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BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

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In the Matter of the Application of Columbus Southern Power Company for Approval of its Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generation Assets. :Case No. 08-917-EL-SSO

In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan. :Case No. 09-918-EL-SSO

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DEPOSITION

of David M. Roush, taken before me, Iris I. Dillion, a Notary Public in and for the State of Ohio, at the offices of Ohio Consumers' Counsel 10 West Broad Street, Columbus, Ohio, on Tuesday, October 28, 2008, at 1:00 p.m.

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ARMSTRONG & OKEY, INC.
185 South Fifth Street, Suite 101
Columbus, Ohio 43215-5201
(614) 224-9481 - (800) 223-9481
Fax - (614) 224-5724

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APPEARANCES:

Janine Migden-Ostrander, Consumers' Counsel
By Maureen R. Grady, Assistant Consumers' Counsel
10 West Broad Street, Suite 1800
Columbus, Ohio 43215-3485

On behalf of Consumer's Counsel

Porter, Wright, Morris & Arthur
By Daniel R. Conway
Huntington Center
41 South High Street
Columbus, Ohio 43215

On behalf of Applicants, Columbus Southern Power Company and Ohio Power Company.

Vorys, Sater, Seymour and Pease, LLP
By Michael J. Settineri
52 East Gay Street
PO Box 1008
Columbus, Ohio 43215-1008

On behalf of Constellation NewEnergy, Inc.; Constellation Energy Commodities Group, Inc.; Integrys Energy Services, Inc.; and Direct Energy Services, LLC, collectively the Competitive Suppliers Group.

ALSO PRESENT:

Daniel Duann, Senior Regulatory Analyst, Ohio Consumers' Counsel

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Tuesday Afternoon Session,

October 28, 2008.

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STIPULATIONS

It is stipulated by and among counsel for the respective parties that the deposition of David M. Roush, a witness herein, called by Ohio Consumers' Counsel under the applicable Rules of Civil Procedure, may be reduced to writing in stenotypy by the Notary, whose notes thereafter may be transcribed out of the presence of the witness; and that proof of the official character and qualification of the Notary is waived.

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DAVID M. ROUSH

being by me first duly sworn, as hereinafter certified, deposes and says as follows:

EXAMINATION

By Ms. Grady:

Q. Good afternoon, Mr. Roush.

A. Good afternoon.

Q. I'm going to have marked as Deposition Exhibit No. 1, the October 10, 2008 Notice to Take Deposition Upon Oral Examination and Request for Production of Documents by the Office of Consumers' Counsel.

(EXHIBIT HEREBY MARKED.)

Q. And Mr. Roush, you will note that in the deposition notice that you were requested to produce at the time of your deposition all documents relating to your testimony in these proceedings or responses to discovery, including, but not limited to, the results of any studies done for these proceedings and any backup documentation, including raw data, for those studies.

In response to that, what documents have you brought with you to the deposition?

MR. CONWAY: My name is Dan Conway and I'm representing the deponent in the deposition, and in response to counsel for OCC's question, our view and position is that the testimony as filed with its exhibits and the responses to discovery that have been provided have been comprehensive and provide OCC with all of the information that's relevant that they have requested or that's developed on behalf of Mr. Roush's testimony.

MS. GRADY: Is that in the nature of an objection, I guess?

MR. CONWAY: No, not really an objection, just an explanation that no, we didn't bring anymore documents with us to the deposition, and the reason why we did not is that our understanding and belief is that what we have provided to you through the filings and through discovery meets the legitimate and comprehensive scope of your request.

MS. GRADY: Okay.

MR. CONWAY: And satisfies the duces tecum aspect of your notice.

Q. Okay, Mr. Roush, let's go to page 3

and 4 of your testimony where you begin to talk about your Exhibit DMR-1. You carry it over, starting on the bottom of page 3 -- starting on the bottom of page 3 and carrying over to 4 you start talking about DMR-1 and you indicate DMR-1 showed the overall revenue increases of the company based on information provided to you by the Companies' witnesses. Do you see that reference on line 21 through 22?

A. That "Exhibit DMR-1 summarizes each component of each Company's request based upon the information provided to me by the Companies' witnesses." I see that language.

Q. Did you sponsor any of the items listed on DMR-1, apart from any items that would have been -- any information that would have been provided to you by other Company witnesses?

A. On Exhibit DMR-1, the column labeled Current Rates for both Companies would have been information that I prepared.

Q. Okay.

A. And I believe the line labeled FAC Components --

Q. Yes.

A. -- the FAC increases would have been calculations inherent in that exhibit. The line labeled Non-FAC Components, Environmental Capital Investment, would have been provided to me by another Company witness. The annual 3 percent non-FAC generation increases are calculations within the exhibit. The line POLR is information provided to me by other Company witnesses. The line labeled Distribution is a calculation within the exhibit that is based upon another exhibit of mine, which is based upon information provided to me by other Company witnesses.

Q. All right.

A. The Energy Efficiency and Peak Demand Reduction line would have been based on information provided to me by other Company witnesses. The Transmission Cost Recovery line, the Current Rates column is a value I calculated. And the Other line, the 2009 -- the current rate and 2009 value would have been values I calculated. The 2011 value would have been a value provided to me by another Company witness. I believe that's everything to the best of my recollection.

Q. Okay. Thank you. So just a question about your previous response. The fuel adjustment, for instance, on DMR-1 page 1 of 2, the fuel adjustment components under current rates would have been a number that was provided to you by another witness; is that correct?

A. I would have calculated it based upon information provided to me by another Company witness.

Q. And that would have been Mr. Nelson?

A. That's correct.

Q. And based upon the number given to you by Mr. Nelson for the FAC components, you were able to then back into a non-FAC component number; is that correct?

A. The non-FAC current rate generation value would have been a calculation of total generation, current total generation SSO revenues less the FAC, yes.

Q. Thank you. Now, on page 4 of your testimony you indicate that DMR-1 does not show any estimate of the potential increase of the economic development cost recovery rider, and

I'm specifically looking at lines 8 through 10. Do you see that reference?

A. Yes, I see that reference.

Q. And can you explain to me why DMR-1 does not show that increase? Was there a reason that that cost recovery rider, or even the transmission cost recovery rider, were not included on DMR-1?

A. Let me parse that into two parts. Let's take the economic development cost recovery rider first.

Q. Okay.

A. The economic development cost recovery rider will be the result -- the cost collected under that rider will be the result of any economic development incentives that the Commission approves. It will be based upon, you know, actual usage of those customers and thus the amount of the incentive they received during the ESP period. So at the time this testimony was prepared, and even today, we don't know -- we don't have any known dollar amounts for me to be able to calculate a rider at this time.

Q. Okay. And before -- I don't mean to

interrupt you. Are you finished with that portion of your answer relating to the economic development rider?

A. Yes, I am.

Q. My question is do you have, does the Company have an estimate at this time of the cost that could potentially be collected as a result of economic development incentives?

A. Not to my knowledge, no.

Q. Now, you were going to go on then to discuss the reason why the transmission cost recovery rider is not included in DMR-1. Can you go ahead and explain that to me now?

A. Sure, I'd be happy to. The transmission cost recovery rider is a rider that the Company updates annually, and we generally make that filing virtually at the end of October in each year, at least the past several years, or few years I guess. So until that filing is completely prepared and calculated, we don't have an estimate of whether the transmission cost recovery rider for 2009 will go up or go down; and similarly, those calculations for 2010 and '11 won't be done until later years.

Q. Do you know what the transmission cost recovery rider is for 2008?

A. Let me ask you to clarify the question. I know what the rider is itself but the rider's got numerous rates. Are you asking do we know what the level of recovery is?

Q. Yes. That's what I'm asking for.

A. And that is the value that would be shown on Exhibit DMR-1 under the Current Rates column for transmission cost recovery.

Q. Can you hang on a second?

A. Sure.

Q. Okay. So I'm going to DMR-1, transmission cost recovery. So you have the rates being recovered and so --

A. That's 2008 value.

Q. 2008 value.

A. Rate level.

Q. The rate level.

A. Yes.

Q. And would that be contained, how that is collected would be contained in a tariff sheet approved by the Commission; is that correct?

A. Yes. This is the result of applying the currently-approved tariff rates to forecast 2009 usage.

Q. So I guess my next question is under the Current Rates column, are you suggesting that the figures that are shown under Current Rates are really the current rates applied to 2009 usage numbers, or does that only affect the transmission cost recovery line?

A. My recollection is that all of the values in the Current Rates column are current rates applied to 2009 forecasted usage levels.

Q. And the 2009 forecasted usage levels, would that be an entire year of forecasts for 2009 or would it reflect some actual and some forecasted?

A. It would be an entire year of forecasted information based upon the -- based upon current rates.

Q. And that's the same for both Ohio Power Company and CSP; is that correct?

A. Yes, that's correct.

Q. Let's go to your testimony, Mr. Roush, at page 5, lines 5 through 9. You indicate that you want to expand the availability of Ohio Power's existing interruptible schedule from 256 megawatts to 450 megawatts. Do you see that reference?

A. Yes, I do.

Q. And you also indicate there that CSP's current limit was not changed since the limitation has not been a constraint. Do you see that reference?

A. Yes.

Q. What is CSP's current limit on existing interruptible service offerings, if you know?

A. It would be the limitation in Columbus Southern's current Schedule IRP-D is 75,000 kVA.

Q. Now, let's go on, Mr. Roush, to line 21 on that page, that's page 5, which carries over into page 6 through line 4, and there you indicate that the Company should be able to count load that is capable of being reduced toward peak reduction goals, even if that load was not reduced at the time of peak due to operational and/or market conditions. Do you see that reference?

A. Yes, I see that reference, although it's paraphrased slightly.

Q. Yes. What is the basis for counting load not actually reduced toward the peak reduction goals?

A. The basis is that under our current Schedule IRP-D there are interruption provisions which the customer's existing customers have agreed to. Those provisions, as they exist today, do not mandate that we interrupt customers at the time of CSP or Ohio Power's peak demand, but that we are permitted to interrupt them for operational or market conditions which dictate the need for a reduction.

The view is that if the Company is near peak or at peak but there are no operational or market needs to reduce them, that to reduce them in order to count them towards the peak reduction goal would be an unnecessary interruption because the system operations and the market conditions, neither one, dictated the need to curtail them.

MS. GRADY: May I have the last portion of that answer reread?

(Answer read.)

Q. Now, when you speak in your testimony of peak reduction goals, are you talking about the statutory peak reduction goals under SB 221 or something else?

A. I'm speaking towards the Companies' peak reduction goals under Senate Bill 221.

Q. Is there any language, if you know, in 221 that would support your practice of counting capable load as opposed to actual interruptible load as being counted toward peak reduction?

A. I don't know one way or the other.

Q. Okay. That's fair enough. Thank you. Can you explain, Mr. Roush, what you mean by the Companies' ability to curtail customer usage and/or to purchase replacement electricity for customers? Can you explain what you mean there? And I'll find the line reference in a second.

A. Lines 21 and 22 of page 5?

Q. Yes.

A. Sure. There are basically two provisions within the Companies' current Schedule IRP-D. One is basically the ability to, in an emergency, ask the customer to curtail, and that's kind of what I mean by curtail customer usage. Basically we say you need to reduce your load. There's no option.

There's a second provision with the Companies' current Schedule IRP-D where the Company can offer the customer the option to purchase replacement electricity, which is basically a circumstance where the customer can choose to pay the price quoted by the Company at that time to continue to operate in lieu of reducing load, or some combination of the two. They may reduce some but purchase some.

Q. Now, when you refer to the Companies' ability to curtail customer usage, you're referring to a mandatory curtailment versus an optional curtailment. Is that what you describe there?

A. I believe that's correct. That's the distinction I was trying to raise is that there are really two provisions; one, a mandatory curtailment --

Q. Yes.

A. -- and one a more optional type reduction.

Q. Thank you. Does the Company curtail or purchase power for their customers for their entire load or for a significant portion of the load?

MR. CONWAY: Could you read the question again?

(Question read.)

MR. CONWAY: I'm going -- I guess I don't understand the question but if you do, you are welcome to try to answer it.

A. When the Company would exercise the provisions of Schedule IRP-D --

Q. Yes.

A. -- there are basically, I think, three parts to the answer to your question.

Q. Okay.

A. First is that each customer's contract would specifically designate how much of their load is firm service and how much is interruptible service, and that would be customer specific based on customer selection. That's kind of the first part of the question.

When the Company calls for a curtailment under Schedule IRP-D, that request for curtailment would be for the amount, the entire amount that the customer has designated as interruptible. So that's the second part of your question.

And then the third part of the question is when provided, when the customer is provided in the notice an option to purchase replacement electricity, the customer has the choice of the amount of their interruptible load that they wish to purchase.

Q. As opposed to an all or nothing?

A. Correct. They have the choice of how much they wish to purchase or not purchase.

Q. Do you know offhand the requirement objectives and goals of SB 221 regarding peak load reduction?

A. No, not offhand. I did not memorize them.

Q. Based on your understanding of 221 and -- strike that.

Based on your understanding of 221, did the Companies already meet the peak load reduction goal by IRP-D, the IRP-D Schedule?

A. I don't know.

Q. Is it your understanding that under Schedule IRP-D, the interruptible power tariff that we're talking about, that the amount of power that can be interrupted to those customers under that schedule ranges from 256 megawatts to 450 megawatts? Let me strike that. Withdraw that question.

On page 6, lines 9 through 10 you indicate that services that previously made economic sense solely for large industrial customers will likely become effective and available to a larger group of customers. Do you see that reference?

A. Yes, I do.

Q. What services and what larger group of customers are you referring to there?

A. In general, I'm referring to price responsive services which may include demand response, and the larger group of customers I'm generally thinking of is the Companies' current offering is, I believe, restricted to customers a megawatt and above, and that with gridSMART technology would have the ability to expand that to a growing number of smaller customers, and I think ultimately all the way down to residential customers.

Q. And when you say ultimately down to residential customers, are you talking about one year down the road, five years down the road, if you know, ten years?

A. I think -- I believe the timing will really be linked to when gridSMART, the environmental technology, is rolled out. If gridSMART is rolled out in place in a year to two years, then I would think about that time we would be able to, for customers that have that technology, to be able to implement programs to those customers. So, you know, as far as a specific time line on gridSMART, I'm not the expert.

Q. Now, on page 10 of your testimony you talk about removing the current FAC component from the generation charges. Let me strike that.

You indicated earlier when we were talking about DMR-1 that it was Mr. Nelson who determined the current FAC component to be separated out. Do you remember that discussion?

A. Yes, I do.

Q. Do you know how Mr. Nelson did that?

A. In a general sense, yes.

Q. Can you explain to me how he did that, in a general sense?

A. I'll give it my best shot based on my memory, but obviously Mr. Nelson can --

Q. Understood.

A. -- correct me wherever I misstate. Mr. Nelson first identified the fuel component that was incorporated in the Companies' standard service offer rebates under Senate Bill 3 for 2001 to 2005. I believe he also identified the additional components that the Company is proposing to be included in the FAC that were not in that traditional EFC, and added those in. Then Mr. Nelson increased those values to recognize the 3 and 7 percent annual generation rate increases that the Companies received under the rate stablization plan for 2006, 2007, and

2008. And then I believe the last component was that he identified for Columbus Southern Power the amount related to the purchase power for the Monongahela Power acquisition and included that. So that's my basic recollection of what he did.

Q. I appreciate that, Mr. Roush. I think it might be finally sinking in. I did talk to Mr. Nelson about that, but that seems to me to be a pretty good explanation. Simple.

Now, you indicate in your testimony that, and you're talking about, again, referring to page 10, you indicate you have talked about one step already in your testimony starting on 9 and carrying over into 10. I'm looking at the next step which you describe on lines 7 through 10 and you state there that -- let me strike that.

Let's go to your third step, okay? The third step you begin to describe on lines 10 through 13 of page 10 of your testimony, and you indicate that you adjusted the non-FAC related generation charges to reflect the recovery of carrying costs related to the incremental 2001 through 2008 environmental capital additions above those already reflected in rates as determined by Mr. Nelson. Do you see that?

A. Yes, I do.

Q. Can you define incremental environmental capital additions as you have used it in your testimony?

A. Sure. And the way I use that in my testimony is those capital additions that are incremental or above the capital additions that have already been reflected in the Companies' rates, either implicitly in the rate stablization plan proceeding or explicitly in the, quote, additional 4 percent generation proceedings.

Q. Okay, Mr. Roush, let me take your answer in pieces and try to understand what you're saying. You're saying that there were incremental capital additions from the period 2001 to 2008 above and beyond those environmental capital additions that were placed in the fuel adjustment clause by Mr. Nelson; is that correct?

A. No. My understanding, and again

Mr. Nelson is probably the better person to talk about it, but I can tell you what I know and he can -- what I know or my recollection. In the Companies' RSP filing, I believe it was Mr. Nelson who identified certain environmental capital additions.

Q. Yes.

A. And in the, quote, additional 4 percent case proceedings, there were further capital additions that were identified, and those capital additions might have been, I don't know, let me use a number for illustration, say it was a hundred dollars of capital additions. What this incremental would be, let's say during the 2001 to 2008 period, the Company spent $120 on capital additions, a hundred of which were reflected in the RSP and the additional 4 percent cases. So we're identifying the additional 20 in this purely hypothetical example of environmental capital additions that's above and beyond what was already set in rates either through the RSP or those additional 4 percent proceedings.

Q. And so you really do not know what

the additional environmental capital additions were that were not explicitly or implicitly set in the RSP. That would have been Mr. Nelson's responsibility?

A. Yes. I don't know that information other than what he provided me.

Q. And you wouldn't know then how Mr. Nelson determined that any incremental capital additions were not incorporated into either the RSP rates or the 4 percent generation rates?

MR. CONWAY: I'm going to object to the question, the use of the word "incorporated." I believe the witness said that the incremental additions that were identified in the RSP case and the additional 4 percent cases, in his words at any rate, were implicitly recognized in the RSP case and he may have said expressly recognized with regard to the RSP case, but I don't think he said they were actually incorporated into those rates; and I also think Mr. Nelson would agree with that characterization, so with that correction.

MS. GRADY: I understand.

Q. Is there a question pending?
A. If there is I don't recall it, so if you wouldn't mind repeating it.
Q. Let me think about that. I don't think we need to pursue that. That's certainly something we can talk to Mr. Nelson about.
Now, with respect to these incremental capital additions, which Mr. Nelson identified, all your responsibility was to reflect carrying costs on these incremental investments for purposes of the non-FAC related generation charge; is that correct?
A. I think so, but let me be specific. Mr. Nelson would have calculated what the incremental additions were, and then he also calculated what the carrying costs on those incremental additions would be for 2009 forward and that is the amount that I then incorporated into the rates.
Q. Okay, thank you, Mr. Nelson -- or Mr. Roush. I keep wanting to say Major Nelson. I was a big "I Dream of Jeannie" fan.
What are the proposed rate increases that you have for your non-FAC generation rate

for CSP and Ohio Power in years 2010 and 2011, and where would I find that information?

A. I guess if you go back to Exhibit DMR-1, that identified two components to the increase and the non-FAC generation. The first is the one we were just discussing, the 2001 to 2008 incremental environmental capital investment and that's the first line.

Q. And for 2010 and 2011 that's shown as zero?

A. That's correct. There is no incremental additional amount above the 84 million increase in '10 and '11 for that item.

And then the second component is that annual, and this is on Ohio Power -- I'm sorry, I flipped to DMR-1, page 2 of 2. Sorry.

Q. Okay.

A. For Ohio Power, the second line says annual 7 percent non-FAC generation increase, and those amounts are shown on that line.

Q. Now, let's talk for a moment about the annual 3 percent non-FAC generation increase and the annual 7 percent non-FAC generation increase. How did the Company determine the increase should be 3 percent for CSP and 7 percent for Ohio Power and what does it specifically relate to?

A. As far as how the Company determined them, I really think you need to talk to Mr. Baker about that. He would have provided those to me.

Q. Okay.

A. As far as what all is -- what those are intended to recover or what makes up those, I only have a general understanding of that. This would include any 2009 and beyond environmental capital expenditures, and just any other on-going increases in non-FAC related generation costs.

Q. And what, if you know, what non-FAC generation related costs would those be, if you know?

A. I can't cite anything specific. In general, it would be that the Companies' on-going non-FAC generation costs would be increasing due to things like the cost of labor, the cost of materials, et cetera, just in general. I can't speak specifically.

Q. That would be something, a question to direct to Mr. Baker specifically? He would be the witness responsible for the non-FAC generation cost increases of 3 and 7 percent?

A. If my memory is correct, yes.

Q. Okay. Now, you also testify, Mr. Roush, to a distribution rate increase for both CSP and Ohio Power, do you not?

A. I designed the rate, the base distribution rate increases based on information provided to me by other witnesses.

Q. Now, can you tell me what the distribution rate increase is intended to recover, if you know, and let's begin with the CSP distribution rate increase. Is it 6 percent or 7 percent? And we can go back to DMR-4 to take a look at that.

A. You can find it either on DMR-1 or DMR-4 and for CSP it's 7 percent annual distribution increase.

Q. Okay. And for Ohio Power it's 6.5 percent?

A. Yes. For Ohio Power it's 6.5 percent annual distribution increase.

Q. I'm sorry. I didn't mean to interrupt. Can you tell me what, for instance, the CSP, what that 7 percent distribution rate increase -- distribution increase is intended to recover, if you know?

A. Sure. And I believe I address that specifically on page 11 of my testimony. Starting at about line 5 it says "Based upon the projected costs of the Companies' Enhanced Reliability Programs and gridSMART initiative," so those are the two items which are included.

Q. And those two items would pertain to the 7 percent increase for CSP as well as the 6.5 percent increase for Ohio Power?

A. Just to be clear, the gridSMART initiative is at this time a CSP only for phase 1. So distribution reliability is a program for both Companies. The gridSMART is a CSP only program.

Q. Of the 7 percent based distribution increase, what percent is attributable to gridSMART and what percent is attributable to the reliability, enhanced reliability program, if you know?

A. No, I don't have that percentage with me.

Q. Are the dollars reflected, would that be reflected on DMR-4, a breakdown of the dollars?

A. Yes. DMR-4 shows a breakdown of the incremental revenue requirement between gridSMART and distribution reliability.

Q. Are there any other cost items, if you know, that comprise the 7 percent or the 6.5 percent distribution rate increase for CSP and Ohio Power, other than what we discussed, the gridSMART and the enhanced reliability program?

A. No. Those are the only components that make up the 7 percent and 6 and a half percent.

Q. Now, let's move along, Mr. Roush, to the POLR charge. You begin talking about the Provider of Last Resort or P-O-L-R charge, POLR, and you indicate on lines 1 through 7 of page 12 that the costs of POLR are allocated based on demand. Do you see that reference?

A. Yes, I do.

Q. Are you referring there to the

allocation between different rate classes or an allocation among individual customers or both?

A. The allocation that I'm discussing there is between rate classes.

Q. Are the POLR charges expressed in a cents per kilowatt hour in the Companies' application, if you know?

A. The POLR charges in the Companies' application are expressed as a cents per kilowatt hour by rate schedule in the Companies' application.

Q. Now, on AEP Exhibit DMR-1 you indicate, do you not, that current rates reflect POLR charges; is that correct?

A. Yes, that's correct. The Company currently has a POLR charge for both CSP and OP.

Q. And the POLR charge that's reflected on, for instance, DMR-1, page 1 of 2, that would be the POLR charge estimate based on 2009 forecasted revenues, is that correct, or usage I should say?

A. The POLR amount shown under Current Rates in Exhibit DMR-1 is based upon the Companies' current POLR rates and forecast 2009 usage.

Q. So for the CSP there's approximately 14.5 million in POLR rates or in POLR -- let me strike that.

Do you know how much POLR revenue is being collected by the Company for, for instance, the 2008 period? Is that a number that the Company keeps and knows of?

A. To answer the first part of your question, I don't know the number. Does the Company have records on how much the Company collected under the POLR rider year to date 2008?

Q. Yes.

A. The answer to that is yes.

Q. And they would have pretty much current information up to maybe several months behind, for instance? We are now in October 2008. Would you assume that the Company has or that the Company -- that you now have revenue figures for perhaps August, up and through August 2008 for the POLR charges collected through customers' rates?

A. We should have the values up through

September for what we have collected year to date under the POLR.

Q. So you're about a month behind in terms of what you're collecting and when you have that figure available?

A. Roughly.

Q. And do you know if the POLR charges collected in 2008 are significantly different from the POLR charges shown as current rates in DMR-1?

A. I would expect that once we get to the end of 2008, the numbers would not be significantly different than the values shown on Exhibit DMR-1. The differences would just be actual 2008 usage versus forecast 2009 usage.

Q. Under the Companies' proposal in this case, does it intend to make an adjustment in some respect to account for the actual, for instance, the actual POLR revenues collected versus the forecasted POLR revenues that you have developed for purposes of DMR-1?

A. Are you asking me if the POLR rates that the Companies proposing are stated rates or whether there's some on-going reconciliation?

Is that the question?

Q. I guess what we're talking about, Mr. Roush, is you've indicated that DMR-1, the Current Rate column really is a reflection of forecasted information for 2009. And so my question really goes to whether or not, when you calculate, when you do the non-FAC component under the Companies' ESP proposal, is there an intention of the Company that forecasted rates will be substituted with actual information and then trued up, if a true-up is necessary?

MR. CONWAY: I'm going to object just because it was a little bit confusing. You did say forecasted information in the predicate to the question, and he's been pretty consistent saying it's forecasted usage; the rates are 2008 rates not forecasted rates.

MS. GRADY: Right. It's 2008 rates with forecasted usage.

Q. I guess my question is if the actual usage differs from the forecasted usage, is there an intention under the Companies' proposal, the ESP proposal to true up the difference between the forecasted revenues and the actual revenues?

A. Just to be clear, we're still specifically talking about the POLR?

Q. Well, I would like to expand this beyond POLR, but let's talk about POLR right now.

A. Okay. That's where I started to get confused. Specifically, in the context of POLR the Companies' proposal is a stated rate that would be established for the entire ESP period 2009, '10, and '11.

Q. And that stated rate for 2009, 2010, and 2011 is as reflected in the current rate column for, speaking of POLR, in the current rate column entitled POLR in DMR-1?

A. No, that's not correct. That's based upon the current rate. The proposed POLR rate would be the current rate plus the increase shown for 2009, and it would be also shown on DMR-4.

Q. And I understand that now. I guess I was jumping the gun. But the current rate to which you're adding additional POLR charges will not be trued up to show what actually occurred versus what was forecasted?

A. I believe the answer to your question is no. I'm just --

Q. No, it will not be trued up?

A. That yeah, there is no -- for example, if we stay on Exhibit DMR-1, page 1 of 2, the 14,580,921 there is no true-up to that. It may be easier to see on Exhibit DMR-5.

Q. I know you said easier to see there. I don't see it. If you could walk me through, I have got DMR-5.

A. I'd be happy to walk you through it. The second column there is labeled Forecast Kilowatt Hours.

Q. Yes.

A. And all I simply did was multiply the forecast kilowatt hours times the current rate.

Q. Yes.

A. To come up with current revenue of $14,580,921.

Q. Got ya; got ya.

A. And then continuing through the exhibit, Mr. Baker provided me the value of

$108,204,637.

Q. As the proposed POLR increase?

A. Proposed total POLR.

Q. Total POLR. So that the $108 million figure includes the 14,580,921 which we've been discussing?

A. Effectively, yes. The 108 is the total POLR dollars.

Q. And that as far as you know, the total POLR dollars are those that will apply in 2009, 2010, and 2011 under your proposal?

A. Correct. The rates shown in that very next column, the proposed rates --

Q. Yes.

A. -- those rates would be in effect for 2009, 2010, and 2011.

Q. And on DMR-1, page 2 of 2, if I took the POLR figure of 39,700,305 I would see that reflected on DMR-5 under the current POLR revenue, and then I would see as well that the proposed POLR for Ohio Power would be the 80,891,126?

A. It's 60; 60,891,126.

Q. 60,891,126, which would include,

effectively, the 39,700,305 POLR shown on DMR-1, page 2 of 2?

A. Correct. The roughly 61 million is the total revenue requirement for POLR.

Q. Now, with respect to the other non-FAC components, we have talked about POLR, and I'm going to DMR-1, back to DMR-1 again. We went through a series of questions which were aimed at determining whether the amount shown for POLR under Current Rates would actually be trued up, and I guess my question goes to all the other items within the Current Rate column. Are those revenues shown in that column, are those ever trued up under the Companies' proposal to reflect not forecasted 2009 figures but what actually occurred in a period, say, 2008 or even 2009?

A. I guess I'm still struggling with the concept of the current rates being trued up, and it may just be terminology. But the way I view this is the Company is setting its proposed rates, and then the question is are the proposed rates trued up to reflect any overrun or collection? Is that what you're asking me?

Q. Yeah, with respect to that first column which shows different components of non-FAC as well as FAC, those are set in stone, never to be touched again even if the actual figures vary by 20 or 30 percent from the 2009 forecasted figures?

A. I guess somehow we're still disconnecting because I'm not understanding your question. I apologize.

Q. Let me try this way. You indicated a while back, Mr. Roush, that when we were talking about DMR-1, column 1, Current Rates, that that is based upon forecasted usage, I believe is what you said, for 2009; is that correct?

A. Yes. The information shown under Current Rates is the application of the Companies' current rates to forecast 2009 usage.

Q. So if the 2009 actual usage varies from the 2009 forecasted usage, it would -- in your proposal there is no true-up of current rates, current rates being as shown on DMR-1, column 1, to actual revenues produced?

A. Could you read the question back?

I apologize.

Q. I'm not trying to make it difficult, Mr. Roush.

A. I know you're not. We're just not connecting.

(Question read.).

A. No, there wouldn't be. And I guess where I'm having the disconnect maybe a little bit is the current rates would not be in effect in 2009.

Q. But the current rates are the base for -- they are the base, are they not, for the 2009 rates? They are the starting point for the 2009 rates so that the current rates listed in column 1 are the base, and then adjustments are applied to that base in 2009, 2010, and 2011?

A. Forecast 2009 usage was the basis for the design of, I believe, virtually all of the rates that the Company is proposing.

Q. If I wanted to determine the total POLR charge -- let me strike that.

On page 14 of your testimony, line 15, you discuss FAC filings, and that's page 14, line 15, and you said "the Companies will make periodic FAC filings in accordance with the Commission's ESP rules." Then you go on to state that you will identify under and over-recovery of actual FAC costs. Do you see that reference where you say "Such filings will include a projection of anticipated FAC costs and identify any current under/over-recovery of actual FAC costs." Do you see that?

A. Yes.

Q. And your tariffs, Mr. Roush, include FAC charges for secondary, primary, and sub/transmission customers; is that correct?

A. There's secondary, primary, and sub/tran/transmission customers.

Q. And the tariff for the fuel adjustment clause would be sheet 80; is that correct?

A. Which company?

Q. There are tariff sheets for different companies? I have got sheet No. 80-1 that appears to be, just says -- well, is that applicable only to one company and not both of them? It says Columbus Southern Power Company. I'm sorry.

A. I just wanted to make sure we're on the same page.

Q. Yeah. So that is for Columbus Southern Power, so there would also be a corresponding tariff sheet for Ohio Power; is that correct?

A. Right, and I believe we numbered them consistently so I believe it's 80-1 for Columbus Southern -- or for Ohio Power.

Q. I appreciate that characterization, or qualification, I guess. If we look at like, for instance, and I have got the CSP sheet No. 80, if we look at the FAC shown there, that shows, does it not, the projected fuel cost of the FAC?

A. No.

Q. Or is that the charge in order to stay within the 15 percent cap, if you know?

A. That is the FAC based upon the limitations to achieve approximately 15 percent.

Q. Okay.

A. For 2009.

Q. Okay. And if you could, I'd like to walk through how the under and over-recovery of actual FAC costs will work. First, in doing so, I want you to leave out the deferral. And to keep it simple, let's suppose that the projected fuel cost of 2009 FAC is exactly 3.5 cents per kilowatt hour. That would be the amount that would be charged during 2009, is that correct, under the way you propose the fuel adjustment clause rider to work?

A. Could you read that back?

(Question read.)

A. Am I understanding your question to say if projected fuel FAC cost for 2009 were 3.5 cents, when you said leave out the deferral, you mean assuming there is no deferral?

Q. Correct.

A. Then the FAC for 2009 would be, it would be not exactly 3.5 cents as we proposed it. The FAC would vary by voltage.

Q. Okay. But let's just say, for instance, for a particular voltage, let's just talk about secondary voltage.

A. Okay.

Q. Your tariff sheet would indicate for the secondary voltage that the fuel adjustment clause charge for secondary is 3.45377. That would be the amount that would be charged during 2009, setting deferrals aside at this point?

A. Under the Companies' proposal the 3.45377 is what would be charged in 2009.

Q. Yes.

A. Just to be clear, under the Companies' proposal that amount does cause a deferral.

Q. Okay. Does cause a deferral?

A. Based on the Companies' forecasts.

Q. Understood. Now, at the end of 2009 or at the beginning of 2007 -- I'm sorry. At the end of 2009 or beginning of 2010, would you be truing up or calculating the actual cost of the FAC accounts?

A. Yes. The Company would be periodically, and I'm not sure what the periodic is, whether it's quarterly or annually, but they, the Company, would periodically calculate here's actual FAC cost, here's actual FAC revenue collected.

Q. Yes.

A. And comparing the two.

Q. Comparing the two. Now, let's suppose that the actual average cost in 2009 was not the 3.45377, but was only, for instance 3.3 cents. Keeping deferrals apart again, this would be an over-collection, would it not, related to the actual FAC?

A. Yes, that would be. If the actual FAC was lower than the 3.45 and change, that would be an over-collection.

Q. And how is the over-collection trued up, if you know, or would it be trued up under the Companies' proposal?

A. Any over or under-recovery, I think that's what the language on page 14 of my testimony was attempting to address, was that any over or under-recovery would be identified and incorporated into the next FAC.

Q. Now, has the Company, in the Companies' proposal, when it under collects, for instance, when there's a difference between the projected fuel adjustment clause charge and what was actually the cost -- let me strike that.

Does the Companies' proposal address carrying costs to be applied to either the over-collection or the under-collection under the fuel adjustment charge?

A. I don't know. I don't know if I'm confused. Are we talking now about the Companies' proposal or the kind of hypothetical we just walked through?

Q. Let's talk about the Companies' proposal first.

A. I believe, and Mr. Assante would be better to answer the question, but my recollection is that for amounts that are being deferred, that there would be a carrying cost on deferrals, but I'm not certain of that.

Q. Okay.

A. I'm just not certain of that, whether my memory is serving me correctly or not. I don't recall anything beyond that.

Q. So you wouldn't recall when there was over-collection, that there is carrying charges proposed for that over-collection?

A. No, I don't recall.

Q. And you indicate that would be Mr. Assante's area, if you know?

A. I believe that would be his area.

He addressed the FAC deferral accounting, which I think is what I said at page 15, lines 4 through 6 of my testimony.

Q. Okay. Thank you. Mr. Roush, do you provide testimony as to what will occur under the final true-up of CSP's power acquisition rider, or let me state it this way. Do you know or do you have a proposal as to how the final true-up of CSP's power acquisition rider will be made?

A. I know we have to do it. I haven't given any thought to that filing yet.

Q. It's too far out, huh? Would the final true-up of the -- would the cessation of the power acquisition rider have an impact on the FAC component or the non-FAC components related to generation?

A. I think the easiest way to answer that question is go back to Exhibit DMR-1.

Q. Yes, that's a good exhibit, huh?

A. And in the Current Rates column the revenues under the current power acquisition rider would be included in the FAC components amount identified for CSP of 604,035,556.

Q. I'm sorry. Which sheet are you looking at?

A. Exhibit DMR-1, page 1 of 2.

Q. I'm sorry. If you could go through that again?

A. Sure. The current power acquisition rider, the revenues associated with that are part of the FAC component identified for CSP under the Current Rate column of 604,035,556.

Q. And so if the power acquisition rider ceases in 2009, as it is intended to, would you agree that there would have to be some recognition of that in calculating the FAC for 2009, 2010, and 2011?

A. Yes, and I believe that is recognized in the Companies' 2009 FAC calculation.

Q. And how is that recognized?

A. That the purchase power costs that drive the -- the power acquisition rider that's currently in rates today, those purchases end at the end of 2008 and are not reflected in the FAC calculation for 2009.

Q. So that the FAC calculation for 2009

has backed out the purchase power acquisition costs?

A. It hasn't backed it out. There is no cost in 2009 related to those purchase power arrangements is my understanding.

Q. But in the current rate, the current FAC component, based upon the 2009 forecasted usage, the 604,035,556 would include the purchase power acquisition costs, correct?

A. Yes. The approximately 604 million includes the purchase power related to Mon Power's power acquisition.

Q. Do you know how much that purchase power is? How much revenue or rates, revenues produced under current rates that would equate to?

A. No, I don't have that.

Q. Is there another witness who might have that information or directly testifies on that?

A. I don't know. I don't know if -- I don't recall Mr. Nelson having that information but it might be there, but I just don't recall.

Q. Mr. Nelson gave you the FAC

component, did he not?

A. He gave me the -- he did not give me the dollar amount. He gave me the rate which applied to kWh.

Q. And the kWh again was a 2009 forecasted usage?

A. Yes, that's correct.

Q. So you'd have to take out that particular component and then apply it to 2009 forecasted usage to determine how much of the current rate revenues are associated with the purchase power acquisition cost?

A. I think that's right. I think that's right.

Q. Now, let's talk for a moment about your testimony about what happens if AEP does not receive approval of your tariff changes by December 30, 2008. And at the moment I'm trying to find out where, to remember where your testimony on that is. Do you remember where that is? Okay, page 15. You say that if AEP does not receive approval of its tariff changes by December 30, 2008, that you propose the implementation of a one-time rider with the ultimately approved ESP rates. Is that a correct characterization of your testimony?

MR. CONWAY: Maureen, I don't mean to interrupt you, but is your question whether or not you synopsized his testimony accurately, or are you just trying to find a beginning point at page 15?

MS. GRADY: Yes, I guess a beginning point.

MR. CONWAY: Okay. And that's where he discusses it is the bottom of 15 and top of 16, and his testimony says whatever it says about it.

MS. GRADY: Right.

Q. And you're proposing a one-time rider, correct?

A. What we're suggesting is that if we don't receive approval by December 30, that rather than implement the ESP rates subject to reconciliation, that we delay the implementation of the rates until we get an order from the Commission, and that we have a one-time rider to collect any unrecovered amounts back to the beginning of the January billing cycle.

Q. Okay. So you would collect the difference between the approved ESP rates and the actual rates that were charged to customer during the time frame December 30, 2008 until the effective date of your approved ESP rates; is that correct?

A. Yes, that's correct.

Q. And what is the basis for this rider in terms of what policy or what rationale are you using to come up with this proposal? Is it based on your reading of 221 or is it based on some other regulatory policy?

A. I think the starting point for it is Senate Bill 221's requirement that the Commission issue an order within 150 days.

Q. Yes.

A. Which would be before December 30, 2008, married with the pragmatism that the regulatory process doesn't always work exactly on ideal time frames. So kind of comparing those two things, saying we fully expect the Commission to do what meets the legislative mandate, but if for some unforseen reason that doesn't happen, that the Company should not be penalized.

Q. Now, Mr. Roush, are there any other provisions of Senate Bill 221, other than the requirement being the order be issued in 150 days, that would suggest or that you would read to permit you to implement this one-time rider?

MR. CONWAY: At this point I'm going to object if you are asking Mr. Roush to render legal opinions about what the law requires or permits, and what the various provisions that might be relevant to the Companies' position of being made whole in the event that the order doesn't come out on a timely basis. So he can testify as to what he understands to be the case, but the Companies' position on this issue is a matter of its interpretation and its counsel's advice about proper interpretation of the law.

Q. I guess you can go ahead and answer the question if you can.

MR. CONWAY: I think he has answered the question but if he has anymore to say about it, he's welcome to provide whatever he knows.

A. Can you repeat the question for me?

(Question read.)

A. I don't recall any others.

Q. Okay. Now, under the -- I'm turning now to customer bill impacts. In your testimony on customer bill impacts, you testified that "Upon implementation, residential customers using 1,000 kWh -- this is on page 16 of your testimony -- using 1,000 kWh of electricity per month would see a monthly increase of $16.13 for CSP and $11.88 for Ohio Power"; is that correct?

A. Yes, that's correct.

Q. Is it your conclusion that the rates that you propose are reasonable and lawful under SB 221?

MR. CONWAY: Objection. You are asking him to render a legal opinion about the Companies' rate proposal. I'll answer that question. The answer is yes, they're reasonable and lawful.

Q. Would you, Mr. Roush, consider these reasonably priced retail electric service?

A. Yes, I would consider the Companies' proposed rates to be reasonable prices.

Q. Would you believe that the rates

that you're proposing would be sufficient to protect at-risk populations?

MR. CONWAY: I'll object to the question. What it means -- what at-risk population means is unclear.

A. I guess the only thing I can say is that our ESP proposal in its totality and the provisions contained within Mr. Hamrock's testimony, I believe, address that at-risk population as defined in Senate Bill 221.

Q. Under the rates that you have proposed under your plan from 2009 and -- strike that. Under the rates that you are proposing, would you agree that you are recognizing the practice of gradualism or not?

A. I think specifically in the context of the Companies' FAC phase-in proposal, that that very much aligns with the principle of gradualism.

Q. And the phase-in proposal as you understand it is the 15 percent, limiting the increase to 15 percent per year during the first three years, and then collecting in subsequent years any increases that have not been -- that have been -- that have not been collected during those first three years from customers in subsequent time frame?

A. I guess I would say it a little bit differently; that the phase-in proposal is to maintain bill increases of approximately 15 percent in the first three years, and then if need to, deferred FAC costs would be collected beginning in 2012 forward.

Q. And if you know, Mr. Roush, the deferred FAC costs that are intended to be collected in the 2011 forward period, do you have an indication of what percent increase to customers' rates those would be?

MR. CONWAY: Object to the use of the word 2011. I think you meant to say 2012.

Q. I'm sorry. 2012.

A. I do not have such a calculation.

Q. Do you know, is there a calculation the Company is filing showing the estimated or forecasted increases that will be incurred as a result of deferring expected costs that are above and beyond the 15 percent per year during the three-year period?

A. Not to my knowledge. The only thing I recall was an example calculation in Mr. Assante's testimony of how the deferrals would be calculated, but I believe that example only used forecast 2009 fuel levels.

Q. Do you know if the Company has, and I understand it's not presented in the case if that's what your testimony is, has the Company done calculations, if you know, as to an estimate or an approximation of the costs of deferrals expected as a result of the plan it's implementing or it's proposing to implement in this case?

A. It may have. I don't recall.

Q. If you know, who would be the AEP -- who would be the witness that would be most familiar with any plan or any estimates or data related to the impact on rates of deferrals above and beyond the 15 percent during the three-year period?

A. I don't know.

Q. Would you know which department or which portion of the Company would be responsible for that kind of information or generating those kind of reports or estimates on the impact of the ESP plan being proposed, and the effect of deferring costs above and beyond the 15 percent into later years?

A. In general, I would expect my group to be involved.

Q. Your group?

A. Yeah.

Q. Being?

A. Regulated pricing and analysis.

Q. Any other groups?

A. I would expect probably Mr. Nelson might also be involved and possibly Mr. Assante. Those are -- I mean, I think between the three of us we would be the ones doing such a calculation and, I don't recall.

Q. Now, on DMR-11 you show typical usage levels for AEP's major tariff schedules. Can you tell me what typical usage is embodied in that bill impact analysis?

A. What we endeavored to show here is a range of usage level that is representative of customers on the various Company rate schedules.

Q. And what is the range of usage level

shown?

MR. CONWAY: Are you asking him what's on DMR-11?

Q. Yes. Okay. So the usage would be in the left-hand column, the kWh column. That would be the usage upon which the bill impact would be calculated; is that correct?

A. The kWh column and the KW column for demand metered customers.

Q. Thank you. Now, Mr. Roush, we have been discussing in quite a bit of detail DMR-1, page 1 and page 2 of 2 where you have the summary of the requested rate increase. Does this reflect the rate increase within the cap adhering to the 15 percent or is this irrespective of the cap?

A. For 2009 this reflects the Companies' proposed increases following that approximate 15 percent guideline. For 2010 and 2011, the calculation is basically assuming that the Company can successfully hit the 15 percent exactly, you know, and that's based upon the maximum FAC increases which I calculated in Exhibit DMR-8.

Q. So the maximum FAC increase reflects not the expected FAC increase but what would be permissible under a 15 percent cap?

A. Yes, that's correct. The FAC increases in 2010 and 2011 are not a projection of what the FAC might actually be. It's a projection of the most that it could be under the Companies' approximate 15 percent guideline.

Q. Does the Company have information that would show the 2010 and 2011 projections of what the FAC will be as opposed to this schedule which limits the FAC increase to stay within the cap?

A. I believe that information was filed in our supplemental filing, I believe.

Q. And when you refer to your supplemental filing, do you know what date you are referring to?

MR. CONWAY: October 16.

Q. Is that the filing that was --

MR. CONWAY: I think I shouldn't speak for you, but.

A. I don't recall the specific date but it was within the past two weeks.

Q. Was that the information that the Company requested a waiver on and the Commission denied the waiver? Is that the information produced as a result of that?

MR. CONWAY: That is what I'm referring to, yes, and I believe Mr. Roush is referring to as a supplemental filing.

Q. Okay. So that information, Mr. Roush, would actually present -- strike that.

MS. GRADY: I think that's all, Mr. Roush. Thank you for your time and I'm going to turn you over to Mr. Settineri.

THE WITNESS: Thank you.

MR. SETTINERI: Off the record.

(Off the record.)

(Mr. Duann leaves.)

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EXAMINATION

By Mr. Settineri:

Q. Mr. Roush, good afternoon. My name is Mike Settineri from the Vorys, Sater, Seymour and Pease law firm. I'm here today on behalf of Constellation NewEnergy, Inc., Constellation

Energy Commodities Group, Inc., Integrys Energy Services, Inc, and Direct Energy Services, LLC.

I want to start first with looking at your testimony, and let's turn to page 5, lines 10, 11, and 12. There you state "Given the meager interest that customers have shown in the current Emergency Curtailable Service (ECS) and Price Curtailable Service (PCS) rider offerings," I'd like you to explain for me what do you mean by meager interest?

A. Basically, I do not recall more than a handful of customers on the AEP system that have signed up for those offerings.

Q. And when you say handful, what do you mean by handful? Can you quantify that for me?

A. No more than -- my recollection is probably not more than ten.

Q. Can you break that out between ECS and PCS?

A. No, I don't think I can.

Q. And just to clarify your answer, you said no more than ten. Is that related to the ECS and PCS offerings?

A. Right.

Q. Not the IRP-D?

A. Correct. The ECS and PCS, not the IRP-D.

Q. Why do you think there's only been a meager interest in those offerings?

A. I think some of it was probably due to some of the provisions within those tariffs. Some of it was probably due to the fact that many of the customers that might have been interested in that were already on tariffs like Schedule IRP-D; and I just don't know how active we were in trying to sign customers up either. That's not my area of responsibility so I don't know for sure, but.

Q. Any other reasons that you can think of why there has been a meager interest or only a handful of customers signed up for those offerings?

A. That's all I can think of at this time.

Q. Now, continuing on line 12 you note that "AEP Ohio proposes significant modifications to the existing offerings." Can you explain to me how those offerings have been modified, and specifically, to improve the meager interest?

A. In the context of the emergency curtailable service or ECS rider, I'm looking at my Exhibit DMR-9.

Q. That's for Columbus Southern Power Company?

A. Yes, and similar changes would have been made for Ohio Power Company. The first change was to make it available to customers with curtailable demands of 1 megawatt instead of 3 megawatts, which was the existing provision.

Q. If I can ask you a question specifically on that; do you have any forecast as to what kind of increase you'll see with the number of customers?

A. No, I don't have one.

Q. Any idea?

A. Not really.

Q. Has anybody talked to you about that?

A. No.

Q. Okay. And then the next modification?

A. I'm focusing on what I would consider the significant modifications. The next one would be the change in the per kilowatt hour credit that would be provided to the customer from a stated rate to a quoted price at the time of the event.

Q. Can you explain that change to me a little more. What is a curtailment credit?

A. Basically, at the time of an event under the previous rider for the amount of kilowatt hours that a customer curtailed, the previous rider had a stated price per kilowatt hour that was curtailed depending on the option the customer selected. Under the proposed rider the Company would quote to the customer a price at the time of the curtailment event. So that provision could allow for that. The quoted price could be greater than the stated price, whereas before the tariff restricted what the payment could be.

Q. And who is developing that quote?

A. I don't know who specifically. It

would be the same folks, the same personnel that notify our other interruptible customers.

Q. Can you just explain to me how is that quotation created? What is it based on?

A. I don't know specifically but I would -- I suspect that there might be some -- I can't, you know, I can't suspect that, that's not correct, because this would be an emergency event. I'm not sure. I'm not sure.

Q. Do you know who would have that information as to how that curtailment credit will be calculated or the basis for the quotation?

A. No, I don't.

Q. Do you know whether that curtailment credit would be higher than the current set rate that's currently in the tariff?

A. I believe it could be higher or lower, depending on the circumstances at the time that it's called.

Q. So a customer, under the ESC rider or service, would that customer know prior to taking this ESC offering what the curtailment credit would be?

A. No, they would not.

Q. Any other modifications to this sheet, specifically again going back to improving on the meager interest or handful of customers taking service or ESC?

A. Yes. The next item is the existing ECS rider had a non-compliance or actually a failure to curtail provision, and that provision had a charge for non-compliance kilowatt hours equal to half of the curtailment credit. The new rider has no charge for non-compliance, so that would be removing that failure to curtail penalty for the customer.

Q. Any other modifications specifically geared towards improving the number of customers participating in this offering?

A. No. I think that is it for tariff ECS. Do you want me to continue through PCS?

Q. In a minute. Can you briefly tell me what would be the penalty for failure to curtail under the ECS?

A. There is no financial penalty. However, if in a given year the customer is contacted and does not curtail twice during a given year, then the Company reserves the right to no longer serve the customer under the rider, but it would still provide electric service to the customer, but they just would no longer -- could no longer be eligible for the rider. It is not an automatic.

Q. Okay. One other question while we're on this sheet. Why was the language -- specifically on sheet 71-1 there's a red line insert says, or the PJM interconnection LLC, and backing up further, that sentence has a comma, if an emergency condition exists on the American Electric Power AEP system or the PJM interconnection LLC. Why was that PJM language added there?

A. At the time the original or the existing character was put in place, the Company was not a member of PJM so it was inserted to recognize that we are now part of the PJM and PJM could declare an emergency in our zone.

Q. Just to explain, what's the difference when you say PJM zone and AEP system, what's the difference?

A. In my mind, and I'm not the expert,

there really is no difference between the old language of the American Electric Power System or the AEP zone within PJM interconnection.

Q. Okay. And the same page, just another quick question, it looks like the seasons have been expanded there. You see winter where there has been a strike-out of December, January, and February and an insert November 15 through March 15, and a similar revision to the summer. Why were the seasons expanded?

A. I believe the summer season was expanded to match PJM's definition of summer; and I think winter was just expanded to correspond to be a four-month period similar to summer.

Q. And the last question on this, going back to the curtailment credit that would be quoted, why the change from a set generation credit to a quoted curtailment credit?

A. I think, again, it goes back to providing a better price quote to the customer rather than a preset price; that, for example, the existing preset prices, I think, have been there for at least eight years, probably longer.

Q. Okay. Thank you. Going back to our original line of questions, we were talking about the meager interest in the offerings, and to switch now to the energy price curtailable service rider sheet, if you can go through that and, again, point to the modifications there that you believe will improve on that meager interest.

A. Certainly.

Q. Thank you.

A. The first thing is similar to ECS, that we're increasing the number of customers who are eligible by reducing the minimum size from 3 megawatts down to 1 megawatt of curtailment demand.

The next change is to provide a day-ahead notification option and a current-day notification option. The previous tariff provided only basically a same-day notification of one hour or greater.

Q. And if I can stop you there and just simply ask, do you think that will improve participation in this offering?

A. Yes, I do.

Q. Can you tell me to what extent you believe it would improve participation in the offering?

A. No, I can't give you a number of additional customers that might be interested now.

Q. Let me ask you, what do you base your belief on that this will improve the offering?

A. The basis of my belief is that some customers prefer to have lead time as far as in order to be able to respond to an event, and that customers might say, well, one hour's notice, I can't respond; but if you tell me the day before, there's some things I might be able to do to shift or reduce load.

Q. And I'm curious, can you identify any customers today?

A. I cannot specifically.

Q. Okay. Continue on then. Any other modifications to this offering?

A. The next component is on sheet 72-1 which previously the offering was basically mandatory. Now the customer is notified and can respond if they do not want to participate in a given event. So it basically allows a customer to make a decision like, well, I've really got to get an order out the door, so I really can't participate today or tomorrow, when you call and give them that option to respond. It has a similar provision to the ECS in that they basically get three opportunities. They can refuse to participate up to twice a season without any issue. If they don't participate three or more times during a season, then the Company would reserve the right to discontinue service under the rider.

Q. And you believe having that ability to not have to curtail upon request would be an improvement that would attract more customers?

A. Yes.

Q. Any other modifications?

A. The compensation for curtailment was changed. Previously, the customer paid either the greater of 3 and a half cents, the minimum price that they specified when they signed up, or 80 percent of the daily price index for energy on peak for the day of the curtailment. That was the previous provision. The current provision still has they'll pay the greater of 3 and a half cents, the minimum price they specified, or 80 percent of the LMP in that hour, in each hour of the curtailment. So the change from a daily price to an hourly price during the event, I would expect, would provide the opportunity for better compensation.

Q. Let me ask you a question -- strike that. Any other modifications on this sheet specifically towards improving customer participation in this ECS offering?

MR. CONWAY: This is the PCS offering.

Q. Thank you, PCS offering.

A. We previously discussed how they do not -- how they have the option to respond whether or not they participate in a given event so those changes -- let's see. The only other change would be there's an option for participating for only 2 hours, for events of only 2 hours' length. Previously, they could choose either 4, 8, or 16 hours. Now they can choose 2, 4, or 8 hours.

Q. That would be the maximum curtailment period?

A. Yes, that's correct.

Q. Anything else?

A. I think that's about it.

Q. Okay. Thank you very much. One question on that. Turning to sheet 72-3, there's a monthly credit shall be equal to the sum of the curtailment credits for the calendar month less any non-compliance charges. What are non-compliance charges?

A. The non-compliance charges would be what are described on the next paragraph where if the customer responds affirmatively that they'll participate in an event and subsequently fails to fully comply with the request for curtailment, then there's a charge for the amount of energy they fail to curtail that's equal to the same -- it's at the same rate as the credit they would be paid for the energy they did curtail.

Q. Is that on top of paying for their energy?

A. As I read the provision, I believe their energy would get billed under whatever normal tariff they're billed under and then the non-compliance charge is a separate calculation.

Q. And again, what are the notice provisions now under this proposed sheet?

A. Customer can select either day-ahead notice or current-day notice.

Q. And previously what was the notice requirement?

A. It was as little as one-hour notice.

Q. Do you view this non-compliance charge as a penalty?

A. I guess I view it more as an incentive to do what they agree to do, that because now they have the option to say yes, I'm going to or no, I'm not going to. If they say yes, I'm going to, I kind of view it as just an incentive to say, okay, well, do what you say.

Q. And if they can't curtail, they will be charged the non-compliance charge?

A. If they told us that they will curtail and then do not curtail, then they would be charged that.

Q. Thank you. Going to the Schedule IRP-D you reference in your testimony, page 5, line 6 to 8, same question; any modifications to this offering that are intended to improve participation? I'm on sheet No. 25-1, Columbus Southern Power Company.

A. For Columbus Southern Power, no. For Ohio Power, the change that I would point to is just making it available to more customers/more megawatts of interruptible load.

Q. Why was that change made?

A. For Ohio Power, Ohio Power is currently fully subscribed so it had no additional to offer. So the change was made to allow them to offer additional to meet the needs of customers and also meet the peak demand reduction requirements placed upon us under the legislation.

Q. Any forecast done as to the difference between 450 megawatts and 256 megawatts, how many customers will be using that?

A. Not that I know of. I only recall a few customers in the past that have expressed interest but were not able to take, to participate on IRP-D.

Q. That's in OP?

A. In OP's territory.

Q. CSP, why was that limit not changed? I think previously you said it was 75,000 kVA; is that correct?

A. That's correct, and it wasn't changed because currently current subscription is nowhere near that level.

Q. Do you know where it is?

A. My memory is not as good as it once was. I think it's somewhere between ten and 20,000 kVA.

Q. Subject to check, I assume. Going back to your testimony then, page 5 again, that's where we'll focus most of our time today, lines 10 through 14. At the end of that sentence you make the statement that "while maintaining a benefit for all of AEP Ohio's customers," what benefit are you pointing to there?

A. I didn't have a specific benefit in mind when I wrote this. I was thinking of it in the more generic sense of the benefit to AEP Ohio of having a certain portion of its load interruptible.

Q. And how would that benefit AEP Ohio?

A. There are a few different ways, and it depends on each offering. One way is to be able to use interruptible load for capacity planning purposes. Another way is to be able to call on interruptible customers in an emergency rather than to have to go to other steps in the emergency plan, like rolling blackouts or that kind of thing. The other would be simply to avoid the need to purchase expensive market power.

Q. Any other benefits to AEP?

A. I guess obviously the fourth one would be to us to comply with Senate Bill's 221 peak demand reduction goals. So other than that, I think that's everything I can think of at this time.

Q. Continuing on page 5, lines 17 and 18, you state "The Companies' interruptible service offerings allow the Companies to reduce their loads when conditions on the system or conditions in the market dictate." First of all, when you say system, what system are you describing?

A. I think primarily the AEP system, but I think equally the PJM system and because everything is related, you know, system conditions to a certain extent even on the entire eastern air connect.

Q. What are some, just give me some examples of conditions that would cause interruptible service offerings to take effect.

MR. CONWAY: Could you repeat that question?

(Question read.)

MR. CONWAY: Are you talking conditions on the system or conditions in the market?

MR. SETTINERI: Conditions on the system first.

MR. CONWAY: Okay.

MR. SETTINERI: Thank you.

A. I think the primary one that comes to mind is the declaration of an emergency. There could be, I guess, other conditions where an emergency has not been declared, but there could be a localized issue as far as system integrity. I think those are the kinds of conditions where that would be referenced. There may be other examples but they fail to come to mind.

Q. That's fine. One thing I wanted to jump to real quick, are you familiar with the Black-Scholes Model that I believe it was Mr. Baker mentioned in his testimony?

A. I have seen it in Mr. Baker's testimony. I have a lot of years ago learned a little bit about it in a classroom environment but I've never done anything with it myself, so.

Q. What I'm curious about is actually whether -- I assume the Black-Scholes Model is running on software. Do you know that?

A. I don't know that. I do not know.

Q. Are you familiar with the existing PJM demand response programs?

A. Yes. I have a certain level of familiarity. I wouldn't consider myself an expert on it, because it's pretty complicated.

Q. Can you provide me with your

familiarity on that?

A. The existing PJM demand response programs include an emergency program, an economic program, it's a synchronized reserve program, and I think it's a regulation program; and some of those programs tend to interweave.

Q. Any other information you can provide me on your familiarity with these programs?

A. The emergency program consists of, I think there's three sub-categories within that: a full emergency program, a capacity emergency program or capacity holding emergency program, and an energy holding emergency program.

The economic program has, I believe, also three sub-categories: a day-ahead program, basically a realtime program, and a realtime dispatchable program.

Q. Are you familiar with any of the payment structures to customers that participate in those programs?

A. Somewhat; somewhat. In the capacity program -- I'm sorry, in the emergency program, if you're in the emergency full or emergency capacity only program, there's compensation based on the RPM clearing price.

For the economic programs, and I may have mistakingly called them energy programs previously, for the economic programs the payments are generally tied to either day ahead or realtime LMP. I believe that's generally the case with the emergency energy only program as well; but then there's some make-whole type provisions for shut-down costs and that's where I start to get lost in the detail.

Q. I appreciate going through that. In regards to the actual dollar amounts that customers can receive in that program, are you familiar with that?

A. I guess in which program, or are you asking about all of them?

Q. In general, any of them. Let's start, are you aware of any of the amounts that customers can receive in that program whether it be --

A. In the emergency capacity related program or emergency full program, I believe the compensation is for the 2008-2009 PJM planning years somewhere around $113 a megawatt day, somewhere in that range.

For the energy programs those are tied to LMP, which varies all over the place.

Q. Have you done any studies or anything comparing the AEP interruptible service offerings to the PJM demand response offerings?

A. I'm not aware of any quantitative studies. Qualitatively, I looked at their programs and our programs, enough to be as familiar as I was earlier, but not ever really done a side-by-side comparison.

Q. Do you have an opinion as to which program is more beneficial to a customer?

A. I would say it depends. Putting myself in the customer's shoes, I would view the PJM emergency full or emergency capacity programs as very attractive. I think I'd also view the existing economic realtime program very attractive from the standpoint, both of those from the standpoint of the participating customer. From the standpoint of all other customers, I would have issues with both of those programs because how it's written because in my view it's really one hand in the other; you know, the participating customers get payments from PJM or through their third party, but PJM is a non-profit entity so it has to get the money from somewhere else. So that's kind of where I'm coming from.

Q. Where does that money come from? And I say that -- let me clarify. You stated you're concerned with where that money is coming from, I assume, to pay customers participating in the PJM.

A. Sure.

Q. So where is that money coming from?

A. There's kind of two layers to that question, and so the first layer for the capacity program as it exists today, payments come from the RPM market clearing which means that it comes from all of the load serving entities who have to buy their capacity in the RPM market.

Q. May I interrupt briefly?

A. Uh-huh.

Q. The RPM market clearing house, is that solely within the AEP zone or the whole PJM interconnection?

A. We're getting a little far afield from my knowledge, but I believe it's carved up into three, at least three separate locations; kind of two that are related to some eastern areas and one that's kind of the rest of the market kind of thing which would include AEP.

Q. And I'm sorry to interrupt.

A. And let me be clear, there's not a clearing house. I think it's just the RPM clearing market. So that's kind of the first layer on the capacity program.

The second tier of that layer is that PJM -- or AEP as an FRR entity within PJM still has to plan capacity as if participating customers are firm load. So there would be a second tier cost of AEP continuing to plan and build capacity that would be paid for by all Ohio customers. That's on the capacity program.

On the energy program or economic program, and I apologize, I'm using those interchangeably a bit, the payments generally, I believe, come from the load serving entity which in this case, if it's not a shopping customer, would be AEP Ohio.

Q. And just to clarify, FRR is fixed resource requirement entities?

A. Yes, that's correct.

Q. Going back to my question, I think it was where is the money coming from for these payments to these people participating, or entities participating in the PJM demand offerings? I want to make sure I have this right. First of all, you're saying that money is coming through the RPM --

A. Market.

Q. Okay. And taking that a step further then, where is that money coming from that's entering the market?

A. From all of the load serving entities to have to procure their capacity in the market.

Q. And another step, those load serving entities where would they be located?

A. I believe we had that before, but it would be the load serving entities that are in the, quote, rest of PJM or the rest of PJM zone for capacity purposes.

Q. And what I'm trying to understand is would it include states outside of Ohio? Would that zone expand outside of Ohio? Would those load serving entities be outside of Ohio, and outside of the AEP service zone?

A. Yes. And similarly, customers outside of Ohio, their costs would also be part of that as well.

Q. So customers outside of Ohio would be able to receive payments, and those load serving entities outside of Ohio would be paying into the market?

A. Yes. I guess both inside and outside of Ohio, yes.

Q. Okay. Thank you. Then you mentioned a second tier which goes back to, if you could, is that money coming in to pay these customers, the customers participating in the PJM program?

A. It's not money transacting between PJM and the customer. It's kind of a byproduct of this current structure of the PJM capacity market, and that customers within it served by an FRR are effectively selling capacity into RPM.

Q. And that's something I wanted to ask about. Page 7 of your testimony, lines 3 to 5, you state there that "AEP Ohio believes that it is not appropriate for customers receiving service at regulated, standard service offer rates to resell utility power at market-based rates through the PJM program." What do you mean by resell power?

A. My understanding from looking back at FERC orders which approve the implementation of the PJM programs was that they, that FERC relied upon identifying these types of programs as true transactions.

The first being a sale from the LSE or the local utility to the customer which was a retail transaction not subject to the jurisdiction of the FERC; and the second transaction being a wholesale sale of that power to PJM. And FERC indicated that they would clearly assert jurisdiction over that wholesale sale.

Q. So I'm just trying to understand this. So if I'm a customer, a standard service offer customer and I curtail through the PJM demand response program, am I taking energy from AEP at that point in time, meaning, the load that I dropped or the energy that I dropped, am I taking any power at that point?

A. The way FERC views it is that your curtailment was effectively taking the power and then reselling it by reducing your load is my understanding of the way FERC views it.

Q. And I'm trying to understand. So technically there is no power being taken by the customer. It is not going through the meter; is that correct?

A. Physically, the power is not flowing through to the customer. It is effectively being redirected.

Q. And how is it being redirected?

A. In that by the customer curtailing the power, it's being redirected elsewhere on the system so the flow of power would go who knows where.

Q. Any other basis for that, for your belief in your testimony that it's a resale of power?

A. No. I think the FERC orders were

kind of the foundation for me, and then that, you know, combined with just the underlying logic of that.

Q. And help me understand more. You mention that that power will just go in the grid and go somewhere, but does AEP, and I say AEP operating companies, have the ability to, as a fixed resource requirement, to put that into the PJM market?

A. I think we might be jumbling topics; the fixed resource requirement related to capacity, and the content we were talking about there is energy.

Q. Flip to capacity. As a fixed resource requirement, explain to me how AEP can make a capacity sale in the PJM market as a fixed resource requirement?

A. And this gets a little out of my expertise so I can only give you a little -- my dumb layman's explanation. AEP has to first demonstrate that it has adequate capacity to meet its load needs plus reserve margin, and then to the extent that AEP has additional capacity, up to a limit of, I believe it's 1300 megawatts, AEP can sell that additional capacity into the PJM RPM market.

Q. Okay. Is that happening today, do you know?

A. It may be. I don't know for certain.

Q. Who would have information on those sales?

A. I'm not sure who specifically would know.

Q. If that limit wasn't in place, how would that affect your concern about reselling utility power?

MR. CONWAY: What limit are you referring to?

Q. The 1300 megawatt limit on an FRR.

A. It wouldn't impact my view one iota.

Q. If you can, can you help me understand, again going back to the flow of revenue or money, if there is an FRR, you make a sale of capacity in the PJM market, where does that revenue flow to?

A. Those sales would be shared among all the generation-owning AEP operating companies.

Q. Would that be -- in going another step, would that then result to the shareholders?

A. No. Those types of sales are treated a number of different ways depending upon their regulatory structure in a given state. In some states there is a sharing, in some states it all flows through the ratepayers. It varies.

Q. How does it set up in Ohio?

A. In Ohio, that's really difficult to say. Under the Companies' proposed ESP, I believe it would accrue to shareholders but I'm not 100 percent certain.

Q. Who would know that?

A. Probably Mr. Baker.

Q. And you mentioned that that revenue flows out of PJM and is shared with the AEP operating companies. Do you recall just saying that?

A. Yes. If a capacity sale was made, it's shared among the generating companies of AEP.

Q. How is it shared? What's the mechanism to do that or the form to do that?

A. I believe it's member load ratio.

Q. I want to back up real quick to page 6, lines 19 to 22 and, actually, you state "However, a unique aspect of the PJM programs is that unregulated entities known in PJM as curtailment service providers can solicit retail customers directly and enroll them in the wholesale PJM program." You say "Even further complicating matters"; stopping there, that implies you believe there's some complication with the current curtailment service providers. Can you explain to me any concerns you have or complications that you believe exist because of that?

A. I believe the primary complication that I believe exists is really a jurisdictional one of whether the state does or does not regulate interruptible service offerings to retail customers.

Q. And what kind of complication does that create?

A. Any number of them; from the main

one that I can think of at this time is that previously the issue of what is appropriate compensation for interruptible customers has been one that has always been a topic of debate in regulatory procedings within the state. And with the construct as it is right now, as we discussed with customers either directly if they're a PJM member enrolling in these programs or going through third-party entities to participate in the programs, that you've taken something that was previously something which state regulators took a great interest in and have basically taken them out of the equation, for lack of a better word.

Q. And to clarify what you're saying, are you saying then there's more an issue of regulation and lack of control by the state over these programs through the PJM? Is that what is complicating?

A. I think there's the regulatory issue, and then there's kind of the issue we were discussing previously about where does the money come from. If ultimately, and this is where it can get conflicted in my mind, what customers get paid to curtail is taken out of the purview of the state regulator, but at the same token the costs to pay for that, to pay those customers is ultimately a cost that those state regulators are going to be asked to pay for, then I see a conflict there.

Q. Any other complications that you believe existed in regard to the curtailment service providers?

A. Not really. I think that gets pretty much to the core of it.

Q. Going to page 7, lines 20 to 23, you state that "AEP Ohio believes its existing Terms and Conditions of Service address the inappropriateness of customer participation." Can you explain to me how do the existing Terms and Conditions of Service address what you believe to be inappropriateness of customer participation?

A. Existing Terms and Conditions of Service, and service ties back to an issue we talked about previously, do not allow the resale of electricity and so based upon the construct of first approval of the PJM programs as a resale of utility power, those two dots connected.

Q. And then why the clarification?

A. Because in my mind not everybody is as familiar with those FERC orders, particularly customers are not as familiar with those FERC orders, so it was proven to clarify.

Q. And just can you point to the Terms and Conditions, can you show me where that exists?

A. For Columbus Southern Power?

Q. Yes.

A. It's on original sheet No. 3-4.

Q. Is that the only clarification that was made?

A. Yes.

Q. Okay. Was a similar clarification made for Ohio Power?

A. Yes, it was. That's on sheet 3-12 for Ohio Power Company.

Q. And again, these are the only two spots where this clarification was inserted?

A. Let me just double check, but I believe that to be true. Yes, that's correct.

Q. Thank you for checking. A few general questions. Have you considered the effect on Ohio customers participating in the PJM program, when I say effect I mean the economic effect, if this prohibition is put in place that we just noted in Terms and Conditions?

A. I've not done any calculation. I think there's a potential opportunity for them to utilize the expanded availability of the Companies' IRP-D that may not have been available to them previously.

Q. That's for Ohio Power?

A. For Ohio Power.

Q. Any studies done?

A. No.

Q. Any discussion done?

A. I do not recall any.

Q. Just help me understand here. If the prohibition goes into place and a company in Pennsylvania participates in the PJM demand response program, we talked about the money, the payments that that customer received would be coming from the load service entities in the PJM market.

A. Are you referencing the capacity program or the energy program?

Q. The energy program. So would there be payments from AEP coming into that market, then going out to that customer in Pennsylvania, not directly but indirectly?

A. Maybe we need to clarify. For the energy program it's the LSE that's serving the customer that makes the payment.

Q. Let me switch that to the capacity.

A. For the capacity program it's the LSEs that are buying their capacity in the RPM market which pay, and since AEP is an FRR entity, it would not pay.

Q. Okay. Going to page 6, lines 1 to 4 of your testimony, you state that "In other words, the Companies should be able to count the load that is capable of being reduced towards peak reduction goals." What do you mean by capable?

A. In my view, capable there means a customer which the Company is able to request that they curtail load, even if they had not requested that that customer curtail load at that given hour.

Q. Okay. Do you believe that the customer participation in the Companies' interruptible service offerings will increase if the PJM prohibition is put in place or is approved?

A. I think it could, but I think that's probably also in combination with, for Ohio Power particularly, the expansion of the availability.

Q. Could it decrease as well?

A. It's possible it could decrease, given the economic environment, as well. A lot of interruptible customers who choose interruptible service are choosing it not necessarily because they really want to interrupt, because they really want to make their product, but they are choosing it to save on their cost of electricity. And so it's possible in this economic environment that some of those customers may no longer choose to be interruptible.

Q. And you mentioned economics tied

with that. A company in Pennsylvania and a company in Ohio, let's say Pennsylvania allows PJM participation. Ohio's application is approved. If the company in Ohio cannot participate, which one would have an economic advantage, competitive advantage over the other company?

A. It depends. For example, Kentucky currently doesn't allow customers to participate in PJM programs, but they do allow Kentucky Power to offer interruptible service to customers.

Q. If you have a state that allows participation and a state that doesn't, and you have two companies, everything is comparable but the only difference is one can participate and one cannot, does the company that is able to participate have a competitive advantage?

MR. CONWAY: Objection. He's already explained that they're not comparable, that the assumption is one that can't be made readily.

MR. SETTINERI: He compared it to Kentucky though, so I think he can answer it.

A. I guess I go back to the previous answer in that I don't perceive the availability of PJM programs as a competitive advantage or disadvantage, particularly when there are other interruptible service offerings available in the state.

MR. SETTINERI: Thank you, Mr. Roush. I have no further questions for you.

MS. GRADY: Thank you very much.

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Thereupon, at 4:35 p.m. the deposition was concluded.

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State of Ohio :
SS:
County of Franklin :

I, David M. Roush, do hereby certify that I have read the foregoing transcript of my deposition given on Tuesday, October 28, 2008; that together with the correction page attached hereto noting changes in form or substance, if any, it is true and correct.

____
David M. Roush

I do hereby certify that the foregoing transcript of the deposition of David M. Roush was submitted to the witness for reading and signing; that after he had stated to the undersigned Notary Public that he had read and examined his deposition, he signed the same in my presence on the ______ day of ________________, 2008.

____

Notary Public

My commission expires ________________, ______.

- - -

CERTIFICATE

State of Ohio :
SS:
County of Franklin :

I, Iris I. Dillion, Notary Public in and for the State of Ohio, duly commissioned and qualified, certify that the within named David M. Roush was by me duly sworn to testify to the whole truth in the cause aforesaid; that the testimony was taken down by me in stenotypy in the presence of saidwitness, afterwards transcribed upon a computer; that the foregoing is a true and correct transcript of the testimony given by said witness taken at the time and place in the foregoing caption specified and completed without adjournment.

I certify that I am not a relative, employee, or attorney of any of the parties hereto, or of any attorney or counsel employed by the parties, or financially interested in the action.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my seal of office at Columbus, Ohio, on this 3rd day of October, 2008.

Iris I. Dillion / 1st

Iris I. Dillion,
Notary Public in and for the
State of Ohio.

My commission expires February 4, 2013.

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FILE

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbus Southern Power Company for Approval of its Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generation Assets.	)	Case No. 08-917-EL-SSO
In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan.	)	Case No. 08-918-EL-SSO

NOTICE TO TAKE DEPOSITIONS UPON ORAL EXAMINATION AND REQUEST FOR PRODUCTION OF DOCUMENTS

Pursuant to Ohio Adm. Code Rule 4901-1-21(B), please take notice that the Ohio Consumers' Counsel ("OCC") will take the oral deposition of the following individuals:

1) J. Craig Baker, Senior Vice President – Regulatory Services, American Electric Service Power Corporation ("AEPSC"), 1 Riverside Plaza, Columbus, Ohio 43215;

2) Gregory A. Earle, Customer Services & Marketing Manager, AEPSC, Columbus Region of AEP Ohio, 850 Tech Center Drive, Gahanna, Ohio 43230;

3) Dr. Anil Kumar Makhija, Professor of Finance - The Ohio State University, 700 E. Fisher Hall, Fisher College of Business, The Ohio State University, Columbus, Ohio 43210;

4) Leonard V. Assante, Vice President of Regulatory Accounting Services, AEPSC, 1 Riverside Plaza, Columbus, Ohio 43215;

5) Karen L. Sloneker, Director of Customer Services and Marketing, AEPSC, 850 Tech Center Drive, Gahanna, Ohio 43230;

6) William K. Castle, Director DSM and Resource Planning, AEPSC, 1 Riverside Plaza, Columbus, Ohio 43215;

7) Karl G, Boyd, Vice President of Distribution Operations, AEPSC, 850 Tech Center Drive, Gahanna, Ohio 43230;

8) David M. Roush, Manager – Regulated Pricing and Analysis, AEPSC, 1 Riverside Plaza, Columbus, Ohio 43215;

9) Joseph Hamrock, President and Chief Operating Officer, AEP Ohio, 850 Tech Center Drive, Gahanna, Ohio 43230;

10) Philip J. Nelson, Director of Strategic Initiatives, AEPSC, 1 Riverside Plaza, Columbus, Ohio 43215,

11) Jay F. Godfrey, Manager – Director Renewable Energy, AEPSC, 155 W. Nationwide Boulevard, Columbus, Ohio 43215.

12) James D. Henry, Vice President of Fuel Procurement, AEPSC, 155 W. Nationwide Boulevard, Columbus, Ohio 43215,

13) A person or person(s) with knowledge and expertise and responsibility for the current and future procurement of coal for Ohio Power and Columbus Southern Power.

14) A person or persons with knowledge and expertise with regard to the preparation of the estimated fuel costs for the 2009 Fuel Adjustment Clause for Ohio Power Company and Columbus Southern Power Company.

15) With respect to the Provider of Last Resort obligation, a person or persons with knowledge and expertise with regard to the development and preparation of the Black Scholes pricing methodology and calculations.

The depositions will take place beginning on October 22, 2008, at 10:00 a.m. and will continue from day to day thereafter until completed, at the offices of the Ohio Consumers' Counsel, 10 W. Broad St., 18th Floor, Columbus, Ohio 43215, or as otherwise agreed to. Parties to the proceeding are invited to attend and cross-examine.

The depositions will be taken of the aforementioned deponents on relevant topics within their expertise, including but not limited to, the subject matter of their testimony.

The depositions will be taken upon oral examination (as upon cross-examination) before an officer authorized by law to take depositions and will continue from day to day, except for holidays and weekends, until completed.

Pursuant to Ohio Adm. Code Rules 4901-1-21(E) and 4901-1-20, the deponent is requested to produce at the time of his or her deposition all documents relating to his or her testimony in these proceedings or responses to discovery, including, but not limited to, the results of any studies done for these proceedings and any backup documentation, including raw data, for those studies.

Respectfully submitted,

Janine Migden-Ostrander
CONSUMERS' COUNSEL

Maureen R. Grady, Counsel of Record
Terry L. Etter
Jacqueline Lake Roberts
Michael E. Idzkowski
Richard C. Reese
Assistant Consumers' Counsel

OHIO CONSUMERS' COUNSEL
10 West Broad Street, 18th Floor
Columbus, Ohio 43215-3485
(614) 466-8574 (T)
(614) 466-9475 (F)
grady@occ.state.oh.us
etter@occ.state.oh.us
roberts@occ.state.oh.us
idzkowski@occ.state.oh.us
reese@occ.state.oh.us

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Notice of Depositions was served via electronic transmittal and by regular U.S. Mail service, postage prepaid, to the persons listed below on this 10th day of October, 2008.

Maureen R. Grady
Assistant Consumers' Counsel

SERVICE LIST

Marvin Resnik
Steve Nourse
AEP Service Corp.
1 Riverside Plaza, 29th Floor
Columbus, OH 43215

John Jones
William Wright
Werner Margard
Assistant Attorneys General
Public Utilities Commission of Ohio
180 E. Broad St., 9th Fl.
Columbus, OH 43215

John W. Bentine
Mark S. Yurick
Matthew S. White
Chester, Willcox & Saxbe LLP
65 East State St., Ste. 1000
Columbus, OH 43215-4213

Attorney for The Kroger Company, Inc.

Nolan Moser
Air & Energy Program Manager
The Ohio Environmental Council
1207 Grandview Ave., Ste. 201
Columbus, OH 43212-3449

Barth E. Royer
Bell & Royer Co. LPA
33 South Grant Avenue
Columbus, OH 43215-3927

The Ohio Environmental Council and
Dominion Retail, Inc.

Trent A. Dougherty
The Ohio Environmental Council
1207 Grandview Ave., Ste. 201
Columbus, OH 43212-3449

M. Howard Petricoff
Stephen M. Howard
Vorys, Sater, Seymour And Pease LLP
52 East Gay S., P. O. Box 1008
Columbus, OH 43216-1008

Attorneys for Constellation NewEnergy, Inc. and Constellation Energy Commodities Group, Inc.

Cynthia A. Fonner
Senior Counsel
Constellation Energy Group, Inc.
550 W. Washington St., Suite 300
Chicago, IL 60661

Attorneys for Constellation NewEnergy, Inc. and Constellation Energy Commodities Group, Inc.

Samuel C. Randazzo
Lisa G. McAlister
Daniel J. Neilsen
Joseph M. Clark
McNees, Wallace & Nurick LLC
21 East State St., 17th Fl.
Columbus, OH 43215

Attorneys for Industrial Energy Users-Ohio

David C. Rinebolt
Colleen L. Mooney
Ohio Partners for Affordable Energy
231 West Lima Street
P.O. Box 1793
Findlay, OH 45839-1793

Attorneys for Ohio Partners for Affordable Energy

David F. Boehm, Esq.
Michael L. Kurtz, Esq.
Boehm, Kurtz & Lowry
36 East Seventh St., Ste. 1510
Cincinnati, OH 45202

Attorneys for The Ohio Energy Group

Daniel R. Conway
Porter Wright Morris & Arthur
Huntington Center
41 S. High Street
Columbus, Ohio 43215

Michael R. Smalz
Joseph V. Maskovyak
Ohio State Legal Services Association
Appalachian People's Action Coalition
555 Buttles Avenue
Columbus, OH 43215

Attorneys for APAC

Richard L. Sites
Ohio Hospital Association
155 East Broad Street, 15th Floor
Columbus, OH 43215-3620

Attorney for Ohio Hospital Association

Henry W. Eckhart
50 W. Broad St., #2117
Columbus, OH 43215

Attorney for The Sierra Club Ohio Chapter and Natural Resources Defense Council

Craig G. Goodman
National Energy Marketers Association
3333 K St., N.W., Ste. 110
Washington, D.C. 20007

Sally W. Bloomfield
Terrence O'Donnell
Bricker & Eckler, LLP
100 South Third Street
Columbus, OH 43215-4291

Attorney for American Wind Energy Association, Wind On The Wires and Ohio Advanced Energy

Larry Gearhardt
Chief Legal Counsel
Ohio Farm Bureau Federation
280 North High St., P.O. Box 182383
Columbus, OH 43218-2383

Clinton A. Vince
Presley R. Reed
Emma F. Hand
Ethan E.Rii
Sonnenschein, Nath & Rosenthal LLP
1301 K Street NW
Suite 600, East Tower
Washington, DC 20005

Attorneys for Ormet Primary Aluminum Corporation

Langdon D. Bell
Bell & Royer Co., LPA
33 South Grant Ave.
Columbus OH 43215-3927

Attorney for Ohio Manufacturer's Association

Scott H. DeBroff
Stephen J. Romeo
Alicia R. Petersen, J.D.
Smigel, Anderson & Sacks, LLP
River Chase Office Center
4431 North Front St.
Harrisburg, PA 17110

Attorneys for ConsumerPowerline

Benjamin Edwards
Law Offices of John L. Alden
One East Livingston Ave.
Columbus, OH 43215-5700

Attorney for ConsumerPowerline

Douglas M. Mancino
McDermott, Will & Emery LLP
2049 Century Park East, Ste. 3800
Los Angeles, CA 90067-3218

Attorney for Morgan Stanley Capital Group, Inc.

Gregory K. Lawrence
McDermott, Will & Emery LLP
28 State Street
Boston, MA 02109

Attorney for Morgan Stanley Capital Group, Inc.

Stephen M. Howard
Vorys, Sater, Seymour And Pease LLP
52 East Gay S., P. O. Box 1008
Columbus, OH 43216-1008

Attorney for Integrys Energy Services, Inc.

Grace C. Wung
McDermott Will & Emery, LLP
600 Thirteenth Street, N.W.
Washington, DC 20005

Attorney for the Commercial Group

sam@mwncmh.com
lmcalister@mwncmh.com
dneilsen@mwncmh.com
jclark@mwncmh.com
Thomas.McNamee@puc.state.oh.us
william.wright@puc.state.oh.us
Werner.Margard@puc.state.oh.us
drinebolt@aol.com
cmooney2@columbus.rr.com
dboehm@bkllawfirm.com
mkurtz@bkllawfirm.com
miresnik@aep.com
stnourse@aep.com
cgoodman@energymarketers.com
LGearhardt@ofbf.org
LBell33@aol.com
sromeo@sasllp.com
sbloomfield@bricker.com
dmancino@mwe.com
gwung@mwe.com
dconway@porterwright.com
BarthRoyer@aol.com
nmoser@theOEC.org
trent@theOEC.org
jbentine@cwslaw.com
myurick@cwslaw.com
mwhite@cwslaw.com
msmalz@oslsa.org
jmaskovyak@oslsa.org
Cynthia.A.Fonner@constellation.com
smhoward@vssp.com
mhpetricoff@vssp.com
ricks@ohanet.org
henryeckhart@aol.com
mhpetricoff@vorys.com
bedwards@aldenlaw.net
mhpetricoff@vorys.com
todonnell@bricker.com
glawrence@mwe.com