FILE

BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

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In the Matter of the Application of the Cincinnati Gas & Electric Company to modify its Nonresidential Generation Rates, to Provide for Market-Based Standard Service Offer Pricing, and to Establish an Alternative Competitive Bid to Service Rate Option Subsequent to the Market Development Period:	Case No.	03-93-EL-ATA
In the Matter of the Application of the Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Certain Costs Associated with Midwest Independent Transmission System Operator.	Case No.	03-2079-EL-AAM
In the Matter of the Application of the Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Capital Investment in its Electric Transmission and Distribution System, and to Establish a Capital Investment Reliability Rider to be Effective After the Market Development Period.	Case No. Case No.	03-2081-EL-AAM 03-2080-EL-ATA

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PROCEEDINGS

before Attorney Examiners Jeanne Kingery and Scott Farkas, at the Public Utilities Commission of Ohio, 180 East Broad Street, Hearing Room 11B, Columbus, Ohio, on Wednesday, May 26, 2004, at 12:00 noon.

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Wednesday Afternoon Session,

May 26, 2004.

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EXAMINER KINGERY: We'll go on the record. This is a continuation of the hearing in Case No. 03-93-EL-ATA, and three other cases that we're hearing at the same time.

The first thing today that we'd like to handle is an issue regarding the possible testimony of Mr. McNamara. There's an issue as to whether he is an expert and whether the testimony should have been prefiled.

We believe, after reviewing the memoranda that were filed on this issue, that he is an expert. It's hard to see how the testimony on this subject would be factual as opposed to expert testimony. We also have a difficult time seeing how it would be truly cross-examination as opposed to direct testimony.

The testimony really should have been prefiled. In theory I suppose you could have subpoenaed him and gotten a deposition and prefiled the deposition as was suggested by

someone in one of the memos; however, we do want to have a complete record and we think that his testimony might be useful, so we want to allow him to testify. But we want to also allow people to have a chance to review that testimony and prepare for cross-examination.

So what we would like to do is have Mr. McNamara testify on direct as early in the sequence as possible, and then after he has testified, we'll figure out whether people need to have time to prepare for the cross-examination, and if so, then we would have him come back at a subsequent time, whether it's later that day or a following day, for cross-examination.

So let's go off the record at this point and discuss now how we need to figure out scheduling.

(Discussion held off the record.)

EXAMINER KINGERY: Let's go back on the record.

MR. FINNIGAN: CG&E will call as its next witness Mr. John P. Steffen.

EXAMINER KINGERY: Please raise your

right hand.

(Witness sworn.)

EXAMINER KINGERY: You may be seated.

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JOHN P. STEFFEN

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

DIRECT EXAMINATION

By Mr. Finnigan:

Q. Good afternoon, Mr. Steffen.

A. Good afternoon.

Q. Are you the same John Steffen who previously filed two sets of testimony in this proceeding?

A. I am.

Q. Do you have before you a document that's been marked as CG&E Exhibit 11?

A. I do.

Q. Can you identify that, please?

A. It is a copy of my direct testimony in this proceeding.

Q. You have before you another document marked as CG&E Exhibit 12.

A. I do.

Q. Can you identify that document?

A. And that is my supplemental direct testimony in this proceeding.

Q. Do you have any changes or corrections to either piece of testimony?

A. I do not.

Q. Do you adopt both pieces of testimony as your testimony in this cause?

A. Yes.

MR. FINNIGAN: Mr. Steffen's available for cross-examination.

EXAMINER KINGERY: Thank you.

MS. HOTZ: Your Honor, with this witness I would like to mark as an OCC exhibit a discovery response that CG&E considers to be confidential; would you like me to approach you with the document?

EXAMINER KINGERY: That would be great; thank you.

MR. FINNIGAN: Your Honor, may I also approach?

EXAMINER KINGERY: You may.

EXAMINER FARKAS: Let's go off.

(Discussion held off the record.)

(The following testimony is confidential.)

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(Open record.)

EXAMINER KINGERY: You may go on.

MS. HOTZ: Your Honor, may I approach?

EXAMINER KINGERY: You may.

MS. HOTZ: I have a packet of seven responses to OCC interrogatories, and I would like to have these marked as OCC exhibits.

EXAMINER KINGERY: They will be marked as OCC exhibits 13 through 19.

(EXHIBITS MARKED FOR IDENTIFICATION.)

Q. (By Ms. Hotz) Mr. Steffen, do you recognize the responses to these interrogatories marked as OCC Exhibit 13 through 19?

A. I do.

Q. Would your answers to these interrogatories -- to any of these interrogatories be the same if you were to answer them today?

A. We'll take them in order.

Q. Yes, that's fine.

A. 13, the answer would be the same.

14 would be the same.

15 would be the same.

16 would be the same.

17 would be the same.

18 would be the same.

And 19 would be the same.

Q. Thank you. That's all I have with those.

Would your answers -- never mind.

You believe that the ETP stipulation was fair, don't you, Mr. Steffen?

A. ETP meaning the Electric Transition Plan.

Q. Yes.

A. Yes, I do.

MS. HOTZ: Your Honor, may I approach the witness, please?

EXAMINER KINGERY: You may.

MS. HOTZ: I don't want this document marked as an exhibit, I just want to give it to recollect it.

Q. In response to interrogatory No. 15, which is the document that I just gave you, you indicate that the ERRSP supersedes the ETP stipulation in several respects, correct?

A. Well, I would note that I was not the witness responsible on this interrogatory.

Q. Which witness was responsible for that one?

A. It's indicated as NA, I believe this was responded to by our legal folks in that there were some legal conclusions called for in the document, in the question.

Q. So you don't have a witness -- CG&E does not have a witness to support this interrogatory?

A. There was no witness named at the time that the interrogatory was returned.

Q. Does CG&E have a witness to support this interrogatory?

MR. FINNIGAN: Let me suggest that you just ask Mr. Steffen whatever question you may want to propound to him and he'll try to answer to the best of his ability.

Q. Does this mean, does the response to that interrogatory mean that the provisions of the ERRSP are inconsistent with the ETP stipulation?

A. I think the word I would use is just

that the ERRSP is a new situation. The ETP was a plan that was done back in the year 2000 knowing what we all knew then. Our proposal in this case, if you go back to the original application, included a willingness to proceed with a competitive market option and included all components of the ETP.

I would characterize the ERRSP as a new plan requested by the Commission, agreed to by us, ultimately stipulated with a number of parties, the majority of the parties, in fact, in this case. So I would call it a new plan, not necessarily some compare and contrast with the ETP.

Q. So would you say that it does supersede the ETP --

A. I would say that --

Q. -- stipulation?

A. Sorry.

Q. Sorry.

A. I would say that the ERRSP certainly has revised some of the components of the ETP as a part and parcel of recommending a new plan to deal with the period 2006 to 2008 which was not

really contemplated in the ETP.

Q. So which provisions of the ETP would be superseded?

MR. FINNIGAN: I'm going to object, your Honor. He just answered that he didn't view this as something that superseded the ETP. I don't think it's fair to ask now which ones were superseded. He characterized this as a new deal.

EXAMINER KINGERY: Can you rephrase your question, please?

Q. Which provisions of the ETP have been revised due to the ERRSP?

MR. FINNIGAN: Same objection.

MS. HOTZ: He said it was revised. He said it was revised.

MR. FINNIGAN: Your Honor, I believe the way he characterized it in his prior testimony was a new deal providing new terms of service for a new period and that you couldn't really compare and contrast these to the ETP stipulation.

EXAMINER KINGERY: Can you try another wording that avoids the word "revised"?

Q. Would you say there are certain provisions of the ETP stipulation that if the ERRSP is implemented would not occur?

A. That's true.

Q. Which provisions would those be?

A. I'm trying to think of what comes to mind, and I don't necessarily claim to have off the top of my head an exhaustive list. Two items that are different under the ERRSP than they were under the ETP are the collection of RTC from residential consumers in the years 2009 and 2010, and the extension of a 5 percent reduction on the generation rate for residential consumers in the years 2006 to 2008. That may not be an exhaustive list but it is the two things that come to mind.

Q. Do you believe that if the Commission permits CG&E to defer distribution and transmission costs, it is an indication that CG&E will probably recover those deferred amounts in the next rate case?

A. I believe it's consistent with the past practices of this Commission that generally if deferrals are allowed, recovery is allowed as

well.

Q. CG&E is really not permitted, under FASB, to defer costs that it does not think the Commission will allow it to recover, is it?

A. I haven't been practicing accounting in a while, but in general I believe it's a true statement that a deferred asset must be probable of recovery to be deferrable for SEC purposes. An asset could be deferred for regulatory purposes pursuant to an order of the Commission irrespective of SEC reporting we do maintain multiple sets of books, SEC books, FERC books and then, of course, tax books, as most entities do.

But with that caveat for SEC level reporting the probability standard is typically applied.

Q. If and when the Commission puts the deferred costs in base rates, it becomes a rate increase for costs incurred during the MDP, would it not?

MR. FINNIGAN: Your Honor, I'm just going to object. I'm wondering if the question could be clarified. I'm not sure whether

Ms. Hotz is asking whether the rate increase would be occurring during the MDP or after the MDP. If that could just be clarified.

EXAMINER KINGERY: Can you clarify that, please?

Q. The question is: If the Commission puts the deferred costs that CG&E is requesting for CG&E -- for distribution and transmission, if the Commission puts the deferred costs in base rates in a future rate case, it becomes a rate increase for costs incurred during the MDP, does it not?

MR. FINNIGAN: Same objection.

EXAMINER KINGERY: Do you understand the question?

THE WITNESS: I believe I do. And my response is no, it becomes a rate increase at the point in time when the Commission grants authority to collect those dollars, and that cannot be done during the MDP. Expiration of the MDP is sort of a gate issue for getting for the next rate increase on the distribution or transmission side.

Q. But the purpose of the deferrals is

to collect costs that did occur during the MDP; isn't that correct?

A. In my mind the purpose of the deferral is just to defer costs for consideration at a later time by the Commission.

Q. And is not the reason for that to effectuate collecting costs that CG&E incurred during the Market Development Period?

A. Could you repeat that one? I'm sorry.

Q. Is not the purpose of the deferrals to allow CG&E to recover costs that it incurred during the Market Development Period?

A. The purpose of the deferral is to defer for regulatory purposes, we talked earlier about SEC purposes, for future consideration by the Commission of a cost, and the request would be to consider that cost in the next base rate case which would be post-MDP. And I believe there's prior -- there's precedent with the Commission that deferrals do not constitute rate increases, so I believe it's a rate increase at the time of the distribution base rate case in which those deferred amounts are allowed for

recovery.

Q. When did CG&E incur these costs?

A. Could you be more specific about which costs?

Q. When did CG&E incur the costs that it is asking to defer for transmission and distribution assets?

A. Could you -- there's both -- I'm confused. On the record there's the stipulation. There's also the ERRSP as testified to previously. Are we talking costs in which of those?

Q. I'm talking about the costs in the ERRSP.

A. I'm sorry, in the ERRSP as in my direct testimony, as described there?

Q. I would say in your direct testimony and also in your supplemental testimony.

A. And that's where my confusion is because the block of costs that were proposed for deferral in my direct testimony is different costs than are proposed for deferral in my supplemental testimony.

Q. Okay. So when are the costs -- when

does CG&E incur the costs in either of those?

A. In the direct testimony the costs would be incurred in the years 2003, 2004. In the supplemental testimony the costs would be incurred during the period 1992 through 2003.

Q. When is the Market Development Period?

A. It began January 1 of '01. It has not yet ended even though we've applied for an end for all classes other than residential, but pursuant to the stipulation in this case for classes other than residential at December 31st of '04 and pursuant to the stipulation for residential at December 31st of '05.

Q. So at least some of those costs were incurred during the market development period.

A. That's correct.

Q. Do you believe that the Commission would allow CG&E to defer costs it did not believe that it will allow CG&E to recover in the next rate case?

MR. FINNIGAN: Objection; calls for speculation as to what the Commission might do.

EXAMINER KINGERY: Sustained.

Q. What will happen if the Commission allows CG&E to defer costs and then does not allow CG&E to recover those costs in the next rate case?

A. To the extent costs are deferred on the books of the company, for either regulatory reporting or SEC reporting, if at some future point the Commission rules that those costs are not recoverable, you would then write them off.

Q. Do you believe that that would affect CG&E in any manner?

A. Maybe if you could be a little more specific.

Q. Do you think it would affect CG&E stock prices?

A. I guess, you know, the stock market baffles me most days. Clearly, earnings up the market tends to like, earnings down the market tends to not like. So depending on the magnitude of a write-down it can at least have a blip in stock market pricing, but I certainly don't -- if I had that stock market crystal ball, I would be doing something else right now.

Q. On page 11 of your direct testimony,

lines 7 through 9.

A. I'm there.

Q. You refer to a deferral process associated with POLR costs.

A. That's correct.

Q. That are above the 10 percent cap. In the application on page 18 and the carryover paragraph from page 17 it is not referred to as a deferral process. Are you proposing that there actually be a deferral process on those carryovers with the cap?

A. In my direct testimony we did propose a deferral of any amounts in excess of the cap, I think I mentioned this earlier, but just to restate, in the stipulation we have not included that proposal, so that proposal does not stand currently.

I would also note that the word "defer" can be used in a variety of ways. I mean there's the SEC bookkeeping definition of a deferred asset. You don't necessarily have to have SEC bookkeeping deferrals to have a deferral for regulatory purposes.

So not necessarily saying that this

proposal as on page 11 of my direct testimony involved deferral for SEC bookkeeping, just saying that -- the point that I was trying to convey was to the extent we were in excess of the 10 percent cap, that excess carried into the next year. So deferred in the sense of set aside and brought into the calculation the next year, whether or not there were SEC bookkeeping deferrals.

I would note, again, that in the stipulation as filed we have not maintained that provision.

Q. Okay. Under the Company's application CG&E can sell plants, can it not?

A. I would note that even prior, since I'm not an attorney, but I would believe that since somewhere around January 1 of '01 we could sell the plants, and I believe we continue to have that right.

Q. If the Company were to sell a plant or transfer a plant to a Cinergy affiliate and then buy replacement power to meet native load, to the extent the cost of the replacement power is greater than the fuel costs of the plant that

was disposed, would those extra costs be passed through to the ratepayers under the fuel and purchased power adjustment of the ERRSP under the stipulation?

A. I'll attempt to answer by explaining what our intention is, and if it doesn't quite get it where you are, I'm sure you'll let me know.

But our intention is that to the extent costs are capacity cost, we have a component of our POLR that deals with capacity and then we have a fuel and purchased power component that deals with identifiable fuel and economy purchases of power. So our intention would be that to the extent that we are making purchases that represent capacity, that those would be recovered through the POLR capacity component. To the extent that we were making purchases that included fuel or economy purchases of power identifiable components, we would intend for those to be in the fuel cost.

Q. In the fuel cost?

A. Yes.

Q. Under the original ERRSP CG&E

proposed to make all of little "g" bypassable; did it not?

A. When you say "original," per the application in the case, the January application?

Q. Yes.

A. The proposal at that point was that little "g," in other words, going back to the ETP definitions, big "G" minus the RTC equals little "g," the original proposal that that little "g" be the bypassable charge or the shopping credit, however you want to call that.

Q. However, under the stipulated ERRSP, CG&E proposed to make 15 percent of the little "g" nonbypassable except for the first 25 percent of the customers, correct?

A. I'm sorry, could you ask again?

Q. But under the more recent stipulated ERRSP, CG&E has proposed to make 15 percent of little "g" nonbypassable except for the first 25 percent of each customer class that switches.

A. That's correct.

Q. Under the original ERRSP fuel costs were not bypassable, correct?

A. That is correct.

Q. And under the stipulated ERRSP, incremental fuel costs are bypassable, right?

A. Also correct.

Q. Now, let's suppose that little "g" is 4 cents per kilowatt-hour, okay? The movement from the original ERRSP to the stipulated ERRSP allows for only 15 percent of little "g" nonbypassable charge, which would result in a 60 cents per kilowatt-hour increase in the price to compare, correct?

MR. FINNIGAN: Could I ask to have that question read back, please?

EXAMINER KINGERY: Please read it back.

(Question read.)

A. It wouldn't be an increase. The .60 would not be an increase.

Q. In the price to compare?

A. Well, I guess an increase relative to what?

Q. From the original. From the original. That would just move the original price to compare.

A. The original being?

Q. Being your 2004 filing, ERRSP 2004 filing.

A. So the baseline, if you will, is the original -- the January filing.

Q. Right.

A. Which was little "g."

Q. Right.

A. And we're comparing that to the revised.

Q. Which is 6/10 of a cent, and the hypothetical is that little "g" is 4 cents per kilowatt-hour.

A. Correct. And then what was the comparison that you were doing? I think that's where I got confused.

Q. The comparison is if you look at the price to compare in the January, 2004, filing with the current stipulated ERRSP and you look just at this element where 15 percent of little "g" becomes nonbypassable, you result in a 6/10 of a cent increase in the price to compare -- or decrease. Decrease.

A. I believe you have a .6 decrease

using the math of the 4 cents and 15 percent.

Q. That's right.

A. The missing piece, of course, is the fuel that gets added back into that number.

Q. Right. Right. And if you look at the fuel charges, the incremental fuel and purchased power costs on JPS-1 of your testimony --

A. I'm there.

Q. -- and fuel charges -- when the fuel charges become bypassable, that results in a raise to the price to compare of 17 cents assuming that 4 cents -- that little "g" is 4 cents per kilowatt-hour.

A. Using the illustrative number on JPS-1 I would agree with your math. I would just note that those fuel costs were for the period July to June of '04, partial, of which -- the last five months of which is projected or budgeted. I think Rogers mentioned the other day in his testimony, we're seeing a jump in fuel prices. So I would note that this was the best data we had given the seven and five, seven months actual, five months projected, that

number could be at least somewhat understated at this moment in time, but it is the illustrative number on JPS-1.

Q. Okay. So couldn't you conclude from this hypothetical that the net decrease in the price to compare from the original ERRSP that was filed in January of 2004 to the stipulated ERRSP is 43 cents per kilowatt-hour? Correct?

A. Using the math that we just used in our hypothetical, that would be correct.

Q. Okay. So using those fuel prices, the stipulation actually decreases the price to compare when compared to the application filed in January of 2004, correct?

A. Using the prices that we just went through, your initial price to compare would be lower, unlike the original proposal where that price to compare never changed, the price to compare in the stipulation will vary with fuel. So it would be speculation on all of our parts to try to say where that will be over the next two, three, four-year period. So I mean, I agree with the numbers we're going through here for purposes of the example, and I think based

on these numbers it would say that out of the box we believe it will be a little lower. I think it's entirely possible that it could -- it will vary and could be higher over the course of the plan.

Q. Okay. Wouldn't fuel prices have to go up 6/10 of a cent per kilowatt-hour to offset the 6 cents reduction from the bypassable charge?

A. Again, using the illustrative numbers that we're using, that would be the correct math.

Q. Well, then doesn't JPS-1 show that fuel prices have gone up only 17 cents per kilowatt-hour from 1999 to 2004?

A. With the caveat that the five months here are budgeted and are not actual numbers. So I would have to say that. I would also note, though, that we are over the first half of this year seeing a fairly rapid rise in fuel costs. The number here would say that for the numbers we had at the point in time that we did these numbers.

Q. Okay.

A. But we are seeing a rise in the costs of coal.

Q. On page 6, lines 7 through 14 of your testimony.

A. Direct testimony?

Q. Yes.

A. I'm sorry, could you say the line again?

Q. Lines 7 through 14.

A. I'm there.

Q. You discuss changes to the ERRSP due to results from the competitive bidding component, correct?

A. That's correct.

Q. If the ERRSP prices are not comparable to market rates, what would prevent the Company from insisting that the Commission terminate the plan early if market prices are high?

A. Well, I mean, as I read the paragraph and I believe it adequately describes our intention, I don't believe we can make the Commission do anything. It basically says that we are willing to reopen discussions on this.

Obviously, there's a couple of ways prices can go, they can go up, they can go down, and I guess they can stay right where they are for the entire four-year period. I don't think any of us know that.

I think this is, call it what you will, the fail-safe provision that it gives both the Company and Commission the right to reopen discussions with the parties to the case for further discussions on the terms of the ERRSP if all of our efforts to date to try to design something to get us all through sort of the incremental 2006 through 2008 period proves to be other than what we all think it might be today.

So it's a reopener, but I struggle with the word that we would make the Commission do anything. I believe what our intention is is we would reopen discussions with the Commission.

Q. On page 7, lines 10 and 11, you discuss deferral of the revenue requirements associated with capital expenditures to sustain and improve the reliability of its transmission and distribution system. Are those expenditures

associated with all distribution expenditures?

A. Direct distribution expenditures, that's correct.

Q. What do you mean by "direct"?

A. You know, poles, wires, transformers, things that directly touch the system. Not allocated common or general plant.

Q. So what would be indirect?

A. Things like common or general plant, shares of --

Q. Common?

A. Common or general. Shares of the office building. Obviously when you do full costing, a share of the office building goes to each line of business. What we are attempting to make very clear here is this is not trying to bring into any kind of a calculation about reliability those allocated costs that would be part of a basic cost of service distribution rate case, but would not have to do with system maintenance or system reliability. So it's those things that touch the electric system is sort of my laymen's way at least of thinking about that.

Q. So would that include enhancements to the distribution system?

A. Upgrades, that kind of thing? Increased capacity on the system?

Q. Yes.

A. Yes, it would.

Q. So it would include it.

A. Yes; again, direct expenditures to the system.

Q. So it would include growth on the system?

A. It would include extensions for load in new areas, for instance, if that's how you're defining "growth," but yes. And I would note that this provision did not carry forward to the stipulation. This was in the original ERRSP filed. It is not a part of the original stipulation, but in response to your question, it would include direct expenditures to the distribution system.

Q. If CG&E charges customers for environmental upgrades through the POLR ERRSP and then sells the plant, will CG&E pass back to customers any gains associated with increased

value of the plant due to the environmental upgrades?

A. I'm not sure what "gains" means. What we've proposed is very similar to a traditional utility revenue requirement calculation, so if we put a scrubber on a plant, that scrubber will have a, I'm guesstimating here, but a 30-year life. What we are proposing to include in the POLR each of the years of the POLR is 1/30, in my example, of the revenue requirement. Not 30/30, but just the one-year component.

So the customers that had the benefit of that plant for that one year would be appropriately charged, but if that plant were sold, certainly we would drop the calculation of revenue requirement on that specific asset out of the POLR calculation. So we would only attribute to the period of ownership and the period of dedication of that asset to the POLR load.

Q. How will the transmission tracker work on page 20, line 14 -- 4, sorry, line 4?

A. Essentially what we're saying with

regard to transmission is that as we move forward and see the world sort of evolving into the three fundamental components of generation, those being generation itself -- I mean the electric side of the business, the components being generation, transmission, distribution, under SB3 generation in Ohio is moving to deregulation -- is there -- under I believe ongoing distribution plant will now and forever be under the jurisdiction of the PUCO.

The transmission plant is sort of between those two. We now find ourselves and our company is a member of the MISO, MISO and actually updates its transmission rates pursuant to running those costs through the FERC process so that the revenue requirement and the costs to be charged for transmission are FERC approved costs.

And you know, I've said it earlier and will note again for the record, I am not an attorney, so I don't understand all the legalities of FERC versus state and preemption and all of those kinds of things. But from sort of an accountant rate-making perspective the

point that we're trying to make here and the point that I've tried to make in my testimony is going forward in that our transmission costs are approved at the FERC and come to us through the MISO, all we are asking to do is to once a year update our transmission rates pursuant to that FERC order as passed back to us from the MISO.

So we are just looking for dollar-for-dollar recovery of our transmission costs, and I think simply that's the Company's proposal.

Q. How does FERC assess how much it will charge CG&E for MISO costs?

A. Ultimately it's -- I don't claim to be intimately familiar with their process, but in general it's a cost-of-service type process much like the process we would go through here -- we went through here in the past in a fully bundled world or we'll go through here in the future in a distribution world. But it's a revenue requirement cost of service type of process like we're used to seeing here.

Q. What kind of MISO activities are associated with these costs?

A. MISO itself? I mean, MISO is in place to sort of coordinate and assist in kind of overseeing the transmission system. The transmission assets are still owned by CG&E in our case, in the case of the other MISO members by the companies.

MISO -- the costs that are includable for the rates set at FERC include the cost of the plant on a company-by-company basis, the cost of maintaining the transmission plant on a company-by-company basis as well as the administrative costs of running the MISO, their computer system and building and those kinds of things so there are certain administrative costs of running the MISO that the MISO incurs and then bills to members.

And then there is sort of the traditional cost of service view on transmission assets and the support thereof.

Q. So will MISO be operating any of CG&E's transmission assets?

A. Procario would have been a better person to give you a technical answer, I'll sort of give you my nontechnical answer and I don't

know if this is going to help or not but we'll try.

We still have operations folks who operate -- I think of MISO more as a coordination of the system function, but we still have crews that go out and work on the lines and we still have system dispatchers who, within our system, work in concert with the MISO. So I'm not sure -- I'm not sure if "operate" is or is not the right word, but we still own the system and we still have folks in our dispatch center who work with dispatching and turning -- dropping lines in and out of the system in cooperation with MISO, and that's about as good of a layman's understanding I have as to how the day-to-day operation works.

Q. Before there was MISO, CG&E had to coordinate its transmission activities with other systems, didn't it?

A. Certainly the world in the good old days was a little more segmented. Utilities tended to plan solely for the activity in their own service territories, and most of the movement of power and coordination between

companies was more in terms of economy purchases and, you know, sort of helping your neighbor.

I think the goals of the MISO are much broader than that, the ability to move power over longer distances, and that sort of thing. So, yes, we've always had people who coordinated with our neighbors. I think who our neighbors are just became a lot bigger because of the MISO footprint is so much larger than just our control area.

Q. So CG&E may have incurred some of these same kinds of costs that FERC is charging CG&E for MISO when it coordinated its own transmission system with others, did it not?

A. I would think any overlap would be very minimal because we still have a full operating dispatch center. I think the coordination is about the larger, as I call the larger footprint of MISO, but I think as far as control area and as far as, you know, we've always had folks who would interact with DP&L or other names, Louisville to the south or whomever, well now some of those same folks perform a similar function back and forth with

the MISO.

So I would believe, I have no data in front of me, but I would believe that any overlap would be minimal.

Q. On page 4 at line 18 of your testimony --

A. I'm there.

Q. -- you state "If the Commission uses a competitive bidding process to test the price to compare against market prices, and the competitive bid market prices are significantly different than the price to compare, then the parties may enter discussions with CG&E regarding future terms and conditions of the ERRSP." Correct?

A. I see that, yes.

Q. From that sentence it appears that CG&E intends the Commission to issue an RSP without the intention of selecting a winning bid or actually awarding anything to a CRES in response to the RFP, correct?

A. Well, I can't speak for what the Commission might do, but I believe your characterization is close to the intention we're

trying to convey, that this is a check bid or a test bid, if you will, that the Commission has that authority.

We don't quarrel with the fact that the Commission has the authority to do market testing, it can be bidding, it can be observation of market data, it can be bids received and accepted by others. We are not attempting in any way to constrain the Commission's ability to do market testing for purposes of ensuring the validity of the process.

Q. Well, if CRES providers are aware that the Commission is testing the market with an RFP, the CRES providers would have incentives to submit very high bids in order to raise the MBSSO or the ERRSP, correct?

MR. FINNIGAN: I'm going to object, your Honor. It presumes that this witness is familiar with CRES provider practices, business practices, and that's not the subject of his direct testimony.

EXAMINER KINGERY: Can you rephrase the question to try to get around that problem?

Q. Wouldn't it make sense to you that if a CRES provider is aware that the Commission is testing the market with an RFP, and the CRES providers believe that the ERRSP market-based standard service offer is too low for them to compete with, that they would have an incentive to submit a high bid in order to raise the MBSSO?

MR. FINNIGAN: I'm going to object on the grounds that it calls for speculation as to what CRES providers might do, might believe.

MR. RANDAZZO: If I might, your Honor, relative to what? Incentive relative to what? It strikes me from the question that the same incentive would exist if you were competitively bidding a service in any event.

EXAMINER KINGERY: I'll sustain the objection.

Q. On JPS-7 you indicate that the 2005 internal peak load projected for one day out of the year is 4,862 megawatts, correct?

A. This exhibit shows that that is our projected 2005 peak megawatts, that's correct.

Q. But the peak load of 4,862 megawatts

is not required on a day-to-day basis, correct?

A. It's true that you may not have to call on that peak load on a day-to-day basis. Call it fortunate or unfortunate, but I would say that it's maybe an unfortunate part of running a utility that has to stand ready to serve at all times, that you have to be ready for that peak moment. Planning around peak is a long-standing utility practice.

Q. During the shoulder months, though, of electric use like in the spring and in the fall, CG&E can pretty much count on not having to meet that peak load, can't they?

A. We are a summer-peaking utility so it's more likely we'll have our peak in the summer and it's likely that we will have shoulder months in any given year.

Q. And during those periods when you are pretty sure you won't have to rely -- you won't have to meet a peak load, CG&E can sell excess -- the excess capacity that it has, can it not?

A. Can, and does occasionally. Obviously, you know, in this area the peaks and

the shoulders tend to be somewhat consistent from company to company, so I think Judah Rose was the better witness to probably talk about peak planning and that kind of thing, but just in kind of a general sense, we all sort of have our peaks similarly and we have sour shoulders similarly. So power is not as valuable in the shoulder months because there typically is not the demand and in the end the price is going to be supply-demand related.

Q. CG&E does not intend to pass back to customers any revenues it makes from the sale of that capacity, does it?

A. CG&E's generation became unregulated at January 1 of '01. Any off-system sales that the Company chooses to or takes advantage of for making off-system sales, I personally believe that question was answered about four years ago.

What we've been asked to do and have worked hard in cooperation with many parties in this case is respond to the Commission's request for a different product, and that product is a first call four-year price for customers, and I

would tell you a first call four-year price is a very different, more premium product than some much lesser amount of off-system sales in a shoulder month.

Q. But any revenues CG&E makes from off-system sales will not go back to those customers on the ERRSP, will they?

A. The revenues that CG&E makes from customers who are not subject to the ERRSP will be kept separate by the deregulated generation company or the generation portion of CG&E. The ERRSP customers will be charged their share of the price of what I would call a premium product which is first call service for a term certain of four years. The ERRSP customers have an absolute call against our generation for four years.

Q. But that's not the question that I'm asking. I'm asking the question as to whether or not CG&E intends to pass back to ERRSP customers any of the revenues that CG&E obtains from the sale -- from off-system sales. Is that true?

A. It is correct that CG&E will keep

distinct second-call profits from first-call charges, and so the answer to your question is no, those items that have nothing to do with an ERRSP customer, be they second call in generation or money we make in the gas business, will not be correlated with ERRSP customers. We have proposed a price to provide a provider of last resort service, in fact, we've provided a package to provide a provider of last resort service for a term certain of four years, first call against our generation premium-price service.

So your question is asking about bringing things that have nothing to do with that service in, and the answer is no, we don't intend to credit those back in any way, shape, or form.

Q. Okay. Would you agree that an accurate comparison cannot be obtained when rates from one time period are compared to rates in another time period?

A. Not necessarily.

Q. When can an accurate comparison be obtained when rates from one time period are

compared to rates in another time period?

A. Maybe I'm not understanding the question. I mean, you can do comparisons of things from two different time periods at any time. The extent to which the comparison will yield similarities or differences is dependent on the change in the underlying drivers of the two analyses.

Q. Well, the question is all things being the same, can you do an accurate comparison between rates from one time period to rates in another time period?

A. Your premise was all things being the same?

Q. Yes.

A. Well, then I would say yes.

Q. Okay. You're saying yes to what?

(Laughter.)

A. To what I thought was your question, but maybe we should --

MR. RANDAZZO: I object to the witness asking to review that again.

THE WITNESS: Sorry.

Q. Okay. The question is: With all

things being the same, all things being the same, would you agree that an accurate comparison cannot be obtained when rates from one time period are compared to rates in another time period?

A. Read that one more time, I'm sorry.

Q. All right. All things being the same, would you agree that an accurate comparison cannot be obtained when rates from one time period are compared to rates in another time period?

A. I would not agree.

EXAMINER KINGERY: Could you please clarify what you mean by "if all things are the same"? I think that's where our hang-up is.

MS. HOLZ: Okay.

EXAMINER FARKAS: You mean excluding price.

MS. HOTZ: Yes, excluding price.

EXAMINER FARKAS: If that was the same, there wouldn't be much -- so excluding the price.

Q. All right. This is the question, I'll give you a hypothetical: If a witness were

to attempt to show that rates are reasonable by comparing rates from one year to rates in three years, do you think that's a reasonable comparison?

A. I'm not understanding the question, I'm sorry.

Q. Suppose that you were asked to critique a witness's testimony and that witness was attempting to say that rates were reasonable during a particular year, let's say 1999, and they said that their proof that these rates are reasonable is that other rates during 1999 to 2003 were similar. Do you think that that comparison is reasonable?

MR. FINNIGAN: Your Honor, I'm going to object. I'm not sure of the scope of this question, and I accept that the scope of cross-examination is broad, but I think this has to be tied to something in the witness's direct testimony. If we could just clarify what part of the witness's direct testimony this is tied to, that would be helpful, and if it's not tied to any part of his direct testimony, then I would object as it's beyond the scope of his

direct testimony.

MS. HOLZ: It doesn't have to be tied to anything in his direct testimony. He's talking about rates, he's sponsoring the plan, I mean, I don't think it has to be tied to anything specific in his testimony.

EXAMINER KINGERY: It needs to be tied to his testimony at least in some way.

MS. HOTZ: Well, he talks about rates and reasonableness of rates.

MR. RANDAZZO: Could we have it at least tied to an issue?

EXAMINER KINGERY: Has he made this sort of comparison that you are asking him to critique?

MS. HOTZ: No.

EXAMINER KINGERY: Unless you can tie it to something that is more directly applicable to his testimony, then I'll have to sustain the objection.

MS. HOTZ: Just strike the question.

Q. (By Ms. Hotz) If CG&E is able to recover incremental -- increases in costs, the amount of up to 8 percent per year, why does

CG&E face any risk with capped rates given CG&E's history of cost increases in the past?

A. Can you clarify the -- I thought I understood the first half of the question, but the second part about history of cost increases in the past?

Q. Yeah, I'm just asking you to think about CG&E's history of cost increases in the past, and I'm asking you if there's anything in that history that leads you to believe that CG&E will face risk with capped rates even when they're able to recover incremental increases up to 8 percent per year.

A. And, again, I still don't quite understand the past history, but let me try to answer the question.

Yeah, I believe we do. I believe we are assuming fairly significant risk over the next four years. As shown on JPS-2, even in the first year we believe our incremental costs are greater than the cap. Caps by definition imply that anything in excess of that cap is a risk to the Company, and I think it's entirely possible that these kinds of costs could be in excess of

that.

Like I say, we've shown that in the first year they are. Environmental regulations in particular, which are a large driver of the POLR, involve risk. And then I would just note there are other areas of the business, health care costs and other costs, it takes a lot of employees to run generating stations and we've made no requests for those kinds of cost recovery. So we're taking risks on costs that are not part of this plan. Certainly we're getting some recovery of the costs that are part of this plan, but even those costs are capped -- the recovery of those costs is capped. The costs themselves are uncapped, the recovery is capped. So I believe that is risk to the Company.

Q. How does the provision in the stipulated ERRSP that ends the Market Development Period on December 31st, 2005 benefit residential customers when the ETP stipulation or the status quo provided the same end of the MDP?

A. Well, if you recall, our earlier

proposal was to actually end the market development period at 12/31/04 for the residential group. As part of the stipulation, we have agreed to not make any effort to do that before 12/31/05, so in that sense we've kind of come full circle to where the ETP stipulation was.

Q. How will residential customers benefit from a delay in the distribution rate case when under Senate Bill 3 the distribution rate increase is not permissible until 2006 anyway?

A. With the caveat that I'm not an attorney, I don't believe that SB3 says that there cannot be a distribution rate increase before 1/1/06. My recollection is that it was -- there needed to be a finding of 20 percent switching or effective competition to bring an end to the market development period.

So I don't believe there was any legal prohibition as to when a distribution case could be prosecuted.

Q. Is there a 20 percent shopping for residential customers in the CG&E service

territory now?

A. No, there is not, but -- and I'm certainly not the witness on this, this was -- Judah Rose was the witness on testimony to the effect that part B or the other of the two tests, the finding of effective competition, he believed a case could be made for that.

Q. If CG&E reaches the first 25 percent of the residential load at noon on the third day of the rate stabilization period, will those customers who attempt to switch at 12:01 on that day not be permitted to bypass the rate stabilization charge?

A. The premise there was 25 percent?

Q. Yes.

A. And that 25 -- yes.

Q. At noon.

A. Then I would agree that they would not be able to bypass the rate stabilization charge.

MS. HOTZ: May I approach the witness, please?

EXAMINER KINGERY: You may.

MS. HOTZ: This is a copy of one of

CG&E's responses to an OCC data request.

Q. Would you please read the question and the response into the record, Mr. Steffen?

A. "In the stipulation at Provision 9 what is the procedure for determining how much of the $7 million will be applied to each of the years for which CG&E will provide the additional kWh bill credit?" And the response --

EXAMINER KINGERY: Excuse me just a minute. That is not what we have.

MS. HOTZ: You don't have that one.

EXAMINER KINGERY: We have request No. 279.

MS. HOTZ: Which one do you have?

THE WITNESS: I have 280.

MS. HOTZ: I'm sorry. I gave you the wrong one, I meant to give you 279, but you can read -- well.

You have 279?

EXAMINER KINGERY: Yes.

MS. HOTZ: I'm sorry, I got two of them here. You might as well keep that one.

THE WITNESS: Okay. Future use.

Q. (By Ms. Hotz) Okay, go ahead.

A. Read --

Q. 279.

A. I'm reading OCC interrogatory 08-279. "In the stipulation at Provision 9 what are the proposed rules that would govern the procedure for a CRES provider to subscribe to and apply for the available 'bill credits'?" Response: "The bill credits will be a CG&E tariff provision applicable to all residential customers on a kWh basis."

Q. Am I correct in assuming that your response means that CG&E and CG&E alone will determine the rules that would govern the procedure for a CRES provider to subscribe for available bill credits?

A. No. What we were trying to clarify here was that a CRES provider would not subscribe to anything if the customer was in the group that was determined to be eligible, so whatever percent of customers was chosen or whatever bill credits were determined for any given calendar year, it would have nothing to do with the credits provider. We would automatically apply that as a tariff provision.

It would be part of our filed tariff with the Commission and the CRES provider would never have to apply. The customer would be eligible just by coming in at the appropriate place in line.

So that's the distinction we were trying to make, that in -- in the response, that it would be a tariff provision, and CRES providers don't need to subscribe.

Q. What is the involvement of any other party in crafting this tariff provision besides CG&E?

A. I would refer you to stipulation and recommendation page 14, footnote 5. "CG&E agrees to work in good faith with the parties to draft and implement tariff language establishing the credit mechanism in stipulation paragraph 9, which is the relevant paragraph, prior to December 31st, 2004."

Q. Does that mean the parties to the stipulation?

A. Literally that's what it means.

Q. Okay.

A. We would invite other interested

parties to participate, but that is what the stipulation says.

Q. If CG&E establishes an affiliated CRES, would that CRES be eligible for bill credits?

MR. FINNIGAN: I'm going to object. He said it was the customer who would get the bill credits.

EXAMINER KINGERY: Can you rephrase the question, please?

Q. Would the customers of that affiliate be permitted to -- would they be eligible for bill credits?

A. If CG&E formed a CRES and if that CRES marketed at retail to residential customers, those customers would take their place in line equal to and no different than any other CRES that would operate in our service territory.

MS. HOTZ: May I approach the witness?

EXAMINER KINGERY: You may.

Q. This is a copy of OCC interrogatory 08-280. Will you please read the question and

the response into the record?

A. This is 280 now.

Q. Yes, 280.

A. So OCC INT 08-280 the request: "In the stipulation at Provision 9 what is the procedure for determining how much of the $7 million will be applied to each of the years for which CRES will provide the additional kWh bill credit?" Response: "CG&E will determine the methodology in consultation with the CRES providers and file the methodology prior to December 31, 2004."

Q. Are all CRES providers going to have an opportunity to consult with CG&E regarding the methodology or are only the CRES providers who have signed on to CG&E's stipulation?

A. As I indicated just a moment or two ago, the footnote on page 14 indicates the parties, and literally that meant the parties to the stipulation, however, as I also attempted to indicate, to the extent there are other parties who have an interest in this provision, we would certainly entertain having other parties at the table. It's not our effort to be exclusionary

here but it is our effort to, as we said, establish a process and use that process for the purpose of establishing these credits.

Q. If a CRES provider is unhappy with the procedure, will the CRES provider have any recourse?

MR. FINNIGAN: I'm going to object, your Honor. This goes to a legal conclusion as to what recourse a CRES provider might have. Mr. Steffen has testified that this matter would involve a tariff change provision and certainly, you know, the procedures for a company to do a tariff change are established by law, and as well as other parties' rights to intervene and state their objections.

EXAMINER KINGERY: To the extent that you know the answer to the question and it does not call for you to make a legal conclusion, you may answer the question.

A. And honestly I don't know any more than what Mr. Finnigan just mentioned.

Q. So as far as you know, except as provided by law, a CRES provider would not have any recourse.

A. I guess I would go the other way, I think our intention is first and foremost to get the parties to the table and -- our goal here is to try to do something good, so the goal is to try to get people at the table to do something good. To the extent someone feels aggrieved by that process, you know, I don't know specifically all the legal recourse available to that party. I would hope we could work it out in the collaborative process, but if not, we certainly have not tried to exclude any party from their already-endowed legal rights.

MS. HOTZ: That's all I have.

EXAMINER KINGERY: Mr. Petricoff, do you have any estimate of how long you'll be?

MR. PETRICOFF: My guess would be about an hour.

EXAMINER KINGERY: Why don't we take a ten-minute break.

(Recess taken.)

EXAMINER KINGERY: Let's go back on the record. Mr. Petricoff.

MR. PETRICOFF: Thank you, your Honor.

CROSS-EXAMINATION

By Mr. Petricoff:

Q. Good morning, Mr. Steffen. My name is Howard Petricoff, and I represent a group of marketers who are working in this case, WPS Energy, Constellation Power Source, Constellation NewEnergy, Strategic Energy, LLC, and Mid-American Energy Company.

Before we get started let me ask, do you have any of the trial exhibits and specifically do you have OMG Exhibits 7 and 8 with you?

A. I do not.

MR. PETRICOFF: May I approach the witness, your Honor?

EXAMINER KINGERY: You may.

MR. PETRICOFF: I also ask if any of the counsel want an extra. And I guess while I'm getting up, your Honor, we're going to have another exhibit that we want to mark here, and maybe I'll do that as well if I'm going to approach the witness.

Your Honor, I think we're up to 11.

EXAMINER KINGERY: 10.

MR. PETRICOFF: Okay, OMG 10. And I'd like to have this marked as OMG 10.

EXAMINER KINGERY: It will be so marked.

(EXHIBIT MARKED FOR IDENTIFICATION.)

EXAMINER KINGERY: Mr. Petricoff, before you continue, we have another Exhibit 10 but I'm not sure whose Exhibit 10 this is. This is a letter from Mr. Marshall at Eagle Energy to PUCO regarding Indian Hill.

MR. SMALL: That's a CG&E document.

EXAMINER KINGERY: That's a CG&E document, okay.

MR. COLBERT: Yes, that's a CG&E exhibit.

EXAMINER KINGERY: Thank you.

Let's go off the record for just a minute.

(Discussion held off the record.)

EXAMINER KINGERY: Back on the record.

Q. (By Mr. Petricoff) Mr. Steffen, if you would, take a look at what has been marked OMG Exhibit 8.

A. I see that.

Q. And are you the same John Steffen who signed and submitted this to the Public Utilities Commission of Ohio?

A. I honestly don't recall signing it, but I assume that, subject to check, yes.

Q. Okay. But you are familiar with this document?

A. I do have a general familiarity.

Q. And you would agree with me that this is the first page of the annual report that Cincinnati Gas & Electric filed with the Public Utilities Commission of Ohio for calendar year 2003?

A. Yes.

Q. On the first line of this document it's entitled, Electric Operating Revenues-Sales." There are three figures, an intrastate, an interstate, and a total. Could you describe for me what the intrastate number represents?

A. I'm fairly certain that that would be revenues from sales within the state of Ohio.

Q. This is more or less the retail

sales to Cincinnati Gas & Electric's customers in its service territory?

A. I don't believe that's necessarily true. I believe it could be any intrastate sale.

Q. Do you know of any intrastate sales other than to retail customers in the service territory by CG&E in 2003?

A. We have a number of wholesale customers in the state of Ohio including during 2003.

Q. And they would be included in this number.

A. I'm speculating that they are. I don't know that for sure one way or the other.

Q. Let's move over to the column entitled "Interstate." Can you tell me what that is?

A. That would be sales outside the state of Ohio.

Q. Would that include sales of power from generating facilities owned by Cincinnati Gas & Electric located in the service territory to customers outside the service territory?

A. I believe that to be possible, but I do not know the extent, if any, that there are such amounts included in this number.

Q. Do you know whether or not this number in the interstate category includes sale of power from generating stations the title of which is owned by PSI?

A. Could you repeat the question?

Q. Sure.

MR. PETRICOFF: Could the court reporter read the question back?

(Question read.)

A. I know that CG&E buys from PSI wholesale power for its marketing operation. Specifically whether there are any dollars in this number, I don't know that for a fact. I don't have any subdetail of this schedule in front of me. But CG&E being our deregulated company, the bulk of the off-system wholesale type transactions are done on the books of CG&E and, again, it's our only deregulated generation company.

And so it does -- CG&E does procure power from PSI on an excess basis for further

sale. I just don't know if there are any of those dollars included here. It is possible.

Q. So it is CG&E personnel that would be conducting these wholesale market transactions that are represented here in the column entitled "Interstate Sales"?

A. Not -- when you say CG&E personnel, not necessarily, because Cinergy Services provides labor resources to CG&E, so it's possible that it would be employees of other than CG&E that would be contributing to these dollars.

Q. But the sales in the wholesale market interstate would be credited to the books of the utility Cincinnati Gas & Electric Company.

A. Certainly, to the extent -- we find ourselves in this odd situation where CG&E the company exists much like it did for many, many years, it has reporting requirements like these that exist like they did for many, many years, and unfortunately you've got this situation now where you've got this deregulated generation that keeps getting sort of jumbled up in all

these numbers.

So you know, yes, there are a lot of deregulated dollars flowing through the FERC accounting system on the books of CG&E even though they're not subject to the regulatory process, it's just kind of an anomaly of the fact that many of the reporting documents that we're required to file have not really kept pace with the current state of the world.

Q. But in the current state of the world, Cincinnati Gas & Electric is the entity that is making these interstate sales reported here in 2003 of being approximately $4.3 billion.

A. It is the legal entity making those sales, that's correct.

Q. And I think you indicated before that there may be Cincinnati Gas & Electric personnel who are directly involved in those wholesale transactions.

A. Or a person -- yes, and possibly personnel of other affiliated companies.

Q. And the personnel from the affiliated company, then, would be working under

some type of contract, accord, or agreement that would bring them over to do this transaction in the name of Cincinnati Gas & Electric Company.

A. Correct, and charge the appropriate, you know, the cost -- the share of their time.

Q. If you would, I'd like you to take a look at what has been marked OMG Exhibit 7 and ask if you recognize this document.

A. Yes. It appears to be two pages out of the Cincinnati Gas & Electric Company's FERC Form 1 for the year 2003.

Q. And do you have some responsibility in preparing the FERC Form 1 for Cincinnati Gas & Electric Company?

A. I do not.

Q. If you will turn to what is marked at the bottom as page 115 of the FERC Form 1 --

A. I'm there.

Q. -- you'll see a number under Current Year that is fairly close to the number that you have reported on Exhibit 8 for calendar year 2003 for electric operation revenue sales. Is, in fact, the number reported in Subcolumn E on page 115 of the Form 1 and the total amount in

first -- I'm sorry, in the second column of the OMG Exhibit 8 first line more or less the same entity, those are the totality of electric sales for the Cincinnati Gas & Electric Company for 2003?

A. As you've observed, there's a little bit of difference in the numbers on the two documents, which I do not have a reconciliation of that, but on an order of magnitude basis, they are very, very close, and these are both CG&E documents for the year 2003 so they're essentially describing similar activity.

Q. Okay. I notice that on Column F on page 115 of the Form 1 for the previous year the total sales was only -- were only $4.3 billion as opposed to $6.4 billion in 2003. Do you know what happened between those two years that increased the sales from the Cincinnati Gas & Electric Company by roughly 50 percent?

A. Don't have any specific reconciliation of those two columns with me. I do know that sometime in that previous year a decision was made, as I kind of alluded to earlier, that since CG&E was the company that

was deregulated for generation, we started doing, on a prospective basis, all of the off-system activity, and I say "all" kind of loosely, but the majority or all of the off-system activity on CG&E, ramped it up on CG&E, ramped it down on PSI because PSI is a fully-regulated utility.

Q. This off-system sales activity, does it consist of more than just the sale of surplus generation and capacity owned by Cincinnati Gas & Electric Company and PSI?

A. Not only would I say it consists of more than that, that is just a very minor portion. This is all of the trading activity that goes on, so any purchase from another utility for sale elsewhere, purchase of financial contracts, purchase -- any kinds of off-system purchases and sales.

So it is possible that some of these sales on an opportunity basis were made off of our owned units, but that is going to be not what makes these numbers what they are.

Q. And so your understanding is that the bulk of the numbers come from other

wholesale and off-system transactions that are being conducted by the Cincinnati Gas & Electric Company.

A. That's correct.

Q. Is one of those activities the sale of power from Cincinnati Gas & Electric Company to the Union Light, Heat & Power Company?

A. That is one.

Q. Is Cincinnati Gas & Electric Company the sole provider of power to Union Light, Heat & Power?

A. It is today.

Q. And from what generating facilities is this responsibility of being the sole provider for Union Light, Heat & Power provided?

A. There is no specific attribution generating facilities to the load of Union. For many years, in the days when all of this was done under a full cost of service regulation, we have planned for our system considering the load of Union and load of CG&E because Union did not have any owned generating assets. So it's sort of the overall structure of the system was planned with the Union Light load in mind.

As we've moved post-2001, as we've kind of moved to a more market-based approach to our plants and dispatch of our plants, we still don't attribute anything specific, as far as specific units, to Union. We dispatch our plants against the market and dispatch to meet the loads of CG&E and Union Light.

Q. Would you dispatch, though, from a PSI generating unit to meet the needs of Union Light, Heat & Power, or just CG&E units?

A. We would dispatch first from the CG&E units. The CG&E-Union Light relationship is the first point of dispatch. To the extent there was surplus power available on PSI that was available at the price called for in the operating agreements between the companies, certainly that power could be acquired, but in general, we dispatch Union off of Cincinnati.

Q. And these generating units that are being used to supply Union Light, Heat & Power, will they be the same units that will receive the environmental compliance equipment that will be funded through the POLR fee?

A. Our proposal is that the POLR will

include the named expenditures on any owned CG&E assets. So it is possible, in the first instance, for POLR costs to be incurred on assets that will be dispatched to meet the load of Union or -- well, to meet the load of Union, and I think it's been noted already in the proceeding, but there is a different procedure in place to actually move some assets, sell some assets from CG&E to Union Light so that Union Light will then sort of stand alone from a generation respect.

Q. Let's focus, then, on -- I want to ask you a question now and I want you to assume that it takes place before any transfer of facilities. At this point wouldn't you agree that it is now possible -- it is probable that the generating facilities that will be supplying Union Light, Heat & Power will have environmental compliance equipment and emission allowances that will be paid for through the POLR fee?

A. It is possible that the generating assets could be dispatched to meet UHLP load, they have no assets of their own today, but I

would note that the CG&E POLR customers have first call on those assets. And I would also note that we are sort of in this situation where we're capacity short, so while, as we sort of talked about earlier, you've got peak and then you've got everything other than the peak. At peak we're short.

So it's possible that in some of the off-peak periods the generation is supplying Union Light. It's also power on peak that we're out buying in the market to meet our full load requirements.

Q. Is there any accounting mechanism that the Company plans to invoke that will recoup the costs for the environmental compliance equipment or the allowances -- emission allowances used to supply Union Light, Heat & Power from the units subject to the POLR fee?

A. Our proposal is that the POLR costs will be what they will be for the units of CG&E, so, you know, like I said, there will be no -- or to use your word, no recoupment in that sense. The first call goes to the CG&E POLR

customers, and the cost of meeting the environmental compliance likewise would flow through the POLR mechanism to the CG&E POLR customers.

Q. You indicated before that you may have to meet Union Light, Heat & Power's requirements from purchased power agreements because the Company is short on generation. Will there be any difference in the amount charged to Union Light, Heat & Power as to whether the generation comes from a CG&E unit or from a purchased power agreement?

A. To Union Light?

Q. Union Light, that's right.

A. Union Light and CG&E, pursuant to a proceeding before the Public Service Commission of Kentucky, agreed on a pricing through -- subject to check I believe it's through 2006, through December 31st, 2006. So between now and then there is a firm contract, it's a FERC market price for the pricing of power between Cincy and Union. It's a formula rate so it varies with usage, but the pricing mechanism is fixed.

Q. Now, earlier you indicated to me that there was plans to transfer some of the generating units from Cincinnati Gas & Electric to Union Light, Heat & Power.

A. That's correct.

Q. Could you tell me which units are going to be transferred?

A. The units are, there is one unit at East Bend, there are six peakers at Woodsdale, and then there's a mid-merit unit which is Miami Fort Unit 6.

Q. If you don't mind, would you turn to your direct testimony, your Exhibit JPS-4?

A. I'm there.

Q. Now, wouldn't you agree with me that this schedule shows, at least for the year through June 2004, the environmental compliance cost increases for Cincinnati Gas & Electric generating facilities?

A. That's correct.

Q. And I note on here that the first item says 2001 additions to East Bend. Is that the same East Bend that's going to get transferred to Union Light, Heat & Power?

A. That would be correct.

Q. If and when that transfer takes place, would the costs associated with East Bend then be removed from the POLR fee mechanism?

A. Absolutely.

Q. When CG&E transfers the units that you just listed to Union Light, Heat & Power, will they have to depend more heavily on purchased power to meet the needs of the retail customer load?

A. Will who have to rely more?

Q. I'm sorry. Will Cincinnati Gas & Electric, after the transfer of these generating facilities to Union Light, Heat & Power, have to buy additional capacity or generation in the open market to fill in for the units that are being transferred?

A. With the caveat that I'm not an engineer and don't do plant dispatch, but I was involved with and a witness in the transfer case before the Public Service Commission of Kentucky, the load that's being served by Union Light and the plants being transferred match fairly well.

So the relative situation for CG&E in terms of capacity versus load is somewhat unchanged because the assets match the load.

Q. Previously you told me that Union Light, Heat & Power did not have a first call on East Bend or Miami Fort because those were pledged to Cincinnati Gas & Electric customers first and, therefore, you expected that some of this generation would come from contract power that was purchased to meet that contract.

Once you switch the title, though, to Union Light, Heat & Power, I assume that they'll be dedicated -- those units will be dedicated to those customers, so wouldn't a concomitant amount of the contract power now come to be the main supply for the Cincinnati Gas & Electric customers?

A. There's no doubt that from a logic perspective, to the extent you move those units, it's possible that CG&E could, I don't have any data that tells me one way or the other, but could require more to purchase more capacity, but recall that the capacity charge is a component of the POLR, so to the extent

that's -- to the extent that's necessary for CG&E to make additional purchased power on some kind of a capacity basis, that's in the POLR component of our proposal, not in the avoidable cost portion of our proposal.

Q. Let's explore that a bit a farther, though, just into the accounting on the POLR aspect.

If, in fact, more of the Cincinnati Gas & Electric Company load is going to be provided by contract power, then wouldn't one expect that the POLR costs would fall because now there will be no emission allowances or environmental equipment -- or as much emission allowances and environmental equipment that's going to be relied on since these units are now going to be primarily devoted to Union Light, Heat & Power?

A. To the extent that there are incremental purchased power dollars expended by the company, the purchased power component of the POLR is a fixed calculation. So we take the risk on that increased power, increased purchased power. Our recovery would not vary

based on that.

To the extent that in your hypothetical, that to the extent those plants left the system and we had lesser environmental, in fact, it would flow through as a lesser component -- a reduced dollar value component of the POLR and could cause the POLR to be lower.

Q. Earlier you indicated to us it was possible that some of the surplus generation or surplus capacity available on a given day could be sold off-system by the Cincinnati Gas & Electric Company. If that were to take place, will there be any mechanism to capture the cost of the emission allowances or the environmental compliance equipment from that generation from the off-system sales and flow that as a credit back to the POLR?

A. As to the emission allowances, we would only charge to the POLR those emission allowances that are specifically attributable to meeting that POLR obligation. So to the extent there were emission allowances used to support off-system sales, they wouldn't be included in the POLR.

To the extent that the capacity costs that are, in fact, included in the POLR, the sort of the hardware costs of keeping the plants in compliance so that we can meet our POLR obligation, those would stand as is. There would be no reduction of those.

As a practical matter for the first part when you make these off-system sales in a shoulder month or whatever, your mind-set is to recover the variable cost or the incremental cost of that. If you can get your variable costs and -- well, if you can recover your full variable costs, you'll make the sale. And so often in an off-system sale there's not going to be any contribution to the fixed cost sides of the equation.

But in any event our proposal is that the POLR is the service we're offering to our native load customers, everybody in our service territory, and that those environmental capacity costs are 100 percent included.

Q. Is it your belief that the contributions to fixed costs were -- the off-system sales for the Cincinnati Gas &

Electric Company in a given year would be de minimis?

A. It's my opinion, that is true.

Q. Then would it likewise follow that if the Commission would order that those be tracked and credited back to the POLR, the loss to the Company would be de minimis?

A. I would say having seen what happens when you try to track joint dispatch and I don't know system/off-system and all of that, the costs of the system support to do that would tend to far outweigh the benefits.

Q. But as a financial loss, accounting difficulty put aside for the moment, this would not be a large financial burden on the Company, if, in fact, there would be a crediting mechanism back to the POLR for off-system sales.

MR. FINNIGAN: Could I just ask for clarification? If you're asking the witness to disregard what the cost to the Company is of implementing that.

MR. PETRICOFF: I don't understand the clarification.

MR. FINNIGAN: Are you asking him to disregard what the system implementation costs would be to credit the off-system sales back?

MR. PETRICOFF: Yes. I was just asking him just in terms of the lost value of the sales itself.

MR. FINNIGAN: Disregarding what the implementation costs.

MR. PETRICOFF: Because we haven't talked about any implementation yet, so at this point -- we'll come to that later, right now, I'm just looking to see what the dollars are in the off-system sales, if you will, above the incremental costs. The incremental costs of supplying the off-system sale.

A. Can we just reask the question?

Q. Oh, yeah. A much better idea.

Is it your belief that the incremental -- I'm sorry, let me try this again.

Assuming that the Commission ordered a method for crediting the contribution to fixed costs received in off-system sales that was nonburdensome, would the impact of a crediting

mechanism be a financial burden on the Company?

A. We don't track data in that kind of way today. I kind of alluded earlier, since 2001 we've pretty much moved toward a deregulated view of dispatch of our generation, and we dispatch against market relative to whatever load we've got going at any given point in time.

That just is a preface to saying there are no systems in place today, the systems are not in place today, to track that sort of thing. I believe, and this is pure judgment on my part, but based on how our -- in talking with our commercial folks and how they think about things and think about these kinds of sales, I do believe that the amount would be de minimis. You could certainly, then, draw the flip side conclusion that, well, then if it's de minimis, why not do it.

And I guess my summary would be I believe, having worked with the systems that we use today to keep track of all the costs between the companies and make sure we get the correct attribution of costs to the PSI, CG&E, the

dispatch of the system, et cetera, I believe that it would be a very expensive proposition to put the software in place to comply.

Q. If you know, does Indiana require PSI to credit back a portion of off-system sales revenue to customers?

A. I do know, and, in fact, we just got an order in the last couple of weeks which sort of revised how we think about that. The answer is yes, there is a sharing mechanism, but again, those are fully regulated plants, and obviously that's not what we're talking about here.

Q. Let's switch subjects here for a moment now and talk about the rate stabilization service and the rate stabilization charge. Could you describe for me the value that a commercial and industrial customer receives in exchange for their payment under the stipulation plan of the rate stabilization charge?

A. The plan as a whole, the RSP as a whole includes a lot of components, and a lot of consideration, and a lot of, you know, reasons why different components exist. One of the components that we felt the need to include was

a rate stabilization charge which is 15 percent of little "g," it was part of our compensation, if you will, for standing ready to meet the POLR obligation that we have. It's the fixed component of the POLR.

Under the stipulation the first 25 percent of load that leaves from the commercial and industrial, you know, that were in your question can avoid the RSC, but they're also giving up their right to come back to us at the standard service offer rate. They are committing to leave our system through the year 2008 and relieve us of that POLR obligation.

The remaining 75 percent of customers, they pay the RSC, but they always have the right to come back to us at a standard service offer rate so there is no penalty for coming back to us.

Q. The next series of questions I'm going to ask you are -- on this area are only about the commercial and industrial customers, as I understand, we have slightly different rules for the residential. So let me put that out as a precursor to you and you can assume I'm

only talking about the commercial and industrial customers unless I say include the residentials.

A. Fair enough.

Q. Is it a fair summary, then, for the C&I customers to say the quid pro quo for paying 15 percent of little "g" is the right to return more or less at will to the ERRSP standard service offer rate?

A. With the caveat I'm not sure it's the quid pro quo, but it is within the quid pro quo and it's part of the overall package that we've offered.

Q. So if we think of it as a service, that's the service, you pay 15 percent of little "g," and you can come back to the standard offer -- service rate whenever you wish with the exception of --

A. I believe that is a feature of the plan.

Q. Right. And I guess we should include that I was maybe a bit flippant when I said "whenever you wish." Within the tariff rules on minimum stay as well.

A. Correct.

Q. Okay. Did the Company price out the cost of this right to return and does the 15 percent of little "g" represent more or less what the Company believes is the cost of standing ready to provide this service?

A. We did not do a calculation specifically of the kind you described. As I said, we kind of looked at any number of features of trying to respond to the Commission's request for a proposed Rate Stabilization Plan and the three high order goals that they established for doing such.

We did include the RSC component. There's no worksheet that supports the 15 percent. In the course of doing this we made certain judgments about what did and did not make sense to us as a company and what we're willing to accept as a company in order to offer this four-year service. So there is not a specific calculation that gets to the 15 percent number.

Q. Is it fair to say, though, even without a specific calculation, that when you

refer to your judgment in setting this, the judgment was to more or less make the charge for the service equal the cost of providing the service with a reasonable return?

MR. FINNIGAN: I'm going to object. He did not say that. If that's the question --

MR. PETRICOFF: That's the question.

EXAMINER KINGERY: You can answer the question.

THE WITNESS: Could I have it --

EXAMINER KINGERY: Would you read back the question?

MR. PETRICOFF: Yeah, I'll just -- why don't we read it back.

(Question read.)

A. There was no specific calculation that would be responsive to the question that you just asked. I mean, clearly no company exists to not charge a fair price for its service and be compensated for those costs, but we did not do a calculation that specifically links the 15 percent rate stabilization charge to recovery of costs including a fair return.

Q. When you set the price for the RSC,

is it fair to say that you didn't say I want to charge an amount to reach a plug number that I need to make this plan work irregardless of what it costs to provide the rate stabilization service? Are you comfortable in making that statement?

A. I guess the statement I am comfortable making is that the RSC is a component of an overall package, that overall package includes any number of features, it includes the RSC, includes the POLR, it includes us standing ready and willing and able to satisfy our POLR obligation. Within the course of considering all of those variables we believed a 15 percent RSC was fair compensation to the Company for -- as a component of that overall package of providing those services.

Q. I want to go a level deeper than that. I'm asking you, did you specifically design the RSC to produce revenue that's greater than the foreseen cost of the service in order to pay for other aspects of the program? And the program here is the ERRSP program.

A. You asked did we specifically do

that, and the answer is no.

Q. If, in fact, the RSC charge is more or less set to meet all of the costs for you to stand ready to give the rate stabilization service, including a reasonable profit, then why is it only limited to 25 percent of the customers? Why do 75 percent of the customers have to buy the service?

A. The Commission, when it issued its what I'll call a challenge to the Company, ours and the other regulated utilities in the state, issued a three-prong challenge, one was revenue stability for the company, rate stability for customers, and the maintenance of a marketplace, a competitive marketplace. Having spent the last three or four months working on this, it's darn hard to juggle those three balls all at the same time.

I would just say that the willingness to forego the RSC is a subsidy that we're providing to help with the third of those goals that I named, which is to attempt to sustain the development of a competitive market. So it's a component of an overall

package that's trying to juggle three goals which don't always harmonize very well.

Q. Would you agree with me on a theoretical basis that if the rate stabilization charge was, in fact, designed to meet the costs of providing the rate stabilization service, that the Company would be fairly indifferent as to whether 75 percent of the customers purchased it or 50 percent of the customers purchased it?

MR. FINNIGAN: I'm going to object just because it assumes a fact not in evidence, that the RSC was designed to meet the cost of service, and Mr. Steffen testified that no such calculation was performed.

MR. PETRICOFF: Well, your Honor, I am probing to find here what the damage is if, in fact, customers who don't want the service don't take it. And whether or not there is an implicit, if not explicit, subsidy built into this RSC charge.

EXAMINER KINGERY: That's overruled. You may answer the question.

MR. RANDAZZO: Your Honor, might I inquire, is the witness to disregard the three

objectives that were identified by the Commission?

MR. PETRICOFF: Nothing to do with the Commission.

MR. RANDAZZO: Okay.

THE WITNESS: Again, can we?

(Question read.)

A. And I guess I'll go back to what I said earlier, sort of the premise is not really the way we thought about this plan. We thought about this plan in its totality. It did not specifically quantify any one component against any need to serve.

We looked at our overall obligation, we looked at the, in a theoretical sense the overall call option, the commitment of our generation on a first-call basis to this block of customers, and there was a certain amount of judgment involved in developing the overall plan and there isn't data that exists that would add up to the 15 percent RSC.

Q. Why don't we move on now to another aspect of this provision of the plan. It is my understanding that if a customer elects --

customer in the first 25 percent of the class load elects to take the option of not purchasing the Rate Stabilization Plan, that if they return, they will return at the incremental cost of providing power to them at the time of their return; is that a correct understanding of how the stipulation would work?

A. In general. We can look at the provision that's in the stipulation, but in general they pay, you know, what I would characterize as a penalty rate, they pay the highest rate, not the standard service offer rate.

Q. And it's the incremental rate, it is whatever CG&E actually pays for that last unit in the market.

A. Well, actually it's -- we might want to look at the words --

Q. Let me amend that. It's what CG&E or one of its subsidiaries pays.

A. I believe it says "affiliates," but it's the highest cost power from the prior month.

Q. So it could be the highest cost of

power from PSI.

A. I believe that would be possible.

Q. Are there other affiliates besides PSI who you would look to here?

A. It could be other affiliates to the extent those other affiliates provided power that was used to serve CG&E consumers during the applicable month.

Q. Besides PSI and Union Light, Heat & Power, who are the other affiliates?

A. Unfortunately, I don't have an organization chart sitting here in front of me, or a company chart, but we do have other affiliates that transact in power. I can't recall if it's called Cinergy Capital Trading, Cinergy Marketing Trading, but we do have other affiliates that do transact in power. The language says by any affiliate to serve any of CG&E's consumers, so to the extent it came from an affiliate to a CG&E consumer it would be subject to this provision.

Q. So basically a nonregulated -- it could be the price of a nonregulated affiliate selling power on the system? I withdraw the

question. I think your last answer was complete.

This customer who has now foregone the right to return at the standard offer, ERRSP standard offer, is now coming back at the highest rate from any affiliate, would they have had to continue to pay the POLR charge?

A. There are two components to the POLR charge, the RSC component --

Q. Right.

A. -- and the variable component. They would have continued to pay the variable component of the POLR charge.

Q. And the variable component is emission allowances for the CG&E generating plants and the environmental control equipment, and capacity margin; is that correct?

A. That's correct.

Q. So even though this customer can't use the facilities for which it has paid for the environmental equipment and the emission allowances and it can't use the reserve capacity that it has paid through the POLR fee, it's going to have to continue to pay the POLR fee.

MR. FINNIGAN: I'm going to object. This question assumes another fact not in evidence, that the customers can't use those facilities. That's not been the testimony that's been introduced in this case to date.

MR. PETRICOFF: Let me amend the "can't use" to say cannot rely upon or call upon.

MR. FINNIGAN: Same objection.

MR. PETRICOFF: Your Honor, the testimony was that you would pay whatever the affiliate charge -- you would pay the highest cost from the affiliate for some other source of power.

MR. FINNIGAN: Your Honor -- I'm sorry. Were you finished?

MR. PETRICOFF: No; I'm done.

MR. FINNIGAN: My objection was simply that the testimony in the case has been that the customers who are switched have a right to call on CG&E's generating facilities at any time that they might want to return to CG&E's service. So that's the nature of my objection.

EXAMINER KINGERY: I think you can

probably rephrase around that.

MR. PETRICOFF: I think that's true.

Q. (By Mr. Petricoff) A customer who elects not to pay the RSC charge would still have to pay the POLR -- the other POLR charges including emission allowances, Homeland Security for the CG&E generation facilities, environmental control equipment for the Cincinnati Gas & Electric generation facilities, and for capacity to meet the marginal reserve for the whole of the Cincinnati Gas & Electric Company load; isn't that correct?

A. They would continue to pay the variable component of the POLR, which includes the kinds of costs that you just defined.

Q. And is it also true that if that customer came back, they would not be entitled necessarily to the use of any of that generation or that capacity? In fact, isn't it possible for the Company to say I don't have any capacity, you have to go without power?

A. First of all, I think the first thing I would say is in general that's exactly why we are -- the POLR function that we are

required to perform is there as the safety net for those kinds of customers. You're correct that there is a disconnect provision in the stipulation for customers who sort of sign off on leaving the system, but nevertheless we believe that we have what I'll call sole and unique responsibility to stand ready to serve all customers within our franchise; we believe that's a -- I'm not a lawyer, but I believe that that's a legal obligation that we must stand ready to deal with.

Q. But under the stipulation that has been proposed in this case, isn't it true that despite the obligation you've just described you could tell that customer we have no capacity available, we have no generation available, and since you opted out of the rate stabilization charge, you will have to be turned off today?

A. It is true that part of the quid pro quo, if you will, for the right to bypass the RSC is the sort of obligation of last resort to be disconnected, but, we still believe that in general we have the ongoing obligation to stand ready to serve.

MR. PETRICOFF: May I have a moment? I think I can avoid the next section of questions, I think we may have answered them, but I just want to take a quick look.

EXAMINER KINGERY: That's fine.

MR. PETRICOFF: This will only take a minute or two.

Q. Mr. Steffen, if you would, I would like you to take a look at what has now been marked OMG 11. Do you recognize this document?

A. I don't have any marking of OMG 11.

EXAMINER KINGERY: I believe this was OMG 10.

MR. PETRICOFF: I'm sorry, OMG 10, I apologize.

Q. What has been marked OMG 10, it is not marked on there, we had it marked by the court reporter after I gave it to you.

Do you recognize this document?

A. It appears to be, I haven't -- don't have the originals to verify against, but it appears to be a response and attachment to an interrogatory response filed by the OMG.

Q. And it's one that you prepared; is

that correct?

A. That is correct.

Q. In this -- and to the best of your knowledge are all of the figures listed on here true and accurate?

A. Yes.

Q. One of the things that I asked for in the interrogatory that resulted in this chart was your calculation or projection of what the POLR charges would be for both residential and nonresidential in the -- during the rate stabilization period, 2005 through 2008. Are the rows entitled "Nonresidential," "POLR" and "Residential POLR" your response to that inquiry?

MR. FINNIGAN: I'm going to object. We don't have the question marked as part of that document, but the question says to assume the maximum 8 percent figure will be used.

MR. PETRICOFF: That's correct.

MR. FINNIGAN: Subject to that clarification, that that was the question, that you asked it as a projection, you asked if it was his projection. The question in the

interrogatory instructed him to assume the maximum --

MR. PETRICOFF: That's true.

Q. Would you agree with me, Mr. Steffen, that in order to fill in these numbers you had to make some projections in terms of what the volumes would be of power sales and the revenues in order to make the calculation?

MR. FINNIGAN: I'm going to object. The question says assume the maximum POLR charges were used.

MR. PETRICOFF: That's true. We have to multiply the 8 percent against something. I'm going to -- what I want to ask the witness is to what did we -- did you apply the 8 percent, and how was that derived.

MR. FINNIGAN: I withdraw the objection.

EXAMINER KINGERY: Thank you.

A. If you look at footnote 1 at the bottom of the page there, note 1, based on billing data for 2003, we used the billing system, our billing system extracted -- we have

some ability to extract revenue data. If we then jump up to the column headed 2005, we took total big "G" right off the billing system, RTC off the billing system and then you can see that's totaled. Then we have the residential on there. Subtract big "G" minus RTC gets you to the next section there which gets you to little "g" numbers. And the residential and nonresidential are separately delineated.

And then using the assumption that was in the interrogatory of 8 percent, we just accepted the 8 percent, multiplied the little "g" for the nonresidential group by 8 percent in every year and multiplied the residential little "g" by 5 by the -- on a cumulative basis and then applied the residential on a 5, 6, 7, and 8 on a cumulative basis that's in the stipulation.

You'll note that the 2005 residential is blank because that was part of the stipulation as well, and you'll also note that we did not inflate these numbers or try to make any changes, the entire schedule was based off that 2003 data. It was data that we had, you know, actual data to base this on, so that

was the assumption we made.

Q. Is it reasonable to use 2003 data for projecting what the costs will be for the period 2005 to 2008? I mean, is this a fairly good projection on what we're looking for in total dollars?

A. Personal opinion, it's reasonable. I mean, as you know, summers get hotter and cooler, winters get colder and warmer. So any 12-month period you select has certain anomalies in it, but given that, you know, throughout this case we have just been using the 2003 billing data, and I'm not uncomfortable that that's a reasonable surrogate.

Q. So for the Commission to look in terms of the order of magnitude for dollar impact, this is not a bad yardstick for what the future will bring under this program.

A. That's a fair assumption.

Q. Okay. Let me take you one more assumption down, and that is in my interrogatory I asked you to assume the maximum ceiling in making these calculations. Is that reasonable to assume that you'll be at the maximum ceiling

for the whole of the rate stabilization period given what you know about environmental compliance costs and allowance costs and the Homeland Security costs?

A. And every time we talk about these things I probably sound a bit like a broken record because you have to caveat that there are a lot of unknowns in the world of Homeland Security, which is a smaller component of that number in the world of environmental, which could be huge numbers; but with that in mind, as we observed earlier with OCC, we did provide some projection amounts, and if you look at that relative to these numbers, the 8 percent assumption is not unreasonable.

Q. Okay. And is it true that for 2005 you are going to be way over the 8 percent in terms of what the costs and the components of the POLR will be?

A. That's correct. And, therefore, the cap would come into play.

Q. Earlier today in a question from Ms. Hotz you indicated that the off-system sale of Cincinnati Gas & Electric generation wouldn't

produce high prices because, basically, when -- off-peak when the Company would be able to make sales prices are low. Do you remember that series of questions?

A. I remember what you just said, not necessarily all the questions in the series, but I did make an observation along those lines.

Q. If a customer in the first 25 percent takes the option and basically indicates to the Company that they will not be coming back on the ERRSP standard offer, couldn't the Company then take the capacity that was devoted to that customer and sell it in the open market even during peak power times?

A. In theory I guess anything's possible, but, in fact, we still believe we have to plan for first call for all of that load, so, in fact, we don't plan to do that. We plan to have the capacity to service the entire POLR load.

Q. But isn't that the quid pro quo from the customer who elects to take the waiver of the rate stabilization charge, that they are releasing you from that first call in order to

avoid paying the RSC charge?

A. Could you repeat that one?

(Question read.)

A. There is a link between customers who avoid the RSC and the price they come back at, but, again, all of the components of the proposed plan and the stipulation need to be viewed as a package, so I can't really say that on every single item there was a -- something on both sides of the equation. We looked at the package in total; we believe we need to be compensated for the POLR obligation. We were willing to, in deference to one of the three Commission goals, to work to sustain the competitive market, we're willing to forego and subsidize, if you will, for the first 25 percent.

So I have trouble linking that those two things are the only two thoughts that came into the equation, the thought process that we went through was all of the components of the plan as a package.

Q. You just testified that we're willing to subsidize the first 25 percent. I

thought your testimony was that you had done no cost calculations as to what the cost of the RSC service was. And if that's the case, how can you say that you've subsidized it if you let people avoid it?

A. We are foregoing revenues that we believe we are otherwise entitled to, and to me, I'm just a simple accountant here, but that's my definition of a subsidy.

Q. So you're saying it's a subsidy in that the Company is going to get less revenue than the Company would otherwise receive as opposed to the customer is going to pay less than the value of the service they receive.

MR. RANDAZZO: Could I have that read back, please?

(Question read.)

A. And from my perspective, the Company will get less revenue than it's otherwise entitled to. It will do that by charging the customer less than that customer otherwise would have paid, but I'll stand by the word "subsidy."

Q. Okay. If you will, I'd like you to turn to, on your direct testimony, JPS-11.

A. I'm there.

Q. And I want to ask you about these definitions of the terms that we have on the columns of JPS-11, I happen to be looking at page 1 of 2, but I think they're the same on both.

A. I'm on page 1.

Q. The first column I see on that is big "G." Could you define for me what big "G" is?

A. The terminology that's used here is terminology that kind of became widely accepted in the days of the ETP, but back when we all did our transition cases in '99/2000, the term big "G" was the term adopted for the unbundled generation rate of the regulated company, of CG&E in this case.

Q. So this is the fully embedded cost of generation at the time of the last rate case.

MR. RANDAZZO: I object.

EXAMINER KINGERY: On what grounds?

MR. RANDAZZO: The definition is statutory.

MR. PETRICOFF: The definition of --

MR. RANDAZZO: Unbundled generation.

MR. PETRICOFF: Oh.

EXAMINER KINGERY: Would you like to rephrase?

MR. PETRICOFF: I'm sorry, what?

EXAMINER KINGERY: Would you rephrase, please?

MR. PETRICOFF: Sure.

Q. (By Mr. Petricoff) The numbers that we see under the column of big "G," that represents functionally the fully embedded costs of generation at the time of the last rate case?

MR. RANDAZZO: I object. Statutory definition of unbundled G is a residual value after subtracting some of the D and the T, and it's statutory. It's not a matter of fact, speculation; it's a matter of law.

MR. PETRICOFF: The question was, if this number was, in fact, the fully embedded cost. I'm not asking him a legal definition, I'm just asking about the number.

MR. RANDAZZO: I guess my point would be, your Honor, that the legal definition trumps whatever value this inquiry might have, and I don't see the purpose or its relevance.

MR. PETRICOFF: I think this is a needless argumentation. I'm asking the question about a number that's on his schedule.

EXAMINER KINGERY: Overruled.

A. In doing the electric transition plan cases, the ETP cases, the effort was to unbundle pursuant to SB3 the Company's rates that were determined in its last rate case prior to that. So this is -- these big "G" rates represent -- and one more sort of preface item, the last time rates were determined, it was really on a fully bundled basis so there was no true build-up of costs from the ground up that represented T, G, and D, so in the transition plan cases considerable hours were spent sort of unbundling the overall bundled rates of the Company.

Big "G" is -- the big "G" rates in Column A are the rates as approved by the Commission in our ETP case, as the unbundled

generation rate for CG&E based on the assumptions as embodied in that case.

Q. And how are the numbers derived for little "g"?

A. Little "g" is quite simply, and you can see the formula, we tried to include the formulas in the headings here just for ease of use, but as you can see, we're in Column B and that's Column A minus C. So little "g" was big "G" minus regulatory transition charges.

So to the extent -- and that was definitional at the time, but to the extent that the Commission allowed recovery of transition costs, those costs were then subtracted from big "G" to get you to little "g."

Q. Are you familiar with what went into the regulatory transition charges?

A. I was the witness on that, I have a general recollection, but I've tried to forget a lot in the last four years.

Q. I believe that you and I were at the same dialogue then as now and the same relative positions. But would you agree with me that in the RTC there are no overt generation expenses,

that these were things like FASB 109 and other regulatory type charges?

MR. RANDAZZO: Could I have the question read back, please?

(Question read.)

EXAMINER KINGERY: Go ahead.

A. Our RTC, this is not a legal conclusion, I believe they're all generation type charges because they had to be related to the generation component of the business in order to be subtracted from big "G."

I think the intent of the question was are there any bricks and mortar type generation or stranded asset kind of components to the calculation. And the answer to that is no. These were things like FAS 109, system implementation costs to achieve the implementation of SB3, other existing generation regulatory assets at the time. But there were no bricks and mortar costs in that respect included in the RTC for CG&E.

MR. PETRICOFF: Your Honor, I think I have no further questions.

Thank you, Mr. Steffen.

THE WITNESS: Thank you.

MR. FINNIGAN: Your Honor, could we take a brief recess to determine whether we have any redirect?

EXAMINER KINGERY: Before you do that let me just make sure that nobody else has any further cross-examination.

Okay, we do have a few questions from the Bench.

THE WITNESS: Okay.

EXAMINER KINGERY: I thought we could do that first.

MR. COLBERT: Sure.

EXAMINER KINGERY: I think these will be fairly brief.

- - -

EXAMINATION

By Examiner Kingery:

Q. First of all, I know that there is discussion in various documents as to the difference in the goals behind the POLR cost and the RSC, I wonder if you can expand on the difference between those two and what they're intended to recover.

A. The two, the RSC and the POLR, are really both part of an overall POLR. There's two components, there's a fixed component and then the variable component.

As we sort of talked about just a short time ago, we looked at this as an overall package from the RSC -- or RSP and then transitioning into the stipulation in the case. We looked at the overall package that we sort of thought would get at the three goals that were set out for us in this case.

As I testified to earlier, there's really no specific calculation of costs that build up to the 15 percent. Our proposal was, and it just sort of is compensation to do the overall plan, that that 15 percent would move from the generation rate to a nonbypassable charge but for the first 25 percent of shoppers, and the remainder of the POLR would be the variable costs that we talked about like Homeland Security and environmental, tax changes, et cetera, that are enumerated.

So it's kind of a two-component POLR that has a fixed and variable component. The

fixed component is 15 percent. The variable components are the other items that are enumerated.

Q. Thank you.

On page 3 of your supplemental testimony, lines 13 through 15, you talk about the fact that Mr. Rose had testified that the rates are in the same range of rates that can be offered by others and you say that they are, therefore, market based. I wonder what "market based" means to you. It seems that what you're saying in that sentence is that because they are similar to other rates, they're based on other rates, and I'm not sure that that's how I would hear the term "market based."

A. And this may be more of a laymen's type explanation, but to me market based is what a willing buyer and a willing seller are willing to transact, buy or sell something for. Witness Rose took a look at our rates relative to rates that others are offering in the market today to see do our rates appear to be reasonable relative to the market?

As I said, this is the rate that

we're willing to offer and put forth as our market rate and live with the market rate through the period 2005 to 2008. The question that we put to Judah Rose to look at was are these numbers reasonable with what others are offering in the marketplace? Are they in the range of rates that others that are offering market rates are offering? And his conclusion was yes, they are.

Q. Okay. Also in your supplemental testimony on the top of page 6 you talk about the fact that there are increases in other types of costs that the Company cannot recover under the ERRSP and we wondered what other types of costs those are.

A. The simple answer is all things not otherwise named so the things that are other than those but significantly like health care costs going up, you know, double digits the last few years and projected to do so going into the future. Labor costs to the extent the employee wage rates go up. Other costs of goods and services that go up in the marketplace.

The compensation that the Company

has asked for through the POLR is compensation for the specific enumerated items and we're willing to hold that price as defined by the formulas herein through the year 2008. Other things like health care, labor cost, cost of materials and supplies, just general repairs to the power plants, if something breaks or something needs to be added or improved, we're taking that risk on those costs. So those are the other kinds of costs that are not enumerated in this plan.

Q. All right. One final question on your supplemental testimony. You have a list of several ways in which this is beneficial to the consumers and the public interest. On page 8, your item 5, you talk about the fact that the modification on the shopping credits will allow residential consumers to continue to switch during 2005 and incentivize prices.

Many of the other items that you've listed you've been able to quantify from a dollar standpoint and you have not quantified that one. I wonder whether you have made an effort to do so and if so, what you found.

A. We have not. The rest were a little more knowable, if you will, or a little more determinable. The question is how many -- you'd have to make an assumption and you would have had to have made that assumption and stated that assumption, are 5 going to switch, 10, 15, 20, 25, without having made an assumption so we felt this was just a conservative view we wanted to make the statement that, you know, that is a value, but we did not make an assumption and attempt to calculate that value.

Q. Okay. All right, we have a few questions on the stipulation. And some of these are fairly clear from the testimony that we've had, but we want to make sure just because the language in the stipulation isn't necessarily crystal clear.

A. Good.

Q. First of all, on page 5 when we're talking about the residential adjustments in the POLR charge, those are cumulative; is that correct? So that the 5 percent would be in 2005, of course, it's waived, and then in 2006 it's really 11 percent of little "g."

A. That is correct.

Q. And et cetera.

A. Yeah.

Q. Okay.

A. As is true above for the 8 percent.

Q. Yes.

A. I mean it's true for both.

Q. Yes.

A. Okay.

Q. The RSC is calculated on Exhibit 3 at 15 percent of little "g." That's not really set forth on page 6, it's just referred to, Exhibit 3 is just referred to. Is it correct that it stays at that number, that is not going to change the RSC amount?

A. That's correct, the 15 percent is a fixed number.

Q. Okay.

A. And the little "g" being a fixed number, the 15 percent of little "g" is a fixed number.

Q. Right.

A. Yeah.

Q. Okay. As to the consumers who would

avoid the RSC, the first 25 percent, if there is a consumer who puts you over the 25 percent so that that consumer's load is on both sides of the 25 percent, how is his load treated? Is he in both camps, or is he treated in the 25 percent or is he not?

A. And what we have done in the past because we had the 20 percent test for incentivized shopping credits, we truly prorate when they go onto the -- let's just assume half their load is above and half is below, they would get half of the incentivized rate and half of the unincentivized rate so the cutoff is at that cap.

Q. Okay. Even if it splits a customer.

A. Yes.

Q. Okay.

A. And we have had that, in fact.

Q. Back on page 7, the third to the fifth line there's a parenthetical that there is no end to the parentheses, we wondered where that should be.

A. Before the comma.

Q. At the end of the 2005?

A. No, I'm sorry, "except shopping customer defined in paragraph 11," close paren.

MR. SMALL: Excuse me, your Honor. I wondered about that myself. I wanted to make sure about this. We're on page 7 and the parenthetical ends after the No. 11?

EXAMINER KINGERY: Yes.

THE WITNESS: Yes.

MR. SMALL: Thank you.

I apologize for that.

Q. That's fine. On page 13 in paragraph 8, two questions, we'd like to clarify that the fuel and economy power purchases are truly on top of the other charges, that is, another charge.

A. It is a separate charge that's added to the 85 percent of little "g" number to constitute the price to compare, or at least the generation component of the price to compare remembering that transmission is also a component of price to compare as well.

Q. Right. So the price to compare becomes the 85 percent plus the fuel and economy

power, plus the transmission cost riders and the RSC, if you are in the first 25 percent.

A. That's correct.

Q. Okay. The next sentence says, "The rate stabilization charge shall be part of the price to compare for the first 25 percent and," a line down, "a component of the POLR charge for the remaining 75 percent." Would an "or" there be more clear as to what you're saying? It's one or the other?

A. I wouldn't necessarily object to that. The point we were trying to get at there was that for the first 25 percent it is bypassable, and for the remaining 75 percent it is nonbypassable so I'll be happy to make that change.

Q. I'm not saying it needs to be changed. We just want to make sure we understand the meaning.

Paragraph 9, are we correct in assuming that this is the RSC that you are dealing with in this paragraph?

A. It is not the RSC.

Q. It is not.

A. No.

Q. Okay. What is this?

A. This is a -- I guess just to kind of come the long way around but the residential group has been the group that has had the least shopping in our service territory, the percent of shoppers is lower than the other groups. What this is is an incentive that we are willing to put on the table up to $7 million over the years 2006, '7 and '8 up to 3 million in any year and it's kind of the question that the OCC was asking about earlier, that in cooperation with the CRES providers, we intend to create a tariff provision that says if you shop, we'll give you a little extra bill credit so it helps to incent residential customers to shop. So it's separate from the RSC. It's a shopping incentive specific to residential customers.

Q. Okay. The last three lines on that page, you talk about purchasing service from a competitive retail electric service provider, and also to people who are served by competitive retail electric service providers not affiliated with CG&E. We're confused about why you have

both of those provisions; are they exclusive? What were you meaning there?

A. I'm sorry, could you rephrase or reask? We're in the last three lines on page 13.

Q. Yes, the last three lines, maybe four lines would be a better place to talk. CG&E is going to establish a tariff that's applicable to the first 25 percent of residential load to purchase CRES service from a CRES provider, and also to residential consumers served by CRES providers not affiliated with CG&E. What is the purpose for the second part of that, the "and to residential consumers"?

A. And actually I believe in the cross-examination with OCC earlier I may have misstated this point, but to the extent residential consumers would be served by a CG&E-related CRES, those consumers would not receive this incentive, it was a way for us to not pull any of those dollars away from the other arm's length marketers who might choose to marked in our service territory.

Q. And I believe you're right. You did

say the opposite.

A. I believe I misspoke on that earlier looking at this. So I'd like to correct that.

Q. Okay.

EXAMINER FARKAS: What's the -- how much is that credit going to be? Is it based on load or anything?

THE WITNESS: Well, and that's really why we proposed the collaborative process. We said we're willing to put the dollars out there, like to sit down, you know, have a collaborative and, obviously, the 3 million could be set at a fairly high credit and used fairly quickly, but incent people fairly quickly to shop or you could make it a little lower and sort of build over time the shopping.

EXAMINER FARKAS: Okay.

THE WITNESS: So the collaborative process with no real company bias for what that credit would look like.

EXAMINER FARKAS: Okay.

Q. Page 16, the end of paragraph 11, you specify there that the POLR charge would be paid by switched nonresidential consumers and by

residential consumers. Isn't it correct that the POLR charge, that is the variable part of the POLR charge, would be paid by all consumers?

A. We're about the fifth line down, beginning?

Q. Yes.

A. The important point there is the years. Beginning in '05 the nonresidential will pay it, beginning in '06 the residential will pay it.

Q. Well, beginning in '05 all nonresidential, not just switched, consumers pay the POLR charge.

A. That's true.

Q. Okay.

A. Wait a minute.

Correct.

Q. Okay. If a -- continuing to look at that sentence, if a nonresidential consumer were shopping at the end of 2004 and, therefore, getting shopping credits, and that consumer kept getting shopping credits in 2005, then would that consumer pay the -- either part of the POLR charge?

A. They would pay the -- it's a customer switched on 12/31/04 who stays switched.

Q. Yes.

A. They would pay the -- well, in a sense the RSC, the 15 percent component, is already in the generation rate they're paying, and so they are paying that. And then they would pay the new POLR charge. So they would pay --

Q. The adjustable part.

A. The adjustable POLR but they would continue to get their shopping credits under the old regime, if you will, going all the way back to the old ETP, the ETP stipulation provided that if you were switched on the last day of the Market Development Period, you could continue under the current structure.

Q. Right.

Page 18, paragraph 17 you talk about a demand-side management tracker initially set at zero. Can you explain that to us?

A. The thought was there has been some interest expressed in us doing some demand-side

management kind of programs, just trying to establish that we're willing to do -- that we're willing to do it in concert with the CCEP which is the group in the Cincinnati area that we've worked with in the past on these kinds of programs.

Obviously, set at zero in the beginning because there is nothing today. Just wanted to kind of establish in this case that we're interested in doing that or willing to do that, and also as the last sentence says, we don't intend to just do that unilaterally, we would intend to bring the programs to the Commission as well as the recovery to the Commission.

Q. Okay. Page 19, paragraph 19, you're talking here about the 5 percent decrease for residential consumers and you talk about it going through 2010, and we wondered how that would work, what your thought there is.

A. Actually what we're saying is the 5 percent proposal, the 5 percent reduction in G is proposed through 2008. This is basically an either-or kind of paragraph. You know, one of

our proposals that was the RTC for residential that was otherwise scheduled to expire at the end of '08 be continued through 2010.

So our proposal is that the RTC continue in the years 2009 and 2010, our proposal is also that we're willing to extend the 5 percent generation reduction in the years '6, '7, and '8 and we're sort of linking those two in this paragraph. But the first half of that is basically saying the maintain the 5 percent generation decrease, it doesn't really say it here but that is intended to be through 2008.

EXAMINER FARKAS: And then how is it going to be extended? Is that something that the Commission would do?

THE WITNESS: The decrease?

EXAMINER FARKAS: No, this extension through 2010.

THE WITNESS: We have in place, and in fact, it's attached to the stipulation, there's a document called Rider RTC, and then it would just be --

EXAMINER FARKAS: So that would be

approved as part of the stipulation?

THE WITNESS: Yes, it would be approved in this case, presumably.

Q. One final page, which is on your Stipulation Exhibit 3. First of all, at the heading -- are you there? I'm sorry.

A. I am, thank you.

Q. Okay. At the heading for POLR Charges there's a footnote 1 which at least on my copy does not refer to anything.

A. It's actually, unfortunately, footnote 1 is on page 2.

Q. Well, that answered one of my other questions which is what about the other rate schedules? I only have one page of that.

A. Oh, no.

Q. So apparently there are some copies that are not complete.

A. No, there is a second page, does include the notes at the bottom and it does include the other --

MR. SMALL: Are we looking at a table of numbers here? I want to make sure I've got all the pages.

EXAMINER KINGERY: Yes, Stipulation Exhibit 3, there apparently should be two pages of Stipulation Exhibit 3.

MR. SMALL: I only have one.

EXAMINER KINGERY: I only have one as well. I am looking at the copy that is the CG&E Exhibit 1.

MR. FINNIGAN: Your Honor, we'll correct that during a break just to supply the second page so that we've got the --

EXAMINER KINGERY: That's fine.

MR. FINNIGAN: -- accurate version in the record.

EXAMINER KINGERY: Okay. Let me just look at my notes for a moment.

Q. The last one is just to clarify that the POLR column there, that last column, Column F, is really the adjustable part of the POLR.

A. That's correct.

Q. Which since the RSC is listed separately.

A. That is correct.

EXAMINER KINGERY: Did you have any further questions?

EXAMINER FARKAS: No.

EXAMINER KINGERY: All right, we'll take a -- how long do you need?

MR. FINNIGAN: Just ten minutes.

EXAMINER KINGERY: Okay, a ten-minute break.

(Recess taken.)

EXAMINER KINGERY: Let's go back on the record.

MR. FINNIGAN: Your Honor, during the break we went and checked Joint Exhibit No. 1 which is the Stipulation and Recommendation, and we were able to determine that in the version that was filed with the Commission there is page 2 of Stipulation Exhibit 3. We've had copies, we just passed them out. We would ask that page 2 of Stipulation Exhibit 3 be added into the record as part of Joint Exhibit 1, which is the Stipulation and Recommendation.

EXAMINER KINGERY: Great. Any objection to that?

(No response.)

EXAMINER KINGERY: It will be added

as such.

MR. FINNIGAN: Thank you, we just have one area of redirect for Mr. Steffen.

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REDIRECT EXAMINATION

By Mr. Finnigan:

Q. Mr. Steffen, do you recall you were asked a series of questions by Ms. Hotz during cross-examination relating to the accounting deferrals that were part of the Stipulation and Recommendation?

A. I do.

Q. Can you summarize what is the nature of the agreement that CG&E reached with the other parties to the Stipulation and Recommendation with respect to the accounting deferrals and what it is that the parties are asking the Commission to approve with respect to the accounting deferrals in this case?

A. Certainly. In paragraph 6 of the stipulation, the stipulation provides for a couple of things, one is approval of the deferrals that were requested, and further, the recovery of those deferrals through a mechanism

on and after January 1, 2006.

The joint parties to the Stipulation agree that the Commission would approve the rate design for those deferrals in CG&E's next base rate case, but our intention is both the deferral and the recovery thereof be the subject of this case.

MR. FINNIGAN: Thank you. No further questions.

EXAMINER KINGERY: Thank you.

MR. RANDAZZO: If I might, your Honor, could I ask the witness a question?

EXAMINER KINGERY: Yes, you may.

MR. RANDAZZO: I think it may help the record.

EXAMINER KINGERY: You may.

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CROSS-EXAMINATION

By Mr. Randazzo:

Q. Mr. Steffen, you indicated that the Commission would approve the rate design for the deferrals. Did you mean the rate design for the recovery of the deferrals?

A. That's correct.

MR. RANDAZZO: Thank you.

EXAMINER KINGERY: Thank you. All right, is there any recross?

(No response.)

EXAMINER KINGERY: All right. You may step down. Thank you.

(Witness excused.)

MR. FINNIGAN: Your Honor, at this time we'd like to move into evidence CG&E Exhibits 11 and 12, the base testimony and the supplemental testimony which was filed.

EXAMINER KINGERY: Any objections?

(No response.)

EXAMINER KINGERY: Okay, they will be admitted.

(EXHIBITS ADMITTED INTO EVIDENCE.)

MR. PETRICOFF: Your Honor, at this time I'd like to move for OMG Exhibit No. 8 for admission into the record.

EXAMINER KINGERY: 8.

MR. PETRICOFF: If you recall, your Honor, well, 8 was first. I'm getting to 10, 10 will come next.

EXAMINER KINGERY: All right.

MR. PETRICOFF: If you recall, when Mr. Rogers was here, he did not recognize or said that he hadn't worked with the Ohio Annual Report, Mr. Steffen did recognize it, and, in fact, claimed its authorship so I'm moving at this time for it to be admitted.

EXAMINER KINGERY: And that's correct, it had not previously been. Is there any objection to its admission?

MR. FINNIGAN: No, your Honor.

EXAMINER KINGERY: Okay, it will be admitted.

(EXHIBIT ADMITTED INTO EVIDENCE.)

MR. PETRICOFF: And, now, your Honor, I'm moving OMG Exhibit 10.

EXAMINER KINGERY: Any objection?

MR. FINNIGAN: No objection.

EXAMINER KINGERY: It will be admitted.

(EXHIBIT ADMITTED INTO EVIDENCE.)

MS. HOTZ: OCC would like to move Exhibits 12 through 19.

EXAMINER KINGERY: Any objections?

MR. FINNIGAN: Your Honor, just with

respect to Exhibits 16 and 18, those have to do with Rider CIR, that was part of the Company's original proposal, but that was not part of the proposal that's in the Stipulation and Recommendation.

MS. HOTZ: Was it part of his testimony?

MR. FINNIGAN: It was part of his testimony with respect to what's in the base application. I mean he wasn't really asked any questions about those two documents other than did you answer this data request and was this your answer. So I think, you know, without any further testimony linking that to is that part of the stipulation, is this part of the Company's original proposal, I would ask that those two be excluded because there's simply no evidence as to how they relate to the case.

MS. HOTZ: Are you withdrawing his testimony?

MR. FINNIGAN: No.

MS. HOTZ: Well then, it should be admitted because it was part of his testimony.

EXAMINER KINGERY: Overruled. They

will be admitted.

(EXHIBITS ADMITTED INTO EVIDENCE.)

EXAMINER KINGERY: Okay. Let's go off the record for a moment.

(Discussion held off the record.)

EXAMINER KINGERY: Let's go back on the record.

We will be adjourned for today and meet back here at 9:00 tomorrow morning.

(Thereupon, the hearing was adjourned at 4:06 p.m.)

- - -

CERTIFICATE

I do hereby certify that the foregoing is a true and correct transcript of the proceedings taken by me in this matter on Wednesday, May 26, 2004, and carefully compared with my original stenographic notes.

Maria DiPaolo Jones, Registered Diplomate Reporter and CRR and Notary Public in and for the State of Ohio.

My commission expires June 19, 2006.

(MDJ-1616)

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EXHIBITS

Case Number 03-93-EL-ATA
03-2079-EL-AAM
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The following exhibit(s) were prefiled and can be located with the pleadings:

Exhibits	Date Filed
CG&E EXHIBITS	
11 - Direct Testimony of John P. Steffen	April 15, 2004
12 - Supplemental Direct Testimony of John P. Steffen	May 20, 2004
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OCC EXHIBITS	
12 - OCC-INT-05-269 response (CONFIDENTIAL)	May 14, 2004

OCC

EXHIBITS

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OCC Exhibit No. 13

Ohio Consumers' Counsel First Set Interrogatories
CG&E Case No. 03-93-EL-ATA
Date Received: February 11, 2004
Response Due: February 23, 2004

OCC-INT-01-001

REQUEST:

1. Identify all analyses or studies that CG&E has performed to evaluate and compare the economic impacts of the CBP and the RSP contained in CG&E's Application.

RESPONSE:

No such analyses have been prepared.

WITNESS RESPONSIBLE: John P. Steffen/Judah Rose

OCC Exhibit No. 14

Ohio Consumers' Counsel Third Set Interrogatories
CG&E Case No. 03-93-EL-ATA
Date Received: April 2, 2004
Response Due: April 12, 2004

OCC-INT-03-052

REQUEST:

52. Referring to the homeland security discussed in the Company's response to OCC-INT-1-002 (d):
    a. Would power generators supplying power through CRES suppliers also have to incur similar costs related to their generation?
    b. If the answer to (a) is negative, why not?
    c. What are the federal/state homeland security regulations with which CG&E must comply?

RESPONSE:

a. Unknown.

b. Not applicable.

c. President George W. Bush outlined major initiatives and guiding principles in the following document "*The National Strategy for the Physical Protection of Critical Infrastructures and Key Assets.*" A copy of that report can be found at the following address:
http://www.dhs.gov/interweb/assetlibrary/Physical_Strategy.pdf

Specific guidelines have also been developed by the North American Electric Reliability Council in its role as the Sector Coordinator for the Electric Sector. These guidelines can be found at the following address:
http://www.esisac.com/publicdocs/Guides/SecurityGuidelinesElectricitySector-Version1.pdf

The State of Ohio has established its own long-term plan for Homeland Security through its Homeland Security Strategic Planning Project. Among other things, the Plan is expected to address the Protection of Critical Infrastructure and Key Assets.
http://www.homelandsecurity.ohio.gov/March04column.pdf

In the interests of guarding the reliability of electric service to its customers, CG&E intends to follow the guidelines that are or will be established by the federal and state governments regarding Homeland Security.

WITNESS RESPONSIBLE: John P. Steffen

OCC Exhibit No. 15

Ohio Consumers' Counsel Fourth Set Interrogatories
CG&E Case No. 03-93-EL-ATA
Date Received: April 16, 2004
Response Due: April 26, 2004

OCC-INT-04-072

REQUEST:

72. Referencing the response to OCC-1-24, what are the estimated total proposed transmission rider revenue requirements for each year the transmission rider will be in effect?

RESPONSE:

The Company does not have an estimate of the revenue requirements for the Transmission Cost Recovery Rider. This Rider will recover all tariffed charges incurred by CG&E on behalf of its retail customers under the applicable regional transmission organization.

WITNESS RESPONSIBLE: John P. Steffen

OCC Exhibit No. 16

Ohio Consumers' Counsel Fourth Set Interrogatories
CG&E Case No. 03-93-EL-ATA
Date Received: April 16, 2004
Response Due: April 26, 2004

OCC-INT-04-090

REQUEST:

90. According to the Company's response to OCC OCC-INT-02-038(c), the CIRR "Estimated Revenue Requirements" calculations (provided in response to OCC-POD-01-008) use a 13.01% rate of return and stated gross gross-up factors that are from a prior, outdated analysis and the rate of return for Rider CIR will be the approved rate of return from the Company's most recent retail base rate case, what are estimated revenue requirements for the CIRR using the approved rate of return from the Company's most recent retail base rate case?

RESPONSE:

This calculation has not been performed.

WITNESS RESPONSIBLE: John P. Steffen

OCC Exhibit No. 17

Ohio Consumers' Counsel Fourth Set Interrogatories
CG&E Case No. 03-93-EL-ATA
Date Received: April 16, 2004
Response Due: April 26, 2004

OCC-INT-04-093

REQUEST:

93. Referring to the Company's Application at page 21, for the competitive bidding process used to test the unbundled generation price under the RSP and the subsequent discussions regarding future terms and conditions of the plan:
    a. Could the Company end the RSP, or change provisions in the RSP, and increase generation rates if the competitive bid indicated that RSP rates were below market price?

RESPONSE: The Company could initiate discussions with the Commission and the parties relating to possible changes in the terms and conditions of the plan.

WITNESS RESPONSIBLE: John P. Steffen

OCC Exhibit No. 18

Ohio Consumers' Counsel Fourth Set Production of Documents
CG&E Case No. 03-93-EL-ATA
Date Received: April 16, 2004
Response Due: April 26, 2004

OCC-POD-04-008

REQUEST:

8. Please provide all work papers, calculations and documentation supporting the CIRR estimated revenue requirements provided in the response to OCC Interrogatory No. 90.

RESPONSE:

This calculation has not been performed.

WITNESS RESPONSIBLE: John P. Steffen

OCC Exhibit No. 19

Ohio Consumers' Counsel Fourth Set Production of Documents
CG&E Case No. 03-93-EL-ATA
Date Received: April 16, 2004
Response Due: April 26, 2004

OCC-POD-04-009

REQUEST:

9. Please provide all work papers, calculations and documentation supporting the Transmission Cost Rider estimated revenue requirements provided in the response to OCC Interrogatory No. 91.

RESPONSE:

The Company does not have an estimate of the revenue requirements for the Transmission Cost Recovery Rider.

WITNESS RESPONSIBLE: John P. Steffen

EXHIBIT

OMG Exhibit 8

Annual Report of THE CINCINNATI GAS & ELECTRIC COMPANY Year Ended December 31, 2003

STATEMENT OF INTRASTATE GROSS EARNINGS

FOR OHIO AT CLOSE OF YEAR

("Intrastate means from one point in Ohio to another point in Ohio, or wholly within Ohio.")

(For the uses and purposes designated in Revised Code Section 4905.10, assessment for maintaining the Public Utilities Commission of Ohio.)

2003

Item	Total	Amount	
		Interstate	Intrastate
Electric Operating Revenues - Sales	6,418,861,890	4,377,377,347	2,041,484,543
Gains from Disposition of Electric Utility Property		- SEE BELOW -	
Revenue from Electric Plant Leased to Others	10,673,425	168,876	10,504,549
Other Utility Operations Income - Electric	39,300,502	75,469	39,225,033
Gas Operating Revenues - Sales	504,543,296	-	504,543,296
Gains from Disposition of Gas Utility Property		- SEE BELOW -	
Revenue from Gas Plant Leased to Others	2,819,867	247,968	2,571,899
Other Utility Oper. Income - Gas	23,838,591	-	23,838,591
Revenues from Merch., Jobbing & Contract Work	2,357,648	-	2,357,648
Revenue from Nonutility Operations		- SEE BELOW -	
Nonoperating Rental Income	25,115	-	25,115
Equity in Earnings of Subsidiary Companies	40,575,131	36,032,985	4,542,146
Interest & Dividend Income	13,452,812	1,131,173	12,321,639
Misc. Nonoperating Revenue	4,888,366,110	4,881,130,446	7,235,664
Gains from Disposition of Property - Gas & Electric	3,212,736	-	3,212,736
Extraordinary Income	50,842,610	50,842,610	
TOTAL GROSS EARNINGS	11,998,869,733	9,347,006,874	2,651,862,859
Earnings or Receipts from Sales to Other Public Utilities for Resale	1,194,883,089	269,619,269	925,263,820
NET GROSS EARNINGS	10,803,986,644	9,077,387,605	1,726,599,039

EXHIBIT

OMG EX. 10

Attachment
OMG-INT-02-001

The Cincinnati Gas & Electric Company
POLR & RSC

	2005	2006	2007	2008	Total
Total Big G	$872,690,000	$872,690,000	$872,690,000	$872,690,000	$3,490,760,000
Total RTC	$120,534,000	$120,534,000	$120,534,000	$120,534,000	$482,136,000
Residential Big G	$308,507,000	$308,507,000	$308,507,000	$308,507,000	$1,234,028,000
Residential RTC	$49,382,000	$49,382,000	$49,382,000	$49,382,000	$197,528,000
Total Little G	$752,156,000	$752,156,000	$752,156,000	$752,156,000	$3,008,624,000
Residential Little G	$259,125,000	$259,125,000	$259,125,000	$259,125,000	$1,036,500,000
Non-Residential Little G	$493,031,000	$493,031,000	$493,031,000	$493,031,000	$1,972,124,000
Non-Residential POLR @ 8%	$39,442,480	$78,884,960	$118,327,440	$157,769,920	$394,424,800
Residential POLR @ 5,6,7,8%		$28,503,750	$46,642,500	$67,372,500	$142,518,750
15% RSC for 25% of Residential Customers		$9,717,188	$9,717,188	$9,717,188	$29,151,563
15% RSC for 25% of Non-Residential Customers	$18,488,663	$18,488,663	$18,488,663	$18,488,663	$73,954,650

Notes:

(1) Based on billing data for 2003

(2) Non-Residential RSC is calculated at 15% of "little g" revenues (RSC is not calculated on a weighted average basis).