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RICHARD C. CAHAAN

being first duly sworn, as prescribed by law, was examined and testified as follows:

DIRECT EXAMINATION

By Mr. McNamee:

Q. Mr. Cahaan, could you state and spell your name for the record, please.

A. Richard C. Cahaan, C-a-h-a-a-n.

Q. Mr. Cahaan, by whom are you employed and in what capacity?

A. I am employed by the Public Utilities Commission as the Chief Economist in the Capital Recovery Financial Analysis Division, Utilities Department, Commission Staff.

Q. What is your business address?

A. 180 East Broad Street, Columbus, Ohio.

MR. McNAMEE: Your Honor, at this time I would ask to have marked for identification as Staff Exhibit 20 a multipage document entitled Prefiled Testimony of Richard C. Cahaan filed February 12.

EXAMINER BOJKO: That will be so marked.

(EXHIBIT MARKED FOR IDENTIFICATION.)

Q. Mr. Cahaan, do you have before you what's just been marked for identification as Staff Exhibit 20?

A. Yes, I do.

Q. Can you identify that document for me?

A. This is the testimony that I prepared or that others in the section I work in prepared with me in terms of the rate of return analysis and a few other areas of this case.

Q. Okay. Do you have any additions, corrections, updates to this testimony?

A. Yes, I do.

Q. What are those, please?

A. There are two instances where the sentence, quote, "the Ohio Energy Group provides no support for its contentions," end quote, there are two instances of the sentence one of which is page 12, lines 19 and 20, it should be deleted insofar as the objections of the OEG have been withdrawn, and the other is page 16, lines 4 and 5.

Q. Are there any other alterations that you need to make?

A. Yes. Page 25, line 3 provides a number of "10.31 percent" as the staff's baseline return on equity. There was a slight miscalculation and backing out this number from the 10 to 11 percent current recommendation the correct number should be 10.27 percent. This change does not affect anything else.

EXAMINER BOJKO: That's the second number on line 3?

THE WITNESS: Right. The number 10.31 is the one that's wrong.

EXAMINER BOJKO: Thank you.

A. And there is one other correction.

Q. Where is that, please?

A. On page 29 -- sorry, not page 29. Oops. 23, the answer beginning on line 6 and going forward, there was some confusion on my part when I was writing the testimony and the direct answer to the question, the question as asked, was corrected, but all the other stuff I put around it was not.

So I wish to strike the first sentence which is "The reduced leverage would argue for a lower cost of equity," I wish to strike the first part of the second sentence which is "To account for this effect," which means that the word "the" that follows it would then become the first letter of a new sentence, and I wish to strike everything after that sentence after the word -- after the three to four basis points, in other words, strike "we recognize" all the way down to the end of that answer. I am sure that some people will be interested in what went wrong here and I'll explain it at the time rather than writing it in now.

Q. Are those all the additions, corrections, updates to this testimony?

A. Yes. There's a comma that should be a semicolon on page 27, but I think I'll just leave it there unless somebody is confused.

Q. Mr. Cahaan, with those corrections, updates, modifications, are the contents of what's been marked for identification as Staff Exhibit 20 true?

A. Yes.

Q. If I were to ask you the questions contained within what's been marked for identification as Staff Exhibit 20 again here today, would your answers today be the same as they are presented therein?

A. Yes.

MR. McNAMEE: With that, the witness is available for cross.

EXAMINER BOJKO: Let's start with, mix it up a little bit, City, do you have any questions?

MR. YURICK: City of Cleveland has no questions for this witness, your Honor.

EXAMINER BOJKO: How about Nucor?

MR. LAVANGA: No questions, your Honor.

EXAMINER BOJKO: How about Schools? Oh, you have questions?

MR. BREITSCHWERDT: No, your Honor.

EXAMINER BOJKO: IEU?

MR. NEILSEN: No questions, your Honor.

EXAMINER BOJKO: OCC?

MR. REESE: Yes, your Honor.

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CROSS-EXAMINATION

By Mr. Reese:

Q. Good afternoon, Mr. Cahaan.

A. Good afternoon. It's a delight to see so many familiar faces again, even if they're in different places in the room.

Q. Good to see you too.

Let's look at page -- the bottom of page 3 and the top of page 4 of your prefiled testimony.

A. Yes.

Q. On pages 3 and 4 of your testimony you modify the staff proposed capital structure from the parent consolidated approach to an average of the three FirstEnergy companies of 51 -- I'm sorry, 51 percent long-term debt and 49 percent common equity; is that correct?

A. Yes, that's not an exact average, but that's an approximate average of what I'll call the combined EDUs.

Q. How did you derive the new capital structure of 51 percent long-term debt and 49 percent common equity?

A. Mathematically or where did it come from?

Q. Both.

A. Well, it was from the companies' testimony, I believe Mr. Pearson's testimony, and it represents the combined capital structure of the three EDUs, although not down to the last -- you know, there's a bit of rounding there.

Q. Can you explain how you think that averaging capital structures of independent or stand-alone utilities result in a capital structure that is representative of each utility separately?

A. I don't. In terms of representative of that particular utility's capital structure as it is, obviously it can't be if I'm taking different capital structures and averaging them. But we are coming up with a rate of return that we are applying to all three companies. We believe that frankly the EDUs of FirstEnergy, although they are separate companies legally, for purposes of rate of return should be treated as one company and we think that there's logic, therefore, in combining the capital structures of these three companies as if they were one company.

I will also point out that, as I mentioned in my testimony, the entire area of capital structure is one in which there is a lot of discussion and turmoil as to what is the appropriate way of handling it, not just in terms of three separate companies but also parent, subsidiary, and hypothetical and a large number of other issues.

We had a rate of return workshop where these things were discussed and there's a lot of differences of opinion, there's no one particular way that has received clear-cut acceptance within the regulatory and electric industry in Ohio.

Q. Mr. Cahaan, to your knowledge has any state regulatory commission or federal regulatory commission approved the approach of averaging stand-alone capital structures of subsidiaries of electric utilities in order to generate one capital structure for such subsidiaries?

A. I don't know either way.

Q. It looks like my next question is from page 23 of your testimony, lines 6 to 9, so it might have just gone away. I may come back to that.

Mr. Cahaan, have you ever recommended the approach of averaging stand-alone capital structures of subsidiaries of electric utilities in order to generate one capital structure?

A. In a rate proceeding, no.

Q. Yes. No?

Mr. Cahaan, do you think a lower ratio of long-term debt will lead to an increase, a decrease, or no change in the cost of debt for the three EDUs?

A. Could I have that question read again?

(Record read.)

A. Making the appropriate all other things being equal assumption so that we're dealing with a certain company that changes its leverage and not comparing what amounts to different companies comparing a consolidated versus a subsidiary or group of subsidiaries so that we're only considering the controlled circumstance of one company, if it were to have a lower amount of leverage, then the cost rate of the debt that would be issued would be less -- would be expected to be less than the cost rate of debt that would be issued by a company that had higher leverage.

If we make an apples to apples kind of situation, the answer would be yes, but only under an apples-to-apples situation.

Q. You just said the answer would be yes. I was asking if it would lead to an increase, decrease, or no change in the cost of debt for the three EDUs.

A. If you had the three EDUs and all the economic conditions in the country stayed the same so we hold all that constant, and if they, for instance, either floated more equity so the equity ratio went up, it became a greater percentage, or they retired some debt so that the debt percentage became less, so it is -- the company is less leveraged, it has a higher equity to debt ratio, if that company did those -- either of those actions, then if they were to include new debt, it would be expected that that new debt would have a lower cost rate than if they hadn't done those actions.

Q. So comparing the staff's adjusted rate of return recommendations with that contained in the -- strike that.

Mr. Cahaan, so comparing your adjusted rate of return recommendation with that contained in the Staff Report, the return on rate base actually increased from a range of 7.90 percent to 8.35 percent to a range of 8.24 percent to 8.72 percent; is that correct?

A. It's in my testimony somewhere.

Q. Subject to check.

A. Subject to check, yeah, sure.

Q. Okay. So isn't it true that the net effect of reducing the utility's debt leverage is actually an increase in the overall cost of capital and the ratepayers are facing a higher revenue requirement and higher rates?

A. No. The thing that is not being pointed out in assuming that it is entirely due to the capital structure percentages is a major determinant that the parent consolidated capital structure contained very -- some very low cost debt in the form of pollution control bonds that are nontaxable and tax subsidized, as you may choose, and have the effect of reducing the debt cost rate.

The EDU capital structure that we're using, we've eliminated any pollution control bonds, these bonds are generation related and not distribution related, pollution control being a generation function. So it is not just the issue of the amount of leverage but also the issue of generation debt being removed from the capital structure that is a change in this case.

Q. Mr. Cahaan, in your opinion should ratepayers receive any benefits from a reduction of debt leverage of the three EDUs?

A. I don't understand the question.

Q. I was afraid you'd say that.

Mr. Cahaan, your idea is to use a capital structure that supports the applicants' distribution function, correct?

A. Correct.

Q. Would you explain why you prefer the concept of averaging the capital structures instead of using the parent consolidated capital structure?

A. I'd like to point out on June 12th, 2007, we held a technical conference to discuss alternative rate of return methods for disaggregated electric distribution utility companies and one of the questions that we had in that workshop was what is the appropriate capital structure to use for an EDU.

The problem that we face is that we began using the parent consolidated capital structure when most of the activities in the parent consolidated enterprise were regulated activities, not necessarily regulated in one particular state but were utility activities.

We've gotten to a situation -- excuse me, and in such a situation the regulated activities were pretty much the body of the dog and the unregulated activities were the tail of the dog. We're getting to a situation where the tail of the dog is the regulated activities and the body of the dog is unregulated and maybe not even electric, in some cases.

And the concept of a parent consolidated capital structure, the negative part of that is that it bears no direct reality in corresponding to the supporting of the activities of the regulated distribution entity. So there's something wrong with using it, the system is broken, and we're searching somewhat desperately and admittedly confusedly for a reasonable solution.

But the parent consolidated capital structure is not a desirable direction to go. It is where we're coming from and it's a default situation that we're still dealing with, but it's not -- it does not have the merit that it used to have.

Q. So the parent consolidated capital structure hasn't been abandoned but it has been for this particular rate case.

A. Obviously it hasn't been abandoned because we used it in the Staff Report in reaction to concerns about using a stand-alone capital structure, but for reasons that I'm prepared to explain we decided that we really should go back to the -- not back to, we really should use the EDU-type capital structure instead of the parent consolidated one.

And I do also wish to point out that in our comments that we put forward after the rate of return workshop we did point out that --

Q. Excuse me, is this in your testimony somewhere?

A. No, this is on a PUCO web page.

Q. Okay.

A. I'm just pointing out that this position has been announced publicly for quite a while.

Q. Which position is that?

A. The one I'm about to say.

Q. Oh, okay. Very good.

A. In fact, let me just read the whole sentence here so that we're not just inappropriately quoting. The first question discussed was what is the appropriate capital structure to use for an EDU. There was general consensus that the continued use of the parent-consolidated capital structure was inappropriate, but there was disagreement as to whether the stand-alone EDU capital structure should be used or whether some sort of hypothetical or ideal capital structure should be employed.

The staff recognizes the concern that a high equity ratio may lead to an inflated estimate of the cost of capital, however, we believe that this would occur only in a mechanistic approach to rate of return analysis, one which ignores the fact that a higher equity ratio reduces financial risk and thus lowers cost rates of both debt and equity.

An aside, this is what you were discussing earlier when you were asking me about equity ratios. Back to what I have on the web.

The staff believes that the stand-alone EDU capital structure is the appropriate place to begin. There may be cases where a modification to this capital structure may be warranted for rate of return purposes. In such cases the reasons for a modification should be demonstrated.

And I think that's what we are discussing here, that we have a stand-alone capital structure and we've modified it in the sense of making an average and we think that's appropriate because we're dealing with a rate of return for three companies together.

Q. So this has been posted on the website since around the time of the June 2000 [sic] workshop?

A. About a month later, after that.

Q. Okay. And the staff --

A. It was a throwback.

Q. I'm sorry?

A. It was a throwback.

Q. Okay.

A. We went back to the idea of the stand-alone because we were not comfortable at that time -- there was significant internal debate. We were not comfortable at that time in proceeding, I think I described this in my testimony, but we -- and I apologize for this, but we revised our opinion.

Q. Let's go to page 7 of your testimony. Specifically lines 17 to 19, your testimony states "Witness Vilbert states that a capital structure reflective of the Ohio EDUs is preferable because it reflects the decisions on how to finance the Companies' distribution assets rather than the aggregate of all the assets of the parent and all its subsidiaries." Do you see this?

A. I do.

Q. Do you think that financial institutions and analysts consider the aggregate of CE -- I'm sorry, of CEI, Toledo Edison, and OE's assets when they make decisions to finance one of them, say Toledo Edison?

A. I think that to a large degree they do in the sense that they look at the companies together. To the extent that these are -- you're talking about first mortgage bonds that are secured, you will, of course, be recognizing the security of that particular bond, collateral embedded in the individual EDU.

But I really don't think that the investment community looks at these three companies as really, really separate in viewing them. If they were drastically different, if one company had such high financial numbers such that it was AA and another company was BBB, then there might be a case to make that the financial community might look at them separately, but I think to a large extent these are three companies that are pretty much having similar economic and financial characteristics and I think to a large extent there is a view that although they are not a single company, they shouldn't be viewed entirely separate either.

And in addition to that I'm emphasizing the fact that we're setting a -- we are trying to set a fair and reasonable return for one return for three companies. We feel that what we have is a situation where the costs of capital are really shared in them. If we were setting three separate rates of return, which I suppose could be done, then we might not want to look at the companies together.

So I think a lot depends upon -- you know, the methodology we choose depends upon the purpose to which it's put.

Q. Look at page 10 of your testimony, lines 7 to 9. You state that your group of comparable companies includes companies with little revenue from electric service and gas utilities; is that correct?

A. I'm sorry, could I have that again? On 7 to 9?

Q. Right. Hold on one second, please. Strike that question.

Let's move to page 12, please. On page 12, lines 6 to 15, you discuss the geometric versus the arithmetic means and you used arithmetic means in your CAPM analysis; is that correct?

A. That's correct.

Q. Do you agree with me that CAPM is based on the theory that the expected return on an asset is related to the expected market risk premium?

A. Yes, I do. I think we'll find out in a moment.

Q. Still on page 12, lines 11 to 15, starting with "Ibbotson prefers the arithmetic," do you see that?

A. Yes, I do.

Q. Isn't it using an average of historical returns -- excuse me, strike that.

Isn't using an average of historical returns reporting past performance?

A. First, I would note that any average of historical returns, whether arithmetic or geometric or random sample, would be reporting past performance. And I personally don't know of a precise way to report future performance, so I'm not sure what other performance there can be assuming performance of some kind of warranted. But if you're laying foundation, I'll certainly agree with you.

Q. Thank you, counselor.

Were you here when OCC witness Adams was cross-examined by FirstEnergy regarding a book titled "Valuation, Measuring and Managing the Value of Companies"? Does that sound familiar?

A. The cross-examination, the book -- I was here when it was discussed in cross-examination, yes, sir.

Q. Okay. Do you remember there was some back and forth on first edition, second edition, third edition?

A. Yes, oh, yes.

Q. I wanted to see what I could -- what I'd have for you I'd like for you to review is the fourth edition of this book.

MR. REESE: If I might the approach, your Honor.

EXAMINER BOJKO: You may.

MR. REESE: May I approach witness, please?

EXAMINER BOJKO: You may.

Q. Now to paraphrase Mr. Korkosz the other day, it's with great trepidation that I approach this, but you'll recall that we had a discussion regarding the arithmetic mean versus the use of the geometric mean that began with the discussion of the CAPM. That sound familiar?

A. Painfully so.

Q. I agree. I want to call your attention to page 299 of the handout that I gave you, if I can identify this, this is what's noted to be the fourth edition -- the first inside page, Mr. Cahaan, if you'll note up at the upper left, does that appear to list four editions?

MR. McNAMEE: I'm going to object as soon as you're done asking.

MR. REESE: You are?

MR. McNAMEE: I am.

MR. REESE: Sure looked like one already.

MR. McNAMEE: I thought you were done. I'm sorry.

Q. Does this look to be the fourth edition that we're looking at here? Do you see the copyright, 1990, 1994, 2000, 2005?

A. Yes, I do.

Q. Okay.

A. Those four dates.

Q. Looks like back on the front cover here it's the publisher McKinsey & Company, authors Tim Koller, Marc Goedhart and David Wessels. Does that look familiar or is that --

A. That's what it says. That's what the book you handed me says.

Q. I'm correct.

A. Yeah.

Q. All right. Let me bring your attention to what's been copied here from pages 291 through 330, chapter's entitled "Estimating the Cost of Capital." Do you see that?

A. Yes.

Q. Okay. There is a question approaching.

Would you please read for me at the bottom of page 299 the sentence or the paragraph that begins "So which averaging method," read that paragraph to its conclusion at the top of page 300. Could you read that for me?

MR. McNAMEE: Object.

EXAMINER BOJKO: Grounds?

MR. McNAMEE: As this document has been provided with no foundation at all, reading its contents are irrelevant at this point so reading from an irrelevant document serves no purpose. We need a foundation essentially.

MR. KORKOSZ: If I may, I would echo the objection on the basis of foundation noting that the fourth -- so-called fourth edition that has been distributed by authors Tim Koller, Mark Goedhart, David Wessels, only one of those three is the author of the first three editions that were discussed earlier, and I would refer the Bench to page 43, footnote 3 of Mr. Aster's testimony to support that fact.

MR. REESE: Your Honor, Mr. Adams was questioned at great length about the four volumes of the publication entitled "Valuation, Measuring and

Managing the Value of Companies." There were three different editions of this particular book that were discussed by Mr. Korkosz with Mr. Adams. The subject was -- the use of -- the use of the arithmetic versus the geometric mean. Mr. Cahaan discusses that in his testimony. Mr. Adams discussed it in his testimony. And the quote, if you will, the cites from the document that I'm about to ask Mr. Cahaan to read into the record go to that issue.

I believe the -- I'm sorry.

EXAMINER BOJKO: The objections, plural, are sustained. You've laid no foundation to determine whether this witness, I don't particularly care right now about Mr. Adams' and Mr. Korkosz's discussion, this is a different witness and you have not laid any foundation of whether he is familiar with this book or took anything from this book.

Q. (By Mr. Reese) Mr. Cahaan, are you familiar with this publication?

A. No. I have not seen this book before.

Q. Were you here for the cross-examination of Mr. Adams?

A. Oh, I saw the predecessors to this book waved in front of, you know, up here, but I never saw the contents of the book. The covers were visible.

Q. Would you agree with me that there is some difference of opinion in the academic community regarding the use of the arithmetic versus the geometric mean?

A. I would not only agree with you about that, but I would note that there seem to be differences in the academic community about a large number of other issues in terms of the proper way of conducting cost of capital research.

I also note that in the various testimonies that have been provided in this case there have been some people who say the DCF is unreliable and the CAPM is reliable, and other people say the CAPM is unreliable and the DCF is reliable.

There seem to be huge differences of opinions in the entire field. There seem to be very, very interesting arcane esoteric discussions of technique and methodology that are very, very valuable to the development of the field as an intellectual exercise. To an extent from the point of -- from my point of view I see this as looking at different editions or rather different -- if there was a consumer report for hammers, for instance, that discussed all the various different hammers as to whether a 20-ounce hammer and a 16-ounce hammer and a 12-ounce hammer versus and a steel shank or a wood shank or Fiberglas shank and looked at all these things and made various recommendations as to the best hammer, that would be interesting, but the really interesting thing is what is the hammer used for and can the person wielding it actually hit the nail.

So I'm not sure that the differences in the techniques are as important as to whether the results make sense. Thank you.

Q. If I could stand up, I would. Okay.

Mr. Cahaan, isn't it true that when -- in regarding market risk premium isn't it true that when compounded, the arithmetic average will be biased upward?

A. I'd have to review things -- review that in various publications that you'd like to send me to. We are stating that we believe that the arithmetic method is the appropriate method. Ibbotson says it is. Other people may say that it may be biased upward. I'm willing to grant for the purpose of argument that it may. The question is:

Are reasonable results produced by various methods or not?

So if you're having only one method, then you might look very closely at whether there's any theoretical bias in that method. If you're using a number of methods, I think it's also important or more important actually to look at what the results are from the methods and whether the results tell you anything. If you're shooting at a target, you want to see where the cluster is of the shots.

Q. Let's go to page 13 and 14 of your testimony. There's a discussion on page 13 of your testimony, begins at page 13 regarding the discounted cash flow analysis. Do you see that?

A. Yes, I do.

Q. Staff used the historical average growth rate of the GNP; is that correct?

A. That's correct.

Q. Can you explain why investors in the companies, the operating companies, look at the growth rate of the GNP when they make decisions to buy FirstEnergy stocks rather than analyzing the earnings and dividends and expected growth rates of FirstEnergy and comparable companies?

A. As the question is phrased, I think the answer is no. This is similar to the question as to does an expert pool player sit and calculate angles of momentum and velocity and other things. There's a model that is similar to the mathematical models of pool that would actually -- that purports anyway to describe how investors must behave. Whether they consciously do behave that way is not part of what the model is purporting to say.

However, the question is how are investor expectations formed? Now, you're suggesting in the question, you said rather than and there were a batch of words there, that those methods would be superior and those methods would be sufficient. I'm not sure from the words that you just used whether those would be sufficient, whether investors would have the ability to make projections of what amounts to earnings growth to infinity from the variables that you specified.

Q. Go to page 17 of your testimony, lines 15 to 20.

A. Yes, I see it.

Q. Let's focus -- I'm sorry, let's focus on page 19, lines 7 to 10. You state that any rate of return within your proposed range is reasonable; is that correct?

A. Yes.

Q. Would the Commission's approval of the low end of the staff proposed rate of return range be in any way confiscatory?

A. Not from the perspective of staff. The staff's view is that the range that we propose is an estimate of the cost of capital and that range reflects the uncertainty with respect to precisely estimating cost of capital; therefore, this uncertainty -- strike that.

Therefore, any point within that range is equally reflective of what we think is the cost of capital. It is not confiscatory if the company is awarded its cost of capital or, to be precise, awarded the opportunity to earn its cost of capital.

Q. Let's go to page 21 of your testimony.

A. Yes.

Q. Let's look at the quoted line 2 where you're talking about the staff had grave misgivings when you considered the stand-alone capital structure and that the capital structures of the three individual operating companies posed problems. That cite I gave is line 2, the rest of it carries over down to line 16.

A. We may have different editions of my testimony. I'm not sure. I've got the one that I --

Q. I think this is the fourth edition.

A. This is the one that was docketed. I don't see --

Q. This is the most recent version of your testimony.

A. Okay.

Q. Page 21, lines 2 and 16. I'm sorry for the confusion. You state that we had -- quote/unquote, "we had grave misgivings."

A. Page 21, line 2, yes.

Q. Yeah, that's correct.

A. That's there, I got it.

Q. And that's regarding considering the stand-alone capital structure. And that, down to line 16, "A capital structure of the three individual operating companies posed problems." Do you see that?

A. Yes. This is what we were -- you were asking about earlier, I believe.

Q. Can you elaborate again what those

problems were?

A. They were conceptual in the sense that two of the companies had capital structures that were -- well, I can't remember which company was which offhand and I can't remember the numbers offhand, but the catch was that two of the companies had capital structures that were leveraged one way, one of the companies had a capital structure leveraged the other way in terms of regarding around the 50/50 line, and since the business risks and all the financial considerations of the companies seemed to be fairly similar, it is not clear why each individual capital structure was the way it was considering the pattern.

This is one of the concerns that we discussed at length at the workshop in terms of using something other than the parent consolidated capital structure is that the individual capital structures can possibly be arbitrary in a sense, can be simply the result of historical events of when financings happen to have been needed and things like that.

So that some degree of judgment would be necessary in terms of whether to accept any capital structure as is. This was what came out of that workshop.

We believe that it is appropriate to accept the combination of these companies, that that capital structure does make sense, at least it makes sense to us, whereas, the individual capital structures seem to be biased -- not biased, determined to an extent by historical acts and need to be whatever they are.

Q. And so far this has just been applied to FirstEnergy, correct?

A. We're groping our way through the fog away from parent consolidated from that wonderful system that worked as long as we had fully integrated regulated utilities and stuff like that and we're -- this is the first, yes.

Q. Okay. Now let's try a couple questions up on page 23 of your testimony. I believe my cite now will be to just lines 7 to 9 of your testimony there because I believe you struck parts of lines 6 and 7 and parts of line 9 through 14; is that correct?

A. Yes.

Q. Okay. Now, the adjustment in the return on equity of 3 to 4 basis points is addressing the lower leverage on average; is that correct?

A. No, that was the confusion that I -- that occurred and that's what I wished to clarify. It is not that.

As you note, one of the reasons my testimony was not filed earlier was that I was out of the country in Havana actually for three weeks and this visit had been arranged a long time ago and had gotten U.S. government clearance and couldn't be changed, and so I came back and had to join the party, shall we say, at a late date.

We had discussions, we had changed the -- revised our opinion from the time of the Staff Report to the time -- to the later time in terms of using the combined EDU capital structure and there was also an adjustment that had been decided upon, and in discussions I frankly was -- when I started to write the testimony in the flurry and postvacation condition I was confused as to what the reason was for this 3 to 4 basis point adjustment.

The reason for the 3 to 4 basis point adjustment is -- let me refer to it. The reason for the rounding down was that the comparable group that was used contained some companies, some of the electric companies, that had or might have some degree of POLR risk.

The FirstEnergy cost of capital recommendation that we are making is very specifically not incorporating any POLR risk. This question of POLR risk has been brought up a number of times in these proceedings to -- and I'd like to make sure that it's clarified at least as far as the staff is concerned, that the staff believes that -- let me start this last sentence again.

In the workshop we addressed the issue of POLR risk for EDUs and the staff comments that came out after the workshop addressed this very specifically, and I'd like to read what we said at that time because that's what our position is now, and this was sort of the agreement of all the parties at the workshop. Although I can't speak for everybody, of course.

I'm reading this. The second question discussed concerning compensation for the risk involved in the legal responsibility of being the provider of last resort (POLR). Three important points were brought out in the discussion. One: Care should be exercised in providing for POLR risk so as not to create a situation of moral hazard. Two: The ideal policy is to eliminate the POLR risk or mitigate it to the greatest extent possible. Three: To the extent that this risk cannot be mitigated, it should be compensated.

We are in a situation where we have a wires company, an EDU, in a distribution case and although legally it has a POLR responsibility going forward, the nature of what that is is totally unclear. The company has an application for an auction before the Commission, this application is I think in the state of suspended animation pending events across the street and legislative activities, but that application basically reduces the POLR risk to zero for the company. It auctions it off, in effect.

Everybody agreed that if the POLR risk exists, it should be mitigated and if not mitigated, compensated, and the catch is nobody knows how much the risk is because we don't know the institutional structure that will exist at the time of the EDU's rates that are in effect or being set here.

Therefore, the staff very strongly believes that this proceeding should not give any award or rate of return compensation for POLR risk and that if POLR risk does exist, then at that time the company should come in and ask for compensation for it. But right now there may be no compensable POLR risk and this is totally unknown.

Given that some of the comparable group were electric utilities that had actual, what the company calls asymmetric risks regarding POLR, we felt it was, therefore -- there was an overestimate of the cost of capital and we needed to reduce it for that reason, we rounded down to nice round numbers given the fact that we have no idea how much to reduce by and did not want to give any impression of what I call spurious precision or whatever it is I --

Q. Spurious accuracy.

A. Spurious accuracy, thank you. So rounding it down those basis points was the appropriate direction, it may be the right amount, it may be too little amount, we frankly don't know and everybody can argue whatever they want because I don't think there is any way of technically knowing how much the POLR risk that's embedded in the other comparable group companies is.

But that was the reason for it. I had

gotten confused as to what the reason for it was and I wrote testimony based upon my confusion. I was made unconfused about it after the testimony was docketed and that's what I'm doing now, in addition to which there seemed to be tremendous confusion regarding the nature of POLR compensation in these proceedings and I wanted to address that issue at length, that's why I did so.

Q. Okay.

MR. REESE: Can I have like 60 seconds?

OCC has no further questions.

EXAMINER BOJKO: Mr. Korkosz, before you begin I'd like to take just a five-minute break and let's keep it to five minutes so we can get done in a reasonable time. Five minutes.

(Recess taken.)

EXAMINER BOJKO: Let's go back on the record. It's Friday afternoon, we want to wrap up.

Mr. Korkosz.

MR. KORKOSZ: Thank you, your Honor.

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CROSS-EXAMINATION

By Mr. Korkosz:

Q. Mr. Cahaan, you started with a correction to your testimony on page 25 correcting the 10.31 percent to 10.27 percent, correct?

A. Yes.

Q. Should that same correction be made to page 23, line 21?

A. Yes, thank you very much.

Q. During your examination you spoke of the generation case that was filed, and I think I copied accurately that you said that that application reduces POLR risk to zero. Do you recall that?

A. The proposed auction case.

Q. Yes, that's correct.

A. Yes.

Q. You recall that.

A. Yes.

Q. You didn't mean to suggest, did you, that the mere filing of that application alone reduces the risk, did you?

A. No, I meant that the process embedded in that application would result in no asymmetric financial risk to the company that was conducted -- to FirstEnergy. That's what I meant after the -- in effect, at the time.

Whether there is -- let me just stop there.

Q. And I think you said that we don't have a conclusion of that proceeding yet, correct?

A. Certainly not.

Q. Is this the first electric base rate case to actually go to hearing since the passage of SB3, to your knowledge?

A. I'm seeing people in the room shake their heads yes.

Q. Do you trust them?

A. I'll trust them.

Q. Well, let me try it this way. There was a Dayton case that was filed in about 2005 or so and that was settled, was it not?

A. I believe so.

Q. And then in about -- at around that same time there was a Cincinnati case before their merger with Duke that was filed and that was also settled, if you'll recall.

A. I'll accept that. Somebody will correct me if I'm wrong.

Q. You can't think of any other electric cases that have come up since SB3, can you?

A. This is like on Millionaire polling the audience. No.

MR. KORKOSZ: Thank you, Mr. Cahaan. Thank you.

EXAMINER BOJKO: Any redirect?

MR. McNAMEE: No.

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EXAMINATION

By Examiner Bojko:

Q. I just have a couple questions, Mr. Cahaan. In your testimony quickly could you turn to page 9?

A. Yes.

Q. On line 13 there's a statement "The Staff Report incorrectly excluded." I just want to confirm that you were summarizing OCC's position there. That's not your assertion, is it?

A. Yes.

Q. Then if you could turn to page 19, I want to ask a couple additional questions. You state that you're giving the Commissioners some flexibility, but you had listed off nine issues under my calculation of items that people -- parties in this proceeding have suggested should affect either up or down the rate of return analysis and I'd like to get your brief opinion on some of those issues starting with the first one being on page 16 which is the execution of contracts for one or two years, that creating a revenue floor for the distribution service and that effect on the rate of return if you have a -- obviously, if you don't have an opinion to some of these, let me know.

A. I think I have a general opinion to them all and that opinion is that parties have brought these issues before this proceeding and made representations that certain conditions exist and are arguing, therefore, the Commission should choose to reward or penalize depending on which party the company based upon the evidence that they have provided.

Opposing parties have had the opportunity to provide information regarding those issues. On some of these issues the staff has provided information. So the record contains all that exists in terms of both factual information regarding all these issues and representations of parties regarding what should be done.

The Commission -- no single issue as far as the staff's concerned is dispositive and should be determining whether the company should get a number that's high or low. It's the totality of all the issues. The judgment as to what is the totality of all issues depends upon how one views the weight of the record on these issues. That's not a staff job. That's a policy type of job of consideration and the staff cannot really add various issues together and say here's what should happen.

And if we haven't already addressed these things, the staff can -- doesn't feel it should even weigh in on them. For instance, there was discussion about tree trimming, the staff gave facts on that. Other people made judgments about that, certainly in one direction, I don't know if it's in both directions, these will be considered by the Commission in determining whether to go high or low in terms of the rate of return in light of all other similar considerations.

What we put forward in this from the rate of return is a cost of capital analysis that provides a range, but the judgment as to where in the range is not a technical decision, it is not a technical subject that can be addressed by staff on a technical basis.

Q. Staff is not making a policy -- taking a policy position on those either then, is that your --

A. To the extent that they have taken a policy position, for instance on tree trimming, they've expressed it. But to put this all together in terms of a recommendation is something that staff is -- it's not that it cannot be done by a technical staff, it is a judgmental thing for the Commission to do.

Q. And I appreciate your reference to other staff members but I think at least in one instance this issue was punted to you, so to speak, because you were the rate of return person, and so I'm asking you specifically beyond what we've already heard in hearing you are not here today to make additional policy statements or to connect anything that was technically spoken about to the rate of return adjustments either way.

A. That's neither my job nor do I think that's the staff's job. I think that would be acting improperly and presumptuous on Commission authority.

EXAMINER BOJKO: I believe that answers

all my questions, thank you.

You are excused, Mr. Cahaan.

MR. McNAMEE: Staff would move for the admission of Staff Exhibit 20.

EXAMINER BOJKO: Any opposition to the admission of Staff Exhibit 20?

Hearing none, it will be so admitted.

(EXHIBIT ADMITTED INTO EVIDENCE.)

EXAMINER BOJKO: As determined I believe on Wednesday, the hearing today will be continued until Friday, February 22nd, at 9 a.m., where we will take rebuttal witnesses at that time and further testimony.

All parties are to file all rebuttal testimony that they may have by 5 p.m. on Wednesday, February 20th, and that includes electronic service at 5 o'clock as well.

Additionally, if parties have multiple rebuttal witnesses, it would be helpful if they could e-mail to all the parties including the Attorney Examiners a witness list, I guess particularly for FirstEnergy because you mentioned you have about eight or nine or ten or that number, obviously recognizing that Mr. Vilbert will go on Monday, and then OCC witness or witnesses will follow thereafter, and we'll address any other parties that might have rebuttal testimony at that time as well.

Anything additional for the record before we adjourn until Friday, the 22nd?

Hearing nothing, we are adjourned.

(The hearing was concluded at 4:47 p.m.)

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CERTIFICATE

I do hereby certify that the foregoing is a true and correct transcript of the proceedings taken by me in this matter on Friday, February 15, 2008, and carefully compared with my original stenographic notes.

Maria DiPaolo Jones
Maria DiPaolo Jones, Registered
Diplomate Reporter and CRR.

(MDJ-3140)

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EXHIBIT

07-551-EL-AIR
07-552-EL-ATA
07-553-EL-AAM
Case Number 07-554-EL-UNC

The following exhibit(s) were prefiled and can be located with the pleadings:

	Exhibits	Date Filed
16	Direct Testimony of Michael A. Castle	2/11/2008
17	Direct Testimony of Trisha J. Smith	2/11/2008
18	Direct Testimony of Robert B. Fortney	2/11/2008
19	Direct Testimony of L'Nard Tufts	2/11/2008
20	Direct Testimony of Richard C. Cahaan	2/12/2008
1	Direct Testimony of Bill Faith	1/10/2008
2	Direct Testimony of Michael R. Smalz	1/10/2008

EXHIBIT

2006 DISTRIBUTION DEFERRAL CAP CALCULATION WITHOUT CARRYING CHARGES

Description	Location Reference	CEI (A)	OE (B)	TE (C)	Total (D = A+B+C)
(1) 2006 Total O&M Expenses Over Base Rate Amounts	Exh. MAC-1 (Pgs 3, 9 & 15) of 19 Line 8)	$42,119,204	$73,359,476	$29,811,399	$145,290,079
(2) Capital Related Deferrals	Exh. MAC-1 (Pgs 4, 10 & 16) of 19 Line 11)	3,240,425	2,925,089	1,331,889	7,497,403
(3) **2006 Total**					$152,787,482
(4) 2006 Total Eligible O&M Expenses - RCP Attachment 2	Exh. MAC-1 (Pgs 3, 9 & 15) of 19 Line 9)	$57,236,103	$73,953,264	$23,612,475	$154,801,842
(5) Capital Related Deferrals	Exh. MAC-1 (Pgs 4, 10 & 16) of 19 Line 11)	3,240,425	2,925,089	1,331,889	7,497,403
(6) **2006 Total**					$162,299,245

EXHIBIT

OCC Ex. 21

ANNUAL REPORT

FirstEnergy

(L) TAXES-

Details of the total taxes for the three years ended December 31, 2006 are shown in the following tables:

GENERAL TAXES	2006	2005	2004
		(In millions)	
Kilowatt-hour excise*	$241	$244	$236
State gross receipts*	159	151	140
Real and personal property	222	222	208
Social security and unemployment	83	79	76
Other	15	17	18
Total general taxes	$720	$713	$678

* *Collected from customers through regulated rates and included in revenue in the Consolidated Statements of Income.*

PROVISION FOR INCOME TAXES	2006	2005	2004
		(In millions)	
Currently payable-			
Federal	$519	$452	$289
State	116	142	135
	635	594	424
Deferred, net-			
Federal	147	72	245
State	28	110	39
	175	182	284
Investment tax credit amortization	(15)	(27)	(27)
Total provision for income taxes	$795	$749	$681

RECONCILIATION OF FEDERAL INCOME TAX EXPENSE AT STATUTORY RATE TO TOTAL PROVISION FOR INCOME TAXES:			
Book income before provision for income taxes	$2,053	$1,628	$1,588
Federal income tax expense at statutory rate	$719	$569	$556
Increases (reductions) in taxes resulting from-			
Amortization of investment tax credits	(15)	(27)	(27)
State income taxes, net of federal income tax benefit	94	165	111
Penalties	–	14	–
Amortization of tax regulatory assets	2	38	33
Preferred stock dividends	5	5	8
Other, net	(10)	(15)	–
Total provision for income taxes	$795	$749	$681

ACCUMULATED DEFERRED INCOME TAXES AS OF DECEMBER 31:			
Property basis differences	$2,595	$2,368	$2,348
Regulatory transition charge	457	537	785
Customer receivables for future income taxes	141	131	103
Deferred customer shopping incentive	219	321	252
Deferred sale and leaseback costs	(86)	(86)	(92)
Nonutility generation costs	(122)	(177)	(174)
Unamortized investment tax credits	(50)	(54)	(61)
Other comprehensive income	(260)	(18)	(219)
Retirement benefits	10	(135)	(280)
Lease market valuation liability	(331)	(361)	(420)
Oyster Creek securitization (Note 10(D))	162	173	184
Loss carryforwards	(426)	(417)	(463)
Loss carryforward valuation reserve	415	402	420
Asset retirement obligations	45	65	71
Nuclear decommissioning	(116)	(105)	(100)
All other	87	82	(30)
Net deferred income tax liability	$2,740	$2,726	$2,324

FirstEnergy records income taxes in accordance with the liability method of accounting. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and loss carryforwards and the amounts recognized for tax purposes. Investment tax credits, which were deferred when utilized, are being amortized over the recovery period of the related property. Deferred income tax liabilities related to temporary tax and accounting basis differences and tax credit carryforward items are recognized at the statutory income tax rates in effect when the liabilities are expected to be paid. Deferred tax assets are recognized based on income tax rates expected to be in effect when they are settled (See Note 9 for Ohio Tax Legislation discussion).

FirstEnergy has certain tax returns that are under review at the audit or appeals level of the IRS and certain state authorities. Reserves have been recorded, and final settlement of these audits is not expected to have an adverse impact on the financial condition or results of operations of FirstEnergy.

FirstEnergy has capital loss carryforwards of approximately $1 billion, most of which expire in 2007. The deferred tax assets associated with these capital loss carryforwards of ($374 million) are fully offset by a valuation allowance as of December 31, 2006, since management is unable to predict whether sufficient capital gains will be generated to utilize all of these capital loss carryforwards. Any ultimate utilization of capital loss carryforwards for which valuation allowances were established through purchase accounting would adjust goodwill.

During 2006 a ($15) million net change in valuation allowance occurred due to Pennsylvania tax law changes and the utilization of capital loss carryforwards to offset realized capital gains resulting in a $1 million adjustment to goodwill. The valuation allowances also include $48 million for deferred tax assets associated with impairment losses related to certain assets.

FirstEnergy has pre-tax net operating loss carryforwards for state and local income tax purposes of approximately $1.034 billion of which $184 million is expected to be utilized. The associated deferred tax assets are $11 million. These losses expire as follows:

Expiration Period	Amount
	(In millions)
2007-2011	$ 332
2012-2016	37
2017-2021	297
2022-2026	368
	$1,034

3. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

FirstEnergy provides noncontributory defined benefit pension plans that cover substantially all of its employees. The trusteed plans provide defined benefits based on years of service and compensation levels. The Company's funding policy is based on actuarial computations using the projected unit credit method. On January 2, 2007 FirstEnergy made a $300 million voluntary cash contribution to its qualified pension plan. Projections indicated that additional cash contributions will not be required before 2016.

FirstEnergy provides a minimum amount of noncontributory life insurance to retired employees in addition to optional contributory insurance. Health care benefits, which include certain employee contributions, deductibles and co-payments, are also available upon retirement to employees hired prior to January 1, 2005, their dependents and, under certain circumstances, their survivors. The Company recognizes the expected cost of providing other postretirement benefits to employees and their beneficiaries and covered dependents from the time employees are hired until they become eligible to receive those benefits. During 2006, FirstEnergy amended the OPEB plan effective in 2008 to cap the monthly contribution for many of the retirees and their spouses receiving subsidized healthcare coverage. In addition, FirstEnergy has obligations to former or inactive employees after employment, but before retirement for disability related benefits.

Pension and OPEB costs are affected by employee demographics (including age, compensation levels, and employment periods), the level of contributions made to the plans and earnings on plan assets. Such factors may be further affected by business combinations which impact employee demographics, plan experience and other factors. Pension and OPEB costs may also be affected by changes in key assumptions, including anticipated rates of return on plan assets, the discount rates and health care trend rates used in determining the projected benefit obligations and pension and OPEB costs. FirstEnergy uses a December 31 measurement date for its pension and OPEB plans. The fair value of the plan assets represents the actual market value as of December 31, 2006.

In December 2006, FirstEnergy adopted SFAS 158. This Statement requires employers to recognize an asset or liability for the overfunded or underfunded status of their pension and other postretirement benefit plans. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. The Statement required employers to recognize all unrecognized prior service costs and credits and unrecognized actuarial gains and losses in AOCL, net of tax. Such amounts will be adjusted as they are subsequently recognized as components of net periodic benefit cost or income pursuant to the current recognition and amortization provisions. The incremental impact of adopting SFAS 158 was a decrease of $1.0 billion in pension assets, a decrease of $383 million in pension liabilities and a decrease in AOCL of $327 million, net of tax.

Obligations and Funded Status As of December 31

	Pension Benefits		Other Benefits	
	2006	**2005**	**2006**	**2005**
	(In millions)			
Change in benefit obligation				
Benefit obligation as of January 1	$4,750	$4,364	$1,884	$ 1,930
Service cost	83	77	34	40
Interest cost	266	254	105	111
Plan participants' contributions	–	–	20	18
Plan amendments	3	15	(620)	(312)
Medicare retiree drug subsidy	–	–	6	–
Actuarial (gain) loss	33	310	(119)	197
Benefits paid	(274)	(270)	(109)	(100)
Benefit obligation as of December 31	$4,861	$4,750	$1,201	$ 1,884
Change in fair value of plan assets				
Fair value of plan assets as of January 1	$4,524	$3,969	$ 573	$ 564
Actual return on plan assets	568	325	69	33
Company contribution	–	500	54	58
Plan participants' contribution	–	–	20	18
Benefits paid	(274)	(270)	(109)	(100)
Fair value of plan assets as of December 31	$4,818	$4,524	$ 607	$ 573
Funded status	$(43)	$(226)	$ (594)	$(1,311)
Accumulated benefit obligation	$4,447	$4,327		

	Pension Benefits		Other Benefits	
	2006	**2005**	**2006**	**2005**
	(In millions)			
Amounts Recognized in the Statement of Financial Position				
Noncurrent assets	$ –	$1,023	$ –	$ –
Current liabilities	–	–	–	–
Noncurrent liabilities	(43)	–	(594)	(1,057)
Net asset (liability) as of December 31	$ (43)	$1,023	$ (594)	$(1,057)
Amounts Recognized in Accumulated Other Comprehensive Income				
Prior service cost (credit)	$ 63	$ –	$(1,190)	$ –
Actuarial loss	982	–	702	–
Net amount recognized	$1,045	$ –	$ (488)	$ –
Assumptions Used to Determine Benefit Obligations As of December 31				
Discount rate	6.00%	5.75%	6.00%	5.75%
Rate of compensation increase	3.50%	3.50%		
Allocation of Plan Assets As of December 31				
Asset Category				
Equity securities	64%	63%	72%	71%
Debt securities	29	33	26	27
Real estate	5	2	1	–
Private equities	1	–	–	–
Cash	1	2	1	2
Total	100%	100%	100%	100%

Estimated Items to be Amortized in 2007 Net Periodic Pension Cost from Accumulated Other Comprehensive Income

	Pension Benefits	Other Benefits
	(In millions)	
Prior service cost (credit)	$10	$(149)
Actuarial loss	$41	$ 45

Components of Net Periodic Benefit Costs

	Pension Benefits			Other Benefits		
	2006	**2005**	**2004**	**2006**	**2005**	**2004**
	(In millions)					
Service cost	$83	$77	$77	$34	$ 40	$ 36
Interest cost	266	254	252	105	111	112
Expected return on plan assets	(396)	(345)	(286)	(46)	(45)	(44)
Amortization of prior service cost	10	8	9	(76)	(45)	(40)
Recognized net actuarial loss	58	36	39	56	40	39
Net periodic cost	$21	$30	$91	$73	$101	$103

Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31

	Pension Benefits			Other Benefits		
	2006	**2005**	**2004**	**2006**	**2005**	**2004**
Discount rate	5.75%	6.00%	6.25%	5.75%	6.00%	6.25%
Expected long-term return on plan assets	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%
Rate of compensation increase	3.50%	3.50%	3.50%			

In selecting an assumed discount rate, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations.

The assumed rates of return on pension plan assets consider historical market returns and economic forecasts for the types of investments held by the Company's pension trusts. The long-term rate of return is developed considering the portfolio's asset allocation strategy.

FirstEnergy employs a total return investment approach whereby a mix of equities and fixed income investments are used to maximize the long-term return on plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status, and corporate financial condition. The investment portfolio contains a diversified blend of equity and fixed-income investments. Furthermore, equity investments are diversified across U.S. and non-U.S. stocks, as well as growth, value, and small and large capitalization funds. Other assets such as real estate are used to enhance long-term returns while improving portfolio diversification. Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives are not used to leverage the portfolio beyond the market value of the underlying investments. Investment risk is measured and monitored on a continuing basis through periodic investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

Assumed Health Care Cost Trend Rates As of December 31	2006	2005
Health care cost trend rate assumed for next year (pre/post-Medicare)	9-11%	9-11%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5%	5%
Year that the rate reaches the ultimate trend rate (pre/post-Medicare)	2011-2013	2010-2012

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(In millions)	
Effect on total of service and interest cost	$ 6	$ (5)
Effect on accumulated postretirement benefit obligation	$33	$(29)

Taking into account estimated employee future service, FirstEnergy expects to make the following benefit payments from plan assets:

	Pension Benefits	Other Benefits
	(In millions)	
2007	$ 247	$ 91
2008	249	91
2009	256	94
2010	269	98
2011	280	101
Years 2012-2016	1,606	537

FirstEnergy also maintains two unfunded benefit plans, an Executive Deferred Compensation Plan (EDCP) and Supplemental Executive Retirement Plan (SERP) under which non-qualified supplemental pension benefits are paid to certain employees in addition to amounts received under the Company's qualified retirement plan, which is subject to IRS limitations on covered compensation. See Note 4(C) for a discussion regarding the stock compensation component of the EDCP. The net periodic pension cost of these plans was $21 million, $16 million and $14 million for the years ended 2006, 2005 and 2004, respectively. The projected benefit obligation and the unfunded status was $170 million and $161 million as of December 31, 2006 and 2005, respectively. The net liability recognized was $301 million and $238 million as of December 31, 2006 and 2005, respectively, and is included in the caption "retirement benefits" on the Consolidated Balance Sheets. The benefit payments, which reflect future service, as appropriate, are expected to be as follows:

	Benefit Payments
	(In millions)
2007	$7
2008	9
2009	8
2010	8
2011	9
Years 2012-2016	61

4. STOCK-BASED COMPENSATION PLANS

FirstEnergy has four stock-based compensation programs: LTIP; EDCP; ESOP; and DCPD. FirstEnergy has also assumed responsibility for several stock-based plans through acquisitions. In 2001, FirstEnergy assumed responsibility for two stock-based plans as a result of its acquisition of GPU. No further stock-based compensation can be awarded under GPU's Stock Option and Restricted Stock Plan for MYR Group Inc. Employees (MYR Plan) or 1990 Stock Plan for Employees of GPU, Inc. and Subsidiaries (GPU Plan). All options and restricted stock under both plans have been converted into FirstEnergy options and restricted stock. Options under the GPU Plan became fully vested on November 7, 2001, and will expire on or before June 1, 2010. Under the MYR Plan, all options and restricted stock maintained their original vesting periods, which ranged from one to four years. As of February 2006, all awards under the MYR Plan were exercised. The Centerior Equity Plan (CE Plan) is an additional stock-based plan administered by FirstEnergy for which it assumed responsibility as a result of the acquisition of Centerior Energy Corporation in 1997. All options are fully vested under the CE Plan, and no further awards are permitted. There were no outstanding options at December 31, 2006 under the CE Plan.

Effective January 1, 2006, FirstEnergy adopted SFAS 123(R), which requires the expensing of stock-based compensation. Under SFAS 123(R), all share-based compensation cost is measured at the grant date based on the fair value of the award, and is recognized as an expense over the employee's requisite service period. FirstEnergy adopted the modified prospective method, under which compensation expense recognized in the year ended December 31, 2006 included the expense for all share-based payments granted prior to but not yet vested as of January 1, 2006. Results for prior periods were not restated.

Prior to the adoption of SFAS 123(R) on January 1, 2006, FirstEnergy's LTIP, EDCP, ESOP, and DCPD stock-based compensation programs were accounted for under the recognition and measurement principles of APB 25 and related interpretations. Under APB 25, no compensation expense was reflected in net income for stock options as all options granted under those plans have exercise prices equal to the market value of the underlying common stock on the respective grant dates, resulting in substantially no intrinsic value. The pro forma effects on net income for stock options were instead disclosed in a footnote to the financial statements. Under APB 25 and SFAS 123(R), compensation expense was recorded in the income statement for restricted

EXHIBIT

OCC Ex. 22

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THIS FILING IS	
Item 1: [X] An Initial (Original) Submission	OR [ ] Resubmission No. ____

Form 1 Approved
OMB No. 1902-0021
(Expires 7/31/2008)
Form 1-F Approved
OMB No. 1902-0029
(Expires 6/30/2007)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 6/30/2007)

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FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Ohio Edison Company	End of 2006/Q4

FERC FORM No.1/3-Q (REV. 02-04)

the sale and leaseback arrangements that are legally restricted for purposes of settling the nuclear decommissioning ARO. As of December 31, 2006, the fair value of the decommissioning trust assets was $118 million.

FIN 47 provides accounting standards for conditional retirement obligations associated with tangible long-lived assets, requiring recognition of the fair value of a liability for an ARO in the period in which it is incurred if a reasonable estimate can be identified. FIN 47 states that an obligation exists even though there may be uncertainty about timing or method of settlement and further clarifies SFAS 143, stating that the uncertainty surrounding the timing and method of settlement when settlement is conditional on a future event occurring should be reflected in the measurement of the liability not in the recognition of the liability. Accounting for conditional ARO under FIN 47 is the same as described above for SFAS 143.

The Company identified applicable legal obligations as defined under the new standard at its retired generating units, substation control rooms, service center buildings, line shops and office buildings, identifying asbestos as the primary conditional ARO. As a result of adopting FIN 47 in December 2005, the Company recorded a conditional ARO liability of $27 million (including accumulated accretion for the period from the date the liability was incurred to the date of adoption), an asset retirement cost of $9 million (recorded as part of the carrying amount of the related long-lived asset) and accumulated depreciation of $9 million. The Company recognized a regulatory liability of $1 million upon adoption of FIN 47 for the transition amounts related to establishing the ARO for asbestos removal from substation control room and service center buildings, therefore requiring a $26 million cumulative effect adjustment ($16 million net of tax) for unrecognized depreciation and accretion to be recorded as of December 31, 2005. The obligation to remediate asbestos, lead paint abatement and other remediation costs at the retired generating units was developed based on site specific studies performed by an independent engineer. The costs of remediation at the substation control rooms, service center buildings, line shops and office buildings were based on costs incurred during recent remediation projects performed at each of these locations, respectively. The conditional ARO liability was the developed utilizing an expected cash flow approach (as discussed in SFAC No. 7, "Using Cash Flow Information and Present Value in Accounting Measurements") to measure the fair value of the ARO. The Company used a probability weighted analysis to estimate when remediation payments would begin.

The following table describes the changes to the ARO balances during 2006 and 2005:

ARO Reconciliation	2006	2005
	(In millions)	
Balance at beginning of year	$ 83	$ 201
Transfers to FGCO and NGC	-	(138)
Accretion	5	13
Revisions in estimated cash flows	-	(20)
FIN 47 ARO upon adoption	-	27
Balance at end of year	$ 88	$ 83

20 - PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

FirstEnergy provides noncontributory defined benefit pension plans that cover substantially all of its employees. The trusteed plans provide defined benefits based on years of service and compensation levels. FirstEnergy's funding policy is based on actuarial computations using the projected unit credit method. FirstEnergy made a $300 million voluntary cash contribution to its qualified pension plan on January 2, 2007 (Company's share was $16 million). Projections indicated that additional cash contributions will not be required before 2016.

FirstEnergy provides a minimum amount of noncontributory life insurance to retired employees in addition to optional contributory insurance. Health care benefits, which include certain employee contributions, deductibles and co-payments, are also available upon retirement to employees hired prior to January 1, 2005, their dependents and, under certain circumstances, their survivors. The Companies recognize the expected cost of providing other postretirement benefits to employees and their beneficiaries and covered dependents from the time employees are hired until they become eligible to receive those benefits. During 2006, FirstEnergy amended the OPEB plan effective in 2008 to cap the monthly contribution for many of the retirees and their spouses receiving subsidized healthcare coverage. In addition, FirstEnergy has obligations to former or inactive employees after employment, but before retirement for disability related benefits.

Pension and other post-employment benefits (OPEB) costs are affected by employee demographics (including age, compensation levels, and employment periods), the level of contributions made to the plans and earnings on plan assets. Such factors may be further affected by business combinations which impact employee demographics, plan experience and other factors. Pension and OPEB costs may also be affected by changes in key assumptions, including anticipated rates of return on plan assets, the discount rates and health care trend rates used in determining the projected benefit obligations and pension and OPEB costs. FirstEnergy uses a December 31 measurement date for its pension and OPEB plans. The fair value of the plan assets represents the actual market value as of December 31, 2006.

In December 2006, FirstEnergy adopted SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans-an amendment of FASB Statements No. 87, 88, 106, and 132(R)" (SFAS 158). This Statement requires an employer to recognize an asset or liability for the overfunded or underfunded status of their pension and other postretirement benefit plans. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. The Statement required employers to recognize all unrecognized prior service costs and credits and unrecognized actuarial gains and losses in accumulated other comprehensive loss (AOCL), net of tax. Such amounts will be adjusted as they are subsequently recognized as components of net periodic benefit cost or income pursuant to the current recognition and amortization provisions. The Company's incremental impact of adopting SFAS 158 was a decrease of $187 million in pension assets, a decrease of $169 million in pension liabilities and a decrease in AOCL of $4 million, net of tax.

With the exception of the Company's share of the net pension (asset) liability at the end of year and net periodic pension expense, the following tables detail the Consolidated FirstEnergy pension plan and OPEB.

As of December 31	Pension Benefits 2006	Pension Benefits 2005	Other Benefits 2006	Other Benefits 2005
	(In millions)			
Change in benefit obligation				
Benefit obligation as of January 1	$ 4,750	$ 4,364	$ 1,884	$ 1,930
Service cost	83	77	34	40
Interest cost	266	254	105	111
Plan participants' contributions	--	--	20	18
Plan amendments	3	15	(620)	(312)
Medicare retiree drug subsidy	--	--	6	--
Actuarial (gain) loss	33	310	(119)	197
Benefits paid	(274)	(270)	(109)	(100)
Benefit obligation as of December 31	$ 4,861	$ 4,750	$ 1,201	$ 1,884
Change in fair value of plan assets				
Fair value of plan assets as of January 1	$ 4,524	$ 3,969	$ 573	$ 564
Actual return on plan assets	567	325	69	33
Company contribution	--	500	54	58
Plan participants' contribution	--	--	20	18
Benefits paid	(273)	(270)	(109)	(100)
Fair value of plan assets as of December 31	$ 4,818	$ 4,524	$ 607	$ 573
Funded status	$ (43)	$ (226)	$ (594)	$ (1,311)
Accumulated benefit obligation	$ 4,447	$ 4,327		
Amounts Recognized in the Statement of Financial Position				
Noncurrent assets	$ --	$ 1,023	$ --	$ --
Current liabilities	--	--	--	--
Noncurrent liabilities	(43)	--	(594)	(1,057)
Net pension asset (liability) as of December 31	$ (43)	$ 1,023	$ (594)	$ (1,057)
Company's share of net pension asset (liability) at end of year	$ 55	$ 183	$ (138)	$ (245)
Amounts Recognized in Accumulated Other Comprehensive Income				
Prior service cost (credit)	$ 63	$ --	$ (1,190)	$ --
Actuarial loss	982	--	702	--
Net amount recognized	$ 1,045	$ --	$ (488)	$ --
Assumptions Used to Determine Benefit Obligations As of December 31				
Discount rate	6.00%	5.75%	6.00%	5.75%
Rate of compensation increase	3.50%	3.50%		
Allocation of Plan Assets As of December 31				
Asset Category				
Equity securities	64%	63%	72%	71%
Debt securities	29	33	26	27
Real estate	5	2	1	--
Private equities	1	--	--	--
Cash	1	2	1	2
Total	100%	100%	100%	100%

Estimated Items to be Amortized in 2007 Net Periodic Pension Cost from Accumulated Other Comprehensive Income	Pension Benefits	Other Benefits
	(In millions)	
Prior service cost (credit)	$10	$ (149)
Actuarial loss	$41	$ 45

Components of Net Periodic Benefit Costs	Pension Benefits 2006	Pension Benefits 2005	Other Benefits 2006	Other Benefits 2005
		(In millions)		
Service cost	$ 83	$ 77	$ 34	$ 40
Interest cost	266	254	105	111
Expected return on plan assets	(396)	(345)	(46)	(45)
Amortization of prior service cost	10	8	(76)	(45)
Recognized net actuarial loss	58	36	56	40
Net periodic cost	$ 21	$ 30	$ 73	$ 101
Company's share of net periodic cost (credit)	$ (4)	$ 1	$ 14	$ 23

Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31	Pension Benefits 2006	Pension Benefits 2005	Other Benefits 2006	Other Benefits 2005
Discount rate	5.75%	6.00%	5.75%	6.00%
Expected long-term return on plan assets	9.00%	9.00%	9.00%	9.00%
Rate of compensation increase	3.50%	3.50%		

In selecting an assumed discount rate, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. The assumed rates of return on pension plan assets consider historical market returns and economic forecasts for the types of investments held by the Company's pension trusts. The long-term rate of return is developed considering the portfolio's asset allocation strategy.

FirstEnergy employs a total return investment approach whereby a mix of equities and fixed income investments are used to maximize the long-term return on plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status, and corporate financial condition. The investment portfolio contains a diversified blend of equity and fixed-income investments. Furthermore, equity investments are diversified across U.S. and non-U.S. stocks, as well as growth, value, and small and large capitalization funds. Other assets such as real estate are used to enhance long-term returns while improving portfolio diversification. Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives are not used to leverage the portfolio beyond the market value of the underlying investments. Investment risk is measured and monitored on a continuing basis through periodic investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

Assumed Health Care Cost Trend Rates As of December 31	2006	2005
Health care cost trend rate assumed for next year (pre/post-Medicare)	9-11%	9-11%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5%	5%
Year that the rate reaches the ultimate trend rate (pre/post-Medicare)	2011-2013	2010-2012

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(In millions)	
Effect on total of service and interest cost	$ 6	$ (5)
Effect on accumulated postretirement benefit obligation	$ 33	$ (29)

Taking into account estimated employee future service, FirstEnergy expects to make the following benefit payments from plan assets:

	Pension Benefits	Other Benefits
	(In millions)	
2007	$ 247	$ 91
2008	249	91
2009	256	94
2010	269	98
2011	280	101
Years 2012-2016	1,606	537

21 - FIRSTENERGY INTRA-SYSTEM GENERATION ASSET TRANSFERS

On May 13, 2005, Penn, and on May 18, 2005, the Ohio Companies entered into certain agreements implementing a series of intra-system generation asset transfers that were completed in the fourth quarter of 2005. The asset transfers resulted in the respective undivided ownership interests of the Ohio Companies and Penn in FirstEnergy's nuclear and non-nuclear generation assets being owned by NGC and FGCO, respectively. The generating plant interests transferred do not include the Company's leasehold interests in certain of the plants that are currently subject to sale and leaseback arrangements with non-affiliates.

On October 24, 2005, the Company completed the intra-system transfer of non-nuclear generation assets to FGCO. Prior to the transfer, FGCO, as lessee under a Master Facility Lease with the Ohio Companies and Penn, leased, operated and maintained the non-nuclear generation assets that it now owns. The asset transfers were consummated pursuant to FGCO's purchase option under the Master Facility Lease.

The difference (approximately $177.7 million which includes $2.7 million applicable to Penn) between the purchase price specified in the Master Facility Lease and the net book value at the date of transfer was credited to equity. FGCO also assumed certain assets and liabilities relating to the purchased units. As consideration, FGCO delivered to the Company promissory notes of approximately $1.0 billion that are secured by liens on the units purchased, bear interest at a rate per annum based on the weighted cost of the Company's long-term debt (3.98%) and mature twenty years after the date of issuance. FGCO may pre-pay a portion of the promissory notes through refunding from time to time of the Company's outstanding pollution control debt. The timing of any refunding will be subject to market conditions and other factors.

On December 16, 2005, the Company completed the intra-system transfer of its respective ownership in the nuclear generation assets to NGC through an asset spin-off by way of dividend. FirstEnergy Nuclear Operating Company (FENOC) continues to operate and maintain the nuclear generation assets.

The purchase price of the generation assets was the net book value as of September 30, 2005. The difference (approximately $20.5 million which includes $3.4 million applicable to Penn) between the purchase price and the net book value at the date of transfer was credited to equity. Pursuant to the Company's Contribution Agreement, the Company made a capital contribution to NGC of its undivided ownership interests in certain nuclear generation assets, the common stock of OES Nuclear Incorporated (OES Nuclear), a wholly owned subsidiary of the Company that held an undivided interest in Perry, together with associated decommissioning trust funds and other related assets. In connection with the contribution, NGC assumed other liabilities associated with the transferred assets. In addition, the Company received promissory notes from NGC in the principal amount of approximately $371.5 million representing the net book value of the contributed assets as of

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THIS FILING IS	
Item 1: [X] An Initial (Original) Submission	OR [ ] Resubmission No. ____

Form 1 Approved
OMB No. 1902-0021
(Expires 7/31/2008)
Form 1-F Approved
OMB No. 1902-0029
(Expires 6/30/2007)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 6/30/2007)

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FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Cleveland Electric Illuminating Company, The	End of 2006/Q4

asbestos removal from substation control room and service center buildings, therefore requiring a $6 million cumulative effect adjustment ($4 million, net of tax) for unrecognized depreciation and accretion to be recorded as of December 31, 2005. The obligation to remediate asbestos, lead paint abatement and other remediation costs at the retired generating units was developed based on site specific studies performed by an independent engineer. The costs of remediation at the substation control rooms, service center buildings, line shops and office buildings were based on costs incurred during recent remediation projects performed at each of these locations, respectively. The conditional ARO liability was developed utilizing an expected cash flow approach (as discussed in SFAC 7) to measure the fair value of the ARO. The Company used a probability weighted analysis to estimate when remediation payments would begin. The effect on income as if FIN 47 had been applied during 2004 is immaterial.

The following table describes the changes to the ARO balances during 2006 and 2005.

ARO Reconciliation	2006	2005
	(In millions)	
Balance at beginning of year	$ 8	$ 272
Liabilities settled	(6)	-
Transfers to FGCO and NGC	-	(247)
Accretion	-	17
Revisions in estimated cash flows	-	(41)
FIN 47 ARO	-	7
Balance at end of year	$ 2	$ 8

18 - PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

FirstEnergy provides noncontributory defined benefit pension plans that cover substantially all of its employees. The trusteed plans provide defined benefits based on years of service and compensation levels. FirstEnergy's funding policy is based on actuarial computations using the projected unit credit method. FirstEnergy made a $300 million voluntary cash contribution to its qualified pension plan on January 2, 2007 (Company's share was $25 million). Projections indicated that additional cash contributions will not be required before 2016.

FirstEnergy provides a minimum amount of noncontributory life insurance to retired employees in addition to optional contributory insurance. Health care benefits, which include certain employee contributions, deductibles and co-payments, are also available upon retirement to employees hired prior to January 1, 2005, their dependents and, under certain circumstances, their survivors. The Company recognizes the expected cost of providing other postretirement benefits to employees and their beneficiaries and covered dependents from the time employees are hired until they become eligible to receive those benefits. During 2006, FirstEnergy amended the other post-employment benefits (OPEB) plan effective in 2008 to cap the monthly contribution for many of the retirees and their spouses receiving subsidized healthcare coverage. In addition, FirstEnergy has obligations to former or inactive employees after employment, but before retirement for disability related benefits.

Pension and OPEB costs are affected by employee demographics (including age, compensation levels, and employment periods), the level of contributions made to the plans and earnings on plan assets. Such factors may be further affected by business combinations which impact employee demographics, plan experience and other factors. Pension and OPEB costs may also be affected by changes in key assumptions, including anticipated rates of return on plan assets, the discount rates and health care trend rates used in determining the projected benefit obligations and pension and OPEB costs. FirstEnergy uses a December 31 measurement date for its pension and OPEB plans. The fair value of the plan assets represents the actual market value as of December 31, 2006.

In December 2006, FirstEnergy adopted SFAS 158. This Statement requires an employer to recognize an asset or liability for the overfunded or underfunded status of their pension and other postretirement benefit plans. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. The Statement required employers to recognize all unrecognized prior service costs and credits and unrecognized actuarial gains and losses in AOCL, net of tax. Such amounts will be adjusted as they are subsequently recognized as components of net periodic benefit cost or income pursuant to the current recognition and amortization provisions. The Company's incremental impact of adopting SFAS 158 was a decrease of $135 million in pension assets, an increase of $39 million in pension liabilities and a decrease in AOCL of $104 million, net of tax.

With the exception of the Company's share of net pension (asset) liability at the end of year and net periodic pension expense, the following tables detail the Consolidated FirstEnergy pension plan and OPEB.

Obligations and Funded Status As of December 31	Pension Benefits 2006	Pension Benefits 2005	Other Benefits 2006	Other Benefits 2005
	(In millions)			
Change in benefit obligation				
Benefit obligation as of January 1	$ 4,750	$ 4,364	$ 1,884	$ 1,930
Service cost	83	77	34	40
Interest cost	266	254	105	111
Plan participants' contributions	-	-	20	18
Plan amendments	3	15	(620)	(312)
Medicare retiree drug subsidy	-	-	6	-
Actuarial (gain) loss	33	310	(119)	197
Benefits paid	(274)	(270)	(109)	(100)
Benefit obligation as of December 31	$ 4,861	$ 4,750	$ 1,201	$ 1,884
Change in fair value of plan assets				
Fair value of plan assets as of January 1	$ 4,524	$ 3,969	$ 573	$ 564
Actual return on plan assets	567	325	69	33
Company contribution	-	500	54	58
Plan participants' contribution	-	-	20	18
Benefits paid	(273)	(270)	(109)	(100)
Fair value of plan assets as of December 31	$ 4,818	$ 4,524	$ 607	$ 573
Funded status	$ (43)	$ (226)	$(594)	$ (1,311)
Accumulated benefit obligation	4,447	4,327		
Amounts Recognized in the Statement of Financial Position				
Noncurrent assets	$ -	$ 1,023	$ -	$ -
Current liabilities	-	-	-	-
Noncurrent liabilities	(43)	-	(594)	(1,057)
Net pension asset (liability) as of Dec 31	$ (43)	$ 1,023	$ (594)	$(1,057)
Company's share of net pension asset (liability) at end of year	$ (13)	$ 139	$ (110)	$ (83)
Amounts Recognized in Accumulated Other Comprehensive Income				
Prior service cost (credit)	$ 63	$ -	$ (1,190)	$ -
Actuarial loss	982	-	702	-
Net amount recognized	$ 1,045	$ -	$ (488)	$ -
Assumptions Used to Determine Benefit Obligations As of December 31				
Discount rate	6.00%	5.75%	6.00%	5.75%
Rate of compensation increase	3.50%	3.50%		
Allocation of Plan Assets As of December 31 Asset Category				
Equity securities	64%	63%	72%	71%
Debt securities	29	33	26	27
Real estate	5	2	1	-
Private equities	1	-	-	-
Cash	1	2	1	2
Total	100%	100%	100%	100%

Estimated Items to Be Amortized in 2007 Net Periodic Pension Cost from Accumulated Other Comprehensive Income	Pension Benifits	Other Benefits
	(In millions)	
Prior service cost (credit)	$ 10	$ (149)
Actuarial loss	$ 41	45

Components of Net Periodic Benefit Costs	Pension Benefits 2006	2005	Other Benefits 2006	2005
		(In millions)		
Service cost	$ 83	$ 77	$ 34	$ 40
Interest cost	266	254	105	111
Expected return on plan assets	(396)	(345)	(46)	(45)
Amortization of prior service cost	10	8	(76)	(45)
Recognized net actuarial loss	58	36	56	40
Net periodic cost	$ 21	$ 30	$ 73	$ 101
Company's share of net periodic cost (income)	$ 4	$ 1	$ 11	$ 15

Weighted-Average Assumptions Used To Determine Net Periodic Benefit Cost for Years Ended December 31	Pension Benefits 2006	2005	Other Benefits 2006	2005
Discount rate	5.75%	6.00%	5.75%	6.00%
Expected long-term return on plan assets	9.00%	9.00%	9.00%	9.00%
Rate of compensation increase	3.50%	3.50%		

In selecting an assumed discount rate, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. The assumed rates of return on pension plan assets consider historical market returns and economic forecasts for the types of investments held by the Company's pension trusts. The long-term rate of return is developed considering the portfolio's asset allocation strategy.

FirstEnergy employs a total return investment approach whereby a mix of equities and fixed income investments are used to maximize the long-term return on plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status, and corporate financial condition. The investment portfolio contains a diversified blend of equity and fixed-income investments. Furthermore, equity investments are diversified across U.S. and non-U.S. stocks, as well as growth, value, and small and large capitalization funds. Other assets such as real estate are used to enhance long-term returns while improving portfolio diversification. Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives are not used to leverage the portfolio beyond the market value of the underlying investments. Investment risk is measured and monitored on a continuing basis through periodic investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

Assumed Health Care Cost Trend Rates As of December 31	2006	2005
Health care cost trend rate assumed for next year (pre/post-Medicare)	9%-11%	9%-11%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5%	5%
Year that the rate reaches the ultimate trend rate (pre/post-Medicare)	2011-2013	2010-2012

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(In millions)	
Effect on total of service and interest cost	$ 6	$ (5)
Effect on postretirement benefit obligation	$ 33	$(29)

Taking into account estimated employee future service, FirstEnergy expects to make the following benefit payments from plan assets:

	Pension Benefits	Other Benefits
	(In millions)	
2007	$ 247	$91
2008	249	91
2009	256	94
2010	269	98
2011	280	101
Years 2012 - 2016	1,606	537

19 - CUMULATIVE EFFECT OF ACCOUNTING CHANGE

Results in 2005 include an after-tax charge of $4 million recorded upon the adoption of FIN 47 in December 2005. The Company identified applicable legal obligations as defined under the new standard at its retired generating units, substation control rooms, service center buildings, line shops and office buildings, identifying asbestos as the primary conditional ARO. The Company recorded a conditional ARO liability of $7 million (including accumulated accretion for the period from the date the liability was incurred to the date of adoption), an asset retirement cost of $2 million (recorded as part of the carrying amount of the related long-lived asset), and accumulated depreciation of $2 million. The Company charged a regulatory liability for $1 million upon adoption of FIN 47 for the transition amounts related to establishing the ARO for asbestos removal from substation control rooms and service center buildings. The remaining cumulative effect adjustment for unrecognized depreciation and accretion of $6 million was charged to income ($4 million, net of tax).

20 - FIRSTENERGY INTRA-SYSTEM GENERATION ASSET TRANSFERS

On May 18, 2005, the Ohio Companies entered into certain agreements implementing a series of intra-system generation asset transfers that were completed in the fourth quarter of 2005. The asset transfers resulted in the respective undivided ownership interests of the Ohio Companies and Penn in FirstEnergy's nuclear and non-nuclear generation assets being owned by NGC and FGCO, respectively. The generating plant interests transferred do not include the Company's leasehold interests in certain of the plants that are currently subject to sale and leaseback arrangements with non-affiliates.

On October 24, 2005, the Ohio Companies completed the intra-system transfer of non-nuclear generation assets to FGCO. Prior to the transfer, FGCO, as lessee under a Master Facility Lease with the Ohio Companies, leased, operated and maintained the non-nuclear generation assets that it now owns. The asset transfers were consummated pursuant to FGCO's purchase option under the Master Facility Lease.

The difference (approximately $33.7 million) between the purchase price specified in the Master Facility Lease and the net book value at the date of transfer was charged to equity. FGCO also assumed certain assets and liabilities relating to the purchased units. As consideration, FGCO delivered to the Company a promissory note of approximately $383.1 million that is secured by a lien on the units purchased, bears interest at a rate per annum based on the weighted cost of the Company's long-term debt (5.99%) and matures twenty years after the date of issuance. FGCO may

EXHIBIT

OCC Ex. 24

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THIS FILING IS	
Item 1: [X] An Initial (Original) Submission	OR [ ] Resubmission No. ____

Form 1 Approved
OMB No. 1902-0021
(Expires 7/31/2008)
Form 1-F Approved
OMB No. 1902-0029
(Expires 6/30/2007)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 6/30/2007)

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FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Toledo Edison Company, The	End of 2006/Q4

18 - PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

FirstEnergy provides noncontributory defined benefit pension plans that cover substantially all of its employees. The trusteed plans provide defined benefits based on years of service and compensation levels. FirstEnergy's funding policy is based on actuarial computations using the projected unit credit method. FirstEnergy made a $300 million voluntary cash contribution to its qualified pension plan on January 2, 2007 (Company's share was $8 million). Projections indicated that additional cash contributions will not be required before 2016.

FirstEnergy provides a minimum amount of noncontributory life insurance to retired employees in addition to optional contributory insurance. Health care benefits, which include certain employee contributions, deductibles and co-payments, are also available upon retirement to employees hired prior to January 1, 2005, their dependents and, under certain circumstances, their survivors. The Company recognizes the expected cost of providing other postretirement benefits to employees and their beneficiaries and covered dependents from the time employees are hired until they become eligible to receive those benefits. During 2006, FirstEnergy amended the other post-employment benefit (OPEB) plan effective in 2008 to cap the monthly contribution for many of the retirees and their spouses receiving subsidized healthcare coverage. In addition, FirstEnergy has obligations to former or inactive employees after employment, but before retirement for disability related benefits.

Pension and OPEB costs are affected by employee demographics (including age, compensation levels, and employment periods), the level of contributions made to the plans and earnings on plan assets. Such factors may be further affected by business combinations which impact employee demographics, plan experience and other factors. Pension and OPEB costs may also be affected by changes in key assumptions, including anticipated rates of return on plan assets, the discount rates and health care trend rates used in determining the projected benefit obligations and pension and OPEB costs. FirstEnergy uses a December 31 measurement date for its pension and OPEB plans. The fair value of the plan assets represents the actual market value as of December 31, 2006.

In December 2006, FirstEnergy adopted SFAS 158, "Employers' Accounting for Defined Benefit Pensions and Other Postretirement Plans-an amendment of FASB Statements No. 87, 88, 106,and 132(R)". This Statement requires employers to recognize an asset or liability for the overfunded or underfunded status of their pension and other postretirement benefit plans. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. The Statement required employers to recognize all unrecognized prior service costs and credits and unrecognized actuarial gains and losses in Accumulated Other Comprehensive Loss (AOCL), net of tax. Such amounts will be adjusted as they are subsequently recognized as components of net periodic benefit cost or income pursuant to the current recognition and amortization provisions. The Company's incremental impact of adopting SFAS 158 was a decrease of $35 million in pension assets, an increase of $34 million in pension liabilities and a decrease in AOCL of $42 million, net of tax.

With the exception of the Company's share of net pension (asset) liability at the end of year and net periodic pension expense, the following tables detail the Consolidated FirstEnergy pension plan and OPEB.

As of December 31	Pension Benefits 2006	Pension Benefits 2005	Other Benefits 2006	Other Benefits 2005
		(In millions)		
Change in benefit obligation				
Benefit obligation as of January 1	$ 4,750	$ 4,364	$ 1,884	$ 1,930
Service cost	83	77	34	40
Interest cost	266	254	105	111
Plan participants' contributions	--	--	20	18
Plan amendments	3	15	(620)	(312)
Medicare retiree drug subsidy	--	--	6	--
Actuarial (gain) loss	33	310	(119)	197
Benefits paid	(274)	(270)	(109)	(100)
Benefit obligation as of December 31	$ 4,861	$ 4,750	$ 1,201	$ 1,884
Change in fair value of plan assets				
Fair value of plan assets as of January 1	$ 4,524	$ 3,969	$ 573	$ 564
Actual return on plan assets	567	325	69	33
Company contribution	--	500	54	58
Plan participants' contribution	--	--	20	18
Benefits paid	(273)	(270)	(109)	(100)
Fair value of plan assets as of December 31	$ 4,818	$ 4,524	$ 607	$ 573
Funded status	$ (43)	$ (226)	$ (594)	$ (1,311)
Accumulated benefit obligation	$ 4,447	$ 4,327		
Amounts Recognized in the Statement of Financial Position				
Noncurrent assets	$ --	$ 1,023	$ --	$ --
Current liabilities	--	--	--	--
Noncurrent liabilities	(43)	--	(594)	(1,057)
Net pension asset (liability) as of December 31	$ (43)	$ 1,023	$ (594)	$ (1,057)
Company's share of net pension asset (liability) at end of year	$ (3)	$ 36	$ (74)	$ (40)
Amounts Recognized in Accumulated Other Comprehensive Income				
Prior service cost (credit)	$ 63	$ --	$ (1,190)	$ --
Actuarial loss	982	--	702	--
Net amount recognized	$ 1,045	$ --	$ (488)	$ --
Assumptions Used to Determine Benefit Obligations As of December 31				
Discount rate	6.00%	5.75%	6.00%	5.75%
Rate of compensation increase	3.50%	3.50%		
Allocation of Plan Assets As of December 31				
Asset Category				
Equity securities	64%	63%	72%	71%
Debt securities	29	33	26	27
Real estate	5	2	1	--
Private equities	1	--	--	--
Cash	1	2	1	2
Total	100%	100%	100%	100%

Estimated Items to be Amortized in 2007 Net Periodic Pension Cost from Accumulated Other Comprehensive Income	Pension Benefits	Other Benefits
	(In millions)	
Prior service cost (credit)	$10	$(149)
Actuarial loss	$41	$ 45

Components of Net Periodic Benefit Costs	Pension Benefits 2006	Pension Benefits 2005	Other Benefits 2006	Other Benefits 2005
	(In millions)			
Service cost	$ 83	$ 77	$ 34	$ 40
Interest cost	266	254	105	111
Expected return on plan assets	(396)	(345)	(46)	(45)
Amortization of prior service cost	10	8	(76)	(45)
Recognized net actuarial loss	58	36	56	40
Net periodic cost	$ 21	$ 30	$ 73	$ 101
Company's share of net periodic cost	$ 1	$ 1	$ 8	$ 9

Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31	Pension Benefits 2006	Pension Benefits 2005	Other Benefits 2006	Other Benefits 2005
Discount rate	5.75%	6.00%	5.75%	6.00%
Expected long-term return on plan assets	9.00%	9.00%	9.00%	9.00%
Rate of compensation increase	3.50%	3.50%		

In selecting an assumed discount rate, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. The assumed rates of return on pension plan assets consider historical market returns and economic forecasts for the types of investments held by the Company's pension trusts. The long-term rate of return is developed considering the portfolio's asset allocation strategy.

FirstEnergy employs a total return investment approach whereby a mix of equities and fixed income investments are used to maximize the long-term return on plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status, and corporate financial condition. The investment portfolio contains a diversified blend of equity and fixed-income investments. Furthermore, equity investments are diversified across U.S. and non-U.S. stocks, as well as growth, value, and small and large capitalization funds. Other assets such as real estate are used to enhance long-term returns while improving portfolio diversification. Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives are not used to leverage the portfolio beyond the market value of the underlying investments. Investment risk is measured and monitored on a continuing basis through periodic investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

Assumed Health Care Cost Trend Rates As of December 31	2006	2005
Health care cost trend rate assumed for next year (pre/post-Medicare)	9-11%	9-11%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5%	5%
Year that the rate reaches the ultimate trend rate (pre/post-Medicare)	2011-2013	2010-2012

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(In millions)	
Effect on total of service and interest cost	$ 6	$ (5)
Effect on accumulated postretirement benefit obligation	$ 33	$ (29)

Taking into account estimated employee future service, FirstEnergy expects to make the following benefit payments from plan assets:

	Pension Benefits	Other Benefits
	(In millions)	
2007	$ 247	$ 91
2008	249	91
2009	256	94
2010	269	98
2011	280	101
Years 2012-2016	1,606	537

19 - FIRSTENERGY INTRA-SYSTEM GENERATION ASSET TRANSFERS

In 2005, the Ohio Companies entered into certain agreements implementing a series of intra-system generation asset transfers that were completed in the fourth quarter of 2005. The asset transfers resulted in the respective undivided ownership interests of the Ohio Companies and Penn in FirstEnergy's nuclear and non-nuclear generation assets being owned by NGC and FGCO, respectively. The generating plant interests transferred do not include the Company's leasehold interests in certain of the plants that are currently subject to sale and leaseback arrangements with non-affiliates.

On October 24, 2005, the Company completed the intra-system transfer of non-nuclear generation assets to FGCO. Prior to the transfer, FGCO, as lessee under a Master Facility Lease with the Ohio Companies, leased, operated and maintained the non-nuclear generation assets that it now owns. The asset transfers were consummated pursuant to FGCO's purchase option under the Master Facility Lease.

The difference (approximately $22.9 million) between the purchase price specified in the Master Facility Lease and the net book value at the date of transfer was credited to equity. FGCO also assumed certain assets and liabilities relating to the purchased units. As consideration, FGCO delivered to the Company a promissory note of approximately $101.0 million that is secured by a lien on the units purchased, bears interest at a rate per annum based on the weighted cost of the Company's long-term debt (4.38%) and matures twenty years after the date of issuance. FGCO may pre-pay a portion of the promissory note through refunding from time to time of the Company's outstanding pollution control debt. The timing of any refunding will be subject to market conditions and other factors.

On December 16, 2005, the Company completed the intra-system transfer of its respective ownership in the nuclear generation assets to NGC through a sale at net book value. FirstEnergy Nuclear Operating Company continues to operate and maintain the nuclear generation assets.

The purchase price of the generation assets was the net book value as of September 30, 2005. The difference (approximately $22.1 million) between the purchase price of the generation assets and the net book value at the date of transfer was credited to equity. NGC also assumed the Company's interest in associated decommissioning trust funds, other related assets and other liabilities associated with the transferred assets. In addition, the Company received a promissory note from NGC in the principal amount of approximately $726.1 million, representing the net book value of the contributed assets as of September 30, 2005, less other liabilities assumed. The note bears interest at a rate per annum based on the Company's weighted average cost of long-term debt (4.38%), matures twenty years from the date of issuance, and is subject to prepayment at any time, in whole or in part, by NGC. In December 2006, the Company recorded a purchase price adjustment of $130.8 million for the nuclear generation asset transfer to adjust intercompany notes and equity accounts to

EXHIBIT

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Edison Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2006/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses	060	05
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)		
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant		148,501
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)		148,501
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)		148,501
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	992,232,832	763,410,523
77	(556) System Control and Load Dispatching		
78	(557) Other Expenses		
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	992,232,832	763,410,523
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,183,282,899	1,046,771,799
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	149	81,708
84	(561) Load Dispatching		581,444
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System		
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	4,235,523	
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	187,340	
93	(562) Station Expenses		65,413
94	(563) Overhead Lines Expenses	833	10,783
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	122,244,492	135,689,579
97	(566) Miscellaneous Transmission Expenses	527,139	787,079
98	(567) Rents	720	
99	TOTAL Operation (Total of lines 83 thru 98)	127,196,196	137,216,006
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	805,916	680,159
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	20,063	
104	(569.2) Maintenance of Computer Software	123,925	
105	(569.3) Maintenance of Communication Equipment	130,425	
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	38,533	108,453
108	(571) Maintenance of Overhead Lines	592,709	873,581
109	(572) Maintenance of Underground Lines		3
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	1,711,571	1,662,196
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	128,907,767	138,878,202

OCC Ex. 25

- Privileged Data

EXHIBIT

OCC Ex. 26

Ohio Edison Company
Case No. 07 - 551 - EL - AIR
Operating Revenue and Expenses By Account - Jurisdictional Allocation
For the Twelve Months Ended February 29, 2008

Data: 3 Months Actual & 9 Months Estimated
Type of Filing: Original X Updated Revised
Work Paper Reference No(s).: B-7, B-7.1, C-4.1, WPC-2.1a-i & WPC-12.1a-c
0

Schedule C-2.1
Page 4 of 8
Witness Responsible:
K. Burcess
T. Fernandez

Line No.	Acct. No.	Account Title		Unadjusted Total Utility	Allocation Factor (%)	Unadjusted Jurisdiction	Allocation / Code Description
		Operation & Maintenance Expenses By Account - Transmission					
1		Operation & Maintenance					
2	561.4	Scheduling, System Cntl & Dispatching	Labor	$0	0.00000%	$0	NODIST
3			Other Than Labor	$6,918,018	0.00000%	$0	NODIST
4	561.8	Reliability Planning & Standard Svcs.	Labor	$0	0.00000%	$0	NODIST
5			Other Than Labor	$98,983	0.00000%	$0	NODIST
6	565	Transmission of Electricity by Others	Labor	$0	0.00000%	$0	NODIST
7			Other Than Labor	$151,799,022	0.00000%	$0	NODIST
8	566	Misc. Transmission Expenses	Labor	$537,051	100.00000%	$537,051	ALLDIST
9			Other Than Labor	$710,080	100.00000%	$710,080	ALLDIST
10	567	Rents	Labor	$0	100.00000%	$0	ALLDIST
11			Other Than Labor	$689	100.00000%	$689	ALLDIST
12	568	Maint. Supervision & Engrg	Labor	$426,143	100.00000%	$426,143	ALLDIST
13			Other Than Labor	$314,658	100.00000%	$314,658	ALLDIST
14	569.1	Maint. of Computer Hardware	Labor	$18,701	100.00000%	$18,701	ALLDIST
15			Other Than Labor	$18,580	100.00000%	$18,580	ALLDIST
16	569.2	Maint. of Computer Software	Labor	$115,687	100.00000%	$115,687	ALLDIST
17			Other Than Labor	$114,942	100.00000%	$114,942	ALLDIST
18	569.3	Maint. of Communication Equip.	Labor	$20,454	100.00000%	$20,454	ALLDIST
19			Other Than Labor	$22,137	100.00000%	$22,137	ALLDIST
20	570	Maint. of Station Equipment	Labor	$16,348	0.23765%	$39	PRODS
21			Other Than Labor	$272,277	92.60811%	$252,151	PRODSa
22	571	Maint. of Overhead Lines	Labor	$388,188	100.00000%	$388,188	ALLDIST
23			Other Than Labor	$400,279	100.00000%	$400,279	ALLDIST
24	573	Maint. of Misc. Transmission	Labor	$710	100.00000%	$710	ALLDIST
25			Other Than Labor	$113,183	100.00000%	$113,183	ALLDIST
26							
27		Summary O&M Expenses - Transmission					
28		Labor - Total		$1,523,176	98.93617%	$1,506,972	WEIGHTED AVERAGE
29		Other Than Labor - Total		$160,782,769	1.21071%	$1,946,619	WEIGHTED AVERAGE
30							
31		Other - Transmission					
32	575.7	Mkt. Admin., Monitoring & Compliance		$9,464,766	0.00000%	$0	NODIST
33							
34		TOTAL TRANSMISSION		$171,770,711	2.01058%	$3,453,592	WEIGHTED AVERAGE

EXHIBIT

OCC Ex. 27

Ohio Edison Company
Case No. 07 - 551 - EL - AIR
Comparative Financial Data

Date Certain: May 31, 2007
Type of Filing: ___ Original X Updated ___ Revised
Work Paper Reference No(s).: B-1, B-2, C-1, C11.2

Schedule: D-5
Page: 2 of 3
Witness Responsible:

J. Pearson

Line No.	Description	Test Year*	2006***	2005**	2004**	2003**	2002**	2001**	2000	1999	1998	1997
28	INCOME AVAILABLE FOR FIXED CHARGES ($MILLIONS)											
29	Interest Charge	$61	$79	$89	$60	$86	$121	$158	$173	$192	$201	$214
30	Net Income(5)	$42	$39	$126	$208	$169	$163	$155	$336	$297	$271	$294
31	Preferred dividends	$0	$0	$3	$3	$9	$7	$11	$11	$12	$12	$12
32	Earnings available for common equity	$42	$39	$123	$205	$160	$156	$144	$325	$285	$259	$282
33	AFUDC % of Earnings avail. for common eq.	0.00%	5.13%	4.07%	1.46%	1.81%	1.28%	1.39%	2.77%	1.40%	0.77%	0.71%
34	COSTS OF CAPITAL											
35	Embedded cost of long-term debt(6)	6.47%	5.62%	4.39%	4.32%	4.51%	5.77%	6.21%	7.56%	7.16%	7.59%	7.28%
36	Embedded cost of preferred stock	N/A	N/A	4.33%	4.38%	4.33%	4.33%	7.77%	7.78%	7.80%	7.80%	6.63%
37	FIXED CHARGE COVERAGE											
38	Pre-tax interest coverage	1.49	1.09	6.95	5.69	3.44	2.94	2.18	3.66	3.14	2.88	2.87
39	Pre-tax interest coverage (excl. AFUDC)	1.49	1.08	6.88	5.64	3.41	2.93	2.17	3.60	3.12	2.85	2.86
40	After tax interest coverage	1.70	1.49	3.14	4.47	2.76	2.35	1.98	2.94	2.55	2.35	2.37
41	After tax fixed charge coverage	1.70	1.52	3.08	4.30	2.71	2.23	1.86	2.82	2.42	2.23	2.26
42	Indenture provision coverage(7)	5.44	22.14	14.57	15.27	15.92	10.48	8.07	7.60	6.69	6.17	6.20
43	STOCK AND BOND RATINGS											
44	Moody's Bond Rating	Baa1	Baa1	Baa1	Baa1	Baa1	Baa1	Baa1	Baa1	Baa2	Baa2	Baa2
45	S&P Bond Rating	BBB+	BBB+	BBB+	BBB	BBB	BBB	BBB	BBB-	BBB-	BBB-	BBB-
46	Moody's Preferred Stock Rating	N/A	N/A	Ba1	Ba1	Ba1	Ba1	Ba1	Ba1	Ba1	Ba1	Ba1
47	S&P Preferred Stock Rating	N/A	N/A	BB+	BB	BB	BB+	BB+	B+	B+	BB-	BB-
48	COMMON STOCK RELATED DATA											
49	Shares outstanding - year end	60	60	100	100	100	100	100	100	100	100	100
50	Shares outstanding-weighted average	70	90	100	100	100	100	100	100	100	100	76,284,768
51	Earning per share-weighted average	no par value	no par value	no par value	no par value	no par value	no par value	no par value	no par value	no par value	no par value	3.70
52	Dividend paid per share	no par value	no par value	no par value	no par value	no par value	no par value	no par value	no par value	no par value	no par value	1.60
53	Dividend declared per share	no par value	no par value	no par value	no par value	no par value	no par value	no par value	no par value	no par value	no par value	1.60
54	Dividend payout ratio (declared)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	40.58%

EXHIBIT

OSC Ex. 8

THE TOLEDO EDISON COMPANY
CASE NO. 07-551-EL-AIR
ANNUALIZED TEST YEAR REVENUES AT PROPOSED VS. MOST CURRENT RATES
FOR THE TWELVE MONTHS ENDED FEBRUARY 2008
(ELECTRIC SERVICE)

DATA: 3 MONTHS ACTUAL - 9 MONTHS ESTIMATED
TYPE OF FILING: AIR UPDATED
WORK PAPER REFERENCE NO(S): WPE-4, SCHEDULE E-4.1

SCHEDULE E-4 (CURRENT)
PAGE 1 OF 1
WITNESS: G. HUSSING

			CURRENT ANNUALIZED									
LINE NO.	RATE CODE	CLASS/ DESCRIPTION	CUSTOMER BILLS[1]	BILLING UNITS (KWH)	MOST CURRENT RATES	CURRENT REVENUE LESS FUEL COST REVENUE[2]	% OF REV TO TOTAL LESS FUEL COST REVENUE	REVENUE INCR LESS FUEL COST REV (F-K)[3]	% INCR IN REV LESS FUEL COST REV (M/K)	FUEL COST REVENUE	CURRENT TOTAL REVENUE (K+H)	TOTAL REVENUE % INCREASE (M/K1)
	(A)	(B)	(C)	(D)	(J)	(K)	(L)	(M)	(N)	(H)	(K1)	(O)
					($/KWH)	($)	(%)	($)	(%)	($)	($)	(%)
1	RS511	RESIDENTIAL RATE (SHEET 10)	2,537,922	1,703,801,199	$0.0352	$59,987,736	37.94	$22,390,672	37.32	$0	$59,987,735	37.32
2	RS518	RESIDENTIAL RATE (SHEET 11)	2,224	332,570	$0.0139	$4,634	0.00	$7,511	162.08	$0	$4,634	162.08
3	RS514	RESIDENTIAL RATE (SHEET12)	172,280	97,311,352	$0.0371	$3,613,627	2.26	$1,196,939	33.12	$0	$3,613,627	33.12
4	RS561	RESIDENTIAL OPTIONAL HEATING RATE (SHEET 13)	2,942	5,060,481	$0.0271	$137,099	0.09	$49,138	36.11	$0	$137,099	36.11
5	RS564	RESIDENTIAL OPTIONAL HEATING RATE (SHEET 14)	271	466,364	$0.0300	$13,979	0.01	$2,686	19.22	$0	$13,979	19.22
6	RS541	RESIDENTIAL RATE (WATER HEATING) (SHEET 15)	281,048	257,896,227	$0.0286	$7,384,499	4.67	$3,263,424	44.19	$0	$7,384,499	44.19
7	RS544	RESIDENTIAL RATE (WATER HEATING) (SHEET 16)	13,160	11,402,968	$0.0197	$224,663	0.14	$240,425	107.06	$0	$224,663	107.06
8	RS571	RESIDENTIAL RATE (SHEET 17)	290,514	373,789,424	$0.0333	$12,430,250	7.86	$1,883,354	15.15	$0	$12,430,250	15.15
9	RS574	RESIDENTIAL RATE (SHEET 18)	16,202	17,517,639	$0.0368	$644,292	0.41	$24,951	3.87	$0	$644,292	3.87
10	RS690	CONTROLLED WATER HEATING (SHEET 50)	2,878	343,800	$0.0416	$14,306	0.01	($2,009)	(14.04)	$0	$14,306	(14.04)
11	RS691	CONTROLLED WATER HEATING (SHEET 51)	45	9,230	$0.0349	$323	0.00	$8	2.39	$0	$323	2.39
12	RS591	RESIDENTIAL RATE (APARTMENT RATE) (SHEET 19)	16,916	11,976,834	$0.0391	$468,137	0.30	$25,601	5.47	$0	$468,137	5.47
13	RS594	RESIDENTIAL RATE (APARTMENT RATE) (SHEET 20)	1,281	1,256,092	$0.0330	$41,470	0.03	$7,160	17.27	$0	$41,470	17.27
14		TOTAL RESIDENTIAL	3,337,457	2,481,166,259	$0.0342	$84,974,917	53.73	$29,088,870	34.23	$0	$84,974,917	34.23
15	GS618	SMALL WATER AND WASTE WATER RATE "WR-1" (ORDINANCE SHEETS 2-5)	1,109	8,580,591	$0.0247	$211,609	0.13	$162,270	76.68	$0	$211,609	76.68
16	GS605	MEDIUM WATER AND WASTE WATER RATE "WR-2" (ORDINANCE SHEETS 6-11)	284	101,742,038	$0.0215	$2,188,028	1.38	($1,253,154)	(57.27)	$0	$2,188,028	(57.27)
17	GS881, GS	SMALL GENERAL SERVICE RATE (SHEET 40)	241	1,618,762	$0.0128	$20,784	0.01	$48,187	231.90	$0	$20,784	231.90
18	GS616	SMALL SCHOOL RATE (SHEET 41)	2,938	64,128,241	$0.0174	$1,115,031	0.71	[illegible]	36.86	$0	$1,115,031	36.86
19	GS614	LARGE SCHOOL RATE (SHEET 42)	773	62,707,227	$0.0086	$537,526	0.34	[illegible]	61.41	$0	$537,526	61.41
20	GS620	LARGE GENERAL SERVICE (SHEET 43)	38	15,883,352	$0.0035	$55,517	0.04	$121,109	218.13	$0	$55,517	218.13
21	GS667	GENERAL SERVICE RATE (SHEET 44)	308,783	368,142,321	$0.0378	$13,929,294	8.81	$3,737,193	26.83	$0	$13,929,294	26.83
22	GS669	SMALL GENERAL SERVICE (SHEET 45)	68,132	1,065,414,815	$0.0197	$21,021,440	13.29	$18,796,161	89.41	$0	$21,021,440	89.41
23	GS628	MEDIUM GENERAL SERVICE (SHEET 46)	5,377	1,020,174,449	$0.0096	$9,760,575	6.17	$11,931,612	122.24	$0	$9,760,575	122.24
24	GS600	GENERAL SERVICE ELECTRIC SPACE CONDITIONING (SHEET 47)	4,347	65,268,448	$0.0063	$410,659	0.26	$1,310,971	319.24	$0	$410,659	319.24
25	GS600	OPTIONAL ELECTRIC PROCESS HEATING AND ELECTRIC BOILER LOAD MANAGEMENT (Sheet 48)	421	56,961,198	$0.0255	$1,454,651	0.92	($469,837)	(32.30)	$0	$1,454,651	(32.30)
26	GS673;GS	GENERAL SERVICE HEATING RATE (SHEET 49)	23,074	95,437,041	$0.0187	$1,788,794	1.13	$1,851,429	103.62	$0	$1,788,794	103.62
27	GS647	LARGE GENERAL SERVICE (SHEET 61)	729	682,583,594	$0.0046	$3,155,268	2.00	$2,436,580	77.22	$0	$3,155,268	77.22
28	GS630	OUTDOOR NIGHT LIGHTING RATE 'GS-13' (SHEETS 53)	1,014	3,166,683	$0.0663	$209,950	0.13	$215,901	102.83	$0	$209,950	102.83
29	GS632	OUTDOOR SECURITY LIGHTING RATE 'GS-18' (SHEET 54)	10,376	12,467,460	$0.1411	$1,759,692	1.11	($396,353)	(22.52)	$0	$1,759,692	(22.52)
30		TOTAL GENERAL SERVICE	427,588	3,624,274,210	$0.0159	$57,618,819	36.43	$39,230,908	68.09	$0	$57,616,819	68.09
31	STLT	STREET LIGHTING SERVICE "SL-1" (SHEETS 71)	45,637	49,510,515	$0.1215	$6,017,613	3.80	($389,596)	(6.47)	$0	$6,017,613	(6.47)
32		TOTAL LIGHTING	45,637	49,510,515	$0.1215	$6,017,613	3.80	($389,596)	(6.47)	$0	$6,017,613	(6.47)
33		SPECIAL CONTRACTS / MANUAL BILLS	1,104	4,508,916,290	-$0.0004	($1,783,447)	(1.13)	$2,818,158	158.02	$0	($1,783,447)	158.02
34		OTHER MISC				$11,326,260	7.16	($208,541)	(1.84)	$0	$11,326,260	(1.84)
35		TOTAL MISC	1,104	4,508,916,290	$0.0021	$9,542,813	6.03	$2,609,617	27.35	$0	$9,542,813	27.35
36		TOTAL COMPANY	3,811,786	10,663,867,274	$0.0148	$158,152,162	100.00	$70,539,798	44.60	$0	$158,152,162	44.60

1. For the POL and STLT the customer bills are number of lamps.
2. Current revenue includes distribution, distribution discounts, kWh tax, tax backout and credits, and muni tax.
3. Revenue increase is based on the proposed E-4.1 schedules.

THE TOLEDO ON COMPANY
CASE NO. ..-651-EL-AIR
ANNUALIZED TEST YEAR REVENUES AT PROPOSED VS. MOST CURRENT RATES
FOR THE TWELVE MONTHS ENDED: FEBRUARY 2008
(ELECTRIC SERVICE)

DATA - 3 MONTHS ACTUAL - 9 MONTHS ESTIMATED
TYPE OF FILING: AIR UPDATE
WORK PAPER REFERENCE NO(S): WPE-4.1a - WPE-4.1q, SCHEDULE E-1

SCHEDULE E-4.1 (PROPOSED)

WITNESS: G. HUSSING

			PROPOSED ANNUALIZED							
LINE NO.	RATE CODE	CLASS/ DESCRIPTION	CUSTOMER BILLS	KWH SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE	FUEL COST REVENUE	PROPOSED TOTAL REVENUE (F+H)
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)	(H)	(I)
				(KWH)		($)	($)	(%)	($)	($)
	GS616	SMALL SCHOOL RATE (SHEET 41)								
1	EXISTING									
2										
3	TOTAL EXISTING DISTRIBUTION		2,938	64,126,241			$1,115,031	100.00	$0	$1,115,031
4										
5										
6	PROPOSED									
7										
8	GS	GENERAL SERVICE - SECONDARY								
9										
10		CUSTOMER CHARGE								
11		BILLS	1,065	17,915,170		$7.00	$7,455	0.49	$0	$7,455
12										
13		CAPACITY CHARGE								
14		UP TO 5 kW OF BILLING DEMAND			5,325	$18.00	$19,170	1.26	$0	$19,170
15		OVER 5 kW, PER kW			60,743	$10.84400	$658,697	43.23	$0	$658,697
16										
17		REACTIVE DEMAND CHARGE								
18		ALL rkVa, PER rkVa			-	$0.36000	$0	0.00	$0	$0
19										
20		CUSTOMER DISCOUNT								
21		ALL kWh, PER kWh		-		($0.01500)	$0	0.00	$0	$0
22										
23		STATE kWh TAX								
24		FIRST 2,000 kWh, PER kWh		2,427,384		$0.00466	$11,305	0.74	$0	$11,305
25		NEXT 13,000 kWh, PER kWh		11,979,506		$0.00420	$50,272	3.30	$0	$50,272
26		ABOVE 15,000 kWh, PER kWh		3,508,280		$0.00364	$12,755	0.84	$0	$12,755
27				17,915,170			$74,332		$0	$74,332
28										
29		TOTAL DISTRIBUTION - GS	1,065	17,915,170			$759,654	49.85	$0	$759,654

THE TOLEDO ON COMPANY
CASE NO. u, -551-EL-AIR
ANNUALIZED TEST YEAR REVENUES AT PROPOSED VS. MOST CURRENT RATES
FOR THE TWELVE MONTHS ENDED: FEBRUARY 2008
(ELECTRIC SERVICE)

DATA - 3 MONTHS ACTUAL - 9 MONTHS ESTIMATED
TYPE OF FILING: AIR UPDATE
WORK PAPER REFERENCE NO(S): WPE-4.1a - WPE-4.1q, SCHEDULE E-1

WITNESS: G. HUSSING

			PROPOSED ANNUALIZED							
LINE NO.	RATE CODE (A)	CLASS/ DESCRIPTION (B)	CUSTOMER BILLS (C)	KWH SALES (D1) (KWH)	BILLING UNITS (D2)	PROPOSED RATES (E) ($)	PROPOSED REVENUE LESS FUEL COST REVENUE (F) ($)	% OF REV TO TOTAL LESS FUEL COST REVENUE (G) (%)	FUEL COST REVENUE (H) ($)	PROPOSED TOTAL REVENUE (F+H) (I) ($)
	GS616	SMALL SCHOOL RATE (SHEET 41)								
30	GP	GENERAL SERVICE - PRIMARY								
31										
32		CUSTOMER CHARGE								
33		BILLS	-			$150.00	$0	0.00	$0	$0
34										
35		CAPACITY CHARGE								
36		ALL kW OF BILLING DEMAND, PER kW			-	$3.34800	$0	0.00	$0	$0
37										
38		REACTIVE DEMAND CHARGE								
39		ALL rkVa, PER rkVa			-	$0.36000	$0	0.00	$0	$0
40										
41		CUSTOMER DISCOUNT								
42		ALL kWh, PER kWh		-		($0.00580)	$0	0.00	$0	$0
43										
44		STATE kWh TAX								
45		FIRST 2,000 kWh, PER kWh		-		$0.00466	$0	0.00	$0	$0
46		NEXT 13,000 kWh, PER kWh		-		$0.00420	$0	0.00	$0	$0
47		ABOVE 15,000 kWh, PER kWh		-		$0.00364	$0	0.00	$0	$0
48				-			$0		$0	$0
49										
50		TOTAL DISTRIBUTION - GP	-	-			$0	0.00	$0	$0
51										
52										
53	GSU	GENERAL SERVICE - SUBTRANSMISSION								
54										
55		CUSTOMER CHARGE								
56		BILLS	-			$200.00	$0	0.00	$0	$0
57										
58		CAPACITY CHARGE								
59		ALL kVa OF BILLING DEMAND, PER kVa			-	$1.77800	$0	0.00	$0	$0
60										
61		REACTIVE DEMAND CHARGE								
62		ALL rkVa, PER rkVa			-	$0.00000	$0	0.00	$0	$0
63										
64		TRANSFORMER CHARGE								
65		ALL kVa OF BILLING DEMAND, PER kVa			-	$0.00000	$0	0.00	$0	$0
66										
67		CUSTOMER DISCOUNT								
68		ALL kWh, PER kWh		-		$0.00000	$0	0.00	$0	$0
69										
70		STATE kWh TAX								
71		FIRST 2,000 kWh, PER kWh		-		$0.00466	$0	0.00	$0	$0
72		NEXT 13,000 kWh, PER kWh		-		$0.00420	$0	0.00	$0	$0
73		ABOVE 15,000 kWh, PER kWh		-		$0.00364	$0	0.00	$0	$0
74				-			$0		$0	$0
75										
76		TOTAL DISTRIBUTION - GSU	-	-			$0	0.00	$0	$0

THE TOLEDO ON COMPANY
CASE NO. ..-551-EL-AIR
ANNUALIZED TEST YEAR REVENUES AT PROPOSED VS. MOST CURRENT RATES
FOR THE TWELVE MONTHS ENDED: FEBRUARY 2008
(ELECTRIC SERVICE)

DATA - 3 MONTHS ACTUAL - 9 MONTHS ESTIMATED
TYPE OF FILING: AIR UPDATE
WORK PAPER REFERENCE NO(S): WPE-4.1a - WPE-4.1q, SCHEDULE E-1

SCHEDULE E-4.1 (PROPOSED)

WITNESS: G. HUSSING

PROPOSED ANNUALIZED

LINE NO.	RATE CODE (A)	CLASS/ DESCRIPTION (B)	CUSTOMER BILLS (C)	KWH SALES (D1) (KWH)	BILLING UNITS (D2)	PROPOSED RATES (E) ($)	PROPOSED REVENUE LESS FUEL COST REVENUE (F) ($)	% OF REV TO TOTAL LESS FUEL COST REVENUE (G) (%)	FUEL COST REVENUE (H) ($)	PROPOSED TOTAL REVENUE (F+H) (I) ($)
	GS616	SMALL SCHOOL RATE (SHEET 41)								
77	GT	GENERAL SERVICE - TRANSMISSION								
78										
79		CUSTOMER CHARGE								
80		BILLS	-			$330.00	$0	0.00	$0	$0
81										
82		CAPACITY CHARGE								
83		ALL kVa OF BILLING DEMAND, PER kVa			-	$0.58900	$0	0.00	$0	$0
84										
85		REACTIVE DEMAND CHARGE								
86		ALL rkVa, PER rkVa			-	$0.00000	$0	0.00	$0	$0
87										
88		TRANSFORMER CHARGE								
89		ALL kVa OF BILLING DEMAND, PER kVa			-	$0.13000	$0	0.00	$0	$0
90										
91		CUSTOMER DISCOUNT								
92		ALL kWh, PER kWh		-		($0.00500)	$0	0.00	$0	$0
93										
94		STATE kWh TAX								
95		FIRST 2,000 kWh, PER kWh		-		$0.00466	$0	0.00	$0	$0
96		NEXT 13,000 kWh, PER kWh		-		$0.00420	$0	0.00	$0	$0
97		ABOVE 15,000 kWh, PER kWh		-		$0.00364	$0	0.00	$0	$0
98				-			$0		$0	$0
99										
100		TOTAL DISTRIBUTION - GT	-	-			$0	0.00	$0	$0
101										
102										
103	SPC - GS	SPECIAL CONTRACT - GENERAL SERVICE - SECONDARY								
104										
105		CUSTOMER CHARGE								
106		BILLS	-			$7.00	$0	0.00	$0	$0
107										
108		CAPACITY CHARGE								
109		UP TO 5 kW OF BILLING DEMAND			-	$18.00	$0	0.00	$0	$0
110		OVER 5 kW, PER kW			-	$10.84400	$0	0.00	$0	$0
111										
112		REACTIVE DEMAND CHARGE								
113		ALL rkVa, PER rkVa			-	$0.36000	$0	0.00	$0	$0
114										
115		CUSTOMER DISCOUNT								
116		ALL kWh, PER kWh		-		($0.01500)	$0	0.00	$0	$0
117										
118		CONTRACT DISCOUNT					$0	0.00	$0	$0
119										
120		STATE kWh TAX								
121		FIRST 2,000 kWh, PER kWh		-		$0.00466	$0	0.00	$0	$0
122		NEXT 13,000 kWh, PER kWh		-		$0.00420	$0	0.00	$0	$0
123		ABOVE 15,000 kWh, PER kWh		-		$0.00364	$0	0.00	$0	$0
124				-			$0		$0	$0
125										
126		TOTAL DISTRIBUTION - SPC-GS	-	-			$0	0.00	$0	$0

THE TOLEDO ON COMPANY
CASE NO. u.-551-EL-AIR
ANNUALIZED TEST YEAR REVENUES AT PROPOSED VS. MOST CURRENT RATES
FOR THE TWELVE MONTHS ENDED: FEBRUARY 2008
(ELECTRIC SERVICE)

DATA - 3 MONTHS ACTUAL - 9 MONTHS ESTIMATED
TYPE OF FILING: AIR UPDATE
WORK PAPER REFERENCE NO(S): WPE-4.1a - WPE-4.1q, SCHEDULE E-1

SCHEDULE E-4.1 (PROPOSED)

WITNESS: G. HUSSING

			PROPOSED ANNUALIZED							
LINE NO.	RATE CODE (A)	CLASS/ DESCRIPTION (B)	CUSTOMER BILLS (C)	KWH SALES (D1) (KWH)	BILLING UNITS (D2)	PROPOSED RATES (E) ($)	PROPOSED REVENUE LESS FUEL COST REVENUE (F) ($)	% OF REV TO TOTAL LESS FUEL COST REVENUE (G) (%)	FUEL COST REVENUE (H) ($)	PROPOSED TOTAL REVENUE (F+H) (I) ($)
	GS616	SMALL SCHOOL RATE (SHEET 41)								
127	SPC - GP	SPECIAL CONTRACT - GENERAL SERVICE - PRIMARY								
128										
129		CUSTOMER CHARGE								
130		BILLS	-			$150.00	$0	0.00	$0	$0
131										
132		CAPACITY CHARGE								
133		ALL kW OF BILLING DEMAND, PER kW			-	$3.34800	$0	0.00	$0	$0
134										
135		REACTIVE DEMAND CHARGE								
136		ALL rkVa, PER rkVa			-	$0.36000	$0	0.00	$0	$0
137										
138		CUSTOMER DISCOUNT								
139		ALL kWh, PER kWh		-		($0.00500)	$0	0.00	$0	$0
140										
141		CONTRACT DISCOUNT					$0	0.00	$0	$0
142										
143		STATE kWh TAX								
144		FIRST 2,000 kWh, PER kWh		-		$0.00466	$0	0.00	$0	$0
145		NEXT 13,000 kWh, PER kWh		-		$0.00420	$0	0.00	$0	$0
146		ABOVE 15,000 kWh, PER kWh		-		$0.00364	$0	0.00	$0	$0
147				-			$0		$0	$0
148										
149		TOTAL DISTRIBUTION - SPC-GP	-	-			$0	0.00	$0	$0
150										
151										
152	SPC - GSU	SPECIAL CONTRACT - GENERAL SERVICE - SUBTRANSMISSION								
153										
154		CUSTOMER CHARGE								
155		BILLS	-			$200.00	$0	0.00	$0	$0
156										
157		CAPACITY CHARGE								
158		ALL kVa OF BILLING DEMAND, PER kVa			-	$1.77800	$0	0.00	$0	$0
159										
160		REACTIVE DEMAND CHARGE								
161		ALL rkVa, PER rkVa			-	$0.00000	$0	0.00	$0	$0
162										
163		TRANSFORMER CHARGE								
164		ALL kVa OF BILLING DEMAND, PER kVa			-	$0.00000	$0	0.00	$0	$0
165										
166		CUSTOMER DISCOUNT								
167		ALL kWh, PER kWh		-		$0.00000	$0	0.00	$0	$0
168										
169		CONTRACT DISCOUNT					$0	0.00	$0	$0
170										
171		STATE kWh TAX								
172		FIRST 2,000 kWh, PER kWh		-		$0.00456	$0	0.00	$0	$0
173		NEXT 13,000 kWh, PER kWh		-		$0.00420	$0	0.00	$0	$0
174		ABOVE 15,000 kWh, PER kWh		-		$0.00364	$0	0.00	$0	$0
175				-			$0		$0	$0
176										
177		TOTAL DISTRIBUTION - SPC-GSU	-	-			$0	0.00	$0	$0

THE TOLEDO ON COMPANY
CASE NO. ..-551-EL-AIR
ANNUALIZED TEST YEAR REVENUES AT PROPOSED VS. MOST CURRENT RATES
FOR THE TWELVE MONTHS ENDED: FEBRUARY 2008
(ELECTRIC SERVICE)

DATA - 3 MONTHS ACTUAL - 9 MONTHS ESTIMATED
TYPE OF FILING: AIR UPDATE
WORK PAPER REFERENCE NO(S): WPE-4.1a - WPE-4.1q, SCHEDULE E-1

SCHEDULE E-4.1 (PROPOSED)

WITNESS: G. HUSSING

			PROPOSED ANNUALIZED								
LINE NO.	RATE CODE (A)	CLASS/ DESCRIPTION (B)	CUSTOMER BILLS (C)	KWH SALES (D1) (KWH)	BILLING UNITS (D2)	PROPOSED RATES (E) ($)	PROPOSED REVENUE LESS FUEL COST REVENUE (F) ($)	% OF REV TO TOTAL LESS FUEL COST REVENUE (G) (%)	FUEL COST REVENUE (H) ($)	PROPOSED TOTAL REVENUE (F+H) (I) ($)
	GS615	SMALL SCHOOL RATE (SHEET 41)								
178	SPC - GT	SPECIAL CONTRACT - GENERAL SERVICE - TRANSMISSION								
179										
180		CUSTOMER CHARGE								
181		BILLS	-			$330.00	$0	0.00	$0	$0
182										
183		CAPACITY CHARGE								
184		ALL kVa OF BILLING DEMAND, PER kVa			-	$0.58900	$0	0.00	$0	$0
185										
186		REACTIVE DEMAND CHARGE								
187		ALL rkVa, PER rkVa			-	$0.00080	$0	0.00	$0	$0
188										
189		TRANSFORMER CHARGE								
190		ALL kVa OF BILLING DEMAND, PER kVa			-	$0.13000	$0	0.00	$0	$0
191										
192		CUSTOMER DISCOUNT								
193		ALL kWh, PER kWh		-		($0.00500)	$0	0.00	$0	$0
194										
195		CONTRACT DISCOUNT					$0	0.00	$0	$0
196										
197		STATE kWh TAX								
198		FIRST 2,000 kWh, PER kWh		-		$0.00466	$0	0.00	$0	$0
199		NEXT 13,000 kWh, PER kWh		-		$0.00420	$0	0.00	$0	$0
200		ABOVE 15,000 kWh, PER kWh		-		$0.00364	$0	0.00	$0	$0
201				-			$0		$0	$0
202										
203		TOTAL DISTRIBUTION - SPC-GT	-	-			$0	0.00	$0	$0
204										
205										
206	SPC - U	SPECIAL CONTRACT - GENERAL SERVICE - UNIQUE								
207										
208		GS - SECONDARY	1,836	44,824,739			$744,247	48.84	$0	$744,247
209		GP - PRIMARY	37	1,386,332			$19,887	1.31	$0	$19,887
210		GSU - SUBTRANSMISSION	0	0			$0	0.00	$0	$0
211		GT - TRANSMISSION	0	0			$0	0.00	$0	$0
212		TOTAL DISTRIBUTION - SPC-U	1,873	46,211,071			$764,133	50.15	$0	$764,133
213										
214										
215		TOTAL PROPOSED DISTRIBUTION	2,938	64,126,241			$1,523,788	100.00	$0	$1,523,788

THE TOLEDO ON COMPANY
CASE NO. ..-551-EL-AIR
ANNUALIZED TEST YEAR REVENUES AT PROPOSED VS. MOST CURRENT RATES
FOR THE TWELVE MONTHS ENDED: FEBRUARY 2008
(ELECTRIC SERVICE)

DATA - 3 MONTHS ACTUAL - 9 MONTHS ESTIMATED
TYPE OF FILING: AIR UPDATE
WORK PAPER REFERENCE NO(S): WPE-4.1a - WPE-4.1q, SCHEDULE E-1

SCHEDULE E-4.1 (PROPOSED)

WITNESS: G. HUSSING

			PROPOSED ANNUALIZED							
LINE NO.	RATE CODE (A)	CLASS/ DESCRIPTION (B)	CUSTOMER BILLS (C)	KWH SALES (D1) (KWH)	BILLING UNITS (D2)	PROPOSED RATES (E) ($)	PROPOSED REVENUE LESS FUEL COST REVENUE (F) ($)	% OF REV TO TOTAL LESS FUEL COST REVENUE (G) (%)	FUEL COST REVENUE (H) ($)	PROPOSED TOTAL REVENUE (F+H) (I) ($)
	GS614	LARGE SCHOOL RATE (SHEET 42)								
1	EXISTING									
2										
3	TOTAL EXISTING DISTRIBUTION		773	62,707,227			$537,526	100.00	$0	$537,526
4										
5										
6	PROPOSED									
7										
8	GS	GENERAL SERVICE - SECONDARY								
9										
10		CUSTOMER CHARGE								
11		BILLS	166	3,698,775		$7.00	$1,162	0.13	$0	$1,162
12										
13		CAPACITY CHARGE								
14		UP TO 5 kW OF BILLING DEMAND			830	$18.00	$2,988	0.34	$0	$2,988
15		OVER 5 kW, PER kW			12,151	$10.84400	$131,765	15.19	$0	$131,765
16										
17		REACTIVE DEMAND CHARGE								
18		ALL rkVa, PER rkVa			3,177	$0.36000	$1,144	0.13	$0	$1,144
19										
20		CUSTOMER DISCOUNT								
21		ALL kWh, PER kWh		-		($0.01500)	$0	0.00	$0	$0
22										
23		STATE kWh TAX								
24		FIRST 2,000 kWh, PER kWh		184,060		$0.00466	$857	0.10	$0	$857
25		NEXT 13,000 kWh, PER kWh		1,196,351		$0.00420	$5,021	0.58	$0	$5,021
26		ABOVE 15,000 kWh, PER kWh		2,318,364		$0.00364	$8,429	0.97	$0	$8,429
27				3,698,775			$14,307		$0	$14,307
28										
29		TOTAL DISTRIBUTION - GS	166	3,698,775			$151,366	17.45	$0	$151,366

THE TOLEDO ON COMPANY
CASE NO. -551-EL-AIR
ANNUALIZED TEST YEAR REVENUES AT PROPOSED VS. MOST CURRENT RATES
FOR THE TWELVE MONTHS ENDED: FEBRUARY 2006
(ELECTRIC SERVICE)

DATA - 3 MONTHS ACTUAL - 9 MONTHS ESTIMATED
TYPE OF FILING: AIR UPDATE
WORK PAPER REFERENCE NO(S): *WPE-4.1a - WPE-4.1q, SCHEDULE E-1*

SCHEDULE E-4.1 (PROPOSED)
Page 35 of 100
WITNESS: G. HUSSING

			PROPOSED ANNUALIZED							
LINE NO.	RATE CODE (A)	CLASS/ DESCRIPTION (B)	CUSTOMER BILLS (C)	KWH SALES (D1) (KWH)	BILLING UNITS (D2)	PROPOSED RATES (E) ($)	PROPOSED REVENUE LESS FUEL COST REVENUE (F) ($)	% OF REV TO TOTAL LESS FUEL COST REVENUE (G) (%)	FUEL COST REVENUE (H) ($)	PROPOSED TOTAL REVENUE (F+H) (I) ($)
	GS614	LARGE SCHOOL RATE (SHEET 42)								
30	GP	GENERAL SERVICE - PRIMARY								
31										
32		CUSTOMER CHARGE								
33		BILLS	135	8,461,046		$150.00	$20,254	2.33	$0	$20,254
34										
35		CAPACITY CHARGE								
36		ALL kW OF BILLING DEMAND, PER kW			30,171	$3.34600	$101,013	11.64	$0	$101,013
37										
38		REACTIVE DEMAND CHARGE								
39		ALL rkVa, PER rkVa			4,275	$0.36000	$1,539	0.18	$0	$1,539
40										
41		CUSTOMER DISCOUNT								
42		ALL kWh, PER kWh		-		($0.00500)	$0	0.00	$0	$0
43										
44		STATE kWh TAX								
45		FIRST 2,000 kWh, PER kWh		118,667		$0.00466	$553	0.06	$0	$553
46		NEXT 13,000 kWh, PER kWh		771,340		$0.00420	$3,237	0.37	$0	$3,237
47		ABOVE 15,000 kWh, PER kWh		7,571,039		$0.00364	$27,526	3.17	$0	$27,526
48				8,461,046			$31,315		$0	$31,315
49										
50		TOTAL DISTRIBUTION - GP	135	8,461,046			$154,121	17.76	$0	$154,121
51										
52										
53	GSU	GENERAL SERVICE - SUBTRANSMISSION								
54										
55		CUSTOMER CHARGE								
56		BILLS	-			$200.00	$0	0.00	$0	$0
57										
58		CAPACITY CHARGE								
59		ALL kVa OF BILLING DEMAND, PER kVa			-	$1.77800	$0	0.00	$0	$0
60										
61		REACTIVE DEMAND CHARGE								
62		ALL rkVa, PER rkVa			-	$0.00000	$0	0.00	$0	$0
63										
64		TRANSFORMER CHARGE								
65		ALL kVa OF BILLING DEMAND, PER kVa			-	$0.00000	$0	0.00	$0	$0
66										
67		CUSTOMER DISCOUNT								
68		ALL kWh, PER kWh		-		$0.00000	$0	0.00	$0	$0
69										
70		STATE kWh TAX								
71		FIRST 2,000 kWh, PER kWh		-		$0.00466	$0	0.00	$0	$0
72		NEXT 13,000 kWh, PER kWh		-		$0.00420	$0	0.00	$0	$0
73		ABOVE 15,000 kWh, PER kWh		-		$0.00364	$0	0.00	$0	$0
74				-			$0		$0	$0
75										
76		TOTAL DISTRIBUTION - GSU	-	-			$0	0.00	$0	$0

THE TOLEDO ON COMPANY
CASE NO. ..-551-EL-AIR
ANNUALIZED TEST YEAR REVENUES AT PROPOSED VS. MOST CURRENT RATES
FOR THE TWELVE MONTHS ENDED: FEBRUARY 2008
(ELECTRIC SERVICE)

DATA - 3 MONTHS ACTUAL - 9 MONTHS ESTIMATED
TYPE OF FILING: AIR UPDATE
WORK PAPER REFERENCE NO(S): WPE-4.1a - WPE-4.1q, SCHEDULE E-1

SCHEDULE E-4.1 (PROPOSED)

WITNESS: G. HUSSING

			PROPOSED ANNUALIZED							
LINE NO.	RATE CODE (A)	CLASS/ DESCRIPTION (B)	CUSTOMER BILLS (C)	KWH SALES (D1)	BILLING UNITS (D2)	PROPOSED RATES (E)	PROPOSED REVENUE LESS FUEL COST REVENUE (F)	% OF REV TO TOTAL LESS FUEL COST REVENUE (G)	FUEL COST REVENUE (H)	PROPOSED TOTAL REVENUE (F+H) (I)
				(KWH)		($)	($)	(%)	($)	($)
	Q8614	LARGE SCHOOL RATE (SHEET 42)								
77	GT	GENERAL SERVICE - TRANSMISSION								
78										
79		CUSTOMER CHARGE								
80		BILLS	-			$320.00	$0	0.00	$0	$0
81										
82		CAPACITY CHARGE								
83		ALL kVa OF BILLING DEMAND, PER kVa			-	$0.58500	$0	0.00	$0	$0
84										
85		REACTIVE DEMAND CHARGE								
86		ALL rkVa, PER rkVa			-	$0.60000	$0	0.00	$0	$0
87										
88		TRANSFORMER CHARGE								
89		ALL kVa OF BILLING DEMAND, PER kVa			-	$0.13000	$0	0.00	$0	$0
90										
91		CUSTOMER DISCOUNT								
92		ALL kWh, PER kWh		-		($0.00500)	$0	0.00	$0	$0
93										
94		STATE kWh TAX								
95		FIRST 2,000 kWh, PER kWh		-		$0.00466	$0	0.00	$0	$0
96		NEXT 13,000 kWh, PER kWh		-		$0.00420	$0	0.00	$0	$0
97		ABOVE 15,000 kWh, PER kWh		-		$0.00364	$0	0.00	$0	$0
98				-			$0		$0	$0
99										
100		TOTAL DISTRIBUTION - GT	-	-			$0	0.00	$0	$0
101										
102										
103	SPC - GS	SPECIAL CONTRACT - GENERAL SERVICE - SECONDARY								
104										
105		CUSTOMER CHARGE								
106		BILLS	-	-		$7.00	$0	0.00	$0	$0
107										
108		CAPACITY CHARGE								
109		UP TO 5 kW OF BILLING DEMAND			-	$18.00	$0	0.00	$0	$0
110		OVER 5 kW, PER kW			-	$10.84400	$0	0.00	$0	$0
111										
112		REACTIVE DEMAND CHARGE								
113		ALL rkVa, PER rkVa			-	$0.36000	$0	0.00	$0	$0
114										
115		CUSTOMER DISCOUNT								
116		ALL kWh, PER kWh		-		($0.01500)	$0	0.00	$0	$0
117										
118		CONTRACT DISCOUNT						0.00	$0	$0
119										
120		STATE kWh TAX								
121		FIRST 2,000 kWh, PER kWh		-		$0.00466	$0	0.00	$0	$0
122		NEXT 13,000 kWh, PER kWh		-		$0.00420	$0	0.00	$0	$0
123		ABOVE 15,000 kWh, PER kWh		-		$0.00364	$0	0.00	$0	$0
124				-			$0		$0	$0
125										
126		TOTAL DISTRIBUTION - SPC-GS	-	-			$0	0.00	$0	$0

THE TOLEDC .ON COMPANY
CASE NO. ..-551-EL-AIR
ANNUALIZED TEST YEAR REVENUES AT PROPOSED VS. MOST CURRENT RATES
FOR THE TWELVE MONTHS ENDED: FEBRUARY 2008
(ELECTRIC SERVICE)

DATA - 3 MONTHS ACTUAL - 9 MONTHS ESTIMATED
TYPE OF FILING: AIR UPDATE
WORK PAPER REFERENCE NO(S): WPE-4.1a - WPE-4.1q, SCHEDULE E-1

SCHEDULE E-4.1 (PROPOSED)
Page 37 of 100
WITNESS: G. HUSSING

			PROPOSED ANNUALIZED							
LINE NO.	RATE CODE	CLASS/ DESCRIPTION	CUSTOMER BILLS	KWH SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE	FUEL COST REVENUE	PROPOSED TOTAL REVENUE (F+H)
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)	(H)	(I)
				(KWH)		($)	($)	(%)	($)	($)
	GS614	LARGE SCHOOL RATE (SHEET 42)								
127	SPC - GP	SPECIAL CONTRACT - GENERAL SERVICE - PRIMARY								
128										
129		CUSTOMER CHARGE								
130		BILLS	-			$150.00	$0	0.00	$0	$0
131										
132		CAPACITY CHARGE								
133		ALL kW OF BILLING DEMAND, PER kW			-	$3.34800	$0	0.00	$0	$0
134										
135		REACTIVE DEMAND CHARGE								
136		ALL rkVa, PER rkVa			-	$0.36000	$0	0.00	$0	$0
137										
138		CUSTOMER DISCOUNT								
139		ALL kWh, PER kWh		-		($0.00500)	$0	0.00	$0	$0
140										
141		CONTRACT DISCOUNT						0.00	$0	$0
142										
143		STATE kWh TAX								
144		FIRST 2,000 kWh, PER kWh		-		$0.00466	$0	0.00	$0	$0
145		NEXT 13,000 kWh, PER kWh		-		$0.00420	$0	0.00	$0	$0
146		ABOVE 15,000 kWh, PER kWh		-		$0.00364	$0	0.00	$0	$0
147				-			$0		$0	$0
148										
149		TOTAL DISTRIBUTION - SPC-GP	-	-			$0	0.00	$0	$0
150										
151										
152	SPC - GSU	SPECIAL CONTRACT - GENERAL SERVICE - SUBTRANSMISSION								
153										
154		CUSTOMER CHARGE								
155		BILLS	-			$200.00	$0	0.00	$0	$0
156										
157		CAPACITY CHARGE								
158		ALL kVa OF BILLING DEMAND, PER kVa			-	$1.77800	$0	0.00	$0	$0
159										
160		REACTIVE DEMAND CHARGE								
161		ALL rkVa, PER rkVa			-	$0.00000	$0	0.00	$0	$0
162										
163		TRANSFORMER CHARGE								
164		ALL kVa OF BILLING DEMAND, PER kVa			-	$0.00000	$0	0.00	$0	$0
165										
166		CUSTOMER DISCOUNT								
167		ALL kWh, PER kWh		-		$0.00000	$0	0.00	$0	$0
168										
169		CONTRACT DISCOUNT						0.00	$0	$0
170										
171		STATE kWh TAX								
172		FIRST 2,000 kWh, PER kWh		-		$0.00466	$0	0.00	$0	$0
173		NEXT 13,000 kWh, PER kWh		-		$0.00420	$0	0.00	$0	$0
174		ABOVE 15,000 kWh, PER kWh		-		$0.00364	$0	0.00	$0	$0
175				-			$0		$0	$0
176										
177		TOTAL DISTRIBUTION - SPC-GSU	-	-			$0	0.00	$0	$0

THE TOLEDC ON COMPANY
CASE NO. .. -551-EL-AIR
ANNUALIZED TEST YEAR REVENUES AT PROPOSED VS. MOST CURRENT RATES
FOR THE TWELVE MONTHS ENDED: FEBRUARY 2008
(ELECTRIC SERVICE)

DATA - 3 MONTHS ACTUAL - 9 MONTHS ESTIMATED
TYPE OF FILING: AIR UPDATE
WORK PAPER REFERENCE NO(S): WPE-4.1a - WPE-4.1q, SCHEDULE E-1

SCHEDULE E-4.1 (PROPOSED)

WITNESS: G. HUSSING

			PROPOSED ANNUALIZED							
LINE NO.	RATE CODE (A)	CLASS/ DESCRIPTION (B)	CUSTOMER BILLS (C)	KWH SALES (D1) (KWH)	BILLING UNITS (D2)	PROPOSED RATES (E) ($)	PROPOSED REVENUE LESS FUEL COST REVENUE (F) ($)	% OF REV TO TOTAL LESS FUEL COST REVENUE (G) (%)	FUEL COST REVENUE (H) ($)	PROPOSED TOTAL REVENUE (F+H) (I) ($)
	GS614	LARGE SCHOOL RATE (SHEET 42)								
178	SPC - GT	SPECIAL CONTRACT - GENERAL SERVICE - TRANSMISSION								
179										
180		CUSTOMER CHARGE								
181		BILLS	-			$326.00	$0	0.00	$0	$0
182										
183		CAPACITY CHARGE								
184		ALL kVa OF BILLING DEMAND, PER kVa			-	$0.58900	$0	0.00	$0	$0
185										
186		REACTIVE DEMAND CHARGE								
187		ALL rkVa, PER rkVa			-	$0.00000	$0	0.00	$0	$0
188										
189		TRANSFORMER CHARGE								
190		ALL kVa OF BILLING DEMAND, PER kVa			-	$0.13000	$0	0.00	$0	$0
191										
192		CUSTOMER DISCOUNT								
193		ALL kWh, PER kWh		-		($0.00500)	$0	0.00	$0	$0
194										
195		CONTRACT DISCOUNT						0.00	$0	$0
196										
197		STATE kWh TAX								
198		FIRST 2,000 kWh, PER kWh		-		$0.00466	$0	0.00	$0	$0
199		NEXT 13,000 kWh, PER kWh		-		$0.00420	$0	0.00	$0	$0
200		ABOVE 15,000 kWh, PER kWh		-		$0.00364	$0	0.00	$0	$0
201				-			$0		$0	$0
202										
203		TOTAL DISTRIBUTION - SPC-GT	-	-			$0	0.00	$0	$0
204										
205										
206	SPC - U	SPECIAL CONTRACT - GENERAL SERVICE - UNIQUE								
207										
208		GS - SECONDARY	195	18,702,540			$232,727	26.82	$0	$232,727
209		GP - PRIMARY	277	31,844,865			$329,412	37.97	$0	$329,412
210		GSU - SUBTRANSMISSION	0	0			$0	0.00	$0	$0
211		GT - TRANSMISSION	0	0			$0	0.00	$0	$0
212		TOTAL DISTRIBUTION - SPC-U	472	50,547,405			$562,139	64.79	$0	$562,139
213										
214										
215		TOTAL PROPOSED DISTRIBUTION	773	62,707,227			$867,626	100.00	$0	$867,626

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
CASE NO. 07-551-EL-AIR
ANNUALIZED TEST YEAR REVENUES AT MOST CURRENT VS. PROPOSED RATES
FOR THE TWELVE MONTHS ENDED: FEBRUARY 2008
(ELECTRIC SERVICE)

DATA: 3 MONTHS ACTUAL - 9 MONTHS ESTIMATED
TYPE OF FILING: AIR UPDATED
WORK PAPER REFERENCE NO(S): WPE-4, SCHEDULE E-4.1

SCHEDULE E-4 (CURRENT)
PAGE 1 OF 1
WITNESS: G. HUSSING

CURRENT ANNUALIZED

LINE NO.	RATE CODE (A)	CLASS/ DESCRIPTION (B)	CUSTOMER BILLS[1] (C)	BILLING UNITS (KWH) (D)	MOST CURRENT RATES (J) ($/KWH)	CURRENT REVENUE LESS FUEL COST REVENUE[2] (K) ($)	% OF REV TO TOTAL LESS FUEL COST REVENUE (L) (%)	REVENUE INCR LESS FUEL COST REV (F - K)[3] (M) ($)	% INCR IN REV LESS FUEL COST REV (M/K) (N) (%)	FUEL COST REVENUE (H) ($)	CURRENT TOTAL REVENUE (K+H) (K1) ($)	TOTAL REVENUE % INCREASE (M/K1) (O) (%)
1	RS50, RS82	RESIDENTIAL (SHEET 10)	6,934,975	4,427,794,787	$0.0419	$185,578,555	42.02	$18,561,039	10.00	$0	$185,578,555	10.00
2	RS51, RS86	RESIDENTIAL PIPP (SHEET 10)	458,709	221,264,802	$0.0411	$9,103,531	2.06	$1,524,126	16.74	$0	$9,103,531	16.74
3	RS58	RESIDENTIAL, ADD-ON HEAT PUMP (SHEET 11)	47,781	7,796,558	$0.0219	$170,608	0.04	$99,246	58.17	$0	$170,608	58.17
4	RS59	RESIDENTIAL, ADD-ON HEAT PUMP PIPP (SHEET 11)	305	22,867	$0.0263	$601	0.00	$258	42.97	$0	$601	42.97
5	RS60, RS82	RESIDENTIAL WATER HEATING (SHEET 12)	314,603	321,670,028	$0.0291	$9,365,278	2.12	$2,810,326	30.01	$0	$9,365,278	30.01
6	RS61, RS85	RESIDENTIAL WATER HEATING PIPP (SHEET 12)	11,476	11,736,852	$0.0266	$311,617	0.07	$124,963	40.10	$0	$311,617	40.10
7	RS80, RS82	RESIDENTIAL SPACE HEATING (SHEET 13)	32,899	30,903,421	$0.0310	$958,515	0.22	$176,144	18.38	$0	$958,515	18.38
8	RS81, RS85	RESIDENTIAL SPACE HEATING PIPP (SHEET 13)	1,315	1,422,847	$0.0273	$38,837	0.01	$11,262	29.05	$0	$38,837	29.05
9	RS70, RS72	RESIDENTIAL WATER AND SPACE HEATING SCHEDULE (SHEET 14)	295,659	550,065,825	$0.0322	$17,725,310	4.01	$522,906	2.95	$0	$17,725,310	2.95
10	RS71, RS75	RESIDENTIAL WATER AND SPACE HEATING SCHEDULE PIPP (SHEET 14)	8,088	10,652,446	$0.0306	$325,605	0.07	$26,697	8.19	$0	$325,605	8.19
11	RS30, RS40	RESIDENTIAL- OPTIONAL ELECTRICALLY HEATED RESIDENTIAL APARTMENT (SHEET 16)	30,230	18,969,489	$0.0358	$679,531	0.15	$77,241	11.37	$0	$679,531	11.37
12	RS31, RS41	RESIDENTIAL- OPTIONAL ELECTRICALLY HEATED RESIDENTIAL APARTMENT PIPP (SHEET 15)	1,447	1,631,912	$0.0243	$39,682	0.01	$16,910	42.61	$0	$39,682	42.61
13		TOTAL RESIDENTIAL	8,133,589	5,609,870,614	$0.0400	$224,297,870	50.79	$23,851,198	10.88	$0	$224,297,870	10.88
14												
15												
16	GS105	GENERAL SERVICE (SHEET 30)	779,839	1,128,304,319	$0.0347	$39,140,126	8.86	$5,323,954	13.60	$0	$39,140,126	13.60
17	GS102	ELECTRIC SPACE CONDITIONING (SHEET 31)	11,616	291,266,612	$0.0068	$1,972,944	0.45	$4,511,310	228.66	$0	$1,972,944	228.66
18	GS125	SMALL GENERAL SERVICE (SHEET 32)	127,277	2,588,345,557	$0.0194	$50,111,172	11.35	$34,604,145	69.05	$0	$50,111,172	69.05
19	GS145	MEDIUM GENERAL SERVICE (SHEET 33)	15,914	2,227,697,569	$0.0146	$32,533,366	7.37	$21,739,879	66.82	$0	$32,533,366	66.82
20	GS130	ALL ELECTRIC LARGE GENERAL SERVICE (SHEET 34)	5,332	526,722,337	$0.0111	$5,847,990	1.32	$889,091	15.20	$0	$5,847,990	15.20
21	GS175	LARGE GENERAL SERVICE (SHEET 35)	3,163	2,306,074,499	$0.0065	$19,671,630	4.45	$8,446,711	42.94	$0	$19,671,630	42.94
22	GS116	SMALL SCHOOL (SHEET 36)	3,434	72,590,125	$0.0244	[illegible]	0.40	[illegible]	11.31	$0	$1,767,788	11.31
23	GS135	LARGE SCHOOL (SHEET 37)	1,468	183,326,462	$0.0253	[illegible]	1.05	[illegible]	2.11	$0	$4,644,226	2.11
24	GS150	LOW LOAD FACTOR (SHEET 38)	5,518	7,428,174	$0.0585	$434,537	0.10	$1,841,276	423.73	$0	$434,537	423.73
25	GS101	OPTIONAL ELECTRIC PROCESS HEATING AND ELECTRIC BOILER LOAD MANAGEMENT SCHEDULE (SHEET 39)	2,287	220,072,816	$0.0117	$2,584,127	0.59	$2,602,830	100.72	$0	$2,584,127	100.72
26	GS100	GENERAL COMMERCIAL SCHEDULE (SHEET 70)	1,202	2,017,039	$0.0393	$79,280	0.02	$13,901	17.53	$0	$79,280	17.53
27	GS120	LARGE GENERAL COMMERCIAL SCHEDULE (SHEET 71)	277	23,514,495	$0.0106	$249,949	0.06	$292,602	117.06	$0	$249,949	117.06
28	GS140	INDUSTRIAL SERVICE (SHEET 72)	146	117,949,100	$0.0054	$636,437	0.14	$447,871	70.37	$0	$636,437	70.37
29	GS926	OUTDOOR NIGHT LIGHTING (SHEET 41)	768	2,186,661	$0.0372	$81,327	0.02	$247,347	304.14	$0	$81,327	304.14
30	POL	OUTDOOR LIGHTING (SHEET 42)	38,124	68,962,199	$0.1287	$8,616,724	1.95	($12,767)	(0.15)	$0	$8,616,724	(0.15)
31		TOTAL GENERAL SERVICE	996,385	9,764,450,160	$0.0172	$168,371,622	38.13	$81,246,196	48.25	$0	$168,371,622	48.25
32												
33												
34	GSSTL	STREET LIGHTING (SHEET 43)	123,603	141,151,173	$0.1204	$16,992,311	3.85	($46,591)	(0.27)	$0	$16,992,311	(0.27)
35	GSTFLT	TRAFFIC CONTROL LIGHTING (SHEET 44)	46,042	28,827,210	$0.0055	$157,978	0.04	$120	0.08	$0	$157,978	0.08
36		TOTAL LIGHTING	169,646	169,978,383	$0.1009	$17,150,290	3.88	($46,471)	(0.27)	$0	$17,150,290	(0.27)
37												
38												
39	SPECIAL CONTRACTS/ MANUAL BILLS		1,378	4,271,033,656		$10,839,459	2.45	$2,756,954	25.43	$0	$10,839,459	25.43
40	OTHER MISC					$20,950,586	4.74	$691,107	3.30	$0	$20,950,586	3.30
41		TOTAL MISC	1,378	4,271,033,656	$0.0074	$31,790,045	7.20	$3,448,061	10.85	$0	$31,790,045	10.85
42												
43		TOTAL COMPANY	8,300,977	19,809,332,813	$0.0223	$441,809,827	100.00	$108,596,923	24.59	$0	$441,809,827	24.59

1. For POL and GSSTL the customer bills are number of lamps.
2. Current revenue includes distribution, distribution discounts, state KWh tax, and muni tax.
3. Revenue increase is based on the proposed E-4.1 schedules.

THE CLEVELAND ELECT   LLUMINATING COMPANY
CASE NO. ..-551-EL-AIR
ANNUALIZED TEST YEAR REVENUES AT PROPOSED VS. MOST CURRENT RATES
FOR THE TWELVE MONTHS ENDED: FEBRUARY 2008
(ELECTRIC SERVICE)

DATA - 3 MONTHS ACTUAL - 9 MONTHS ESTIMATED
TYPE OF FILING: AIR UPDATE
WORK PAPER REFERENCE NO(S): WPE-4.1a - WPE-4.1q, SCHEDULE E-1

SCHEDULE E-4.1 (PROPOSED)
Page 47 of 100
WITNESS: G. HUSSING

PROPOSED ANNUALIZED

LINE NO.	RATE CODE (A)	CLASS/ DESCRIPTION (B)	CUSTOMER BILLS (C)	KWH SALES (D1) (KWH)	BILLING UNITS (D2)	PROPOSED RATES (E) ($)	PROPOSED REVENUE LESS FUEL COST REVENUE (F) ($)	% OF REV TO TOTAL LESS FUEL COST REVENUE (G) (%)	FUEL COST REVENUE (H) ($)	PROPOSED TOTAL REVENUE (F+H) (I) ($)
	GS116	SMALL SCHOOL (SHEET 30)								
178	SPC - GT	SPECIAL CONTRACT - GENERAL SERVICE - TRANSMISSION								
179										
180		CUSTOMER CHARGE								
181		BILLS	-			$320.00	$0	0.00	$0	$0
182										
183		CAPACITY CHARGE								
184		ALL kVa OF BILLING DEMAND, PER kVa			-	$0.32500	$0	0.00	$0	$0
185										
186		REACTIVE DEMAND CHARGE								
187		ALL rkVa, PER rkVa			-	$0.00000	$0	0.00	$0	$0
188										
189		TRANSFORMER CHARGE								
190		ALL kVa OF BILLING DEMAND, PER kVa			-	$0.31900	$0	0.00	$0	$0
191										
192		CUSTOMER DISCOUNT								
193		ALL kWh, PER kWh		-		$0.00000	$0	0.00	$0	$0
194										
195		CONTRACT DISCOUNT					$0	0.00	$0	$0
196										
197		STATE kWh TAX								
198		FIRST 2,000 kWh, PER kWh		-		$0.00466	$0	0.00	$0	$0
199		NEXT 13,000 kWh, PER kWh		-		$0.00420	$0	0.00	$0	$0
200		ABOVE 15,000 kWh, PER kWh		-		$0.00364	$0	0.00	$0	$0
201				-			$0		$0	$0
202										
203		TOTAL DISTRIBUTION - SPC-GT	-	-			$0	0.00	$0	$0
204										
205										
206	SPC - U	SPECIAL CONTRACT - GENERAL SERVICE - UNIQUE								
207										
208		GS - SECONDARY	2,372	46,849,866			$1,088,217	55.31	$0	$1,088,217
209		GP - PRIMARY	0	0			$0	0.00	$0	$0
210		GSU - SUBTRANSMISSION	0	0			$0	0.00	$0	$0
211		GT - TRANSMISSION	0	0			$0	0.00	$0	$0
212		TOTAL DISTRIBUTION - SPC-U	2,372	46,849,866			$1,088,217	55.31	$0	$1,088,217
213										
214										
215		TOTAL PROPOSED DISTRIBUTION	3,434	72,590,125			$1,967,641	100.00	$0	$1,967,641

THE CLEVELAND ELECT ...LUMINATING COMPANY
CASE NO. ..-551-EL-AIR
ANNUALIZED TEST YEAR REVENUES AT PROPOSED VS. MOST CURRENT RATES
FOR THE TWELVE MONTHS ENDED: FEBRUARY 2008
(ELECTRIC SERVICE)

DATA - 3 MONTHS ACTUAL - 9 MONTHS ESTIMATED
TYPE OF FILING: AIR UPDATE
WORK PAPER REFERENCE NO(S): WPE-4.1a - WPE-4.1q, SCHEDULE E-1

SCHEDULE E-4.1 (PROPOSED)

WITNESS: G. HUSSING

LINE NO.	RATE CODE (A)	CLASS/ DESCRIPTION (B)	CUSTOMER BILLS (C)	KWH SALES (D1) (KWH)	BILLING UNITS (D2)	PROPOSED RATES (E) ($)	PROPOSED REVENUE LESS FUEL COST REVENUE (F) ($)	% OF REV TO TOTAL LESS FUEL COST REVENUE (G) (%)	FUEL COST REVENUE (H) ($)	PROPOSED TOTAL REVENUE (F+H) (I) ($)
	CS136	LARGE SCHOOL (SHEET 37)								
1	EXISTING									
2										
3	TOTAL EXISTING DISTRIBUTION		1,468	383,326,462			$4,644,226	100.00	$0	$4,644,226
4										
5										
6	PROPOSED									
7										
8	GS	GENERAL SERVICE - SECONDARY								
9										
10		CUSTOMER CHARGE								
11		BILLS	153	20,853,959		$7.00	$1,071	0.02	$0	$1,071
12										
13		CAPACITY CHARGE								
14		UP TO 5 kW OF BILLING DEMAND			765	$18.00	$2,754	0.06	$0	$2,754
15		OVER 5 kW, PER kW			65,345	$9.16400	$598,822	12.63	$0	$598,822
16										
17		REACTIVE DEMAND CHARGE								
18		ALL rkVa, PER rkVa			33,984	$0.36000	$12,234	0.26	$0	$12,234
19										
20		CUSTOMER DISCOUNT								
21		ALL kWh, PER kWh		-		($0.01500)	$0	0.00	$0	$0
22										
23		STATE kWh TAX								
24		FIRST 2,000 kWh, PER kWh		22,085		$0.00466	$103	0.00	$0	$103
25		NEXT 13,000 kWh, PER kWh		3,121,014		$0.00420	$13,097	0.28	$0	$13,097
26		ABOVE 15,000 kWh, PER kWh		17,710,860		$0.00364	$64,391	1.36	$0	$64,391
27				20,853,959			$77,591		$0	$77,591
28										
29		TOTAL DISTRIBUTION - GS	153	20,853,959			$692,472	14.60	$0	$692,472

THE CLEVELAND ELECT ...LUMINATING COMPANY
CASE NO. 07-551-EL-AIR
ANNUALIZED TEST YEAR REVENUES AT PROPOSED VS. MOST CURRENT RATES
FOR THE TWELVE MONTHS ENDED: FEBRUARY 2008
(ELECTRIC SERVICE)

DATA - 3 MONTHS ACTUAL - 9 MONTHS ESTIMATED
TYPE OF FILING: AIR UPDATE
WORK PAPER REFERENCE NO(S): WPE-4.1a - WPE-4.1q, SCHEDULE E-1

SCHEDULE E-4.1 (PROPOSED)

WITNESS: G. HUSSING

			PROPOSED ANNUALIZED								
LINE NO.	RATE CODE	CLASS/ DESCRIPTION	CUSTOMER BILLS	KWH SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE	FUEL COST REVENUE	PROPOSED TOTAL REVENUE (F+H)
	(A)	(B)	(C)	(D1) (KWH)	(D2)	(E) ($)	(F) ($)	(G) (%)	(H) ($)	(I) ($)
	GS135	LARGE SCHOOL (SHEET 37)								
30	GP	GENERAL SERVICE - PRIMARY								
31										
32		CUSTOMER CHARGE								
33		BILLS	-			$150.00	$0	0.00	$0	$0
34										
35		CAPACITY CHARGE								
36		ALL kW OF BILLING DEMAND, PER kW			-	$3.28600	$0	0.00	$0	$0
37										
38		REACTIVE DEMAND CHARGE								
39		ALL rkVa, PER rkVa			-	$0.36000	$0	0.00	$0	$0
40										
41		CUSTOMER DISCOUNT								
42		ALL kWh, PER kWh		-		($0.00500)	$0	0.00	$0	$0
43										
44		STATE kWh TAX								
45		FIRST 2,000 kWh, PER kWh		-		$0.00466	$0	0.00	$0	$0
46		NEXT 13,000 kWh, PER kWh		-		$0.00420	$0	0.00	$0	$0
47		ABOVE 15,000 kWh, PER kWh		-		$0.00364	$0	0.00	$0	$0
48				-			$0		$0	$0
49										
50		TOTAL DISTRIBUTION - GP	-	-			$0	0.00	$0	$0
51										
52										
53	GSU	GENERAL SERVICE - SUBTRANSMISSION								
54										
55		CUSTOMER CHARGE								
56		BILLS	-			$180.00	$0	0.00	$0	$0
57										
58		CAPACITY CHARGE								
59		ALL kW OF BILLING DEMAND, PER kW			-	$1.87500	$0	0.00	$0	$0
60										
61		REACTIVE DEMAND CHARGE								
62		ALL rkVa, PER rkVa			-	$0.36000	$0	0.00	$0	$0
63										
64		TRANSFORMER CHARGE								
65		ALL kW OF BILLING DEMAND, PER kW			-	$0.37000	$0	0.00	$0	$0
66										
67		CUSTOMER DISCOUNT								
68		ALL kWh, PER kWh		-		$0.00000	$0	0.00	$0	$0
69										
70		STATE kWh TAX								
71		FIRST 2,000 kWh, PER kWh		-		$0.00466	$0	0.00	$0	$0
72		NEXT 13,000 kWh, PER kWh		-		$0.00420	$0	0.00	$0	$0
73		ABOVE 15,000 kWh, PER kWh		-		$0.00364	$0	0.00	$0	$0
74				-			$0		$0	$0
75										
76		TOTAL DISTRIBUTION - GSU	-	-			$0	0.00	$0	$0

THE CLEVELAND ELECT ILLUMINATING COMPANY
CASE NO. ..-651-EL-AIR
ANNUALIZED TEST YEAR REVENUES AT PROPOSED VS. MOST CURRENT RATES
FOR THE TWELVE MONTHS ENDED: FEBRUARY 2008
(ELECTRIC SERVICE)

DATA - 3 MONTHS ACTUAL - 9 MONTHS ESTIMATED
TYPE OF FILING: AIR UPDATE
WORK PAPER REFERENCE NO(S): WPE-4.1a - WPE-4.1q, SCHEDULE E-1

SCHEDULE E-4.1 (PROPOSED)

WITNESS: G. HUSSING

			PROPOSED ANNUALIZED							
LINE NO.	RATE CODE	CLASS/ DESCRIPTION	CUSTOMER BILLS	KWH SALES	BILLING UNITS	PROPOSED RATES	PROPOSED REVENUE LESS FUEL COST REVENUE	% OF REV TO TOTAL LESS FUEL COST REVENUE	FUEL COST REVENUE	PROPOSED TOTAL REVENUE (F+H)
	(A)	(B)	(C)	(D1)	(D2)	(E)	(F)	(G)	(H)	(I)
				(KWH)		($)	($)	(%)	($)	($)
	GS135	LARGE SCHOOL (SHEET 37)								
77	GT	GENERAL SERVICE - TRANSMISSION								
78										
79		CUSTOMER CHARGE								
80		BILLS	-			$120.00	$0	0.00	$0	$0
81										
82		CAPACITY CHARGE								
83		ALL kVa OF BILLING DEMAND, PER kVa			-	$0.32500	$0	0.00	$0	$0
84										
85		REACTIVE DEMAND CHARGE								
86		ALL rkVa, PER rkVa			-	$0.00000	$0	0.00	$0	$0
87										
88		TRANSFORMER CHARGE								
89		ALL kVa OF BILLING DEMAND, PER kVa			-	$0.31000	$0	0.00	$0	$0
90										
91		CUSTOMER DISCOUNT								
92		ALL kWh, PER kWh		-		$0.00000	$0	0.00	$0	$0
93										
94		STATE kWh TAX								
95		FIRST 2,000 kWh, PER kWh		-		$0.00466	$0	0.00	$0	$0
96		NEXT 13,000 kWh, PER kWh		-		$0.00420	$0	0.00	$0	$0
97		ABOVE 15,000 kWh, PER kWh		-		$0.00364	$0	0.00	$0	$0
98				-			$0		$0	$0
99										
100		TOTAL DISTRIBUTION - GT	-	-			$0	0.00	$0	$0
101										
102										
103	SPC - GS	SPECIAL CONTRACT - GENERAL SERVICE - SECONDARY								
104										
105		CUSTOMER CHARGE								
106		BILLS	350	61,703,896		$7.00	$2,450	0.05	$0	$2,450
107										
108		CAPACITY CHARGE								
109		UP TO 5 kW OF BILLING DEMAND			1,750	$18.00	$6,300	0.13	$0	$6,300
110		OVER 5 kW, PER kW			177,273	$9.16400	$1,624,530	34.26	$0	$1,624,530
111										
112		REACTIVE DEMAND CHARGE								
113		ALL rkVa, PER rkVa			102,182	$0.36000	$36,786	0.78	$0	$36,786
114										
115		CUSTOMER DISCOUNT								
116		ALL kWh, PER kWh		-		($0.01500)	$0	0.00	$0	$0
117										
118		CONTRACT DISCOUNT					$0	0.00	$0	$0
119										
120		STATE kWh TAX								
121		FIRST 2,000 kWh, PER kWh		692,635		$0.00466	$3,226	0.07	$0	$3,226
122		NEXT 13,000 kWh, PER kWh		4,502,128		$0.00420	$18,893	0.40	$0	$18,893
123		ABOVE 15,000 kWh, PER kWh		56,509,133		$0.00364	$205,448	4.33	$0	$205,448
124				61,703,896			$227,567		$0	$227,567
125										
126		TOTAL DISTRIBUTION - SPC-GS	350	61,703,896			$1,897,633	40.01	$0	$1,897,633

			PROPOSED ANNUALIZED							
LINE NO.	RATE CODE (A)	CLASS/ DESCRIPTION (B)	CUSTOMER BILLS (C)	KWH SALES (D1) (KWH)	BILLING UNITS (D2)	PROPOSED RATES (E) ($)	PROPOSED REVENUE LESS FUEL COST REVENUE (F) ($)	% OF REV TO TOTAL LESS FUEL COST REVENUE (G) (%)	FUEL COST REVENUE (H) ($)	PROPOSED TOTAL REVENUE (F+H) (I) ($)
	GS135	LARGE SCHOOL (SHEET 37)								
127	SPC - GP	SPECIAL CONTRACT - GENERAL SERVICE - PRIMARY								
129		CUSTOMER CHARGE								
130		BILLS	48	8,975,521		$150.00	$7,200	0.15	$0	$7,200
132		CAPACITY CHARGE								
133		ALL kW OF BILLING DEMAND, PER kW			25,790	$3.28600	$84,745	1.79	$0	$84,745
135		REACTIVE DEMAND CHARGE								
136		ALL rkVa, PER rkVa			14,263	$0.36000	$5,135	0.11	$0	$5,135
138		CUSTOMER DISCOUNT								
139		ALL kWh, PER kWh		-		($0.00500)	$0	0.00	$0	$0
141		CONTRACT DISCOUNT					$0	0.00	$0	$0
143		STATE kWh TAX								
144		FIRST 2,000 kWh, PER kWh		96,806		$0.00466	$451	0.01	$0	$451
145		NEXT 13,000 kWh, PER kWh		629,240		$0.00420	$2,641	0.06	$0	$2,641
146		ABOVE 15,000 kWh, PER kWh		8,249,475		$0.00364	$29,992	0.63	$0	$29,992
147				8,975,521			$33,084		$0	$33,084
149		TOTAL DISTRIBUTION - SPC-GP	48	8,975,521			$130,163	2.74	$0	$130,163
152	SPC - GSU	SPECIAL CONTRACT - GENERAL SERVICE - SUBTRANSMISSION								
154		CUSTOMER CHARGE								
155		BILLS	24	9,643,715		$180.00	$4,320	0.09	$0	$4,320
157		CAPACITY CHARGE								
158		ALL kW OF BILLING DEMAND, PER kW			24,891	$1.87500	$46,670	0.98	$0	$46,670
160		REACTIVE DEMAND CHARGE								
161		ALL rkVa, PER rkVa			18,309	$0.36000	$6,591	0.14	$0	$6,591
163		TRANSFORMER CHARGE								
164		ALL kW OF BILLING DEMAND, PER kW			24,891	$0.57000	$14,188	0.30	$0	$14,188
166		CUSTOMER DISCOUNT								
167		ALL kWh, PER kWh		-		$0.00000	$0	0.00	$0	$0
169		CONTRACT DISCOUNT					$0	0.00	$0	$0
171		STATE kWh TAX								
172		FIRST 2,000 kWh, PER kWh		45,849		$0.00466	$214	0.00	$0	$214
173		NEXT 13,000 kWh, PER kWh		298,015		$0.00420	$1,251	0.03	$0	$1,251
174		ABOVE 15,000 kWh, PER kWh		9,299,851		$0.00364	$33,811	0.71	$0	$33,811
175				9,643,715			$35,275		$0	$35,275
177		TOTAL DISTRIBUTION - SPC-GSU	24	9,643,715			$107,045	2.26	$0	$107,045

THE CLEVELAND ELEC' LLUMINATING COMPANY
CASE NO. ..-551-EL-AIR
ANNUALIZED TEST YEAR REVENUES AT PROPOSED VS. MOST CURRENT RATES
FOR THE TWELVE MONTHS ENDED: FEBRUARY 2008
(ELECTRIC SERVICE)

DATA - 3 MONTHS ACTUAL - 9 MONTHS ESTIMATED
TYPE OF FILING: AIR UPDATE
WORK PAPER REFERENCE NO(S): WPE-4.1a - WPE-4.1q, SCHEDULE E-1

SCHEDULE E-4.1 (PROPOSED)

WITNESS: G. HUSSING

			PROPOSED ANNUALIZED							
LINE NO.	RATE CODE (A)	CLASS/ DESCRIPTION (B)	CUSTOMER BILLS (C)	KWH SALES (D1) (KWH)	BILLING UNITS (D2)	PROPOSED RATES (E) ($)	PROPOSED REVENUE LESS FUEL COST REVENUE (F) ($)	% OF REV TO TOTAL LESS FUEL COST REVENUE (G) (%)	FUEL COST REVENUE (H) ($)	PROPOSED TOTAL REVENUE (F+H) (I) ($)
	GS135	LARGE SCHOOL (SHEET 37)								
178	SPC - GT	SPECIAL CONTRACT - GENERAL SERVICE - TRANSMISSION								
179										
180		CUSTOMER CHARGE								
181		BILLS	-			$320.00	$0	0.00	$0	$0
182										
183		CAPACITY CHARGE								
184		ALL kVa OF BILLING DEMAND, PER kVa			-	$0.32500	$0	0.00	$0	$0
185										
186		REACTIVE DEMAND CHARGE								
187		ALL rkVa, PER rkVa			-	$0.00000	$0	0.00	$0	$0
188										
189		TRANSFORMER CHARGE								
190		ALL kVa OF BILLING DEMAND, PER kVa			-	$0.31000	$0	0.00	$0	$0
191										
192		CUSTOMER DISCOUNT								
193		ALL kWh, PER kWh		-		$0.00000	$0	0.00	$0	$0
194										
195		CONTRACT DISCOUNT					$0	0.00	$0	$0
196										
197		STATE kWh TAX								
198		FIRST 2,000 kWh, PER kWh		-		$0.00466	$0	0.00	$0	$0
199		NEXT 13,000 kWh, PER kWh		-		$0.00420	$0	0.00	$0	$0
200		ABOVE 15,000 kWh, PER kWh		-		$0.00364	$0	0.00	$0	$0
201				-			$0		$0	$0
202										
203		TOTAL DISTRIBUTION - SPC-GT	-	-			$0	0.00	$0	$0
204										
205										
206	SPC - U	SPECIAL CONTRACT - GENERAL SERVICE - UNIQUE								
207										
208		GS - SECONDARY	893	82,149,370			$1,915,115	40.38	$0	$1,915,115
209		GP - PRIMARY	0	0			$0	0.00	$0	$0
210		GSU - SUBTRANSMISSION	0	0			$0	0.00	$0	$0
211		GT - TRANSMISSION	0	0			$0	0.00	$0	$0
212		TOTAL DISTRIBUTION - SPC-U	893	82,149,370			$1,915,115	40.38	$0	$1,915,115
213										
214										
215		TOTAL PROPOSED DISTRIBUTION	1,468	183,326,462			$4,742,427	100.00	$0	$4,742,427