.

still face material uncertainty as to how this issue will ultimately be resolved, when it will be resolved, and even if it will be resolved. This continuing uncertainty means continuing additional risk for investors, which means a higher cost of capital relative to a sample of companies without POLR obligations.

Q45. Do you have any evidence that investors feel this way?

A45. Yes. For example, Moody's Industry Outlook for the U.S. Electric Utility Sector specifically mentions the risk associated with the transformation of the industry in the states that started on the path of restructuring in the late 1990s.[49] Similarly, S&P in its "Top 10 U.S. Electric Utility Credit Issues For 2008 And Beyond," discusses the issue of regulatory and legislative backlash against rising energy prices as a risk for investors and notes "[l]ooming battles over transition rules in Ohio and Pennsylvania may not be as contentious [as those in Maryland and Illinois], but there is risk that electric providers could be harmed."[50] Fitch Ratings also notes that "[e]lectric utilities that emerge from rate freezes or multi-year tariff settlements or subject to disproportionate increases in costs and in greatest need of tariff increases remain most at risk. The risk is heightened by the convergence of rising costs for fuel, equipment and maintenance materials, pension and medical benefits, and infrastructure investments."[51]

Q46. But if you consider POLR obligations as a basis for moving towards the higher end of a cost of equity range, should you not also consider mechanisms that reduce the risks faced by the Companies?

A46. If such mechanisms existed and actually reduced the systematic risk of the Companies, then certainly they should be considered as well.

Q47. The Solganick Direct identifies the new rate design proposal by the Companies as one such mechanism. In fact, Mr. Solganick recommends reducing the recommended cost of equity by 50 basis points for the cost of service allocation to a specific set of customers because of the rate design supposed reduction in the

[49] "Industry Outlook – U.S. Electric Utility Sector," January 2008, Moody's Corporate Finance, pp. 7-9.

[50] "Top 10 U.S. Electric Utility Credit Issues For 2008 And Beyond," Standard & Poor's Ratings Direct, January 28, 2008, p.3.

[51] U.S. Utilities, Power and Gas 2008 Outlook," Fitch Ratings, Corporates, December 11, 2007, p.5.

Companies' business risks.[52] Do you believe that this reduction in the cost of equity is appropriate?

A47. No. First, I disagree with the claim that this mechanism reduces the risk that is *relevant* to the required rate of return on equity. The Solganick Direct draws a parallel between the new rate design policy and decoupling mechanisms observed in other industries. Based upon the assumed similarity, the Solganick Direct then argues that because the adoption of decoupling mechanisms in other industries sometimes results in a reduction in the allowed return on equity that a reduction of 50 basis points is appropriate here.[53] The Solganick Direct provides no evidence that the Companies' new rate design proposal will reduce the Companies' systematic risk, i.e., the risk that affects the cost of capital. It merely asserts that risk will be reduced, but the cost of capital is only affected by changes in *systematic* risk, as described in the Vilbert Direct.[54] Without such evidence of a reduction in systematic risk, a reduction is the cost of equity is not warranted. Second, the Solganick Direct's recommendation is a selective adjustment to one particular class of customers based upon one particular revision in the rate design for that one class of customers without consideration of the totality of the risks for that class of customers compared to the totality of risks for all classes of customers. I believe that such a selective adjustment to the cost of service for one particular class of customers is not warranted and likely to lead to endless debates about the relative risk of one class of customers compared to another. Such selective rate making should be rejected.

Q48. Does the fact that you have not addressed everything discussed in the Adams Direct, the Cahaan Direct, or the Solganick Direct imply that you agree with everything you have not addressed?

A48. No, it does not.

Q49. Does this conclude your Rebuttal Testimony?

A49. Yes.

[52] Solganick Direct, pp. 34-35, and 37.

[53] *Ibid.*

[54] Vilbert Direct, Appendix C, pp. 9-10.

[Company Exhibit 13-C]

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio	)	
Edison Company, The Cleveland Electric	)	
Illuminating Company, and The Toledo	)	Case No. 07-551-EL-AIR
Edison Company for Authority to	)	Case No. 07-552-EL-ATA
Increase Rates for Distribution Service,	)	Case No. 07-553-EL-AAM
Modify Certain Accounting Practices	)	Case No. 07-554-EL-UNC
and for Tariff Approvals	)	

REBUTTAL TESTIMONY OF

GREGORY F. HUSSING

ON BEHALF OF

OHIO EDISON COMPANY
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
THE TOLEDO EDISON COMPANY

___ Management policies, practices, and organization

___ Operating income

___ Rate base

___ Allocations

___ Rate of return

_X_ Rates and tariffs

___ Other –Case Overview,
Revenue Requirements
Gross Rev. Conversion Factor

Q. PLEASE STATE YOUR NAME FOR THE RECORD.

A. My name is Gregory F. Hussing.

Q. ARE YOU THE SAME GREGORY F. HUSSING THAT PROVIDED INITIAL, UPDATE AND SUPPLEMENTAL TESTIMONY THAT WAS FILED IN THIS PROCEEDING ON JUNE 7, 2007, AUGUST 6, 2007, AND JANUARY 10, 2008 RESPECTIVELY?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to address issues raised in the direct testimony of witnesses testifying on behalf of Intervening parties

Q. PLEASE IDENTIFY THE WITNESSES THAT YOU WILL BE ADDRESSING.

A. I will address the testimony of Mr. Solganick for the Ohio Schools Council and Mr. Goins for Nucor Marion Steel.

Q. DOES YOUR TESTIMONY APPLY TO ALL THREE OPERATING COMPANIES?

A. Unless otherwise stated, yes, it does.

Q. HAVE YOU REVIEWED MR. SOLGANICK'S TESTIMONY?

A. Yes I have.

Q. DO YOU HAVE ANY CONCERNS REGARDING HIS ANALYSIS?

A. Yes, I have three general concerns.

Q. PLEASE EXPLAIN YOUR FIRST CONCERN.

A. My first concern is Mr. Solganick's sample of schools used to extrapolate results to the total population of schools. Mr. Solganick states in his testimony that he did not select the sample of schools, but was provided the data from the Ohio School Council (OSC). In the Companies' cross examination of his testimony he stated that the sample was randomly selected not by him but by the OSC. But Mr. Solganick's request of OSC that those school accounts should include small, medium, and large accounts suggests that the sample was not randomly selected at all. Mr. Solganick provides no additional information in his testimony to support the notion that the sample was randomly selected. When reviewing his work papers, only 26 school districts out of 249 were used to represent the entire school population, with almost half of the sample data coming from only four districts. In addition, he includes six school accounts that take service on electric space conditioning tariffs, which are available exclusively for electric heating commercial customers. Such accounts are not representative of the population of schools on the whole or typical school usage. Finally, his sample does not include any accounts taking service on the Small School rate in Toledo Edison. It is important to note that, as part of the normal billing process for the Energy for Education program, the OSC was provided the monthly billing information contained in Company Exhibit 20, specifically including identification of the billing period and measured demands. During cross examination, Mr. Solganick confirmed that his conclusions were based on this sample. Therefore, Mr. Solganick's conclusion set forth in his testimony and Exhibit HS-7cannot reasonably be relied upon as evidence of the demand characteristics of the total population of schools.

Q. WHAT IS YOUR SECOND CONCERN?

A. On page 27 and in Exhibit HS-6 of his testimony, Mr. Solganick presents an analysis of energy usage of schools included in his sample. He concludes, "This demonstrates that on an energy basis, school consumption is focused on the instructional school year rather than the Companies' peak summer periods."[1] Energy consumption is not necessarily indicative of peak demands. Lower or higher energy consumption does not necessarily indicate lower or higher demands. For example a school facility in which the air-conditioning was used just once during the month may have the same monthly billed demand as if the air-conditioning was used every day. However, the energy consumption for the two months would be different. But in the present case an analysis of usage would be unnecessary because the vast majority of schools have demand meters.

Q. WHAT IS YOUR THIRD CONCERN WITH MR. SOLGANICK'S ANALYSIS?

A. I believe his average demand ratios displayed in Exhibit HS-7 are misleading and if relied upon would lead to improper conclusions. He calculates a monthly demand ratio for each school account in his sample by dividing the billing demand for a particular month by the peak billing demand for the 12 month period. He refers to the collection of demand ratios from each of the schools for a given month as a "billing set". The average demand ratio for a billing set (month) as calculated by Mr. Solganick in his final results are a simple average of the individual school's demand ratios, that force each school to have the same weighting *regardless of the magnitude of the schools actual demand.*. For example, according to Mr. Solganick's analysis a school with a demand of 10 kW impacts his final average demand ratio as much as a school with a demand of 800 kW. In order to show the difference between an average-demand ratio which does not take into consideration the magnitude of the schools actual demand and a weighted-demand ratio that accounts for the magnitude of the schools actual demand I have created a set of tables. For illustrative purposes Table 1 below displays the monthly demands of three example schools (named "Small", "Medium", and "Large"). Note that these are individual customers and not a group of customers. From the monthly data for each of the schools, the average-demand ratios for each school in the "billing sets" of Month A, Month B, and Month C as shown in Table 2, were calculated, for comparative purposes, in the same fashion as Mr. Solganick performed in his calculations used in his Exhibit HS-7.

[1] Sogalnick testimony, page 27, lines 9-11.

Table 1 - Demands – KW					
Month	Large	Medium	Small	Total	Weighted Demand Ratio
(1)	(2)	(3)	(4)	(5)	(6)
A	800	160	4	964	1.00
B	200	240	10	450	0.47
C	400	400	10	810	0.84
Maximum	800	400	10	964	

Table 1 - Column 6 shows the results of creating a weighted-demand ratio. It is calculated by dividing each month's total demand (Column 5; sum of the three schools demands in columns 2-4) to the maximum month's total demand. The larger the ratio the greater the total of the demands of the three customers for a given month. This table accounts for the magnitude of each school's monthly demand.

Table 2 – Average Demand Ratios (Similar to Exhibit HS-7)				
Billing Set	Large	Medium	Small	Average Demand Ratio
(1)	(2)	(3)	(4)	(5)
A	1.00	0.40	0.40	0.60
B	0.25	0.60	1.00	0.62
C	0.50	1.00	1.00	0.83

Table 2-Column 2 was calculated by dividing the monthly demand in Table 1 by the maximum demand for the same column. For example the value of .25 was calculated by dividing the demand of 200 by the demand of 800. Table 2-Column 3 and 4 were done in a similar fashion. Table 2-Column 5 is the non-weighted average of the schools' demand ratios for each month, which is a simple average of columns 2-4. For example the value of .60 is equal to the sum of 1.00 + 0.40 + 0.40 divided by three. From this column Mr. Solganick would conclude that the peak demand occurs in Month C. Since this table does not account for the magnitude of each school's billing demand, different conclusions are drawn concerning the relative magnitude of peak demands for each month as compared to those that are drawn from Table 1. For example, one would correctly conclude from Table 1 that schools peak in Month A, while Table 2 makes it appear as though they peak in Month C. A review of the hypothetical demand data in Table 1 leads to the correct conclusion that the schools as a group indeed did peak in Month A and not in Month C. Based upon Mr. Solganick's average-demand ratio methodology, I believe his Exhibit HS-7 is flawed and should not be used in any school analysis.

Q. HAVE YOU PERFORMED AN ANALYIS ADDESSING YOUR CONCERNS OF MR. SOLGANICK'S SAMPLE DATA AND HIS USE OF A NON-WEIGHTED DEMAND RATIO METHODOLIGY?

A. Yes, instead of relying on sampling, I used actual data from 1,500 of the OSC accounts under the Energy for Education program. In addition, I performed an analysis that reflected the sum of the school loads to create monthly weighted demand ratios.

Q. HAVE YOU PREPARED A TABLE THAT DEPICTS THE AGGREGATE DEMANDS AND THE WEIGHTED DEMAND RATIOS FOR THE COMPANIES ON A COMBINED BASIS?

A. Yes, it is marked as Table 3 below, and represents data from 1,500 OSC accounts that participate in the Energy for Education program.

Table 3	All Companies - TE, OE, and CEI		
Period	Number of Customers	Sum of Non-Coincident Demand (NCD) in MW	Weighted Demand Ratio
Aug-06	1,500	233	0.91
Sep-06	1,500	256	0.99
Oct-06	1,500	247	0.96
Nov-06	1,500	227	0.88
Dec-07	1,500	223	0.87
Jan-07	1,500	215	0.84
Feb-07	1,500	218	0.85
Mar-07	1,500	229	0.89
Apr-07	1,500	235	0.91
May-07	1,500	257	1.00
Jun-07	1,500	235	0.91
Jul-07	1,500	193	0.75

Q. WHAT ARE YOUR CONCLUSIONS BASED UPON TABLE 3?

A. I conclude that the aggregate monthly billing demands of schools in both summer and non-summer months are not appreciably different as Mr. Solganick concluded, and therefore I recommend that the Commission not adopt Mr. Solganick's recommendation for a unique rate adjustment for school accounts.

Q. IS IT APPROPRIATE TO INCLUDE SCHOOLS IN THE GENERAL SERVICE RATE CLASSES?

A. Yes. We have chosen to group general service customers using the point of service voltage level as the criteria for determining rate classes. In this respect, schools are identical to the other customers included in the general service rate class. Mr. Solganick advocates a direction of increased special interest rates based upon identity of customer that is not consistent with a goal of simplified rate design and service voltage-based distribution rates proposed in this case. Subgroup pricing would result in additional rate schedules and added complexity. In addition, rate schedules specifically designed for schools are not always utilized by the schools. This is evident by the fact that approximately 38% of schools in CEI and 37% of schools in TE that take part in the Energy for Education Program do not take service currently under a school rate, but rather under another general service schedule. The Companies recommended distribution rate structure is rational and appropriate for the distribution rate design in this case.

Q. WHAT IS THE TREND ACROSS OHIO RELATIVE TO SPECIFIC SCHOOL RATES?

A. First, Ohio Edison has never had a specific school rate. Further, the number of schools on school rates have been diminishing in Ohio as reflected in the tariffs of Dayton Power & Light and Ohio Power. Both companies school rates are in the process of elimination, with Ohio Power's rate schedule expiring at the end of 2008, as approved by the PUCO, and Dayton Power & Light's school rate having been grandfathered for many years.

Q. HOW DO THE SCHOOLS IN OHIO EDISON SERVICE TERRITORY CURRENTLY TAKE SERVICE ?

A. The schools in Ohio Edison service territory utilize two different rates, General Service Secondary and General Service Large. The schools that take service from secondary voltages are served under General Service Secondary. The schools that take primary service are served under General Service Large-Primary. This is similar to the rate classifications which we have proposed for all three companies in this case.

Q. DO THE COMPANIES ADVOCATE THAT SCHOOLS BE PERMITTED TO TAKE SERVICE UNDER THE BUSINESS DISTRIBUTION CREDIT RIDER?

A. No, unless the school account takes service under a rate schedule listed on the Business Distribution Credit Rider (BDCR) as of December 31, 2008. The BDCR is designed for end-use electric heating processes. Therefore it would be inappropriate to use this Rider for non-heating loads. If the rider were applied to schools, the cost responsibility shift to other general service customers would be significant. For example, if only the schools that are presently under the Companies' Energy for Education program were added to the Business Distribution Credit Rider, it is estimated that over $10.6 million dollars would need to be recovered from other customers to pay for the additional discount. If all school accounts were included the amount of the revenue shift would be much larger.

Q. HOW DOES THE STIPULATION ON REVENUE DISTRIBUTION AFFECT THE PERCENT INCREASES FOR TOLEDO EDISON GENERAL SERVICE CUSTOMERS?

A. The Stipulation reduces the proposed distribution rate increase for the Toledo Edison General Service Secondary rate class by approximately 10%, as compared to the Company's proposal as filed.

Q. HAVE YOU REVIEWED MR. SOLGANICK'S ANALYSIS OF THE NET EFFECT OF THE COMPANIES' PROPOSED CONTRACT DEMAND PROVISIONS?

A. Yes I have.

Q. WHAT IS YOUR FIRST CONCERN?

A. Based upon the testimony of several witnesses in this proceeding, it appears that the language in the proposed General Service tariffs related to Contract Demand has caused confusion as to the Companies' intentions regarding implementation of that provision.

Q. ARE THE COMPANIES PROPOSING TO CLARIFY THE CONTRACT DEMAND LANGUAGE IN ITS PROPOSED GENERAL SERVICE TARIFFS?

A. Yes. The Companies believe the following language is more precise and better reflects how the Contract Demand provision will be applied to customers. Existing customers generally will not be affected by the new Contract Demand language, unless they experience a significant change in service. Existing customers with a Contract Demand will remain at their existing Contract Demand level, as it exists on December 31, 2008. The following language will supplant the existing Contract Demand language currently set forth in the Companies' proposed General Service tariffs:

"The Contract Demand shall be specified in the contract for electric service of customers establishing service after December 31, 2008 and of customers requiring or requesting a significant change in service. The Contract Demand shall be 60% of the customer's expected, typical monthly peak load. Customers with a Contract Demand on December 31, 2008 will remain at that existing Contract Demand level, until such time as they reestablish service or request or require a significant change in service."

I have included an example of these changes to the contract demand language in the proposed General Service tariff sheets as Attachment GFH-1.

Q. IS MR. SOLGANICK'S CONCERN THAT AN INADVERTENT PEAK DEMAND WILL INCREASE THE LEVEL OF THE CONTRACT DEMAND VALID ?

A. No. An inadvertent peak demand would have no effect on the determination of the level of the Contract Demand since it would not reflect the customers expected typical demand. Therefore, his Exhibit HS-9 does not accurately reflect the

Companies' intended application of the Contract Demand provision of the proposed tariffs.

Q. DO YOU AGREE MR. SOLGANICK'S RECOMMENDATION THAT FOR SCHOOL FACILITIES WITH A DEMONSTRABLE SEASONALITY THAT THE CONTRACT DEMAND SHOULD NOT APPLY DURING THE MONTHS OF JUNE, JULY, AND AUGUST?

A. No, the Companies' distribution facilities are fixed assets that do not vary with season. Consequently, the proposed distribution tariffs are designed to recover costs over an annual period, not by season.

Q. HAVE YOU REVIEWED MR. GOINS' TESTIMONY?

A. Yes, I have.

Q. DO YOU AGREE WITH MR. GOINS THAT GENERATION SERVICE ISSUES SHOULD BE ADDRESSED IN THIS CASE?

A. No, because this is a distribution service case.

Q. DO YOU AGREE WITH MR. GOINS THAT INTERRUPTIBLE SERVICE PROVIDES BENEFITS TO THE DISTRIBUTION SYSTEM?

A. No, distribution service is predominantly asset-based. The costs incurred to provide distribution service to customers are predominantly fixed and do not vary with the level of customer usage, but rather are more related to the level of investment associated with that service. The majority of the Mr. Goins' testimony describes non-distribution related aspects of electric service. The only distribution related comment made is that under certain conditions, interruptible load may create distribution-related benefits. Once again, distribution costs are predominantly fixed to serve the load requirements of the customer during interruptible and non-interruptible operation. Interruptible customers have the option, and historically have exercised that option, to buy-through during economic curtailment events. With the ability and history of such customers operating during economic interruptions, no distribution benefits are realized

Q. DO YOU AGREE WITH MR. GOINS' PROPOSED CHANGE TO A 60 MINUTE BILLING DEMAND?

A. No, the Companies must incur the level of distribution investment to provide facilities of adequate capacity needed to provide service to the customer at their peak demand. Both the Companies' existing and proposed General Service rates are demand based in order to best reflect the underlying cost structure of the required distribution facilities to serve the customers' needs. The Companies, consistent with long standing standard utility practice, utilize demand periods such as 30 minutes or shorter to better measure the actual peak occurrence that the distribution facilities will be required to serve. A demand interval of 60 minutes will average the magnitude of the customer's actual peak demand. A 30 minute demand interval better reflects the magnitude of the customer's actual peak demand, thus creating a better matching between the distribution investment required to serve the customer and the customer's actual demand placed on the system. Further, switching from the standard 30 minute demand interval to a 60 minute period would also require the unnecessary replacement of all the general service meters now in service. Such an undertaking would be a significant project and create significant additional expenses. Finally, if the demand interval were increased from the proposed tariffs, as filed, it would cause the billing units to decrease and thus the proposed charges would increase because demands from a 60-minute interval would always be lower than or equal to demands from a 30-minute interval.

Q. DO YOU AGREE WITH MR. GOINS' PROPOSED DETERMINATION OF BILLING DEMAND?

A. No, the witness recommends that billing demand provisions for transmission and sub-transmission customers be changed. He advocates calculating the monthly billing demand for such customers to reflect the higher of a customer's maximum 60-minute demand during system peak hours or a specified percentage such as 60 percent of the customer's highest billing demand in the preceding 11 months. As discussed above, an inadvertent peak created by the customer will not establish a minimum demand for determination of future billing loads since that inadvertent peak would not represent the expected, typical monthly demand. In addition, the Companies' distribution facilities are fixed assets that do not vary with time or season, thus the timing of the customer's monthly peak demand is inconsequential, whether it occurs during system peak hours or not.

Q. IS THERE A NEED TO UPDATE CONTRACTED LOAD LEVELS WHEN A CUSTOMER INCREASES LOAD?

A. Yes. Mr. Goins also objects to the proposed tariffs providing the Companies the ability to require a customer with added load to enter into a new contract for electric service. It is important that the Companies have an updated contract clearly stating new load requirements of the customer in order to confirm the customer and the

Companies have the same understanding regarding load levels. This is necessary to ensure effective and adequate capacity planning by the Companies.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, at this time.

GENERAL SERVICE - SECONDARY (RATE "GS")

AVAILABILITY:

Available to general service installations requiring Secondary Service. Secondary Service is defined in the Company's Electric Service Regulations. Choice of voltage shall be at the option of the Company.

SERVICE:

All service under this rate schedule will be served through one meter for each installation.

RATE:

All charges under this rate schedule shall be calculated as described below and charged on a monthly basis.

Distribution Charges:	
Service Charge:	$7.00
Capacity Charge:	
Up to 5 kW of billing demand	$18.00
For each kW over 5 kW of billing demand	$6.653
Reactive Demand Charge applicable to three phase customers only	
For each rkVA of reactive billing demand	$0.36

BILLING DEMAND:

The billing demand for the month shall be the greatest of:

1. Measured Demand, being the highest thirty (30) minute integrated kW
2. 5.0 kW
3. The Contract Demand

Measured Demand shall be estimated for all customers not having a demand meter and using over 1,000 kWh per month by applying a factor of 200 by the following formula: Measured Demand = kWh / 200.

~~The Contract Demand shall be specified in the Contract for electric service, which shall reflect the customer's expected, typical monthly peak load.~~

REACTIVE BILLING DEMAND:

For installations metered with reactive energy metering, the reactive billing demand in rkVA for the month shall be determined by multiplying the Measured Demand by the ratio of the measured lagging reactive kilovoltampere hours to the measured kilowatthours by the following formula: rkVA = Measured Demand X (measured lagging reactive kilovoltampere hours ÷ measured kilowatthours). For all other installations, the reactive billing demand shall be the integrated reactive demand occurring coincident with the Measured Demand.

GENERAL SERVICE - SECONDARY (RATE "GS")

CONTRACT:

Electric service hereunder shall be furnished in accordance with a written contract, at the Company's discretion, which by its term shall be in full force and effect for a minimum period of one year and shall continue in force thereafter from year to year unless either party shall give to the other not less than 60 days notice in writing prior to the expiration date of any said yearly periods that the contract shall be terminated at the expiration date of said yearly period. When a contract is terminated in the manner provided herein, the service will be discontinued.

The Contract Demand shall be specified in the contract for electric service of customers establishing service after December 31, 2008 and of customers requiring or requesting a significant change in service. The Contract Demand shall be 60% of the customer's expected, typical monthly peak load. Customers with a Contract Demand on December 31, 2008 will remain at that existing Contract Demand level, until such time as they reestablish service or request or require a significant change in service.

~~When the service is reestablished for the benefit of the same customer at the same location within a period of less than twelve months from the date when service was discontinued, all of the conditions during the previous contract period applicable to billing shall apply and the contract demand shall not be less than 60% of the highest billing demand during the last eleven months of the previous contract period.~~

If the customer's capacity or service requirements increase, the Company, at its sole and exlusive judgement, may at any time require the customer to enter into a new contract for electric service.

GENERAL SERVICE - PRIMARY (RATE "GP")

AVAILABILITY:

Available to general service installations requiring Primary Service. Primary Service is defined in the Company's Electric Service Regulations. Choice of voltage shall be at the option of the Company.

SERVICE:

All service under this rate schedule will be served through one meter for each installation.

The customer will be responsible for all transforming, controlling, regulating and protective equipment and its operation and maintenance.

RATE:

All charges under this rate schedule shall be applied as described below and charged on a monthly basis.

Distribution Charges:	
Service Charge:	$150.00
Capacity Charge:	
For each kW of billing demand	$3.052
Reactive Demand Charge applicable to three phase customers only	
For each rkVA of reactive billing demand	$0.36

BILLING DEMAND:

The billing demand for the month shall be the greatest of:

1. Measured Demand, being the highest thirty (30) minute integrated kW
2. 30.0 kW
3. The Contract Demand

~~The Contract Demand shall be specified in the Contract for electric service, which shall reflect the customer's expected, typical monthly peak load.~~

REACTIVE BILLING DEMAND:

For installations metered with reactive energy metering, the reactive billing demand in rkVA for the month shall be determined by multiplying the Measured Demand by the ratio of the measured lagging reactive kilovoltampere hours to the measured kilowatthours by the following formula: rkVA = Measured Demand X (measured lagging reactive kilovoltampere hours ÷ measured kilowatthours). For all other installations, the reactive billing demand shall be the integrated reactive demand occurring coincident with the Measured Demand.

GENERAL SERVICE - PRIMARY (RATE "GP")

APPLICABLE RIDERS:

The charges included with the applicable riders as designated on the Summary Rider, Tariff Sheet 80 shall be added to the Rates and charges set forth above.

ADJUSTMENT FOR SECONDARY METERING:

The Company reserves the right to install the metering equipment on either the primary or secondary side of the transformers serving the customer, and when installed on the secondary side, at the Company's option, the Company shall correct for transformer losses by one of the two following methods: 1.) by using compensating-metering equipment or 2.) by increasing all demand and energy registrations by 2% each.

SPECIAL METERS:

Time-Of-Day and Interval Metering is available from the Company. Charges for such service are specified in the Miscellaneous Charges, Tariff Sheet 75.

DUPLICATE CIRCUIT SERVICE:

When service is furnished to provide redundancy to the Company's main service as requested by the customer, a contract demand shall be established by mutual agreement and shall be specified in the service contract. Such installations shall be considered Premium and shall be a separate account from the customer's main service.

ELECTRIC SERVICE REGULATIONS:

The Company's Electric Service Regulations shall apply to the installation and use of electric service.

CONTRACT:

Electric service hereunder shall be furnished in accordance with a written contract, which by its term shall be in full force and effect for a minimum period of two years and shall continue in force thereafter from year to year unless either party shall give to the other not less than 60 days notice in writing prior to the expiration date of any said yearly periods that the contract shall be terminated at the expiration date of said yearly period. When a contract is terminated in the manner provided herein, the service will be discontinued.

The Contract Demand shall be specified in the contract for electric service of customers establishing service after December 31, 2008 and of customers requiring or requesting a significant change in service. The Contract Demand shall be 60% of the customer's expected, typical monthly peak load. Customers with a Contract Demand on December 31, 2008 will remain at that existing Contract Demand level, until such time as they reestablish service or request or require a significant change in service.

~~When the service is reestablished for the benefit of the same customer at the same location within a period of less than twelve months from the date when service was discontinued, all of the conditions during the previous contract period applicable to billing shall apply and the contract demand shall not be less than 60% of the highest billing demand during the last eleven months of the previous contract period.~~

GENERAL SERVICE - PRIMARY (RATE "GP")

If the customer's capacity or service requirements increase, the Company, at its sole and exlusive judgement, may at any time require the customer to enter into a new contract for electric service.

GENERAL SERVICE - SUBTRANSMISSION (RATE "GSU")

AVAILABILITY:

Available to general service installations requiring Subtransmission Service. Subtransmission Service is defined in the Company's Electric Service Regulations. Choice of voltage shall be at the option of the Company.

SERVICE:

All service under this rate schedule will be served through one meter for each installation.

The customer will be responsible for all transforming, controlling, regulating and protective equipment and its operation and maintenance.

RATE:

All charges under this rate schedule shall be calculated as described below and charged on a monthly basis.

Distribution Charges:

Service Charge:	$200.00
Capacity Charge:	
For Each kVA of billing demand	$1.218

BILLING DEMAND:

The billing demand for the month shall be the greatest of:

1. Measured Demand, being the highest thirty (30) minute integrated kVA
2. 30.0 kVA
3. The Contract Demand

~~The Contract Demand shall be specified in the Contract for electric service, which shall reflect the customer's expected, typical monthly peak load.~~

APPLICABLE RIDERS:

The charges included with the applicable riders as designated on the Summary Rider, Tariff Sheet 80 shall be added to the Rates and charges set forth above.

ADJUSTMENT FOR SECONDARY METERING:

The Company reserves the right to install the metering equipment on either the primary or secondary side of the transformers serving the customer, and when installed on the secondary side, at the Company's option, the Company shall correct for transformer losses by one of the two following methods: 1.) by using compensating-metering equipment or 2.) by increasing all demand and energy registrations by 2% each.

GENERAL SERVICE - SUBTRANSMISSION (RATE "GSU")

SPECIAL METERS:

Time-Of-Day and Interval Metering is available from the Company. Charges for such service are specified in the Miscellaneous Charges, Tariff Sheet 75.

DUPLICATE CIRCUIT SERVICE:

When service is furnished to provide redundancy to the Company's main service as requested by the customer, a contract demand shall be established by mutual agreement and shall be specified in the service contract. Such installations shall be considered Premium and shall be a separate account from the customer's main service.

ELECTRIC SERVICE REGULATIONS:

The Company's Electric Service Regulations shall apply to the installation and use of electric service. The Company's general policy of supplying regulated voltages does not apply to this rate schedule.

CONTRACT:

Electric service hereunder shall be furnished in accordance with a written contract, which by its term shall be in full force and effect for a minimum period of two years and shall continue in force thereafter from year to year unless either party shall give to the other not less than 60 days notice in writing prior to the expiration date of any said yearly periods that the contract shall be terminated at the expiration date of said yearly period. When a contract is terminated in the manner provided herein, the service will be discontinued.

The Contract Demand shall be specified in the contract for electric service of customers establishing service after December 31, 2008 and of customers requiring or requesting a significant change in service. The Contract Demand shall be 60% of the customer's expected, typical monthly peak load. Customers with a Contract Demand on December 31, 2008 will remain at that existing Contract Demand level, until such time as they reestablish service or request or require a significant change in service.

~~When the service is reestablished for the benefit of the same customer at the same location within a period of less than twelve months from the date when service was discontinued, all of the conditions during the previous contract period applicable to billing shall apply and the contract demand shall not be less than 60% of the highest billing demand during the last eleven months of the previous contract period.~~

If the customer's capacity or service requirements increase, the Company, at its sole and exlusive judgement, may at any time require the customer to enter into a new contract for electric service.

GENERAL SERVICE - TRANSMISSION (RATE "GT")

AVAILABILITY:

Available to general service installations requiring Transmission Service. Transmission Service is defined in the Company's Electric Service Regulations. Choice of voltage shall be at the option of the Company.

SERVICE:

All service under this rate schedule will be served through one meter for each installation.

The customer will be responsible for all transforming, controlling, regulating and protective equipment and its operation and maintenance.

RATE:

All charges under this rate schedule shall be calculated as described below and charged on a monthly basis.

Distribution Charges:	
Service Charge:	$320.00
Capacity Charge:	
For Each kVA of billing demand	$0.930

BILLING DEMAND:

The billing demand for the month shall be the greatest of:

1. Measured Demand, being the highest thirty (30) minute integrated kVA.
2. 100.0 kVA
3. The Contract Demand

~~The Contract Demand shall be specified in the Contract for electric service, which shall reflect the customer's expected, typical monthly peak load.~~

APPLICABLE RIDERS:

The charges included with the applicable riders as designated on the Summary Rider, Tariff Sheet 80 shall be added to the Rates and charges set forth above.

ADJUSTMENT FOR SECONDARY METERING:

The Company reserves the right to install the metering equipment on either the primary or secondary side of the transformers serving the customer, and when installed on the secondary side, at the Company's option, the Company shall correct for transformer losses by one of the two following methods: 1.) by using compensating-metering equipment or 2.) by increasing all demand and energy registrations by 2% each.

GENERAL SERVICE - TRANSMISSION (RATE "GT")

SPECIAL METERS:

Time-Of-Day and Interval Metering is available from the Company. Charges for such service are specified in the Miscellaneous Charges, Tariff Sheet 75.

ELECTRIC SERVICE REGULATIONS:

The Company's Electric Service Regulations shall apply to the installation and use of electric service. The Company's general policy of supplying regulated voltages does not apply to this rate schedule.

CONTRACT:

Electric service hereunder shall be furnished in accordance with a written contract, which by its term shall be in full force and effect for a minimum period of one year and shall continue in force thereafter from year to year unless either party shall give to the other not less than 60 days notice in writing prior to the expiration date of any said yearly periods that the contract shall be terminated at the expiration date of said yearly period. When a contract is terminated in the manner provided herein, the service will be discontinued.

The Contract Demand shall be specified in the contract for electric service of customers establishing service after December 31, 2008 and of customers requiring or requesting a significant change in service. The Contract Demand shall be 60% of the customer's expected, typical monthly peak load. Customers with a Contract Demand on December 31, 2008 will remain at that existing Contract Demand level, until such time as they reestablish service or request or require a significant change in service.

~~When the service is reestablished for the benefit of the same customer at the same location within a period of less than twelve months from the date when service was discontinued, all of the conditions during the previous contract period applicable to billing shall apply and the contract demand shall not be less than 60% of the highest billing demand during the last eleven months of the previous contract period.~~

If the customer's capacity or service requirements increase, the Company, at its sole and exlusive judgement, may at any time require the customer to enter into a new contract for electric service.

[Company Exhibit 15-C]

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Increase Rates for Distribution Service, Modify Certain Accounting Practices and for Tariff Approvals	)	Case No. 07-551-EL-AIR Case No. 07-552-EL-ATA Case No. 07-553-EL-AAM Case No. 07-554-EL-UNC

REBUTTAL TESTIMONY OF

KEVIN L. NORRIS

ON BEHALF OF

OHIO EDISON COMPANY
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
THE TOLEDO EDISON COMPANY

___ Management policies, practices, and organization

___ Operating income

___ Rate base

___ Allocations

___ Rate of return

X Rates and tariffs

___ Other

Q. PLEASE STATE YOUR NAME FOR THE RECORD.

A. My name is Kevin L. Norris.

Q. ARE YOU THE SAME KEVIN L. NORRIS THAT PROVIDED INITIAL AND SUPPLEMENTAL TESTIMONY THAT WAS FILED IN THIS PROCEEDING ON JUNE 7, 2007 AND JANUARY 10, 2008 RESPECTIVELY?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to address certain statements made in the Prefiled Testimony of Staff Witness Peter Baker and Staff Witness Barbara Bossart that were each filed with the Commission on January 30, 2008. I will also address the Direct Testimony of Bill Faith, filed on behalf of Ohio Partners for Affordable Energy (OPAE) on January 10, 2008.

Q. DOES YOUR REBUTTAL TESTIMONY APPLY TO ALL THREE OPERATING COMPANIES?

A. Yes, it does.

Q. PLEASE IDENTIFY THE SPECIFIC STATEMENTS THAT YOU WILL BE ADDRESSING IN MR. BAKER'S PREFILED TESTIMONY.

A. I will be addressing Witness Baker's statements related to parallel interconnections that begin on page 8, line 15 of his Prefiled Testimony and continues through page 10.

Q. PLEASE BRIEFLY EXPLAIN

A. First, I think some background information may be helpful. The Staff Report at page 21 for each of the Companies stated that Section VIII.D of the Electric Service Regulations requires customers who want parallel interconnection with the Companies' system to pay for a dedicated telephone line for an interval meter.

Q. IS THIS CORRECT?

A. No, it is not. Section VIII.D of the Electric Service Regulations requires that certain customers with parallel interconnection (whether a net-metering customer or not) provide a direct telephone line to the Companies' load dispatcher. This section does not require a direct telephone line for an interval meter. I am not sure what Mr. Baker is referring to when he uses the term "special electric meter" on page 8 of his testimony. However, the Companies are only seeking to preserve the ability to require certain customers, which may include net metering customers, to provide a direct telephone line to the Companies' load dispatcher.

Q. WHY IS IT IMPORTANT THAT THE TARIFF LANGUAGE ALLOW THE COMPANIES THE OPTION TO REQUIRE A CUSTOMER TO PROVIDE A DIRECT TELEPHONE LINE TO THE COMPANIES LOAD DISPATCHER?

A. This communication link to the Companies' load dispatcher may be needed to communicate critical information related to safety and reliability issues. Such information may include notification of when the customer is coming off line, when the customer is operating at reduced capacity, or when the Companies need the customer to either start up or shut down to support system reliability. The

Companies will not always require this direct telephone line, however, on a case by case basis this information could be crucial

Q. TURNING TO WITNESS BOSSART'S PREFILED TESTIMONY, WHAT SPECIFIC STATEMENTS WILL YOU ADDRESS?

A. I will be addressing Witness Bossart's statements pertaining to the Companies' objection V.a.9 that begins on page 4, line 6 of her Prefiled Testimony and continues through page 5.

Q. PLEASE EXPLAIN.

A. Witness Bossart states on page 4 of her Prefiled Testimony that "Staff believes that this [Field Collection] charge is a collection charge, as the title indicates, not a trip charge". The Companies' position is that the Field Collection Charge is a field charge assessed when the Companies make a field visit for the purpose of attempting to collect on a delinquent account. The Companies' proposal is to charge this Field Collection Charge directly to the customer who caused the expense.

Q. DO YOU AGREE WITH WITNESS BOSSART'S RECOMMENDATION THAT THE COMPANIES ASSESS THE FIELD COLLECTION CHARGE ONLY WHEN PAYMENT IS COLLECTED?

A. No, I do not. Whether payment is collected or service is disconnected, the Companies have incurred the expense of sending a representative to the customer's premises.

Q. WOULD THERE NEED TO BE ANY ADJUSTMENTS MADE TO THE OVERALL REVENUE REQUIREMENTS FROM BASE RATES IF THE FIELD COLLECTION CHARGE IS NOT CHARGED ON EACH VISIT, BUT ONLY WHEN PAYMENT IS RECEIVED?

A. Yes. Since the Companies calculated the miscellaneous revenues (which are included in other revenue and not base rate revenue) based on charging the Field Collection Charge on each visit, the miscellaneous revenues would have to be appropriately adjusted, with an equal corresponding adjustment in the amount of revenues needed from base rates.

Q. WHAT IS THE EFFECT OF NOT CHARGING THE FIELD COLLECTION CHARGE ON EACH VISIT, BUT ONLY WHEN PAYMENT IS RECEIVED?

A. The Field Collection Charge was proposed to require the customer creating avoidable expenses to pay such expenses. The Companies incur expenses each time they make a field visit to a customer (regardless of whether payment is received) to collect the delinquent amount. On some occasions a customer, in an effort to keep the lights on, will request that the Company make an additional visit because the customer expects that funds will be available in the near future. The Companies in most cases will honor this request. However, the result of not charging for the additional visit is that all customers pay for the additional expense the Companies incur to make such visits. The Companies are proposing that the customer requesting the additional visit pay the additional expense.

Q. ARE THERE OTHER STATEMENTS BY WITNESS BOSSART THAT YOU WANT TO ADDRESS?

A. Yes. At page 7 of Witness Bossart's testimony she discusses OPAE's Objection X. This objection (OPAE Objection X) basically claims that the Staff Report requires that all customers pay a $200 temporary service drop, including low income customers who are receiving health and safety services under a utility funded program, when they have electrical upgrades.

Q. WHAT IS YOUR CONCERN WITH WITNESS BOSSART'S TESTIMONY RELATED TO OPAE'S OBJECTION X?

A. I believe both OPAE in raising the objection and Staff in agreeing with it fail to realize that the temporary service drop has not, nor will it be, charged to low income customers who are receiving health and safety services under a utility-funded program for upgrading service.

Q. TURNING NOW TO THE DIRECT TESTIMONY OF OPAE WITNESS FAITH, WHAT ARE YOUR COMMENTS RELATED TO HIS TESTIMONY?

A. Witness Faith's testimony points out the potential negative impacts of payday lenders on families in Ohio. The Companies have not experienced any problems with the use of payday lenders and would like to retain payday lenders as an option for customers to pay their electric service bill.

Q. DO YOU AGREE WITH WITNESS FAITH'S DIRECT TESTIMONY WHERE HE ULTIMATELY RECOMMENDS THAT ALL UTILITIES

AGREE TO CEASE USING PAYDAY LENDERS AS AUTHORIZED PAYMENT STATIONS?

A. No, I do not. Witness Faith ignores the many valid reasons why payday lenders are utilized as authorized payment stations by the Companies.

Q. WHAT ARE SOME OF THE VALID REASONS FOR UTILIZING PAYDAY LENDERS AS AUTHORIZED PAYMENT AGENTS?

A. Payday lenders are utilized because of their stability and number of locations (often near public transportation). In addition, such payday lenders are selectively screened by Western Union and CheckFreePay based on several criteria including experience and recommendations.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

[Company Exhibit 16-C]

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Increase Rates for Distribution Service, Modify Certain Accounting Practices and for Tariff Approvals	)	**Case No. 07-551-EL-AIR** **Case No. 07-552-EL-ATA** **Case No. 07-553-EL-AAM** **Case No. 07-554-EL-UNC**

REBUTTAL TESTIMONY OF

STEVEN E. OUELLETTE

ON BEHALF OF

OHIO EDISON COMPANY
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
THE TOLEDO EDISON COMPANY

__ Management policies, practices, and organization
X Operating Income
__ Rate Base
__ Allocations
__ Rate of Return
X Rates and tariffs
__ Other

Q. PLEASE STATE YOUR NAME FOR THE RECORD.

A. My name is Steven E. Ouellette.

Q. ARE YOU THE SAME STEVEN E. OUELLETTE THAT PROVIDED DIRECT AND SUPPLEMENTAL TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to address the objections to the Staff Report and Direct Testimony of The Office of the Ohio Consumers' Counsel ("OCC") and Ohio Partners for Affordable Energy (OPAE) in regards to Demand Side Management ("DSM") activities and low-income energy efficiency programs.

Q. WHAT DEMAND SIDE MANAGEMENT PROGRAMS DO THE COMPANIES CURRENTLY OFFER IN OHIO?

A. The Companies currently offer the Direct Load Control ("DLC') Program and the Home Performance with Energy Star ("HPES") Program. The implementation of both programs is pursuant to the Rate Certainty Plan Supplemental Stipulation ("RCP Stipulation") in Case 05-1125-EL-ATA.

Q. PLEASE BRIEFLY DISCUSS PROVISIONS OF THE RCP STIPULATION IN REGARDS TO THE DSM PROGRAMS?

A. Pursuant to the RCP Stipulation, the Companies agreed to implement DSM programs for 2006 - 2008 with a budget of $25 million. The Companies also agreed to provide an additional $3 million in funding over the 2007-2008 time period. Any funding not spent during the 2006 - 2008 time frame rolls over for one year. Continuation of either of these DSM programs is subject to the programs meeting a Total Resource Cost ("TRC") Test. In addition, all DSM costs incurred as a result of the implementation of these programs, including lost distribution revenues, are deferred and recovered through the proposed DSM Rider beginning on January 1, 2009 for the Companies.

Q. WHAT IS THE STATUS OF THE DLC PROGRAM AND THE HPES PROGRAM?

A. Due to legal challenges in the RSP and RCP cases, Ohio Supreme Court review of the Commission's action and the associated uncertainty surrounding the RSP and RCP, both programs were implemented as pilots during the latter half of 2007 and are still in their infancy. As of the end of 2007, a portion of the funding remains for the programs to be spent in 2008. It is expected that some funding will remain at the end of the year in 2008, thus extending the programs into 2009.

Q. IN HIS DIRECT TESTIMONY, WILSON GONZALEZ OF THE OCC RECOMMENDS THAT THE COMPANIES SPEND APPROXIMATELY $49 MILLION PER YEAR ON THE CURRENT AND NEW ENERGY EFFICIENCY PROGRAMS STARTING IN 2009. IS THIS LEVEL OF FUNDING AND IMPLEMENTATION OF NEW PROGRAMS APPROPRIATE AT THIS TIME?

A. No. As discussed above and in the Staff Report, the Companies' current DSM programs are in their infancy and it is therefore premature to state whether they are definitively meeting objectives as well as cost versus benefit standards. Participation in the DLC Program and the HPES Program will increase throughout

2008 and the TRC Test will not occur until sometime in the 4th quarter of 2008. Therefore, the Companies will not know the results of the existing DSM initiatives until later in 2008 or early in 2009. These results are critical in that the Companies must know whether the current DSM programs meet their objectives, as well as the results of the cost-effectiveness test and customers' perspectives of the programs' benefits. In addition, it is estimated that there will be sufficient funding remaining at the end of 2008 to roll the programs over into 2009. Therefore, allocating additional funds to the current and/or new programs before the results of existing initiatives are known would be inappropriate.

Q. ARE THERE ADDITIONAL REASONS WHY IMPLEMENTING NEW PROGRAMS IS INAPPROPRIATE AT THIS TIME?

A. Yes. As stated in the Staff Report, it is not yet clear what new state laws, policy initiatives, or regulations may come out of the Governor's proposed energy bill that will impact energy efficiency and DSM efforts. In addition, the Commission has had recent workshops discussing potential DSM programs for the future and how they will fit into Ohio's regulatory environment. With this uncertainty regarding DSM and energy efficiency legislation, it would be imprudent to begin implementing new programs.

Q. IN HIS DIRECT TESTIMONY, WILSON GONZALEZ OF THE OCC RECOMMENDS EXPLORING THE IMPLEMENTATION OF A RESIDENTIAL APPLIANCE PROGRAM (INCLUDING RECYCLING OF REMOVED UNITS) AND A RESIDENTIAL AIR-CONDITIONING PROGRAM. DO YOU AGREE WITH HIS ASSESSMENT?

A. No. The Companies' current HPES Program already offers these services. The HPES Program offers recycling service of refrigerators and window air-conditioning units. In addition, the HPES program offers incentives for customers to upgrade their air-conditioning system to a high-efficiency model.

Q. IN HIS DIRECT TESTIMONY, WILSON GONZALEZ OF THE OCC RECOMMENDS THAT AN ENERGY EFFICIENCY SPENDING LEVEL OF $24.25 PER CUSTOMER IS APPROPRIATE. DO YOU AGREE?

A. No. Varying energy efficiency programs require different levels of investment. In addition, Mr. Gonzalez has provided no evidence or compelling justification that this level of spending would pass a cost-effectiveness TRC Test.

Q. IN HIS DIRECT TESTIMONY, MICAHEL SMALZ OF OPAE RECOMMENDS AN INCREASE IN FUNDING OF $5.5 MILLION FOR LOW-INCOME ENERGY EFFICIENCY PROGRAMS. DO YOU AGREE?

A. No. This level of funding is excessive and unreasonable. Low-income customers receive funds and assistance from multiple state agencies and programs, such as the Percentage of Income Payment Plan. Given the funding provided by the Companies to low-income programs, additional funding for low-income energy efficiency programs from the Companies is not warranted or appropriate at the level suggested by OPAE Witness Smalz.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

[Company Exhibit 17-C]

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio	)	
Edison Company, The Cleveland Electric	)	
Illuminating Company, and The Toledo	)	Case No. 07-551-EL-AIR
Edison Company for Authority to	)	Case No. 07-552-EL-ATA
Increase Rates for Distribution Service,	)	Case No. 07-553-EL-AAM
Modify Certain Accounting Practices	)	Case No. 07-554-EL-UNC
and for Tariff Approvals	)	

REBUTTAL TESTIMONY OF

SUSAN LETTRICH

ON BEHALF OF

OHIO EDISON COMPANY
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
THE TOLEDO EDISON COMPANY

____ Management policies, practices, and organization

____ Operating income

____ Rate base

____ Allocations

____ Rate of return

____ Rates and tariffs

_X_ Other –System Safety and Reliability

Q. PLEASE STATE YOUR NAME FOR THE RECORD.

A. My name is Susan Lettrich.

Q. ARE YOU THE SAME SUSAN LETTRICH THAT PROVIDED DIRECT TESTIMONY THAT WAS FILED IN THIS PROCEEDING ON JANUARY 10, 2008?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to address issues raised in the testimony of the witness testifying on behalf of The Office of the Ohio Consumers' Counsel ("the OCC") and the witnesses testifying on behalf of the Staff of the Commission ("Staff").

Q. PLEASE IDENTIFY THE WITNESSES THAT YOU WILL BE ADDRESSING.

A. I will be addressing the Direct Testimony of David W. Cleaver filed in this proceeding on behalf of the OCC on January 10, 2008. I will also address the Pre-filed Testimony of Mario F. Scaramellino, Jr., Duane A. Roberts and Peter K. Baker, each filed in this proceeding on behalf of the Staff on January 30, 2008, February 1, 2008 and January 30, 2008, respectively.

Q. DOES YOUR REBUTTAL TESTIMONY APPLY TO ALL THREE COMPANIES?

A. Unless otherwise stated, yes, it does.

Q. HAVE YOU REVIEWED MR. CLEAVER'S DIRECT TESTIMONY?

A. Yes, I have.

Q. WHAT WILL YOU ADDRESS FROM MR. CLEAVER'S DIRECT TESTIMONY?

A. I will address the OCC position pertaining to the Companies' reliability, record keeping practices, and practice to deal with trees outside the right-of-way.

Q. PLEASE STATE THE OCC POSITION ON RELIABILITY?

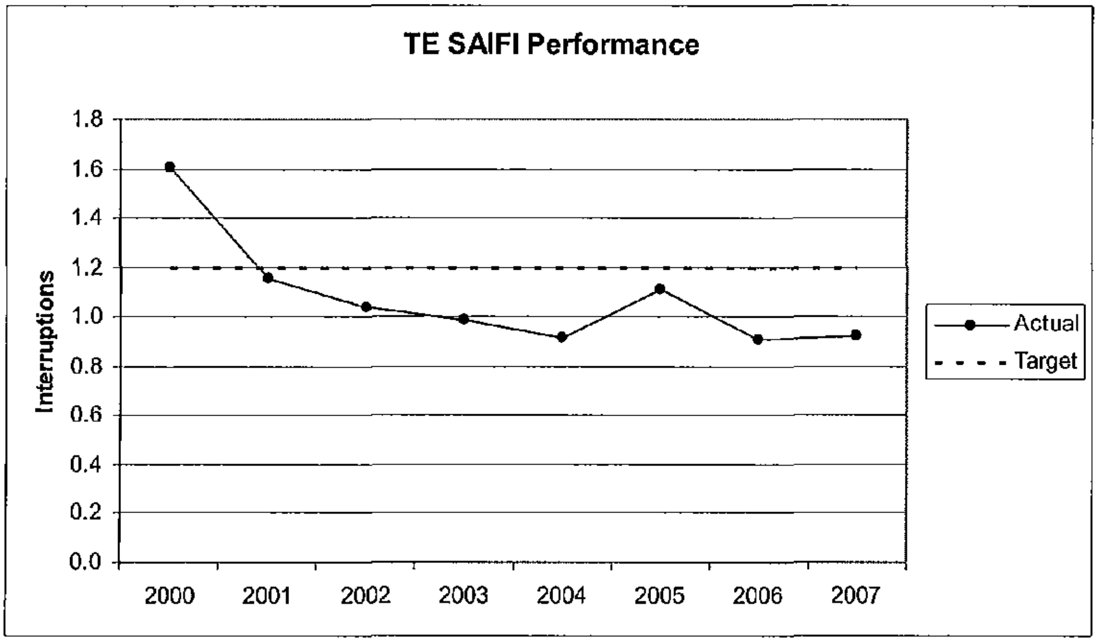
A. On page 15, Mr. Cleaver references a "decline in service reliability" and states that "System reliability index performance prior to 2007 (with major storm data excluded) for CEI and OE has demonstrated a trend of reduced reliability, particularly in the area of outage frequency (SAIFI) and average duration of outages (CAIDI)." Mr. Cleaver is incorrect. Based on CEI's and Ohio Edison's reliability index performance, service reliability has not been declining. In fact, Ohio Edison and CEI have demonstrated marked improvement.

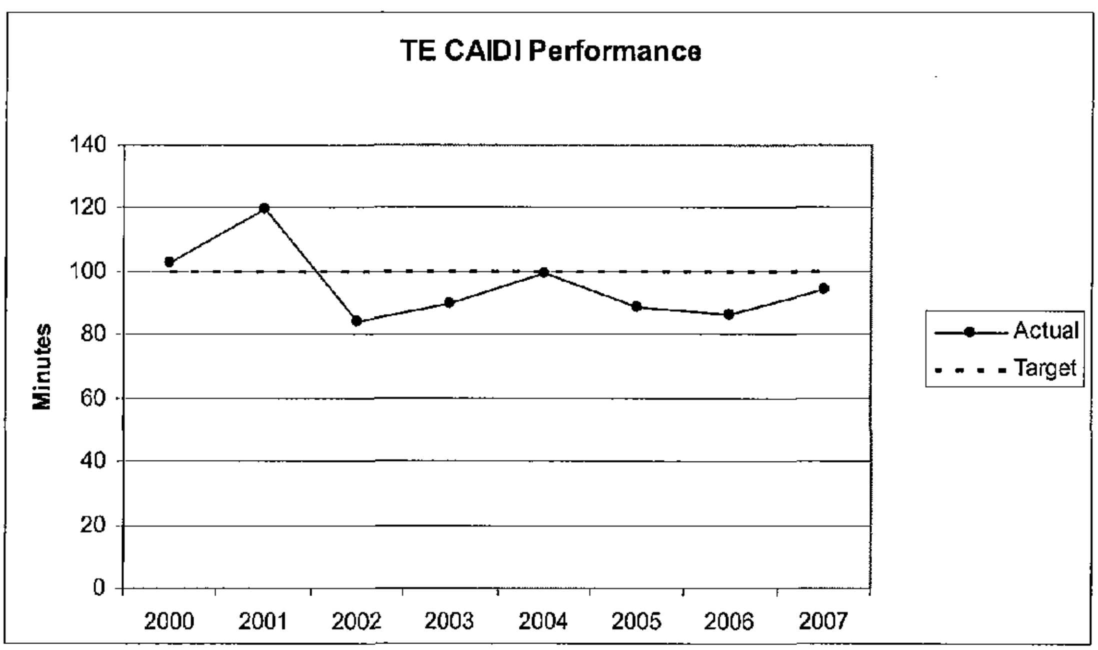
Q. HAS TOLEDO EDISON'S SAIFI AND CAIDI PERFORMANCE DEMONSTRATED A DECLINE IN SERVICE RELIABILITY OR A TREND OF REDUCED RELIABILITY?

A. Absolutely not. Mr. Cleaver at times in his testimony refers to each of the Companies generally as "the Company" or "FirstEnergy". However, Toledo Edison consistently outperformed its SAIFI targets each year from 2001-2007 and its CAIDI targets each year from 2002-2007, as demonstrated on Chart SL-1 below. Thus, it is unreasonable to include Toledo Edison in any discussions pertaining to missed reliability targets.

Chart SL-1

Toledo Edison's 8 Year Reliability Performance Index





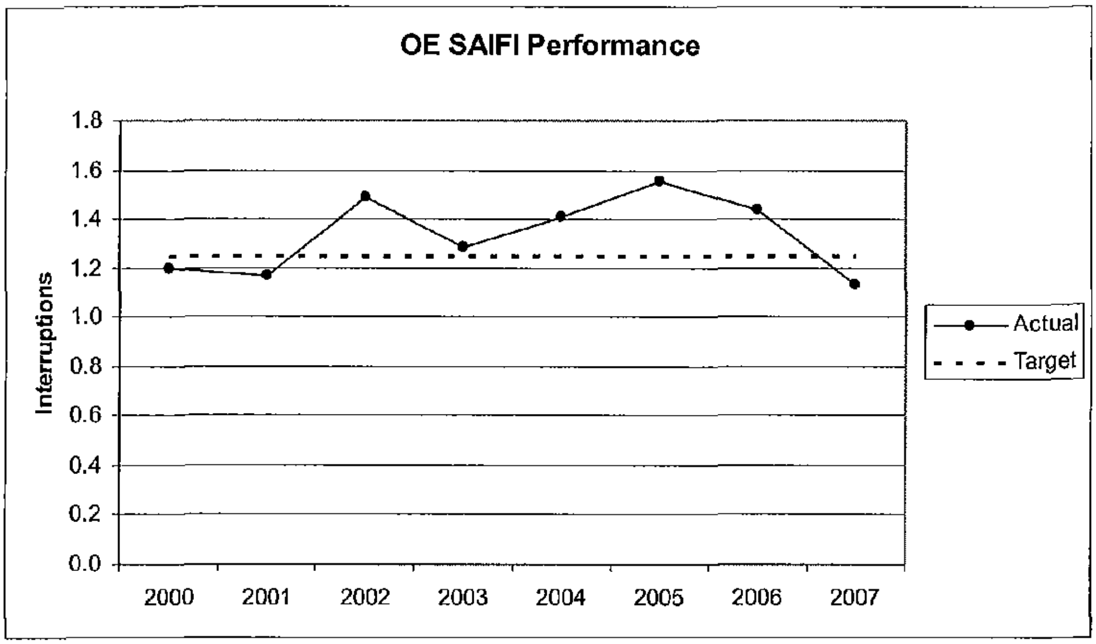
Q. HAS OHIO EDISON'S SAIFI AND CAIDI PERFORMANCE DEMONSTRATED A DECLINE IN SERVICE RELIABILITY OR A TREND OF REDUCED RELIABILITY?

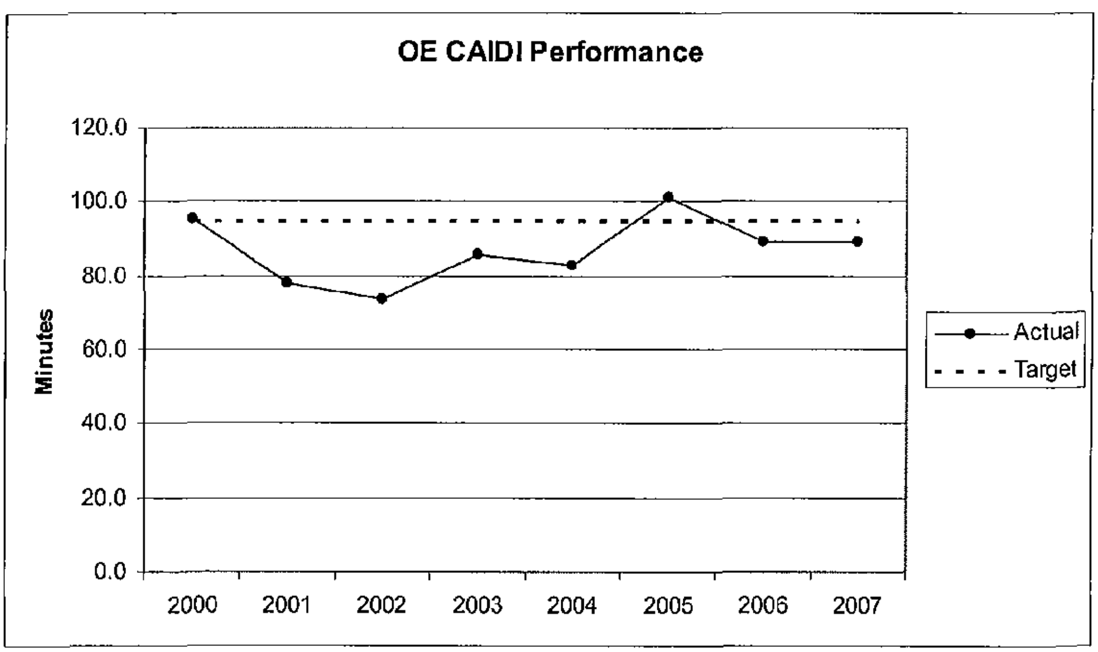
A. No. Ohio Edison's SAIFI and CAIDI performance does not demonstrate a decline in service reliability or a trend of reduced reliability using the years 2000-2007 as a reference point. In fact, setting aside 2005 when Ohio Edison missed its CAIDI target by only 6.3 minutes, Ohio Edison has consistently met or outperformed its CAIDI targets. As for SAIFI, Ohio Edison's 2000 and 2001 SAIFI performance outperformed its SAIFI target. Ohio Edison did not meet its SAIFI target in 2002-2004. However, in 2004 with the revision of Rule 10 and working with Staff, Ohio Edison submitted a Rule 10 action plan documenting steps it would implement to gradually get reliability levels back on track. In 2006, Ohio Edison's SAIFI had improved by 7% over 2005 and the un-audited 2007 SAIFI number indicates that SAIFI has improved an additional 21.5% and has now outperformed its SAIFI target, as set forth below in Chart SL-2.

[INTENTIONALLY LEFT BLANK SEE CHART SL-2 ON PAGE 5]

Figure SL-2

Ohio Edison's 8 Year Reliability Performance Index



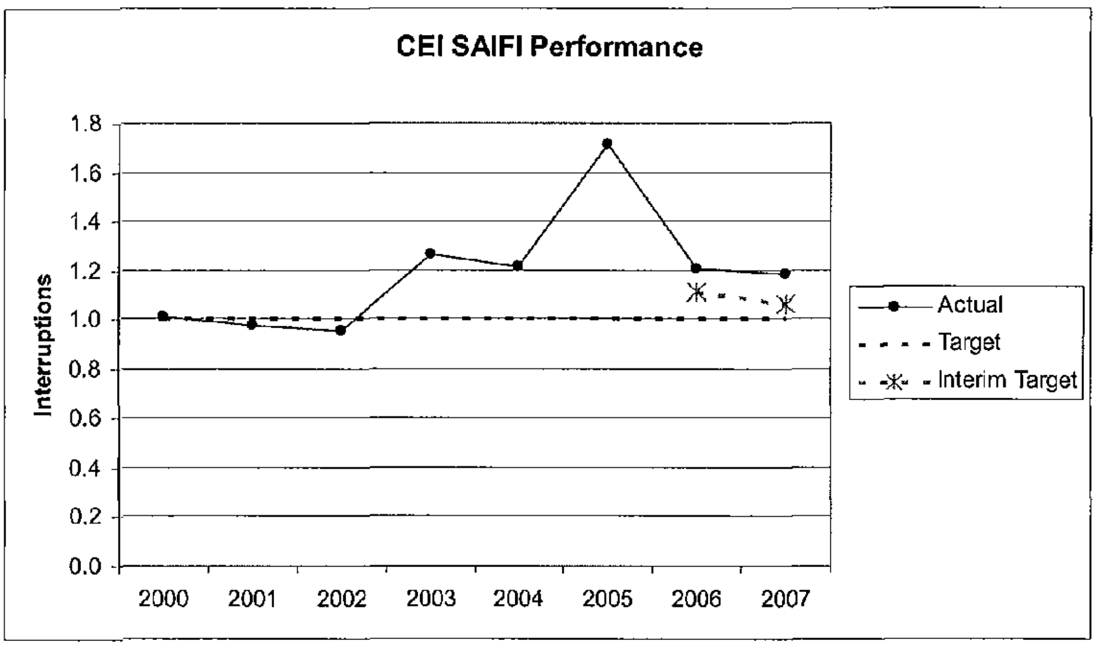


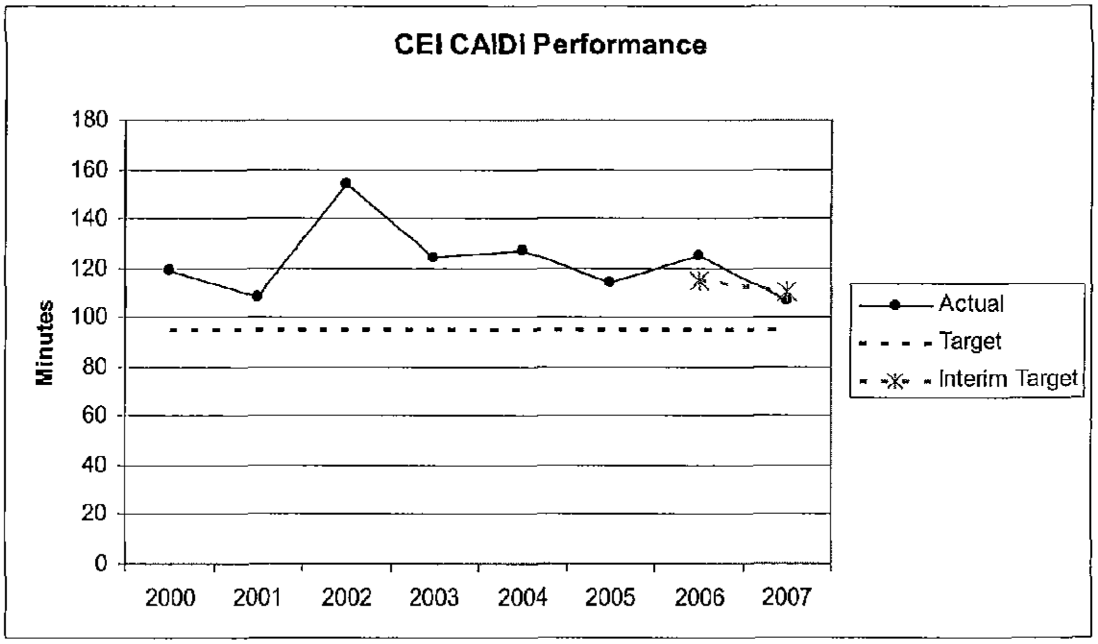
Q. HAS CEI'S SAIFI AND CAIDI PERFORMANCE DEMONSTRATED A DECLINE IN SERVICE RELIABILITY OR A TREND OF REDUCED RELIABILITY?

A. No. It is not correct to state that CEI's SAIFI and CAIDI performance has demonstrated a decline in service reliability or a trend of reduced reliability. CEI's SAIFI and CAIDI performance sets forth a series of improvements and setbacks from 2000-2007 as demonstrated on Chart SL-3 below. Similar to Ohio Edison, CEI submitted a Rule 10 action plan in 2004, the results of which appeared to decrease CAIDI but increase SAIFI. In 2005, CEI submitted another action plan under which the operational results appeared to increase CAIDI but decrease SAIFI. In addition to CEI's items for implementation pursuant to its 2005 Rule 10 action plan, CEI agreed to hire an independent consultant selected by Staff if its 2006 and 2007 reliability numbers did not meet certain interim targets. The purpose of the consultant was to drill down into CEI's infrastructure and operational practices to ascertain what was preventing CEI from meeting top quartile SAIFI and second quartile CAIDI targets and then to make recommendations to improve the reliability in the CEI service territory. CEI is committed to reaching its top quartile SAIFI target and second quartile CAIDI target. This commitment is demonstrated in its acceptance of 22 of the 25 UMS recommendations that are set forth on pages 77-79 of the CEI Staff Report, which includes the UMS recommendation to maintain capital spending at the level currently planned for 2008. Moreover, the 2007 un-audited numbers indicate that CEI is heading in the right direction. CEI's SAIFI is at its lowest point since CEI outperformed its target in 2002, and CEI's CAIDI outperformed its interim target and is at its best level based on the data for the 2000-2007 timeframe. In light of CEI's recent direction of performance metrics, its proactive steps to meet its aggressive targets, and its productive relationships with Staff, I don't think it is appropriate that any punitive measures be imposed.

Figure SL-3

CEI's 8 Year Reliability Performance Index





Q. DO YOU BELIEVE THE TARGETS OF CEI OR OHIO EDISON REPRESENT MINIMUM STANDARDS FOR RELIABLE SERVICE?

A. Absolutely not. CEI's SAIFI target is particularly aggressive when compared to Ohio Edison's and Toledo Edison's SAIFI targets. The UMS Assessment on page 12 found that CEI's SAIFI target reflected top quartile performance compared to a sampling of 66 other electric distribution utilities. CEI's CAIDI target is also aggressive, however, to a lesser degree than its SAIFI target. The UMS Assessment on page 12 found that from "an industry-wide perspective, the challenge confronting CEI [in meeting its targets] is that of striving to meet 'top quartile' performance in SAIFI and 'second quartile' performance in CAIDI." Moreover, based on the chart on page 12 of the UMS Assessment, Ohio Edison's SAIFI and CAIDI targets represent second quartile performance in the industry. I don't think that targets set at top or second quartile performance in the industry can be characterized as "minimum standards".

Q. DO THE COMPANIES SUPPORT STRIVING TO MEET FIRST AND SECOND QUARTILE PERFORMANCE?

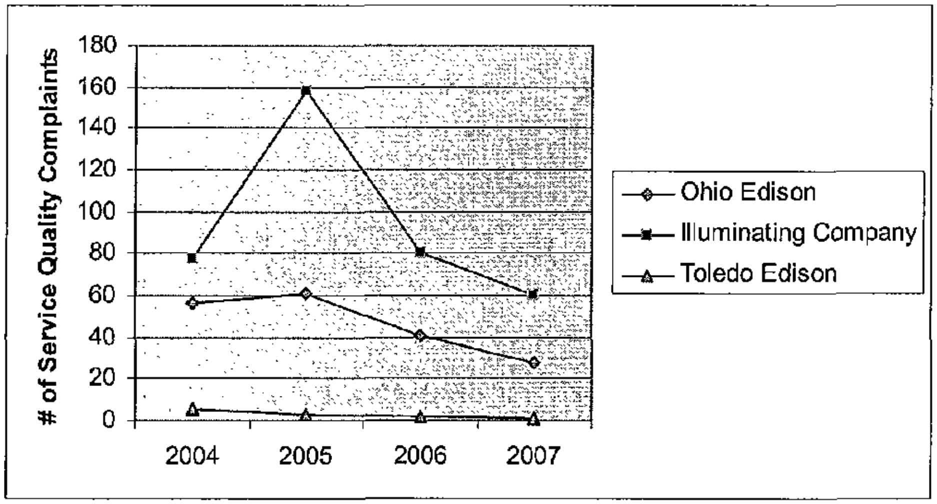
A. Yes. The Companies are committed to their aggressive targets and strive to exceed customer expectations. The Companies have had ongoing discussions with Staff regarding the appropriateness of certain targets, but have not pushed to change their targets because of the great challenge aggressive targets present. However, this proceeding has highlighted how those outside of the process unfortunately confuse top and second quartile performance with some sort of minimum standard.

Q. HOW DO THE COMPANIES MEASURE CUSTOMER EXPECTATIONS WHEN IT COMES TO RELIABILITY?

A. While there is no one way to measure customer expectations, one source of data that the Companies use is the number of service quality complaints received by the Commission and the OCC within a year. Chart SL-4 below sets forth the number of service quality complaints for each company for the years 2004 – 2007. A correlation is commonly made between an electric utility's reliability performance level and the number of service complaints. The correlation provides that as reliability improves, the number of service complaints go down. Further, a reduction in service quality complaints is a general indicator of customer expectations being met. The number of service quality complaints has lessened by 31% and 25% for CEI and Ohio Edison respectively from 2006 to 2007. This reduction in service quality complaints is an indicator that the customer perception of CEI's and Ohio Edison's reliability is improving.

Figure SL-4

Number of Service Quality Complaints



Q. DO YOU AGREE WITH THE OCC'S CONTENTIONS REGARDING THE COMPANIES' RECORD KEEPING SYSTEMS AND POLICIES?

A. No. On page 14, Mr. Cleaver states "FirstEnergy's record keeping systems and policies on a companywide basis do not meet the requirement of the present ESSS rules and also are inadequate for the purpose of verifying the Company's reliability performance, particularly in the area of its pole and circuit inspection and vegetation control programs." The Companies have different systems for different types of records and Mr. Cleaver is wrong to suggest that the Companies' record keeping systems and policies do not meet the requirements of the present ESSS rule. In fact, certain record keeping systems utilize advanced technology to quantify, analyze and store information. Mr. Cleaver is also wrong in his assumption that records verify reliability performance. The Companies use a state of the art outage management system called PowerOn. PowerOn provides a precise system of measuring outage events, the number of customers impacted and the duration of the events. Through PowerOn the Companies capture all relevant outage related data that is used in calculating reliability indices such as CAIDI and SAIFI.

Q. WHAT ARE THE COMPANIES' RECORD KEEPING SYSTEMS FOR INSPECTION AND MAINTENANCE RECORDS?

A. The Companies' distribution inspection and maintenance records are stored as hard copy and also in the Companies' SAP system; hardcopy records are retained for the time appropriate to demonstrate compliance with the ESSS rules. Such records include but are not limited to, maintenance plans; records of inspection work performed; inspection results; records of corrective work performed; and repair work.

Q. DOES MR. CLEAVER MAKE ANY OTHER COMMENTS PERTAINING TO THE COMPANIES' RECORD KEEPING WITH WHICH YOU DISAGREE?

A. Yes. On page 17 of Mr. Cleaver's direct testimony, he suggests that distribution maintenance records are an indicator of "how well the system is or is not performing". This is simply not correct. The Companies rely on the PowerOn system to measure system performance. In fact, there have been upgrades to the PowerOn system as well as to the Companies' GIS (Graphical Information System) that have enhanced the Companies' abilities, not only to track reliability performance on an operating company level, but also to track at a circuit and customer level. Today, outage data from PowerOn is integrated into the GIS system allowing the Companies to evaluate reliability of not only specific circuits, but also portions of circuits. The Companies use PowerOn outage data through GIS to identify the historical outage causes experienced on a circuit, a portion of a circuit and even at a specific customer premise. The days of viewing and evaluating such information through maintenance records have long since passed.

Q. DO YOU AGREE WITH THE OCC'S CONTENTION ABOUT THE COMPANIES' PROGRAM FOR DEALING WITH TREES OUTSIDE THE RIGHT-OF-WAY?

A. No. Mr. Cleaver states on page 15 of his testimony that "FirstEnergy does not currently have a specific program to deal with trees outside the right-of-way as part of the vegetation management effort". This statement is absolutely incorrect. The Companies do have a practice for maintaining trees and other vegetation outside the right-of-way.

Q. WHAT IS THE COMPANIES' PROGRAM TO ADDRESS TREES OUTSIDE THE RIGHT-OF-WAY?

A. The Companies inspect and remove priority trees located outside the right-of-way that are dead, dying, diseased, or significantly leaning. Trees located outside the right-of-way are also subject to removal if they possess one or more of the following characteristics: visible signs of severe insect, animal or mechanical damage, tree is uprooting, poor site conditions (for example: shallow soils, wet area or along stream bank), tree is split, twisted, damaged by lightning, fast growing or structurally weak species (aspen, willow, poplar, basswood). In addition, a healthy tree located outside the right-of- way is evaluated for removal based on its height and the risk of reaching a conductor if the tree fell, its general proximity to a conductor, the direction of prevailing winds, topography of the land and direction of lean. The ultimate decision is based on whether the tree is likely to interfere with the Companies' lines and/or conductors.

Q. WHAT IS THE COMPANIES' PROGRAM TO ADDRESS OTHER VEGETATION OUTSIDE THE RIGHT-OF-WAY?

A. The Companies inspect and prune encroaching and overhanging branches located outside the right-of-way that may grow into electric lines within the four year cycle. Special emphasis is placed on removing overhanging branches that are structurally weak or dead, which could fall or blow into the conductor and cause an outage. Pruning is done in such a manner to achieve a minimum of four years of clearance from conductors and is based on tree species and growing conditions.

Q. HAVE YOU REVIEWED MR. SCARAMELLINO'S PREFILED TESTIONY?

A. Yes. I have.

Q. WHAT WILL YOU ADDRESS FROM MR. SCARAMELLINO'S PREFILED TESTIONY?

A. I will address Staffs position on the Companies' quality control practice for line reclosers and line capacitors; record keeping and record retention practice for right-of-way vegetation control; and the two-pole program.

Q. DO THE COMPANIES AGREE WITH MR. SCARAMELLINO'S TESTIMONY PERTAINING TO THE COMPANIES' QUALITY CONTROL PRACTICE FOR LINE RECLOSERS?

A. No. Mr. Scaramellino recommends that CEI and TE commit to performing the quality control oversight practice for line reclosers that Ohio Edison had previously committed to perform for line capacitors. Line reclosers, however, are very different from line capacitors and already receive quarterly inspection for quality control.

Q. WHAT IS THE PROBLEM WITH MR. SCARAMELLINO'S RECOMMENDATION PERTAINING TO LINE RECLOSERS?

A. Mr. Scaramellino does not distinguish the Companies' quality control practices for line reclosers from the Companies' quality control practices for line capacitors. On page 3 of Mr. Scaramellino's Pre-filed Testimony he describes the Companies' quality control practice as primarily a review of completion date and field inspection signatures. This is not correct for line reclosers. The Companies' quality control of line reclosers also includes quarterly inspections by qualified personnel that visually inspect the line recloser and records the number of times the recloser opened and closed. This process is much different from the form review and annual inspection performed on line capacitors.

Q. DO CEI AND TOLEDO EDISON SUPPORT IMPLEMENTING THE QUALITY CONTROL PRACTICES CURRENTLY UTILIIZED BY OHIO EDISON FOR LINE CAPACITORS?

A. Yes. Now that Staff has clarified its recommendation as it pertains to line capacitors, CEI and TE are not opposed to adopting the line capacitor review process with audit checkpoints for in-process and completion audits currently being utilized by Ohio Edison. Moreover, Ohio Edison will maintain its current process.

Q. ARE THE COMPANIES IN COMPLIANCE WITH THE OHIO ADMINISTRATIVE CODE ("OAC") IN CONNECTION WITH THEIR RECORD KEEPING FOR RIGHT-OF-WAY VEGETATION CONTROL?

A. Absolutely. Mr. Scaramellino is completely wrong in stating that the Companies have violated the OAC. The Companies had and still maintain hard copy records demonstrating compliance with their right-of-way vegetation control practice that dates back before 2003. The issue here is not that the Companies failed to retain records sufficient to demonstrate compliance, but rather that the Companies could not provide Staff the information for this prior period electronically or generate an electronic report without a substantial burdensome effort.

Q. HOW DID THIS ISSUE ARISE?

A. Staff in this proceeding requested the date, month and year that work was started and completed on every single circuit of each of the three Companies for the period 2003-2006. The Companies responded that full compliance with the request was overly burdensome but did provide a sample.

Q. WAS IT UNUSUAL FOR STAFF TO REQUEST INFORMATION ON EVERY CIRCUIT FOR THE FOUR YEAR CYCLE?

A. Yes. Staff has traditionally taken an auditing approach to compliance review. Staff would request information on a Staff selected sample of circuits (typically 40 to 60 circuits) and the Companies would provide data to demonstrate compliance with its right-of-way vegetation control practice and the applicable OAC provisions. Given this smaller sample size, the Companies could manually gather the information using the hard copy records.

Q. WHY WAS STAFF'S REQUEST OVERLY BURDENSOME?

A. Staff retroactively abandoned the auditing approach and requested that each of the Companies provide data on every single circuit from 2003-2006. This data request would have required the Companies to sort through over 72 boxes of records and notate the specific start and specific end dates for approximately 2400 circuits.

Q. WHY DO THE COMPANIES OBJECT TO PROVIDING THAT INFORMATION?

A. As I stated before, that would be an incredible undertaking. Staff has consistently audited the Companies' records based on a sampling approach. To now retroactively require proof of compliance by auditing every single record is unreasonable.

Q. GOING FORWARD WOULD THE COMPANIES OBJECT TO PROVIDING STAFF PROOF OF COMPLIANCE ON EACH CIRCUIT?

A. No. The Companies now through their Internet Vegetation Management System ("IVMS") have the technology going forward to reduce the workload and more importantly, the Companies now have notice of Staff's revised practice.

Q. PLEASE EXPLAIN THE TECHNOLOGY THAT THE COMPANIES HAD BEFORE IVMS?

A. Prior to IVMS the Companies had a very basic vegetation management system. This system which was referred to as the Vegetation Management System contained information from timesheets and tracked invoices. Circuit trim schedules (last maintained/next maintained) were maintained separately using spreadsheets. This system did not track circuit trim schedules or specific start/end dates and such information was only available by referring to the hard copy record.

Q. WHEN WAS IVMS IMPLEMENTED?

A. The Companies implemented IVMS in 2003 in an effort to consolidate the vegetation management systems of companies comprising FirstEnergy.

Q. HOW WAS IVMS USED?

A. Although IVMS had a number of capabilities (such as input of timesheets, certain trim schedules, certain circuit information, billing information, specific start and end dates, etc.), at the time it was implemented such functions were not utilized corporate-wide. The main function was to notify forestry specialists when maintenance was last performed and next scheduled. The Companies would routinely reset the fields in the database after a vegetation cycle to reflect that the cycle was complete.

Q. WHEN DID THE COMPANIES BEGIN ENTERING SPECIFIC START AND END DATES?

A. In 2005, the Companies began recording specific start and end dates in IVMS. It is possible that certain regions may have input certain specific start and end dates into IVMS before 2005 but it was not a corporate-wide practice. IVMS has the capability of electronically storing information (including specific start and end dates) on all circuits and generating a report which provides a four year cycle.

Q. ARE YOU AWARE WHY STAFF MAY HAVE BELIEVED THAT THE COMPANIES HAD SPECIFIC START AND END DATES AVAILABLE ELECTRONICALLY FOR ALL CIRCUITS?

A. Yes. In 2004 Staff held an audit at Ohio Edison's Mansfield office to confirm compliance with the Companies' right-of way vegetation control record keeping. The audit included approximately 56 circuits and Staff was provided specific start and end dates. At the time, the IVMS had been partially populated with data that included the 56 circuits chosen for the audit. An electronic report was viewed by Staff at the time for these particular circuits even though the database was not yet fully populated with system-wide data.

Q. STAFF RECOMMENDS THAT THE COMPANIES MAINTAIN A PRECISE 48 MONTH CYCLE AND RELY ON SPECIFIC START DATES AND END DATES TO VERIFY COMPLIANCE. DO THE COMPANIES AGREE?

A. No. This recommendation is arbitrary and likely to lower reliability. Moreover, it is inconsistent with the Companies' right-of-way vegetation control practice submitted and accepted by Staff. Currently, at the start of each year the forestry department develops a plan directed toward ranking each of the circuits scheduled for trimming in the given year. The purpose of this ranking is to decide in what order the circuits are to be trimmed so that the results have the greatest positive effect on system reliability. There are several pieces of information taken into account to formulate the plan. The most important piece is that reliability issues are evaluated. Each year designated personnel from forestry and engineering meet to determine which circuits need to be trimmed immediately because they pose a potential reliability risk. Next, location of the circuit (urban vs. rural) is taken into account. Forestry personnel attempt to trim the circuits located in urban areas before the crowded summer months. Lastly, customer density and circuit miles are taken into account. Circuits that serve the largest number of customers are often trimmed before circuits serving fewer customers. The length of the circuit is considered to make sure there is adequate time to complete the trimming work in the given year. This is important since circuit length can vary significantly. For example, in the 2008 list of circuits, one operating company has a circuit that is 110 line miles compared to another that is only 0.12 line miles. Therefore, this has to be taken into account when planning the work.

Q. IS MR. SCARAMELLINO CORRECT IN STATING THAT UNDER THE COMPANIES' FOUR YEAR CYCLE 4 YEARS AND 11 MONTHS COULD ELAPSE BETWEEN THE SCHEDULED TRIMMING ACTIVITY ON A CIRCUIT?

A. Yes. It is possible for a circuit to go 4 years and 11 months however it is also possible for a circuit to go 3 years and 1 month. The Companies are simply seeking to maintain the flexibility to schedule the work required to be performed in a given year based on sound industry practice and the critical need of the circuit.

Q. WHAT DOES IT MEAN TO SCHEDULE THE WORK REQUIRED FOR A GIVEN YEAR BASED ON THE CRITICAL NEED?

A. Consider the example of two circuits. The first circuit, based on its last maintained end date (hypothetically January 10, 2004), would be due for scheduled trimming on January 10, 2008, if a precise 48 month cycle were applied. The second circuit, based on its last maintained end date, would be due August 10, 2008, again if a precise 48 month cycle were applied. But there may be a critical need to maintain the second circuit before the spring growing season. If the same critical need does not exist for the first circuit the Companies will re-prioritize the work and trim the second circuit in January and the first circuit in August.

Q. HOW IS MR. SCARAMELLINO'S RECOMMENDATION INCONSISTENT WITH THE COMPANIES' RIGHT-OF-WAY VEGETATION CONTROL PRACTICE SUBMITTED PURSUANT TO RULE 27?

A. The Companies' Right-of-way Vegetation Control Practice provides "Vegetation is routinely pruned, controlled or removed approximately every four years or as required, to maintain reliability and access, make repairs, or restore service." The term "approximately" is included to capture the flexibility necessary to address the prioritization described in the prior answer and also to account for carryover due to property owner refusals, or delays due to weather.

Q. WHAT OTHER CONCERNS DO THE COMPANIES HAVE PERTAINING TO RIGHT-OF-WAY-VEGETATION CONTROL?

A. Staff has recommended that the Companies maintain records for eight years demonstrating compliance with two four year cycles. The Companies are not opposed going forward to retain the specific start and end dates for eight years in IVMS database records, but the Companies maintain their objection to retaining any hard copy data on such records for eight years.

Q. WHY DO THE COMPANIES OBJECT TO RETAINING HARD COPY DATA FOR EIGHT YEARS?

A. Such a request would require the Companies to store an inordinate amount of paper with no value if the four year cycle has already been confirmed for the first four years. For example, such a request for the retention of eight years of records would require the Companies to store approximately 144 boxes of data. The boxes would include approximately 240,000 documents. The documents would include, but not be limited to, time sheets, inspection forms, refusal forms and circuit maps. We do not believe that maintaining this volume of paper records will improve the vegetation management program.

Q. ARE THE COMPANIES WILLING TO DEVELOP A PROCESS PERTAINING TO TWO-POLE CONDITIONS?

A. Yes. Now that Staff has clarified its recommendation, the Companies will continue to participate in the process pertaining to two-pole conditions. However, the Companies are opposed to any recommendation or finding that would require the Companies to remove the pole or cause removal of the old pole and attachments of other pole attaching companies. The Companies do not have the expertise to handle any fiber optic or other equipment associated with the telecommunication or cable industry.

Q. WHAT ARE THE PROBLEMS ASSOCIATED WITH REMOVING POLES WITH TELECOMMUNICATION OR CABLE COMPANY ATTACHMENTS?

A. The vast majority of two-pole conditions are created by the failure of telecommunication entities to remove their attachments. The Companies' concerns are twofold. First, attempting to remove such attachments poses a significant safety risk to our employees. Second, our employees are not trained nor qualified to cut, splice and relocate these lines, nor do they have the knowledge necessary to assess whether the equipment is still providing service to customers. Any attempt by our employees to work on this equipment may adversely affect that equipment or the service to those customers. Moreover, the Companies do not have the design and construction standards of the other pole attaching companies that would be needed to remove such equipment and poles.

Q. HOW HAVE THE COMPANIES ATTEMPTED TO RESOLVE TWO-POLE CONDITIONS?

A. The Companies have voluntarily participated in Staff's Task Force and have agreed to include two-pole identification as part of their required five year circuit inspections. In addition, the Companies agreed to Staff's recommendation that the Companies develop a systematic means of tracking all two-pole conditions in their service territories including: the location of poles; date of transfer of electric service; and the date of pole removal.

Q. HAVE YOU REVIEWED MR. ROBERTS' PREFILED TESTIMONY?

A. Yes I have. And as I understand it, Mr. Roberts' Pre-filed Testimony is applicable only to Ohio Edison.

Q. DOES OHIO EDISON HAVE ANY CONCERNS WITH MR. ROBERTS' PREFILED TESTIMONY?

A. Yes. Ohio Edison has two concerns.

Q. PLEASE EXPLAIN OHIO EDISON'S FIRST CONCERN WITH MR. ROBERTS' TESTIMONY.

A. Ohio Edison is concerned that Staff has recommended that Ohio Edison thoroughly investigate all service interruptions coded "unknown" without limiting its request to exclude service interruptions that occur during a storm.

Q. WHY SHOULD STAFF'S REQUEST BE LIMITED TO EXCLUDE SERVICE INTERRUPTIONS THAT OCCUR DURING A STORM?

A. Typically, outages are spread out over the course of a year and it is manageable to perform a root cause analysis on such outages coded "unknown". However, in the case of a storm there is a high concentration of outages and a group of such storm related outages may be coded as "unknown". It would be a tremendous amount of work to go back and investigate each of the minor or major storm related outages to ascertain the root cause of each specific outage (wind, tree branch, vehicle, etc.). Ohio Edison currently does not have the resources to commit to such a large undertaking.

Q. WHAT IS OHIO EDISON'S CURRENT PRACTICE?

A. Ohio Edison has a detailed focus on determining the root cause of outages coded "unknown" on days that are not effected by storm conditions, which Staff believed was commendable. The practice does not include performing root cause analysis for outages that occur during a storm.

Q. PLEASE EXPLAIN OHIO EDISON'S SECOND CONCERN WITH MR. ROBERTS' TESTIMONY.

A. Staff recommended that Ohio Edison perform "enhanced" vegetation clearance on its distribution system. This "enhanced" program would consist of removing overhang that arises from outside the right-of-way. This recommendation arises from Staff's concerns about outages that are coded as "Trees/Not Preventable". Ohio Edison's position is that neither Ohio Edison nor Staff has sufficient information that establishes whether overhang from trees outside the right-of-way creates a reliability problem. In an effort to obtain sufficient data, however, Ohio Edison is willing to begin gathering information on outages caused by overhang outside the right-of-way.

Q. HOW DID THIS ISSUE ARISE?

A. Staff in this proceeding requested information on whether Trees/Not Preventable caused outages was caused by overhanging branches/limbs from outside the right-of-way or by trees/branches/limbs from outside the right-of-way other than overhang. The information presumably could have aided Staff in making a targeted recommendation pertaining to either "overhang" or "other than overhang". Ohio Edison responded that the Company did not track the level of detail requested by Staff but Staff nonetheless made its recommendation pertaining to an "enhanced" vegetation program without underlying data. In fact, Staff acknowledges that its recommendation is based on this lack of information. Mr. Roberts' states on page 5 of his Prefiled Testimony that "it is [Ohio Edison's] failure to maintain data on Trees/Not Preventable caused outages that prompts Staff's recommended vegetation clearance practices to enhance [Ohio Edison's] reliability".

Q. WHAT IS THE PROBLEM WITH STAFF'S RECOMMENDATION?

A. At this time neither Ohio Edison nor Staff based on Mr. Roberts' Prefiled Testimony is aware of whether "overhang" or "other than overhang" is driving the number of Trees/Not Preventable. Unlike vegetation in Ohio Edison's right-of-way where the Company has easement rights to maintain the vegetation, an outage cause coded as "Trees/Not Preventable" means that the tree causing the outage was located outside Ohio Edison's right-of-way. As I explained earlier in this testimony, Ohio Edison's current practice includes removing overhang which is likely to cause problems regardless whether the tree is located inside or outside the right-of-way. The issue here is Staff's blanket endorsement through its recommendation that Ohio Edison trim all overhang before there is enough information to determine what percent if any of overhang that arises from outside the right-of-way is causing outages. For that reason it is premature to recommend that Ohio Edison expend its resources to remove overhang as described by Staff.

Q. WILL OHIO EDISON TRACK TREES/NOT PREVENTABLE TO TREND OUTAGES CAUSED BY OVERHANG?

A. Yes. As stated before Ohio Edison is willing to begin gathering information on outages due to overhang. Ohio Edison will track such data so that a fact-based assessment can be made of how Ohio Edison can cost effectively reduce the number of Trees/Not Preventable outages.

Q. HAVE YOU REVIEWED MR. BAKER'S PREFILED TESTIMONY?

A. Yes. I have and I would like to make two clarifications.

Q. WHAT CLARIFICATIONS WOULD YOU LIKE TO MAKE TO MR. BAKER'S PREFILED TESTIMONY?

A. I believe even with the Corrective Page to Prefiled Testimony of Peter Baker there still may be a degree of confusion around the $84.7 million capital spend amount.

Q. PLEASE EXPLAIN THE CONFUSION AROUND THE $84.7 MILLION CAPITAL SPEND.

A. First, I want to make clear that the $84.7 million capital spend is a 2008 budgeted number. Second, the $84.7 million is composed of $68,245,000 (distribution facilities); $4,055,000 (sub-transmission facilities) (and approximately $12.4 million of bulk transmission facilities within the CEI service territory that are owned by ATSI).

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.