BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

- - -

In the Matter of the :
Application of Columbus :
Southern Power Company :
and Ohio Power Company :
for Authority to Establish:
a Standard Service Offer : Case No. 11-346-EL-SSO
Pursuant to §4928.143, : Case No. 11-348-EL-SSO
Ohio Rev. Code, in the :
Form of an Electric :
Security Plan. :

In the Matter of the :
Application of Columbus :
Southern Power Company : Case No. 11-349-EL-AAM
and Ohio Power Company : Case No. 11-350-EL-AAM
for Approval of Certain :
Accounting Authority. :

- - -

PROCEEDINGS

before Ms. Greta See and Mr. Jonathan Tauber, Attorney Examiners, and Commissioner Andre Porter, at the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-A, Columbus, Ohio, called at 8:30 a.m. on Tuesday, May 22, 2012.

- - -

VOLUME IV

- - -

ARMSTRONG & OKEY, INC.
222 East Town Street, Second Floor
Columbus, Ohio 43215-5201
(614) 224-9481 - (800) 223-9481
Fax - (614) 224-5724

- - -

APPEARANCES:

American Electric Power Service Corporation
By Mr. Steven T. Nourse
Mr. Matthew J. Satterwhite
and Mr. Yazen Alami
One Riverside Plaza, 29th Floor
Columbus, Ohio 43215

Porter, Wright, Morris & Arthur, LLP
By Mr. Daniel R. Conway
and Ms. Christen Moore
41 South High Street
Columbus, Ohio 43215

On behalf of the Ohio Power Company and Columbus Southern Power Company.

AEP Retail Energy Partners, LLC
By Mr. Jay E. Jadwin
155 West Nationwide Boulevard, Suite 500
Columbus, Ohio 43215

On behalf of the AEP Retail Energy Partners.

FirstEnergy Service Company
By Mr. Mark A. Hayden
76 South Main Street
Akron, Ohio 44308

Jones Day
By Mr. David A. Kutik
North Point
901 Lakeside Avenue
Cleveland, Ohio 44114

Jones Day
By Ms. Allison E. Haedt
325 John J. McConnell Boulevard, Suite 600
Columbus, Ohio 43215

Calfee, Halter & Griswold LLP
By Mr. James F. Lang
and Ms. Laura C. McBride
1400 KeyBank Center
800 Superior Avenue
Cleveland, Ohio 44114

APPEARANCES: (Continued)

Calfee, Halter & Griswold, LLP
By Mr. N. Trevor Alexander
Fifth Third Center, Suite 1100
21 East State Street
Columbus, Ohio 43215

On behalf of the FirstEnergy Service Corporation.

McNees, Wallace & Nurick, LLC
By Mr. Frank P. Darr
Mr. Samuel C. Randazzo
Mr. Joseph E. Oliker
and Mr. Matthew R. Pritchard
Fifth Third Center, Suite 1700
21 East State Street
Columbus, Ohio 43215-4228

On behalf of the Industrial Energy Users of Ohio.

Taft, Stettinius & Hollister
By Mr. Zachary D. Kravitz
and Mr. Mark S. Yurick
65 East State Street, Suite 1000
Columbus, Ohio 43215

On behalf of the Kroger Company.

Office of the Ohio Consumers' Counsel
By Ms. Maureen R. Grady
Mr. Terry L. Etter
and Mr. Joseph P. Serio
Assistant Consumers' Counsel
10 West Broad Street, Suite 1800
Columbus, Ohio 43215

On behalf of the Residential Ratepayers of Columbus Southern Power Company and Ohio Power Company.

\- - -

APPEARANCES: (Continued)

Mike DeWine, Ohio Attorney General
By William Wright, Section Chief
Public Utilities Section
Mr. Steven L. Beeler
Mr. John H. Jones
and Mr. Werner L. Margard, III
Assistant Attorneys General
180 East Broad Street, 6th Floor
Columbus, Ohio 43215-3793

On behalf of the staff of the Public Utilities Commission of Ohio.

Ice Miller, LLP
By Mr. Christopher L. Miller
Mr. Gregory J. Dunn
and Mr. Asim Z. Haque
250 West Street
Columbus, Ohio 43215

On behalf of the Association of Individual Colleges and Universities, City of Upper Arlington, City of Grove City, and City of Hillsboro.

Boehm, Kurtz & Lowry
By Mr. Michael L. Kurtz
Mr. Kurt J. Boehm
and Ms. Jody M. Kyler
36 East Seventh Street, Suite 1510
Cincinnati, Ohio 45202

On behalf of Ohio Energy Group.

Duke Energy Ohio, Inc.
By Ms. Jeanne W. Kingery
155 East Broad Street, 21st Floor
Columbus, Ohio 43215

Duke Energy Ohio, Inc.
By Ms. Amy B. Spiller
Ms. Elizabeth Watts
and Mr. Rocco D'Ascenzo
139 East Fourth Street
Cincinnati, Ohio 45202

APPEARANCES: (Continued)

Thompson Hine, LLP
By Mr. Philip B. Sineneng
41 South High Street, Suite 1700
Columbus, Ohio 43215

On behalf of the Retail Sales and Duke Energy Commercial Asset Management.

Eberly McMahon, LLC
By Mr. Robert A. McMahon
Ms. Elizabeth Watt
and Mr. Rocco D'Ascenzo
2321 Kemper Lane, Suite 100
Cincinnati, Ohio 45206

On behalf of Duke Energy Ohio.

Bricker & Eckler, LLP
By Mr. Thomas J. O'Brien
100 South Third Street
Columbus, Ohio 43215-4291

Ohio Hospital Association
By Mr. Richard L. Sites
155 East Broad Street, 15th Floor
Columbus, Ohio 43215

On behalf of the Ohio Hospital Association.

Bricker & Eckler, LLP
By Ms. Lisa Gatchell McAlister
and Mr. J. Thomas Siwo
100 South Third Street
Columbus, Ohio 43215-4291

On behalf of Ohio Manufacturers Association.

Bell & Royer Co., LPA
By Mr. Barth E. Royer
33 South Grant Avenue
Columbus, Ohio 43215

On behalf of Dominion Retail, Inc.

APPEARANCES: (Continued)

Vorys, Sater, Seymour & Pease, LLP
By Mr. M. Howard Petricoff
and Ms. Lija Kaleps-Clark
52 East Gay Street
P.O. Box 1008
Columbus, Ohio 43216-1008

On behalf of the Exelon Generation Company, Constellation NewEnergy, Inc., Constellation Energy Commodities Group, Inc., Retail Energy Supply Association, Direct Energy Services, and Direct Energy Business, LLC, The Compete Coalition, and PJM Power Providers Group.

Eimer, Stahl, Klevorn & Solberg, LLP
By Mr. David M. Stahl
and Mr. Scott C. Solberg
224 South Michigan Avenue, Suite 1100
Chicago, Illinois 60604

On behalf of Constellation Exelon Generation Company, LLC.

Covington & Burling, LLP
By Mr. William Massey
1201 Pennsylvania Avenue, N.W.
Washington, D.C. 20004

On behalf of The Compete Coalition.

Ohio Poverty Law Center
By Mr. Joseph V. Maskovyak
and Mr. Michael Smalz
555 Buttles Avenue
Columbus, Ohio 43215

On behalf of Appalachian Peace and Justice Network.

- - -

APPEARANCES: (Continued)

Keating, Muething & Klekamp PLL
By Mr. David A. Meyer
One East Fourth Street, Suite 1400
Cincinnati, Ohio 45202

Keating, Muething & Klekamp, PLL
Ms. Holly Rachel Smith
HITT Business Center
3803 Rectortown Road
Marshall, Virginia 20115

On behalf of Wal-Mart Stores East, LP, and Sam's East, Inc.

Bricker & Eckler, LLP
By Mr. Christopher L. Montgomery
Mr. Matthew Warnock
and Mr. Terrence O'Donnell
100 South Third Street
Columbus, Ohio 43215

On behalf of Paulding Wind Farm, LLC.

SNR Denton US, LLP
By Ms. Emma F. Hand
Mr. Thomas R. Millar
and Mr. Daniel D. Barnowski
1301 K Street NW
Suite 600 East Tower
Washington, D.C. 20005

On behalf of Ormet Primary Aluminum Corporation.

EnerNOC, Inc.
By Mr. Gregory J. Poulos
471 East Broad Street, Suite 1520
Columbus, Ohio 43215

On behalf of EnerNOC.

APPEARANCES: (Continued)

Kegler, Brown, Hill & Ritter, LPA
By Mr. Roger P. Sugarman
Capitol Square, Suite 1800
65 East State Street
Columbus, Ohio 43215

On behalf of National Federation of Independent Business, Ohio Chapter.

Bailey Cavalieri, LLC
By Mr. Dane Stinson
10 West Broad Street
Columbus, Ohio 43215

On behalf of the Ohio Association of School Business Officials, Ohio School Boards Association, Buckeye Association of School Administrators, and Ohio Schools Council.

Whitt Sturtevant, LLP
By Mr. Mark A. Whitt
Ms. Melissa L. Thompson
and Mr. Andrew John Campbell
PNC Plaza, Suite 2020
155 East Broad Street
Columbus, Ohio 43215

Interstate Gas Supply, Inc.
By Mr. Vincent Parisi
and Mr. Matthew White
6100 Emerald Parkway
Dublin, Ohio 43016

On behalf of the Interstate Gas Supply, Inc.

Vectren Source
By Mr. Joseph M. Clark
6641 North High Street, Suite 200
Worthington, Ohio 43085

On behalf of Direct Energy Services and Direct Energy Business.

APPEARANCES: (Continued)

Thompson Hine, LLP
By Ms. Carolyn S. Flahive
Ms. Stephanie Chmiel
and Mr. Michael Dillard
41 South High Street, Suite 1700
Columbus, Ohio 43215

On behalf of Border Energy Electric Services, Inc.

Williams, Allwein & Moser
By Mr. Todd M. Williams
Two Maritime Plaza
Toledo, Ohio, 43604

On behalf of the Ohio Business Council for a Clean Environment.

William, Allwein & Moser
By Mr. Christopher J. Allwein
1373 Grandview Avenue, Suite 212
Columbus, Ohio 43212

On behalf of the Natural Resources Defense Council.

Dayton Power & Light Company
By Ms. Judi L. Sobecki
1065 Woodman Drive
Dayton, Ohio 45432

On behalf of Dayton Power & Light.

Ohio Automobile Dealers Association
By Mr. Charles C. Howard
and Ms. Sarah Bruce
655 Metro Place South, Suite 270
Dublin, Ohio 43017

On behalf of the Ohio Automobile Dealers Association.

APPEARANCES: (Continued)

Hahn, Loeser & Parks, LLP
By Mr. Randy Hart
200 Huntington Building
Cleveland, Ohio 44114

On behalf of Summit and Fostoria Ethanol.

Matthew Cox Law, Ltd.
By Mr. Matthew Cox
4145 St. Theresa Boulevard
Avon, Ohio 44011

On behalf of the Council of Smaller Enterprises.

The Behal Law Group, LLC
By Mr. Jack D'Aurora
501 South High Street
Columbus, Ohio 43215

On behalf of the University of Toledo.

- - -

INDEX

- - -

INDEX (Continued)

- - -

INDEX (Continued)

- - -

- - -

Tuesday Morning Session,
May 22, 2012.
- - -

EXAMINER SEE: Let's go on the record. Let's take brief appearances of the parties, we'll start with the company, go around the room.

MR. SATTERWHITE: Thank you, your Honor. On behalf of Ohio Power Company Matt Satterwhite, Steve Nourse, Yazen Alami, Christen Moore, Dan Conway.

EXAMINER SEE: Mr. Serio.

MR. SERIO: Thank you, your Honor. On behalf of Ohio Consumers' Counsel, Bruce Weston, Maureen Grady, Joseph Serio, Terry Etter.

EXAMINER SEE: Next.

MR. LANG: On behalf of FirstEnergy Solutions Mark Hayden, Jim Lang, and David Kutik.

MR. DARR: Good morning, your Honor. On behalf of IEU-Ohio, Sam Randazzo, Matt Pritchard, Joe Oliker, and Frank Darr.

MR. SINENENG: Good morning. On behalf of Duke Energy Retail and Duke Energy Commercial Asset Management, Amy Spiller, Jeanne Kingery, and Philip Sineneng.

MS. KYLER: Good morning. On behalf of

the Ohio Energy Group Michael Kurtz, Kurt Boehm, and Jody Kyler.

MR. SIWO: Good morning. On behalf of the Ohio Manufacturers Association, Lisa McAlister and Thomas Siwo.

MR. SUGARMAN: Roger Sugarman on behalf of NFIB-Ohio.

MS. THOMPSON: Good morning. On behalf of Interstate Gas Supply, Incorporated, Mark Whitt, Melissa Thompson, Andrew Campbell, Vince Parisi, Matt White.

MR. BARNOWSKI: Good morning. On behalf of Ormet, Dan Barnowski, Emma Hand, and Tom Millar.

MS. KALEPS-CLARK: Good morning. On behalf of Exelon Generation Company, Constellation NewEnergy, Constellation Energy Commodities Group, David Stahl, M. Howard Petricoff, on behalf of the Retail Energy Supply Association and Direct Energy, M. Howard Petricoff and Lija Kaleps-Clark.

MR. O'BRIEN: Good morning, your Honors. On behalf of the Ohio Hospital Association, Rick Sites and Tom O'Brien.

MR. MARGARD: Werner Margard and Steven Beeler, Assistant Attorneys General on behalf of the Commission staff.

MR. COX: On behalf of the Council of Small Enterprises, Matt Cox.

MR. STINSON: On behalf of Ohio Schools, Dane Stinson.

EXAMINER SEE: Any other counsel in the room that wishes to enter an appearance?

Mr. Satterwhite, your next witness.

MR. SATTERWHITE: Thank you, your Honor. Just so everyone's aware with the scheduling we're going to do today, we're starting with Mr. Kirkpatrick, then going to Mr. Roush and Ms. Thomas.

EXAMINER SEE: That is correct.

MR. SATTERWHITE: At this time I call Mr. Kirkpatrick to the stand.

EXAMINER SEE: Mr. Kirkpatrick, if you would please raise your right hand.

(Witness sworn.)

EXAMINER SEE: Thank you. Have a seat.

Please cut the microphone on.

Mr. Conway.

Mr. Satterwhite, you might want to get the long-neck mic.

MR. SATTERWHITE: Thank you.

\- - -

THOMAS L. KIRKPATRICK

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

DIRECT EXAMINATION

By Mr. Satterwhite:

Q. Mr. Kirkpatrick, can you please state your name, title, and business address for the record?

A. Yes. My name's Thomas L. Kirkpatrick. I'm Vice President of Distribution Operations for Ohio Power Company. My business address is 850 Tech Center Drive, Gahanna, Ohio.

Q. And did you cause testimony to be filed under your name in this case on March 30th, 2012?

A. Yes, I did.

MR. SATTERWHITE: Your Honor, at this time I'd like to mark as AEP Exhibit 110 the direct testimony of Thomas L. Kirkpatrick. May I approach?

EXAMINER SEE: Yes.

(EXHIBIT MARKED FOR IDENTIFICATION.)

Q. Mr. Kirkpatrick, could you please identify the document I've just put in front of you marked AEP Exhibit 110.

A. This is the direct testimony that I prepared in preparation for this hearing.

Q. And do you have any changes or corrections to this testimony?
A. I do not.
Q. Do you adopt this testimony as your own in today's proceeding?
A. I do.
MR. SATTERWHITE: Your Honor, at this time I would move for admission of AEP Exhibit 110 subject to cross-examination.
EXAMINER SEE: Okay. Mr. Lang.
MR. LANG: Thank you, your Honor. FES has no questions.
EXAMINER SEE: I'm sorry, hold on for just a second. Let me verify if there are any motions to strike.
Okay. No motions to strike. No questions for FES?
Mr. Serio?
MR. SERIO: Thank you, your Honor.

- - -

CROSS-EXAMINATION

By Mr. Serio:
Q. Morning, Mr. Kirkpatrick.
A. Good morning.
Q. Can you please give me a really quick

background of what your duties as Vice President of Distribution involve?

A. My responsibilities are for the -- essentially the engineering design, construction, operation, maintenance of AEP Ohio's distribution system.

Q. So are you responsible for service reliability?

A. Yes, I am.

Q. And does that service reliability include reporting to the PUCO?

A. It does.

Q. On page 2 of your testimony, you mention that you're sponsoring continuation of the enhanced service reliability plan, correct?

A. That's correct.

Q. And then in addition you're sponsoring new reliability programs under the distribution investment rider, correct?

A. That's correct.

Q. On page 9 of your testimony, on line 8 you talk about an incremental $18 million. That's incremental to the current enhanced service reliability plan?

A. What that's referring to is that when we complete the process of catching up our system to the point where we can be on a four-year cycle, we will require an additional $18 million in our base O&M or 18 million above our base O&M to maintain the distribution system on that four-year cycle.

Q. Are you asking for that 18 million in this proceeding?

A. Yes, we are.

Q. Okay. Now, on page 10 of your testimony you talk about the gridSMART expansion, and lines 11 and 12 there you mention improved reliability, improved customer awareness of energy usage, and then justify the expense. Is there something missing at the end or is that meant to just say "justify the expense"?

A. I believe that phrase just doesn't belong there.

Q. So your testimony would end after "...awareness of energy usage," and then a period?

A. Yes, sir.

Q. Now, the two factors that you mentioned, the "improved reliability," how do you measure that improved reliability?

A. Improved reliability is measured numerically through the performance standards that we have set up with the Commission, and we measure three different indices, two of which are adopted by the Commission, one is our SAIFI standard, our system average interruption frequency index, the other is our SAIDI standard which is our system average interruption duration index, and the third is our CAIDI which is the customer average interruption duration index.

The SAIFI and the CAIDI are the two elements that we file and work with the Commission in establishing guidelines and targets for performance in those two indices.

Q. Those are just straight metrics, correct?

A. Those are performance metrics, yes.

Q. Very objective standard, no subjectivity in that?

A. Yes, sir.

Q. Now, although you deleted the words, how does the company measure the expense that's involved versus the improved reliability? Do you do a cost-benefit analysis?

A. Are you speaking of the gridSMART program specifically --

Q. Yes.

A. -- which is where this is?

Q. Yes.

A. Yes, we put forth the preliminary analysis of the expected performance of our gridSMART demonstration project. That project is, as you know, still underway and, in fact, the demonstration project runs through the end of 2013.

As we approach the end of that project we'll be pulling together the information that we've been collecting throughout to determine whether or not the investments made in these advanced technologies meet the test of supporting continuation of the project or not, and that test -- that analysis will look at the benefits to the customer, the benefits to society as a whole, as well as the more numerical benefits to reliability, performance, et cetera.

Q. And that will be compared to the cost of the program?

A. Yes. That will be part of the analysis. Just so counsel know, we do intend, in our upcoming standard setting review with the Commission this summer, to include some of the preliminary results on reliability performance into our new standard setting. So we believe it's prudent at this part -- to look at what we've accomplished at this point and begin the movement in adjusting our reliability standards as a result of this program.

Q. Now, will the cost-benefit analysis that you do, are those updated over time or do you do that once and then you leave it static after that?

A. Well, again, the gridSMART program is a new program. It's a new demonstration project, as you know. And this is the first time we've done anything of this nature.

As I mentioned, we will, at the end of our demonstration project, which runs through 2013, take a step back and look at all the investment and look at the investment in the different strategies involving gridSMART and determine which ones have the greatest value, which ones don't, and then move forward in developing, in concert with staff and others, a plan for further deployment of some of these gridSMART technologies.

Q. Now, on page 11 of your testimony you talk about the proposed DIR and you list four factors there. Do you see that?

A. I see the four bullets at the bottom of page 11, yes.

Q. Are the four bullets intended to maintain or improve system reliability?

A. It's actually a combination of both. We believe that the investment that we make will help to move the reliability needle, if you will, in a favorable means, but we also understand that the vast infrastructure that we have in AEP Ohio with over 31,000 miles of overhead distribution lines, for example, over 800,000 poles, that as these assets age, that the do-nothing approach would lead to degradation of service from the current levels over time.

So it's a combination of working to stem the failure rate that is inherent in aging assets as well as improve the reliability of those assets that are underperforming today.

Q. Looking at the improvement aspect, as you plan the program, do you have a level of improvement in mind going into it? For example, are you looking at improving reliability 10 percent? 15 percent? Or are you just looking to, quote, improve reliability?

A. I wouldn't say that we have a hard target for that. What we do when we put together plans for any of our capital spend, whether it be within the DIR or not, the intent of that is to address and identify those items that would yield the greatest improvement to our customers. So we do evaluate our projects and do evaluate our spend based upon the improvement that we expect to see from that particular asset group for our customers.

That improvement in and of itself, you know, you're targeting and you have to presuppose what your levels of failures might be in the future, and whether you can look at some analysis and have an understanding of what that might be, it's still looking at the future and predicting what it will be and that's never an exact science.

Q. But based on your expectations, do you sit down ahead of time and say by spending $50 million we expect to see a 5-percent improvement in our CAIDI numbers or our other metrics that we report to the Commission?

A. I think what we do is we look at it actually in a more granular level than that. I'll give you an example. If we're looking at an improvement project to replace 15,000 feet of cable in a subdivision that it serves and we've had a dozen failures of that cable over the last two years, for example, our expectation is that the failures will go to zero.

So the distribution business is a lot more granular in nature than, say, the transmission or substation business where many of our projects are highly targeted to specific areas and they're meant to address the reliability issues and concerns that you have in those areas themselves.

So when I replace cable in a subdivision, I don't expect any more failures in that subdivision. So as you look at accumulating, then, the value of that across multiple subdivisions, then you can make some judgments what that might mean for that asset class in general.

Q. Do you do any kind of analysis where you would -- in using your example you had a piece of cable that resulted in 12 failures previously, you anticipate it's going to reduce the failures to zero, do you go back afterwards and look to see if the failure rate dropped to zero to make sure that the investment you made took care of the problem and that you have a measurable benefit from it?

A. We look at that on a class basis, yes. So we definitely do. And whenever we have a -- whenever we have a cable failure, there's a couple things that happen. For example, we have a team of folks who are in charge of, if you will, or own the circuit performance and will look at newly installed cable to determine whether or not there's an installation problem or something of that nature. But by and large, we monitor that, I would say, with our circuit engineers to make sure that the intended result is achieved.

Q. On page 13 of your testimony you identify a figure of in excess of $150 million. First, when you say "in excess," how much in excess of 150 are you talking about?

A. My current distribution capital budget is about $153 million right now I believe. It's in that neighborhood. It's just a little bit higher than 150.

Q. Is that an annual budget or is that over a period of time?

A. That is my calendar year 2012 budget.

Q. Now, it talks about 150 million in distribution assets. What exactly do you mean by "distribution assets" there?

A. Those would be capital expenditures in the FERC accounts related to distribution system.

Q. Now, are those targeted for specific projects or is that just a general in order to deal with anything that's going to come up?

A. No. We have a combination of what you might call categories of spend for the capital dollars in AEP. Certainly one of those categories is reactive spend, capital spend to address existing failures or emergent issues, but we also have capital spend in other areas.

One example would be our customer service spend for capital, capital extension of lines to certain customers, capital clearing to provide for those lines would be in the kind of customer bucket, if you will.

We have a capital spend in a general category called "capacity" and in that area we upgrade our system to make sure that it has the needed capacity to meet our customer demand at the time of peak.

We also have a category of spend in the asset renewal side. So this is proactive spend for, you know, identifying, from past history, areas where we need to make an investment in our assets in order to relieve pressure on us being driven by performance from those assets.

And then, finally, there's small reliability projects. These are projects that are very small in nature that take maybe a day or two to complete in the field and a little bit of engineering work that are really meant to address small area reliability concerns by our customers.

So it's a combination of these different categories of spend that we build a capital budget in the latter part, typically in the third and early fourth quarter of each year, that lays out funding in each of these areas given what we believe the spend will be, and then we work with that throughout the year.

The distribution business is a very dynamic business, it's not like substation or transmission, as I mentioned, really typically have long lead, long duration type projects. Our projects are very short in nature. We plan them out, we lay out a general plan in each of those categories, but we also try to be responsive throughout the year to our customers' needs.

Q. Now, that 150-plus million, that's all in the capital spending, correct?

A. That's correct.

Q. Now, do you have spending in addition to the capital spending for your reliability programs?

A. I'm not sure I understand. Could you reask that question again?

Q. Do you have O&M spending that's targeted to reliability?

A. Absolutely. We have O&M spending that's targeted to a number of areas. Obviously, like capital, O&M has multiple components to it. There is clearly a reactive component to it: The O&M spend associated with recovery from system outages, storms, equipment failure where capital elements are not involved.

We also have programmatic O&M spend where we programmatically perform various maintenance and duties, inspection duties on the inspection performance in accordance with the ESSS rules here at the Commission and in compliance with those rules and service to our customers. Those include things like circuit inspections, pole inspections, recloser inspections, capacity bank inspections, largely a number of various kinds of inspections of the condition of our system. And then, from that, come obviously repairs that are made necessary from the inspections, so.

Q. What is the ballpark of the O&M spending that you do in a year on reliability?

A. It's hard to break out the difference between reactive spend and planned spend. My total O&M budget is in the neighborhood of about $130 million and, right now, I don't know what that split would be between reactive and planned.

Q. Is it in the neighborhood of a 50/50? Do you know if one is significantly larger than the other?

A. I would judge it to be at least 50 percent planned if not a little bit more. In that neighborhood. It's close.

Q. Thank you.

Now, you just mentioned the Commission ESSS rules, so you're familiar with the Commission's rules on the different reliability reporting requirements that the company has with regard to the Commission -- the different reliability standards?

A. Yes, I'm generally familiar with those.

Q. And are you familiar with the company's annual system improvement plan report that you filed with the Commission?

A. I'm not sure what that report is. I don't know for sure.

MR. SERIO: Can I approach, your Honor?

EXAMINER SEE: Yes.

MR. SERIO: I have two documents I'd like to mark for identification, the first one is a one-page document, it's a Columbus & Southern Power company interrogatory response to this case, interrogatory 211, I'd like to mark that as OCC Exhibit 106.

And the other one is a multiple-page document entitled "Annual Report of the Ohio Power Company" in docket number 12-996-EL-ESS, I'd like to mark that as OCC Exhibit 107.

(EXHIBITS MARKED FOR IDENTIFICATION.)

Q. If you'll take a moment to look at those two, Mr. Kirkpatrick.

A. Okay.

Q. If we can start with 106. Are you familiar with this document at all?

A. I did not prepare this document nor have I seen it in the past.

Q. Are you familiar with the FERC chart of accounts?

A. I am, yes.

Q. In fact, that's the chart of accounts you mentioned previously when you talked about distribution assets that you need.

A. That's correct.

Q. Okay. And then Exhibit 107, that's the annual report. Are you familiar with this document?

A. I have not prepared this document nor have I seen this document in the past.

Q. Is this prepared by someone that works under you, if you know?
A. I don't know. I don't believe so.
Q. Do you know who would be involved in preparing this report and who they might report to?
A. Offhand, I don't. I would expect it to be somebody in utility plant accounting, but I don't know.
Q. If you look at OCC Exhibit 107, you look at the second page of the document and, after that, under the "Account\SubAccount," it mentions the FERC accounts there, are those FERC accounts that you're familiar with?
A. I'm sorry, Exhibit one-oh --
Q. Exhibit 107, the multiple-page document.
A. Which page are you referring to?
Q. If you look at the second, third, and fourth pages, in the first column it lists account and subaccounts and then it lists some FERC account numbers there. Are you familiar with those FERC accounts?
A. Just generally speaking.
Q. Are those the same type of FERC accounts that you're familiar with that are listed on Exhibit 106, the one-page document that I gave you?

A. The one on OCC Exhibit 106 lists the FERC accounts 360 through 374. Those are capital accounts.

FERC account 107, I'm not an accountant, I don't know exactly what that is.

FERC accounts 580 through 589 shown on the third page of your handout which is listed as page 54, I believe those to be O&M accounts. Likewise FERC account, again, 107 and 580, 589.

Q. Now, if you look at the second page of OCC Exhibit 107, I believe in the very first line after where it says "Electric Service and Safety Standards," it says "8.a." and then it lists the section of the administrative code. Do you see that?

A. That long legal term there, yes, 4901.

Q. Yeah.

A. Colon 1, dash, yes, sir.

Q. After that, it's "Distribution Capital Expenditures - Reliability Specific," correct?

A. Yes, sir.

Q. And, in fact, if you look at the next three pages of this document, that heading is on all four of the pages, correct? That this is reliability specific.

A. Yes.

Q. These accounts.

A. Yes, sir.

Q. Now, to the extent that the FERC accounts you list in OCC Exhibit 106 would be the accounts that would be used in the DIR program, to the best of your knowledge would those appear in a report similar to the annual report that Ohio Power Company would -- that Ohio Power Company actually filed with the PUCO in Exhibit 107?

MR. SATTERWHITE: Objection, your Honor. I think the witness has testified he's not familiar with either one of these documents. The questions so far have really just been what's on the face of it so the witness could read what was there and some general questions about FERC account numbers. Now he's asking him how this would be applied on his documents when he stated these look like accounting documents that aren't his at all.

MR. SERIO: Let me rephrase the question, your Honor.

Q. Are you aware of any kind of a report that the company would make to the Commission that would show a breakdown of the different FERC accounts that are listed on OCC Exhibit No. 106?

A. I'm not familiar with all the reports that are provided to the Commission, so I don't know, sir.

Q. Do you know if the company has any plan to make sure that it would file something with the Commission to give them a breakdown of the different accounts that are listed under the DIR program?

A. I don't know that it's been determined what the reporting requirements will be for the DIR program. I do know that we, when we write work orders, et cetera, that we know which of these FERC accounts are being operated on for sure.

Q. Would you have any objection to filing a report similar to the annual report in OCC Exhibit No. 107 documenting the different FERC accounts listed on OCC Exhibit 106?

MR. SATTERWHITE: I'll object again, your Honor. The witness hasn't seen the report before, doesn't know what the report is, so a question that asks if they're willing to file something consistent with that, he's already established he doesn't know what the document is, it's inappropriate.

EXAMINER SEE: You wanted to respond, Mr. Serio?

MR. SERIO: If you'd like, your Honor.

The witness indicated he understands what the different FERC accounts are that are listed on Exhibit 106. Whether he's familiar with the report in 107 or not, I'm asking if he would be willing to agree that the company would file a similar type report for those FERC accounts for the DIR program that the company's asking for in this case that involves hundreds of millions of dollars. I think it's a valid question for the person in charge of reliability and reliability reported to the PUCO.

MR. SATTERWHITE: If I may, your Honor, he's given him four pages of a 186-page report. It could have a lot of other connotations of what this report is. If he wants to ask a general question about reporting, I think that's appropriate, but to ask him to accept a report he's already identified he's not familiar with is the objection I have.

EXAMINER SEE: The objection is sustained.

Q. (By Mr. Serio) As part of the DIR program that you've proposed, did you plan to do any kind of reporting to the PUCO for the different spending that you're going to do?

A. Yes. We understand that along with the DIR will come a requirement for an annual prudency review, if you will, that will be conducted, I believe, in the third quarter when the third quarter FERC accounts are published. The Commission staff in their testimony has recommended that that would be the, if you will, the annual review time period. We do not take any exception to that recommendation.

Q. Are you planning on doing that reporting by breaking down the different amounts in the DIR by the different FERC accounts?

A. Our plan was to work in concert with the Commission to determine what they believe they need to see to determine their prudency review. At such point we come to that agreement, whether it be on a project basis or FERC-account basis, we'll act accordingly.

Q. You indicated previously that you thought your capital budget for 2011 was approximately 153 million. Do you know if that budget has varied significantly over the last few years?

A. It's slightly higher than last year. I think it's lower than in some previous years. I've only been in this position for a little less than two years, a year and a half, so it's hard for me to look back on the history and -- though I do believe there were higher capital spend years in prior years, however.

Q. On page 15 of your testimony you talk about proactive replacement, and I think you've mentioned that term a couple other times. Would you define for me what you mean by "proactive replacement"?

A. Perhaps it's best to define first what it's not. We do a significant amount of capital expenditure on reactive replacement where a piece of equipment fails in service and the replacement cost, if it's a capital item, is a capital charge.

We do a little bit of, currently a little bit of proactive replacement, if you will, looking at some performance metrics on different asset classes, and based upon those performance metrics, particularly on a -- in a targeted area, do some replacement strategy.

So what I'm referring to in the testimony is really to continue to expand the analytics around some of these asset classes and look for a little bit more detailed breakdown of the predictors of performance and predictors of future failure and then take a program that's targeted towards that and, if you will, the difference between shooting with a shotgun and a rifle is more precise, and working to identify those specific assets that have the highest likelihood of failure based upon their performance history either as a group or individually.

Q. Proactive replacement involves you replacing it before it fails, correct?

A. That's correct.

Q. Does the company do proactive replacement today?

A. To the extent that we replace in-service operating equipment with new equipment, yes. An example of that, once again, is cable replacement in our underground residential distribution segment, also called "URD."

As I mentioned, we respond to, for instance, subdivisions that have a high number of failures within the subdivision and make the decision that the cable is at its end of life. So we'll replace the entire cable system in that subdivision.

One could argue whether that's proactive or reactive. It's certainly reactive to the fact that there were a number of failures leading up to that. It's proactive in the sense that you're replacing assets that are actually in service and operating at the time they're replaced. So it's a combination of both.

Q. To the extent that you're talking about doing more proactive replacement going forward, you're talking about doing more of the replacement where you'd actually replace equipment that is functional at the time but equipment that you deem to be nearing the end of its life or it may not be as reliable, correct?

A. There's a combination of factors there. As I mentioned, yes, we're doing that today with the cable example I just gave. But that's really using lagging indicators, if you will, of utility performance, and what we intend to do is use leading indicators and those are indicators on using the history of how the asset performed, a little bit of history of a similar asset across a broader industry group.

We would also look at those pieces of equipment that have been shown to perhaps be, create problems that couldn't be certified as that being part of the problem but we strongly suspect it might be.

In addition we have asset classes that, after some period of time, the maintenance costs of those classes would show a steep increase in maintenance costs or needs from a calibration standpoint and we target those types of assets as well.

So it's a combination of factors, but your premise that we would replace a piece of equipment before it actually fails, fails violently in a way that could cause significant -- or, cause harm to the public or certainly an outage, it would be our target, yes.

Q. Now, in your current capital spending plans, do you currently allocate dollars to replace unreliable and obsolete equipment?

A. To a very small extent. Again, the biggest area that we do that in is in underground cable where the lagging indicators are very strong in that regard and we are responding to a combination of factors, not just the cable failure itself, but honestly the feedback from the customers that are served by those customers.

So to that extent that is -- there is a little bit of dollars in our budget targeting that. We do, and have on occasion in the last year, spent a little bit of the money on some proactive substation breaker replacements where we knew we had some vintage of breakers that were problematic for us.

Q. Now, you indicated previously that maintenance reports that go to the Commission fall under your responsibility, correct?

A. Yes, sir.

MR. SERIO: Can I approach, your Honor?

EXAMINER SEE: Yes.

MR. SERIO: I have a multiple-page document I'd like to mark for purposes of identification as OCC Exhibit 108. It has a cover letter dated October 27th, 2010, from American Electric Power Company to director John Williams at the PUCO in Case No. 10-2385-EL-ESS.

(EXHIBIT MARKED FOR IDENTIFICATION.)

Q. Are you familiar with this, Mr. Kirkpatrick?

A. I would say I've seen this a long time ago. I don't recall the detailed content of it.

Q. But this is one of the reports that falls under your responsibilities, correct?

A. Yes. This is a report that would have had input from my team.

Q. Now, I'd like you to turn to Attachment G in the report, unfortunately the pages are not numbered, it's about two-thirds of the way back in the document.

A. I'm there.

Q. And if you go to the second page after

Attachment G, there's a heading that says "Substations: Circuit Breakers and Reclosers."

A. I see that.

Q. If you go to the bottom of the page under "Outcome and Incorporation," it indicates there that the AEP company's capital plans include "...funding for replacing equipment that has become unreliable or obsolete." Do you see that?

MR. SATTERWHITE: I'm sorry, Joe, I'm not sure I'm in the same place. Attachment G on top says "Substation: Station Inspections," right?

MR. SERIO: The second page after that.

MR. SATTERWHITE: So on the top it says "Maintenance Activities."

THE WITNESS: No, the next page.

MR. SATTERWHITE: Okay. Didn't go enough pages. Thanks.

Q. (By Mr. Serio) The sentence I read talks about replacing equipment that's become unreliable or obsolete. Would you agree with me that that's what you -- is that what you mean by "proactive replacement"?

A. No; I'd suggest that that's reactive replacement. The implication in reading that would suggest that upon an inspection process, when it's determined that the equipment should be replaced, it's replaced.

To me -- and I haven't read the whole document, but based upon what I see is that's reactive to an inspection and analysis. So I would consider that more reactive.

Q. The next sentence there says "This may have been" and then the carryover to the next page "caused by but not limited to deteriorating components, lack of available parts from vendors, and equipment problems causing repeated customer outages." Now, would that still be in your mind reactive or do you consider that proactive?

A. That's reactive. But that might be one of the inputs that you use to develop a proactive program.

To give you an example of that, a station servicer or a mechanic visits a substation due to an annual maintenance check on a breaker, finds that there's some parts that are worn that the breaker would not -- would perhaps not operate properly when called upon to operate.

So the capital dollars, and what this is referring to, I believe, is that they couldn't get parts for it and components are bad and we suspect this particular piece of equipment would lead to customer outages. There is a fund that we would fund a capital project to replace that.

I would then take that information about that particular breaker and then look at that vintage of breaker, that manufacturer, that model number of breaker, look to determine how many of those we had on the system, look at past inspection and maintenance records and determine whether or not there's a trend of this particular breaker exhibiting the same exact problems, and then that would be one of the sets of inputs that you'd have into does it make sense to have a more proactive approach to this, rather than waiting to find, on inspection, a breaker that might not operate when called upon.

Q. On page 16 of your testimony you talk about an example of an asset that provides -- that would provide benefits to customers if it was included in the DIR. Is that what you mean by one of the examples of doing the proactive approach rather than reactive?

A. Yes. As I described just a moment ago, that approach of looking at an asset at that granular level would be one of the proactive means of identifying a broader group of assets that might make sense to replace given what's found in the history of inspections and maintenance on those types of items.

Q. And in your testimony the one example that you give is the distribution substation circuit breakers, correct?

A. That is one example, yes.

Q. Did you give other examples in your testimony? Or was that the only one?

A. As I read that it looks like that's the only one.

Q. Okay. I just wanted to make sure I didn't miss something.

Now, you indicate there that there's almost 400 distribution circuit breakers that are over 40 years old. Do you know how much an individual circuit breaker costs?

A. No, I couldn't put a single number on it. There's a lot of variables on what a circuit breaker would cost. It depends upon, you know, where that circuit breaker is, the fault that it's expected to interrupt for, whether or not there's a control house present or not, whether it's a self-contained unit. So it's a variable -- the costs could be, in fact, pretty wide.

Q. So the example of you give of 400 over 40 years old, you couldn't tell me how expensive it would be to replace all 400 of those?

A. Not today, I couldn't.

Q. Now, the example that you give here, the substation circuit breakers, that would be an example of one of the items that you would proactively go out and replace before you had any kind of failures, correct?

A. Yes. As I mentioned.

Q. Now, you mentioned here the 400 that are over 40 years old. Are you saying that those would be targeted for proactive replacement under the DIR?

A. No. I don't mean to imply that all 400 of those would be targeted. I'm giving an example that we have an aging asset group out there of a pretty large number of critical components in our distribution system. Just because something's old, thank goodness, doesn't mean it's bad.

We would evaluate the products by vintage, by manufacturer, by experience, and make a determination on, again, as a longer example I previously supplied to you, making a determination whether that asset class justifies, for that asset type specifically, justifies a more aggressive approach.

There are breakers that are 40 years old that are operating very, very well, and I would not -- age alone is not a criteria for replacement. I would never look at that at all.

Q. Now, your example of the substation circuit breakers being one of the items where you would get a customer benefit from proactive replacement, have you done any kind of quantification of how much improved service reliability would result from that proactive replacement of substation circuit breakers?

A. No, we haven't, because we haven't obviously detailed the breakers that would be replaced. You have to look at -- that's the thing with the distribution business, as you target assets to replace the individual assets themselves, you make an assessment on the impact that that replacement of that asset would have.

Once you get your subset of devices that you believe, based upon your analysis, are appropriate for consideration of proactive replacement, you look at the history of those assets, you look at the likelihood, and this is where a little bit of engineering assessment and judgment comes into play, is what is the likely future failure of those assets based upon what we've seen in the past.

And using that likely forward-looking failure assessment in conjunction with its past history, you make a determination for that asset type or these, say, hundred breakers that we've targeted now, this is what we believe will be the impact to reliability going forward.

Q. Has the company done any kind of cost-benefit analysis using your one example on the substation circuit breakers as to the cost under the DIR program versus the benefit that customers would get from improving reliability?

A. Not specifically. The cost-benefit analysis is a challenging analysis to do. You have to, first and foremost, put a value on what you believe a minute of SAIDI or a minute of CAIDI or two-tenths of a movement in of SAIFI is to a customer and that's a challenging situation.

So having a, you know, if a minute of CAIDI is worth a million dollars, then I can use that as kind of a placeholder, if you will, for value proposition. I think you've got to look at, there's a number of value drivers that can't be monetized as well.

You have to consider the customer experience in this, the customers who are having outages avoided for them, you have to look at your commercial customers who value a continuous supply of electricity that we provide for the viability of their businesses, industrial customers.

So there's a lot of social benefits to be gained on top of the reliability improvement to customers. It's a complex set of equations. You know, the reliability standards that we have that we work collaboratively with the Commission and others to establish are essentially the proxy for, we believe, the proxy for that cost-benefit analysis.

Q. So you'd agree with me that there is some trade off of dollars for reliability, correct?

A. I'm not sure what you mean by "trade off," if you could explain that.

Q. When you do any kind of analysis you're comparing the dollars you would spend to improve reliability to determine if the improved reliability is worth the amount of dollars that would be spent, correct?

A. I think that's a fair assessment, yes.

Q. And when you make that assessment, you have to determine, or do you determine that there is a point where spending for some reliability may not be worth the cost?

A. Well, certainly if I had an infinite budget, I would spend infinitely to improve reliability, but we don't have an infinite budget.

So in our budget planning process and project planning, when we put together a project plan, you look at the various options for projects you have, and if I spend a million dollars on an improvement project that yields a reduction in a dozen one-hour outages to customers, and I spend a million dollars, that yields a reduction of only five one-hour outages, I'm going to pick the one that provided more to the customer.

So we do that type of analysis and evaluation dynamically when we put together our business plans.

Q. And does what customers expect from the company as far as cost and reliability get factored into that equation?

A. Absolutely. I think you can't, you know, you have to understand that it's a balancing act between spending a significant amount of dollars to fix a very small problem versus spending that same fund -- spending that same amount somewhere elsewhere, you get more benefit to the broader customer base.

There are times when we do spend money in improving reliability to a smaller subset of customers just because reliability has become intolerable and we understand that, but, by and large, we're making investments in our infrastructure to support, if you will, the greater bang for the buck for reliability improvement.

Q. If you'd look at page 19 of your testimony, lines 18 to 20.

A. Yes.

Q. You indicate that 19 percent of residential customers, 20 percent of commercial customers believe future reliability expectations will increase over the next five years. Do you see that?

A. Yes, sir.

Q. So that means that 81 percent of residential customers and 80 percent of commercial customers do not believe or have expectations that future reliability will increase over the next five years, correct?

A. That is correct. However, you have to look at the 71 percent and 73 percent of the commercial and -- residential and commercial customers who expect reliability to remain the same. And our program that we're talking about here is addressing not just those 19 and 20 percent as you mentioned, but it's really making sure that the 71 percent and 73 percent do not see degradation in reliability.

Q. Can you break down the DIR program between the level of costs that are going to go to maintaining the system that the majority of the customers expect in reliability versus the percentage that's going to go towards improving the system that a minority of customers expect?

A. I don't believe you can do that. I don't see how.

Q. So you're saying you can't break down the DIR program and say 80 percent of the program's aimed at maintenance, maintaining the current level of reliability, and 20 percent is aimed at improving reliability.

A. Let me answer that this way: Each of our reliability investments is intended to improve the reliability of those customers served and the assets that are being replaced or invested in. So we expect for any individual investment that there will be a reliability improvement for those customers.

When taken, then, collectively as a whole, all 1.5 million customers of AEP Ohio, then you're blending, if you will, the reliability performance of the existing system that has had no investment in it in that current year with parts or very small parts of the system that actually have an investment made.

So that's where, you know, translating the impact to those customers that you had initially identified and proactively worked at improving their reliability, blended with the rest of the assets that are actually in place, you get either a holdings or an improving of reliability.

So, again, maybe to be clearer, every investment we make is intended to improve reliability. But we don't invest in every asset in the system every year so, therefore, other assets are either going to improve or degrade and at some point in time you've got to balance.

Q. Right. But over the course of a period of time, certain investments are made in order to maintain a level of reliability versus the level of investment that's aimed at improving the overall reliability, correct?

A. I don't believe that's correct. I don't make an investment saying this will keep the status quo. I make an investment saying this will improve reliability of those customers served by this asset. So I believe every investment we make is intended at improving the reliability of the customers served at that asset. It's very discrete.

Q. Previously we talked about the smart grid and I believe you indicated there was a different proceeding where the smart grid was going to be addressed. Do you recall that?

A. What I recall stating is that it's our intention to -- now, the vast majority of the components of the smart grid are now in place as part of the demonstration project to evaluate the performance of the system for the next two years, nearly two years, and, at the end of the demonstration project, formulate a plan, value-based plan, working in concert with staff to determine where we go next with gridSMART.

Q. There is a different reliability case coming up next month, is that where you would intend to address the smart grid issues?

A. What I referred to is, yes, a reliability case filing that we need to make on what our new standards of reliability are going to be going forward, and we are committed to taking the very early results and recognize it's very limited at this point, but feel confident enough in those early results that we can take some of them into account in setting those standards in the next proceeding, yes.

Q. Would that proceeding be the proceeding where customer specifications would be addressed?

A. Relative to the gridSMART investment or relative to the going-forward position of the company and the standard that we're going to set, I would say is part of that as well, as it is in this case.

MR. SERIO: That's all I have, your Honor.

Thank you, Mr. Kirkpatrick.

THE WITNESS: Thank you.

EXAMINER SEE: Mr. Pritchard? Mr. Darr?

MR. DARR: No questions, your Honor.

EXAMINER SEE: Mr. Sineneng?

MR. SINENENG: No questions, your Honor.

EXAMINER SEE: Thank you.

Ms. Kyler?

MS. KYLER: No questions.

EXAMINER SEE: Mr. Siwo?

MR. SIWO: No questions, your Honor.

EXAMINER SEE: Mr. Sugarman?

MR. SUGARMAN: Yes. Thank you, your Honor.

- - -

CROSS-EXAMINATION

By Mr. Sugarman:

Q. Good morning, Mr. Kirkpatrick.

A. Good morning.

Q. Is it accurate to say that even were the DIR not approved in this proceeding that AEP would continue to make capital expenditures on an annual basis to maintain system reliability?

A. It's accurate to say we'll invest capital in our distribution system going forward.

Q. You'll have an annual budget for capital expenditures and you'll continue to have an annual budget for O&M expenses as well?

A. Yes, sir, or else we don't come to work in the morning.

Q. I'm sorry, I missed the last part.

A. Yes, or else we don't come to work in the morning.

Q. Okay. I don't think we'll change that in this proceeding, sir.

Are you familiar with Mr. Allen's

testimony that was filed in this case on the DIR?

A. I have some familiarity with it.

Q. Have you read it?

A. I have read the portion that applies to my testimony.

Q. Right. And you're aware, then, that Mr. Allen talks about the DIR as allowing recovery of carrying costs on incremental distribution plant. Are you aware of that statement, sir?

A. Not having his testimony directly in front of me, I'm generally aware of that, yes.

Q. For your counsel's reference, and the Bench, I was reading from page 9 at line 16 where he was asked to explain the DIR and he says, "It will allow recovery of carrying costs on incremental distribution plant." Do you understand what is meant by "incremental distribution plant"?

A. I believe the intent is to recover carrying costs on capital spend within the FERC chart of accounts that we talked about just recently with the OCC attorney.

Q. And I understand that the chart of accounts relates to that particular distribution plant. What is meant by incremental distribution plant over and above what appears on the FERC chart of accounts, if anything? "Incremental" suggests additional, over and above some floor to me. I'm asking what it means, if anything, to you in the context of this DIR.

A. To me, my understanding of the DIR and recovery is that it will recover all capital costs in the FERC chart of accounts from 360 to 374 that we expend on the distribution system.

Q. And "carrying costs" mean to you what, sir?

A. I'm an engineer, I'm not an accountant. I'd have to defer to my accounting friends and Mr. Allen on that, if you would, please.

Q. Fair enough.

Did you or someone on your team or under your direction prepare a study, analysis, or other type of report that supports the type of specific investments that will be made if the DIR is approved?

A. Not specifically by way of a detailed plan. We have, as I previously mentioned, we have an annual work plan that has elements of all these investments already included in that.

What we're asking for and what we're demonstrating in this proceeding is that we believe the current level of funding is not going to be sufficient to maintain the level of reliability that is needed and required by our customers.

And the basic premise of that is, that as a status quo condition here, with the current level of spend, that the failure rates of equipment, as they age, will increase, and reliability will degrade on a large-scale view.

Q. When was the current level of spend established, sir?

A. We have a distribution capital budget that's developed and derived in part with our input and in part with the corporation's view with the available capital for us. It varies a little bit year in/year out depending on any larger projects that come due, any special projects that pop up, but, by and large, we've been in the 140 to 150 range for a few years now.

Q. Isn't it true that there was a recently-concluded distribution case that resulted in a revenue increase and a new distribution asset recovery rider for the company?

A. Yes, I believe there's a settlement in that case. Yes.

Q. That resulted in a new distribution asset recovery rider, correct?

A. I believe so. I'm just not terribly familiar with all the details of that case.

Q. Were you not personally involved in that case?

A. I was not involved -- I filed testimony, again, in support of the DIR, in support of our ESRR, the same essential things we're testifying to here. As far as the DAR and other elements, it was not part of my testimony and I was not the supporting witness on that.

Q. Are you aware, sir, that the new rider became effective at the beginning of 2012?

A. I believe that to be the case.

Q. And are you aware also that the rider that was approved was done so to collect the costs of distribution system improvements and expenses?

A. I'm generally aware that the rider was to recover the cost of deferred assets on the books. Exactly what all those deferred assets are, I can't speak to that.

Q. That would be Mr. Allen or someone in your accounting department.

A. I think Mr. Allen or Mr. Dias.

Q. Now, you're aware also that there is a proposed cap on the DIR through the transition

period, sir.
A. I am aware of that, yes.
Q. Are you aware of how those cap numbers were arrived at?
A. No, sir.
Q. Did you provide any input based upon your job responsibilities and experience with respect to distribution reliability and replacement, as you've testified here this morning, with respect to arriving at caps proposed for this DIR?
A. I did not.
Q. You don't know how the numbers were arrived at, then, the cap numbers for the DIR?
A. No, I don't know how those numbers were arrived at.
Q. Do you believe that anyone in your department prepared information, studies, or analyses that allowed the company to come up with the amount necessary for the specific DIR?
A. No one in my organization.
Q. You're --
A. I'm sorry. Did you say "DIR" or "DAR"? Excuse me.
Q. I'm only talking about the DIR.
A. DIR.

Q. Yes, sir.
A. I thought previously your questions were around the DAR. Okay.
Q. No. Specifically with respect to the proposed caps that you're aware of for the DIR in this proceeding, my question was whether or not you, or anyone under your direction or control, had prepared studies, analyses, or reports that underlie the proposed amount of the annual caps through the transition period in this proceeding?
A. No, sir. The only information we provided was the information in the investment that we desire to make in the distribution system, investment levels. How they arrived at the capped amounts through negotiations in settlement, I was not a party to.
Q. Well, the capped amounts are proposed in this proceeding, sir, not in the prior proceeding. I'm focusing on the caps that are proposed for the DIR before the Commission in this proceeding.
A. Myself nor my team did any work in that regard.
Q. So you're simply unaware of how those incremental -- excuse me, strike that.
You're simply unaware of how those

amounts of the proposed caps were arrived at with respect to a distribution investment rider.

A. That's correct.

Q. If I could ask you to look at your testimony, sir, on page 8.

A. Yes, sir.

Q. And with respect to Chart 2 that appears on that page, what is it that you are intending to convey with respect to the 2012, 2013, and 2014 spend that appears in your Chart 2 on page 8 of your testimony?

A. That represents both the O&M line and the capital line for 2012, 2013, and 2014, that represents the request for recovery under the ESRR.

Q. And has nothing to do with the DIR.

A. No, sir.

Q. Okay. Just making sure.

If you would, then, your testimony and some questions by Mr. Serio focused on customer surveys and customer attitudes that are mentioned on page 19 of your testimony, and do you know, Mr. Kirkpatrick, whether or not the customer surveys that are reflected in your testimony were conducted prior to the implementation of the new rate that was recovered in the prior proceeding that resulted in the stipulation that you mentioned earlier?

A. I don't know for sure when these surveys were taken.

Q. Well, you mentioned customer survey results for 2011.

A. Okay.

Q. You don't know when in 2011 those results were captured?

A. Not specifically, no.

Q. Okay. Were there questions on the customer survey that also dealt with pricing of distribution for customers in the AEP system?

A. I'm not thoroughly familiar with the survey and all its elements, so I don't know that.

MR. SUGARMAN: Your Honor, may I approach the witness, please, with some exhibits?

EXAMINER SEE: Yes.

MR. SUGARMAN: I want to mark three exhibits while I'm up here to save some time. Reserving 101 for Mr. Geiger's testimony, this first one would be NFIB-Ohio Exhibit 102. And I'd also like to mark 103 and 104. For the record, 102 has also Bates range at the top right-hand page RRG001 through RRG004. Exhibit 103, NIFB-Ohio 103 would be a two-page document, RRG016, 017.

Last one that I'm marking is 104 which is a multi-page document, RRG006 through 015.

MR. SERIO: Counsel, I have a question. There is an account number on NFIB Exhibit 103, should that be blacked out?

MR. SUGARMAN: We can deal with that in a second.

These are all prefiled with Mr. Kyger's testimony, so customers are aware of it, we can do that if it's . . .

(EXHIBITS MARKED FOR IDENTIFICATION.)

Q. (By Mr. Sugarman) Mr. Kirkpatrick, you've marked, have you not, as you've been handed the Exhibits 102, 103, and 104 that are in front of you?

A. Yes, I have.

Q. I know you're not going to recognize the names of these three distinct customers, but I wanted to ask you some questions about the bills that are attached to each of the three exhibits, sir.

First on Exhibit 102 and directing your attention to RRG002 which is the second page of the exhibit, do you see the bill dated December 19, 2011?

A. I do.

Q. And the distribution service charge on this particular bill is what, sir?

A. $5,549.25.

Q. And if you skip the next page and go to the last page of the Exhibit, RRG004, can you verify that this is the same account number for the same customer that we just discussed the distribution service charge?

A. Account number is the same.

Q. All right. And the distribution service charge that you read previously is $5,549.25 for the bill date December 19, 2011, is what for January 23, 2012?

A. Under distribution service it's 13,546.21.

Q. And can you compare the energy usage between the two months to account for the increase in the distribution service charge?

MR. SATTERWHITE: Your Honor, at this point I'll object. It's beyond the scope of this witness's testimony. We're dealing with rates from the unapproved stipulation which are no longer in effect, I believe.

MR. SUGARMAN: These are rates that this customer's paying as a result of service provided by AEP.

MR. SATTERWHITE: Either way, the

witness's testimony, and when we started here, was on reliability surveys for service, and now the -- what's being presented is asking this person to analyze bills.

MR. SUGARMAN: Could I respond?

EXAMINER SEE: You may.

MR. SUGARMAN: All right. If nothing else comes out of this proceeding, hopefully some impact of what is going on here upon business customers as examples is relevant to the Commission's determination.

And what these three bills and what this witness's testimony will go to is both what is being charged for distribution currently, what is the result of the recently enacted and passed and passed-along rate tariff that is currently in existence.

And now, beyond that, what this witness's testimony also goes to is the DIR which is a request for yet again get incremental funding relating to distribution services that are being passed along ultimately to customers.

So what the company is asking impacts customers in the state, I think, is incredibly relevant and important to this proceeding and to the

Commission's determination of whether or not this aspect of the modified ESP is justified, appropriate, and, if so, what impact it will have on consumers in this state.

MR. SATTERWHITE: We agree Mr. Roush has been made available and is a witness who discusses impacts, bill impacts. As my original objection was, it's beyond the scope of this witness's testimony.

EXAMINER SEE: And the objection is sustained as to this witness. The objection is sustained as to this witness.

MR. SUGARMAN: Okay. And that would be the same as to Exhibits 103 and 104, since the line of questions would be similar, your Honor?

EXAMINER SEE: Yes.

MR. SUGARMAN: In that case I will pass the witness.

EXAMINER SEE: Ms. Thompson?

MS. THOMPSON: No questions, your Honor. Thank you.

EXAMINER SEE: Mr. Barnowski or Ms. Hand?

MR. BARNOWSKI: No questions, your Honor, but I want to clarify one thing while I pass the mic. Based on the ruling from the Bench, the questions that we would have as to rate impact are going to be addressed by Mr. Roush and so I should save those questions for Mr. Roush; is that -- on the average customer? I think I heard Mr. Satterwhite say that, but I don't want to put myself in a position when I say no questions and pass the mic, and Mr. Roush takes the stand and I ask him about customer impacts on rates and I draw a similar objection.

EXAMINER SEE: If you noticed, we were talking about the distribution service in relation to a particular customer bill. There was an objection raised by Mr. Satterwhite in regards to this witness and that objection was sustained.

MR. BARNOWSKI: Okay. Thank you, your Honor. No questions.

EXAMINER SEE: Ms. Kaleps-Clark?

MS. KALEPS-CLARK: No questions, your Honor. Thank you.

EXAMINER SEE: Mr. O'Brien?

MR. O'BRIEN: No questions, your Honor. Thank you.

EXAMINER SEE: Mr. Margard?

MR. MARGARD: No questions, your Honor.

EXAMINER SEE: Is there any other counsel in the room that -- Mr. Cox is not here?

Mr. Stinson?

MR. STINSON: No, your Honor.

EXAMINER SEE: Mr. Cox?

Let the record reflect Mr. Cox is no longer in the room.

Mr. Satterwhite?

MR. SATTERWHITE: Could I have five minutes, your Honor?

EXAMINER SEE: Yes.

MR. SATTERWHITE: Thank you.

(Recess taken.)

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

Mr. Satterwhite?

MR. SATTERWHITE: Just one housekeeping matter, your Honor.

\- - -

REDIRECT EXAMINATION

By Mr. Satterwhite:

Q. Mr. Kirkpatrick, you remember some questions from Mr. Serio relating to page 10 of your testimony where there was confusion about whether some words on line 12 belong in your testimony or not?

A. Yes, sir, I remember that.

Q. And on the break did you get a chance to reread that sentence to determine whether that is a change to your testimony or not a change to your testimony?

A. Yes, I reread that sentence, and when I first looked at it under questioning from Mr. Serio, it looks like the words "justify the expense" were kind of hanging out there on their own.

When I reread that and looked at the whole sentence from the very beginning, it's pretty clear to me that the intent there is additional gridSMART deployment where benefits to the customers justify the expense will be considered. So that prepositional phrase in the middle of that kind of threw me off.

But, yeah, the intent around -- I think I mentioned it in another question that I answered -- is we intend to look at the results following the demonstration project and look at the benefits to customers and determine whether or not there's -- further deployment of gridSMART is justifiable given the expense and benefits.

Q. So you're not seeking to change your testimony; you're leaving those three words in?

A. Yes, those three words do belong in there in retrospect.

MR. SATTERWHITE: Thank you. That's all I have, your Honor.

EXAMINER SEE: Recross? Mr. Serio?

MR. SERIO: Yes, your Honor. Thank you.

- - -

RECROSS-EXAMINATION

By Mr. Serio:

Q. Mr. Kirkpatrick, the three words "justify the expense," it's your testimony that the company needs to justify the expense in order to move forward, not that the spending justifies the expense.

A. Correct. It's my testimony that at the end of the gridSMART demonstration project that we'll look at the benefits to the customers and the expense and determine whether or not the benefit that the customers received for the expense incurred justified moving forward with additional deployment.

MR. SERIO: Okay. Thank you.

That's all, your Honor.

EXAMINER SEE: Mr. Lang?

MR. LANG: No questions. Thank you, your Honor.

EXAMINER SEE: Mr. Darr?

MR. DARR: No, thank you.

EXAMINER SEE: Mr. Sineneng?

MR. SINENENG: No. Thank you.

EXAMINER SEE: Ms. Kyler?

MS. KYLER: No questions.

EXAMINER SEE: Mr. Siwo?

MR. SIWO: No questions, your Honor.

EXAMINER SEE: Mr. Sugarman?

MR. SUGARMAN: No questions.

EXAMINER SEE: Ms. Thompson?

MS. THOMPSON: No questions.

EXAMINER SEE: Mr. Barnowski?

MR. BARNOWSKI: No questions.

EXAMINER SEE: Ms. Kaleps-Clark?

MS. KALEPS-CLARK: No questions, your Honor.

EXAMINER SEE: Mr. O'Brien?

MR. O'BRIEN: No questions, your Honor.

EXAMINER SEE: Mr. Margard?

MR. MARGARD: No questions, your Honor.

EXAMINER SEE: Mr. Stinson?

MR. STINSON: No questions, your Honor.

EXAMINER SEE: Commissioner Porter?

\- - -

EXAMINATION

By Commissioner Porter:

Q. Just quickly, I just had a couple

questions about the future expectations of the gridSMART program for the systemwide deployment of smart meters, and you just discussed the data that's going to be collected and how you're going to use that data.

Can you just describe for me the company's plans and expectations for overall customer benefit? If you were looking at this on an aggregate basis, what would the gridSMART program -- I'm sorry, what would need to be demonstrated so that the company would suggest or apply to the Commission that there be a system-wide deployment of smart meters? What types of benefits would we need to see?

A. I believe there's a number of different benefits that you'd look for out of the program. Number one is on the operational side, which I'm most directly involved in, would be an improvement in reliability, an improvement in our ability to respond to customer outages, about having more discrete information about individual customers who are out of service, by taking the detailed information from taking these two-way AMI meters and putting it -- include it into our decision-making processes from the operations standpoint. That's one side of it.

The other is on the customer side, how

are we able to influence customer behaviors and move them to use energy more wisely. How are we able to enable the customers to lower their energy use on a day-to-day basis and throughout their billing periods.

How are we able to deploy technology that, in a passive way, can wield benefits to the customers such as the IVVC which, you know, yields benefits to the customers in reduced energy usage and reduced demand without the customers actually taking an active role in doing that.

So those are the broader elements from a higher level that you'd expect to see that -- you have to look at the customer benefit from a societal means as well in reducing their carbon footprint and being able to reduce their energy use and their demand on the system.

Q. So I think I heard that correctly, there are reliability benefits, there are also, then, customer engagement and response types of benefits, and then the last one that was there was a societal type of benefit. Are any of those more important than the other, or are any of those weighted more heavily than the other in the analysis of the overall benefit of metering rollout?

A. As an operations person, I tend to lean a lot toward the operations side of the business, and our customer service team, I think, has a better handle on the customer side, customer benefit side.

I don't think that any work's been done, and I've not been directly involved in the gridSMART program. A couple other principals in our company have been, Karen Sloneker and others, to -- but I don't believe any work's been done to say this is worth 10 percent, that's worth 15 percent, this is worth 20 percent; I think that's a collaborative approach.

We do agree with staff and the Commission that we need to work together with them and other interested parties in determining what -- really what is the best mix in prioritizing the value that you get. There's a lot of different value chains that accrue, you have to look at that mix of value chain and what you're willing to spend or incur costs on that are shared amongst all of our customers to improve on. It's a challenge.

Q. There are 24 months, I think in the testimony, 24 months that are required of data collection and that's connected with the Department of Energy's funding of components of this gridSMART --

A. That's my understanding.

Q. -- program.

Is it possible in your thoughts -- on the operational side, is it possible in your thoughts that, you know, reliability benefits from these meters, that the reliability benefits would be understood more expeditiously than 24 months?

A. I qualify it and say yes, I think one has to look at a number of elements to determine whether or not it's a good -- that you can make that decision sooner than later. Certainly you have to go through all four seasons with all your circuits in play, for instance, from the distribution automation standpoint.

But you also have to look at the conditions those four seasons provide and you may enter into a year, and this year might be the beginning of an example of a year where the storm levels, the wind levels, those type of things aren't like they were last year, for instance.

And we have provided data to the Commission staff on the differences in last year and this year relative -- or last year and the year before relative to how severe the weather was.

So I think you've got to be careful in using a small timeframe to judge how -- the breadth of success that you'll have. Clearly in just a short time that we've had with some of our distribution automation in place, for instance, we've seen some benefits and I testified, I don't know if you were in the room at the time, that which would intend to roll some of those into this summer's standard setting process for reliability since we have some -- a little information that's available to us.

I think waiting two years is prudent in the sense that it gives you the ability to go through two seasons, two years of the same seasons, it gives you a broader -- a broader set of history to make better judgments from.

You have to be careful not to -- you know, sometimes engineers tend to be analysis by paralysis and we don't want to do that either. So we have to, at some point in time, put a stake in the ground and say this is what we believe.

We've seen encouraging results from other types of the program, the IVVC has been very encouraging as I think has been discussed with the Commission in past briefings as well.

COMMISSIONER PORTER: Thank you.

That's all I have, your Honors.

EXAMINER SEE: Thank you, Mr. Kirkpatrick.

THE WITNESS: Thank you.

MR. SATTERWHITE: Thank you, your Honor. At this point I'd like to re-move AEP Exhibit 110, direct testimony of Thomas Kirkpatrick.

EXAMINER SEE: Are there any objections to the admission of AEP 110?

Hearing none, AEP Exhibit 110 is admitted into the record.

(EXHIBIT ADMITTED INTO EVIDENCE.)

EXAMINER SEE: Mr. Serio?

MR. SERIO: I'd like to move OCC Exhibits 106, 107, and 108 into the record, your Honor.

EXAMINER SEE: Are there any objections to OCC Exhibits 106, 107, or 108?

MR. SATTERWHITE: Your Honor, the company has no objection to 108, but would object to 106 and 107. I believe the witness stated, on the stand, he wasn't familiar with these, he hadn't seen them before. There were some questions asked just as what was on the face of the document, but he said he's not an accountant, it looks like an accounting document. The only questions that were asked really referred to overall FERC accounts and general knowledge, not the document.

And Exhibit 106 wasn't even sponsored by this witness; it was sponsored by a witness from a previous version of the many versions of this case. It wasn't part of the modified ESP as a discovery response.

EXAMINER SEE: Mr. Serio?

MR. SERIO: Thank you, your Honor. OCC Exhibit 106 talks about the potential distribution assets that Mr. Kirkpatrick is familiar with. He was familiar with the fact that those are FERC accounts and that those specific FERC accounts are for facilities that fall under his purview, and that would fall under the DIR that he was sponsoring.

OCC Exhibit No. 107 is a report to the Commission that falls under his purview. He may not be familiar with it, but it's an annual report that the company makes and, more important to that, it's a publicly-filed document in a different docket with the PUCO and it should be able to stand on its own.

EXAMINER SEE: Any comments as to 108, Mr. Serio?

MR. SERIO: I think the company said they would accept 108.

MR. SATTERWHITE: Yeah, no objection on that.

EXAMINER SEE: OCC Exhibits 106, 107, and 108 are admitted into the record.

MR. SERIO: Thank you, your Honor.

(EXHIBITS ADMITTED INTO EVIDENCE.)

EXAMINER SEE: Mr. Sugarman?

MR. SUGARMAN: Given the Bench's ruling, I'll wait to offer the exhibits at a later time.

EXAMINER SEE: Okay. Mr. Satterwhite, your next witness.

MR. SATTERWHITE: Thank you, your Honor. The company would call David M. Roush to the stand.

EXAMINER SEE: Mr. Roush, would you raise your right hand?

(Witness sworn.)

EXAMINER SEE: Thank you. Have a seat.

MR. SATTERWHITE: Thank you, your Honor.

\- - -

DAVID M. ROUSH

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

DIRECT EXAMINATION

By Mr. Satterwhite:

Q. Mr. Roush, could you please state your name, title, and business address for the record?

A. My name is David M. Roush. My business address is 1 Riverside Plaza, Columbus, Ohio, 43215. I am Director of Regulated Pricing and Analysis.

Q. Mr. Roush, did you cause testimony to be filed in this case under your name on March 30th and then supplemental testimony on May 2nd?

A. Yes, I did.

MR. SATTERWHITE: Your Honor, at this point I'd like to mark Mr. Roush's testimony from March 31st that was prefiled as AEP Exhibit No. 111, and then Mr. Roush's supplemental Commission-ordered testimony from May 2nd as AEP Exhibit 112.

May I approach?

EXAMINER SEE: Yes.

(EXHIBITS MARKED FOR IDENTIFICATION.)

Q. Mr. Roush, can you please identify AEP Exhibit 111 that I just placed in front of you?

A. It is my direct testimony and exhibits filed in this proceeding on March 30th.

Q. Was that prepared by you or under your direction?

A. Yes, it was.

Q. Do you have any changes or corrections to that testimony today?

A. Yes, I do.

Q. Can you tell us where, please?

A. Exhibit DMR-5, page 13 and 14 of 238. On those pages at the bottom of page 13 and top of page 14 there are redline deletions and redline insertions; neither of those should have -- the redline deletions should not have been deleted and the redline insertions should not have been inserted.

So what's shown as deleted should be reinstated and the inserted language should be removed.

Q. That's at the bottom of page 13 over to the top of 14, essentially undo the track changes function?

A. Yes, that's correct.

Q. Are there any other changes?

MR. SERIO: Your Honor, before we go further, I'm having trouble finding -- DMR-5, you said?

THE WITNESS: Yes, sir.

EXAMINER SEE: Which is attached to your direct testimony?

THE WITNESS: Yes, ma'am.

MR. SATTERWHITE: It's the bigger exhibit.

THE WITNESS: If you have a spiral-bound version, it might be in a separate book.

MR. SATTERWHITE: Here's a copy with the page tabbed, the changes.

Do you want me to wait?

EXAMINER SEE: Go ahead.

Q. (By Mr. Satterwhite) Were there any other changes to your testimony filed on March 30th, 2012?

A. No, there were not.

Q. And then could you also please identify the document I placed in front of you as AEP Exhibit 112?

A. That is my supplemental Commission-ordered testimony and exhibit filed May 2nd in this proceeding.

Q. Was this prepared by you or under your direction?

A. Yes, it was.

Q. And do you have any changes today to this testimony?

A. No, I do not.

Q. Do you adopt AEP Exhibits 111 and 112 as your testimony today in this proceeding?

A. Yes, I do.

MR. SATTERWHITE: Your Honor, at this point I would move for admission of AEP Exhibits 111 and 112 pending cross-examination.

EXAMINER SEE: Mr. Lang?

MR. LANG: Thank you, your Honor.

- - -

CROSS-EXAMINATION

By Mr. Lang:

Q. And good morning, Mr. Roush.

A. Good morning.

Q. I want to ask you first about the fuel adjustment clause discussion you have in your testimony. Now, on your Exhibit DMR-1, the FAC charge is based on second quarter 2012 costs; is that correct?

A. It reflects the company's second quarter 2012 forecast FAC as filed with the Commission, correct.

Q. And when you say "forecast," what do you mean by "forecast"?

A. Each quarter, under the quarterly FAC process, we project the FAC for the coming quarter and also incorporate any reconciliation from the previous period. So that is what was filed in March of 2012, projecting what the FAC would be for April, May, June of 2012.

Q. Now, for each of the four time periods shown on your Exhibit DMR-1, you are using the same FAC charge; is that right?

A. The same forecast FAC for the second quarter of 2012, depending on which time period you were looking at, it may be on a rate by -- rate zone basis or on a merged basis.

Q. So the first section that's on DMR-1, on page 1 on the left side of the page, that's the current 2012 rates; is that right?

A. The title of the whole section is "Current 2012 rates before Proposed ESP" and the FAC would be the second quarter FAC by rate zone.

Q. So the current 2012 rate for the FAC that you're showing there on a combined basis would be at the bottom and in bold print would be $3.61 per kWh?

A. You kind of said dollars and cents in the same statement, so let me say 3.61 cents per kilowatt-hour.

Q. And then you hold that charge constant through December 2014 on your Exhibit DMR-1; is that correct?

A. It's effectively constant. I think it changes just a little because of the rounding, and I think on the second page of Exhibit DMR-1 it actually drops to 1.60, but that's just rounding.

Q. Do you know whether the FAC charge to SSO customers actually will remain constant through December 2014?

A. No. As stated in my testimony, the FAC will continue to operate which will mean it will be adjusted quarterly.

Q. Do you know whether FAC costs have increased over the past year?

A. I don't know for certain. I know the FAC charge for some customers has gone up beginning January of 2012 with the expiration of the FAC caps, but the underlying costs, whether those have gone up or down, I don't know.

Q. Now, on Exhibit DMR-2, what do the FAC charges reflected on that exhibit represent?

A. Those would represent those same second quarter FAC rates applied to the connected load volumes for the periods displayed in Exhibit DMR-2 on a unmerged basis in some instances and on a merged or unified basis in other instances.

Q. So under the -- now, for each time period you show a "Current" column and a "Proposed" column on Exhibit DMR-2. Do you see that?

A. Yes, I do.

Q. And under where it says "Current" is that the existing rates that would match the current 2012 rates on DMR-1?

A. Actually, both the current and the proposed would be based on the same FAC rates that are in Exhibit DMR-1. The differences are the application of those rates to the particular volumes in this exhibit versus the volumes that were used to establish the second quarter FAC rate.

Q. So on DMR-1, the FAC under current 2012 rates before proposed ESP for the Columbus Southern rate zone is 3.99 cents per kWh, and that would track to the 39.91 per megawatt-hour that's on DMR-2 for -- also for this ESP rate zone; is that right?

A. Correct; for all instances where the unmerged value is used or the by-rate-zone value is used.

Q. And the same thing for the Ohio Power rate zone, has $3 -- well, 3.35 cents per kWh on DMR-1 tracks to the -- is that $33.52 per megawatt-hour on DMR-2?

A. Correct.

Q. Now, the total at the bottom on DMR-1, the 3.61, does not track directly to the 36.36 that's on DMR-2. Why is that?
A. Again, that goes back to the volume weighting. Everything in Exhibit DMR-1 is using the same data that was presented back in January of 2011 which was based on projected nonshopping volumes for 2012; whereas, everything shown in Exhibit DMR-2 is based upon connected load forecasts for the respective periods to be consistent with the data that Witness Thomas was using this information for.
Q. So Exhibit DMR-1 does not include or does not account for any changes that would result from changes in shopping levels; is that right?
A. That's correct, yeah. There's a constant level of shopping and/or nonshopping reflected in Exhibit DMR-1 throughout the periods to allow for the rate comparison to be relevant, because if you looked at, say, in one period you had X level of shopping and the next period you had Y level of shopping, that could change -- that would change the overall dollars and make for the comparison much harder for folks to follow.
So for simplicity, in Exhibit DMR-1 I used a consistent -- a set consistent level of

volumes across all the periods.

Q. So for purposes of Exhibit DMR-1, what is the shopping assumption that's underlying the calculations in that exhibit?

A. It was the projected shopping for 2012 that was done sometime in late-2010, so -- because I have so many numbers in my exhibits and workpapers, I didn't want to introduce a whole new set of numbers in the modified ESP, so that's the level that I have stuck with throughout this proceeding.

Q. Do you remember what that assumed shopping level was?

A. I don't know, but I think it was roughly in the 10- to 15-percent range which, you know, with hindsight was too low of a projection.

Q. Now, on DMR-2, looking at the first two columns for June 2012 through May 2013, both the current and the proposed columns have the same FAC rate and then, in the next column, the June 2013 through May 2014 section, the current and proposed are different rates, and actually the current goes up by 1 cent but the proposed drops by 33 cents. Can you explain why that is?

A. Sure. Basically what I took was the data from the second quarter FAC filing and from that filing we had rates by rate zone; from that same data I computed rates that would apply on a unified or merged basis to both rate zones.

That calculation is based upon the volumes for second quarter, the projected volumes for second quarter 2012, so when you apply those same rates to projected volumes for June '13 to May '14, you come up with slightly different answers. Mainly due to rounding, but it's really due to kind of the volume weighting.

So the current column in June 2013 to May 2014 is applying the current FAC rates for the second quarter to projected volumes for June '13 to May '14.

And the proposed column, taking those same current rates but on a merged basis and applying that to the projected volumes, and that's what's producing the slightly different answer is basically the load by rate zone for the second quarter of 2012 is slightly -- that split between rate zones of the load is slightly different for a full calendar year projection June '13 to May '14.

So when you apply the same rates to different volumes, you come up with a, you know, a slightly different answer which is what the 36.02

versus the 36.36.

Q. So why are the -- under the proposed columns, why are the load volumes different than under the other side?

A. Between the current and proposed column, for any period, the volumes are the same. It's when I take a rate on a rate-zone basis and calculate what the merged rate would be, and I'm calculating that based on second quarter 2012 volumes based on the FAC filing, that split of the load for that actual -- for that three-month forecast for the second quarter of 2012 is different enough from the annual forecast for June '13 to May '14 that when I apply that merged rate to those volumes, I come up with a different answer. And it's pretty small. It's just rounding.

Q. So the total volume that you are using for June 2013 through May 2014 is the same, but because of the -- because you're merging the FAC rate starting in June 2013, that's what results in the calculation difference.

A. Right. Because I calculated the merged rate based on the data in the FAC filing which was just a three-month period.

Q. The same would be true for the June through December 2014 numbers that you show?

A. Correct.

Q. Now, the current rates are what you provided to Miss Thomas that she uses for the generation service price; is that your understanding?

A. I believe that's correct, but I don't have Witness Thomas's exhibit in front of me to recall which elements she used. But from Exhibit DMR-2, I believe they pulled virtually all of the numbers from the current column but also numbers from the proposed columns as well.

Q. And the values from the proposed column are what would reflect the proposed ESP price; is that right?

A. I believe that's correct, yes.

Q. So with regard to the FAC charges shown on your Exhibit DMR-1, would the rates be different under the proposed ESP as compared to what it would be if the existing ESP continued forward with fuel cost adjustments?

A. Would you read that back, please?

(Record read.)

A. I'm sorry, did you mean DMR-1 or DMR-2?

Q. On DMR-2.

A. Thanks.

I guess beginning -- under the proposed

ESP, beginning with June of '13 with the merger of the FAC, the FAC rates would be different than continuing the current by-rate-zone FAC rates, and really is somewhat of a timing issue.

What we've been discussing here is when you calculate the merged versus unmerged FAC rate, what point in time do you do that computation, and then how are the volumes that you used in that computation than the volumes you actually experienced prospectively, so I think there's a little bit of a timing issue is what we're seeing.

Q. And over the time period of the ESP, would the -- would the total revenue for the FAC be different under the proposed ESP versus, you know, what you show as kind of the current rates?

A. It could be, but, ultimately, any difference would be purely timing. If I calculate the FAC on a quarterly basis following our current quarterly process, whether I calculate the FAC on a merged or an unmerged basis, the cost target I think will be -- the actual cost will be the same.

But when you design the rates, apply it to actual usage and then do it over/underrecovery, because of the timing of that, you could be off a little bit depending on which way you do it. But, generally, the underlying costs, whether the rate itself is merged or unmerged, the underlying costs for Ohio Power Company during the period ought to be the same either way.

Q. Right. And so, in either case, AEP Ohio will have an FAC that allows it to collect its actual fuel costs incurred during the ESP period, correct?

A. At least through the end of '14.

Q. Right. Thank you.

And there's not something in the modified ESP that will cause those fuel costs to drop if the modified ESP is approved; is that right?

A. Sitting here today, I can't think of something in the modified ESP that would change the FAC costs other than potentially the 5 percent auction that is proposed. There may be other things, but I can't think of them at the moment.

Q. Now, in your testimony you also discuss the phase-in recovery rider, or the PIRR, and the proposal, as you discuss in your testimony, is to begin implementing or assessing the charges for the PIRR would start in June of 2013; is that right?

A. Yes, that's correct. We're proposing to delay implementing the PIRR until 2013.

Q. And your understanding is that the

one-year delay in implementing the PIRR is just part of the package of the ESP proposal; is that fair?

A. Yes, that's fair.

Q. And the proposal also is to merge the FAC rates for both rate zones also effective June 2013.

A. Yes, that's correct. That would time the merger of the FAC at the same time that we're implementing the PIRR on a merged basis as well.

Q. So for the first year of the ESP, assuming it starts June 1, 2012, the PIRR would not be in effect during that first year, there would be no PIRR charge, correct?

A. Correct.

Q. And during that first year the FAC would be in effect, but on a separate rate-zone basis; is that right?

A. That's correct. The FAC would continue with kind of the administrative split of the charge by rate zone.

Q. And same as with the delay in the PIRR, the one-year delay in merging the FAC rates, your understanding is that that's also part of the total package of the ESP proposal; is that right?

A. Yes, that's correct.

Q. So for the first year of the ESP while the FAC rates are not merged, the FAC paid by Ohio Power customers will be less than the FAC paid by Columbus Southern customers.

A. Yes, I think generally that's correct.

Q. And using the table that you have on page 6, based on the current FAC Ohio Power transmission voltage customers that you're showing here in this table would pay $6.04 per megawatt-hour less than Columbus Southern transmission voltage customers; is that right?

A. Yes. Those are based on the second quarter FAC -- FAC costs, the difference between an OP transmission rate zone customer's FAC charge and a CSP rate zone transmission customer's FAC charge is approximately $6.04 a megawatt-hour, yes.

Q. One of the results of that is that Ohio Power customers in the Ohio Power rate zone, their price to compare is lower using the FAC by rate zone than by using the merged FAC; is that correct?

A. Yes; based on, again, going back to it's the second quarter FAC, so based on that, yes, the OP rate zone customer's price to compare would be lower using the unmerged, or the rates by rate zone, than they would on a merged basis; and, conversely, the CSP customer's price to compare is higher than it would be if the merged FAC were used.

Q. Now, do you agree that in terms of rate design objectives there is not a reason to delay merging the FAC rates for one year?

A. Yes, I'd agree there's not a rate design objective. I think part of the -- what I was demonstrating on page 6 is that timing them, the merger of the FAC with the implementation of the PIRR on a merged basis, kind of managed the impact of both of those actions.

Q. Now, the PIRR costs could be securitized in 2013? If you know.

A. I think Witness Hawkins would have known better, but that sounds like an awfully aggressive time table.

Q. Well, assuming the PIRR is securitized, we'll say either in 2013 or 2014, if that occurs, then it would be replaced by phase-in recovery charges. Is that your understanding?

A. I guess I don't know the right terminology, but generally, you know, if you're securitizing, there has to be a mechanism to provide the revenue stream to fund the bonds.

Q. Have you done any analysis yet of rate impact if the PIRR is securitized during the ESP period?

A. I don't recall doing one, but generally my understanding is the direction would be securitization would potentially reduce the cost to customers.

Q. So your understanding would be that the impact on rates should be some downward adjustment if the phase-in recovery charges for securitization would replace the PIRR.

A. Yes, that's my general understanding based on those two assumptions: One is that the financing costs would be reduced; the other is that potentially the collection period could be extended beyond the 2012 to 2018 period that the Commission previously approved.

MR. LANG: Your Honor, I'd like to try an exhibit. May I approach?

EXAMINER SEE: Yes.

MR. LANG: Your Honors, if I could have this marked as FES Exhibit No. 110.

(EXHIBIT MARKED FOR IDENTIFICATION.)

Q. Mr. Roush, do you have in front of you what I've asked to be marked as FES No. 110?

A. Yes, I do.

Q. Can you -- there's two tables on this page. In the first one that's titled "Rate Change for Transmission Voltage Customers," do you see that at the top of the page?

A. Yes, I do.

Q. With regard to where it shows the second quarter 2012 FAC rates unmerged and merged, and then the change associated with merging the FAC, can you confirm that those are consistent both with your table on page 6 and your associated workpapers?

A. I apologize, I was so busy looking at the numbers, could you repeat the question?

Q. All right. Basically the question was can you confirm that the FAC rates starting at the top there, down through the change associated with merging the FAC, the minus 3.65 and the plus 3.29, that those numbers are consistent with both your table on page 6 and your associated workpapers.

A. The first three rows of numbers are consistent with the table on page 6 of my testimony and workpaper DMR-page 7.

Q. And then also --

A. With that rounding. Sorry.

Q. And then also for the PIRR rate that is shown for transmission voltage customers beginning June 2013, that is the -- is that the correct rate,

again, consistent with your workpapers?
A. Yes, it is.
Q. And can you confirm the same thing, then, for -- now, what's in your table shown on page 6 was just for transmission voltage customers, correct?
A. That's correct, the table on page 6 of my testimony is just transmission voltage customers and all other voltage, primary and secondary, are shown on WP DMR-7.
Q. So a residential customer would be secondary voltage; is that right?
A. That's correct.
Q. So the second table shown here on Exhibit 110 for secondary voltage customers, can you confirm that the numbers shown there are also consistent with your workpapers?
A. The values, the first five rows of values are all consistent with my workpapers for secondary voltage customers.
Q. Now, looking at the transmission voltage table, if the FAC rates were to be merged in 2012 instead of 2013, then, as shown here, the impact on the FAC for CSP rate zone customers would be a decline of $3 -- 3.65 -- $3, yeah, $3.65 per megawatt-hour, correct?

A. If the merged FAC were implemented in June of '12?

Q. Yes.

A. Then the merged FAC, based on the data from the second quarter FAC filing, would result in a $3.65 per megawatt -- see, I did what you did -- a $3.65 per megawatt-hour reduction for CSP rate zone transmission voltage customers. So merging the rate into June of 2012 would produce the FAC rate for CSP customers and increase the FAC rate for OP rate zone customers.

Q. And the increase would be the $2.39 per megawatt-hour shown under the OPCO or OPCo rate zone; is that right?

A. Correct. Based on second quarter FAC data.

Q. And then starting the PIRR as proposed in June 2013 in either rate zone accounts an additional charge of $3.04; is that right?

A. That's correct.

Q. And that's a similar impact for secondary voltage customers with a merged FAC in the first year of the ESP: Columbus Southern rate zone customers would see a decrease $3.73; OPCo rate zone customers would see an increase of approximately $2.34.

A. Yes. Again, based on the hypothetical you're presenting and the fact that we're talking about the calculation based on the second quarter FAC. Obviously, that's not what we're proposing in the CSP.

Q. And the -- again, with the PIRR starting in June 2013, that for the secondary voltage customers that would be a new charge of $3.21 per megawatt-hour; is that correct?

A. Approximately, that's correct.

Q. Then when you go to third quarter 2012 FAC costs, as you say, you know, when you go -- when you move on a quarterly basis, these rates are going to change somewhat quarter by quarter, correct?

A. That's correct. The FAC rates will change quarterly, so any comparisons versus -- of merged versus unmerged will change quarterly. Similarly, the PIRR values are estimates as well.

Q. Now, with regard to the transmission cost recovery rider, the TCRR, you are proposing to merge those rates into a single set of rates upon implementation of the modified ESP; is that right?

A. That's correct.

Q. Why is it important to do that?

A. I think merging any number of these rates are the end objective because we now only have Ohio Power Company as a merged entity, so the underlying data, the underlying costs, there's only a single set of books now for Ohio Power Company, so ultimately all of the riders should be merged.

Now, we've agreed, like in the D case, we agreed to maintain separate distribution rates by rate zone for a period of time, so for other reasons, you know, we've delayed the merger of certain items, for example the base distribution rates or under the modified ESP as we're proposing delaying the merger of the FAC, I think mainly to manage bill impacts for customers.

Whereas the merged transmission rider is a good example for a residential customer using a thousand kilowatt-hours between the two rate zones, there's really not that much difference between the rate.

Whereas, as we were discussing earlier, there's a pretty good difference between the FAC rate. So for those things that are not too far apart like the transmission rider, we'd like to get that done sooner rather than later; for the FAC for under the modified ESP we proposed to delay that.

Q. So because there has been a merger and there's only Ohio Power Company, Ohio Power Company doesn't actually have costs by rate zone anymore; is that fair?

A. I would say in general that's fair. There may be certain items that are historically padded or to be related to something or the other, but Mr. Mitchell could have probably explained that better than me.

Q. Now, the same reasons why you're merging the TCRR holds true for the other riders that are being merged into a single set of rates as part of the modified ESP; is that correct?

A. I'd say generally that's fair. Ultimately all of the rates should be merged, you know, the process of accomplishing that, you know, can be spread out over time.

In my experience we had a merger in Michigan where it actually was almost 20 years between the time the merger was consummated and we finally got rates unified between the two rate areas.

Q. We all here in Ohio always think we're better than Michigan, so hopefully we'll get the 20 years.

Now, the rider's being merged, in addition to the TCRR it also includes the ESRR; is

that right?
A. I'm going to cheat and look at my Exhibit DMR-4 because it lays it out.
Q. Certainly.
A. Yes, we're proposing to unify those rates.
Q. And also the EDR.
A. Yes, that's correct.
Q. And the EE/PDR.
A. Yes, that's correct.
Q. And the gridSMART rider.
A. Yes, that's correct.
Q. And you already have unified rates for the deferred asset recovery rider.
A. Yes, that's correct.
Q. The kilowatt-hour rider.
A. Kilowatt-hour tax rider, yes.
Q. And the residential distribution credit rider.
A. Yes, that's correct.
Q. And then the proposed DIR, RSR, and GRR will all also be unified rates, correct?
A. Yes. With the one caveat that my expectation is the GRR would be unified, but that's ultimately going to be determined in another

proceeding.

Q. Okay. The design for the GRR hasn't been done yet and is not part of this case.

A. Correct.

Q. Now, as a general matter, would you agree that rates should be designed to avoid cross-subsidies?

A. As a general matter, in a traditional cost-of-service regulation world, absolutely.

Q. And, as a general matter, you would want to avoid cross-subsidies both between classes and within a class; is that right?

A. Yes, as a general matter, in traditional cost-of-service ratemaking that would be a fundamental premise and, obviously, folks will debate, over extensive periods of time, the cost of service methodology, how quickly is too quickly to get there, those kinds of things.

Q. Are you also familiar with a rate design principle known as "gradualism"?

A. Yes; that's kind of what I just alluded to in the previous answer.

Q. And what is "gradualism"?

A. In my mind I think it's most -- again, this is in a traditional cost-of-service world. In a traditional cost-of-service world, the view is generally everybody can agree that you want to eliminate subsidies and get to cost of service.

Generally when everyone -- nobody can agree on what the right cost-of-service methodology is to determine that cost of service, but most folks can agree that you have to factor in things like bill impacts and other items into determining how quickly you transition to that end state of eliminating subsidies and getting to cost of service.

Q. Now, is it fair to say that you see a distinction between traditional cost-of-service principles and rate design applicable to traditional cost-of-service principles and, you know, what happens in an ESP case?

A. Yes, that's definitely an issue I've struggled with quite a bit, you know, in a distribution rate case in Ohio. I have all those nice planks and tools of cost of service and the traditional principles of eliminating subsidies and gradualism, and all those tools are part of my toolbox in a traditional distribution rate case in Ohio. Whereas, the rules around the ESP and -- an even more confusing thing to me -- the MRO are much more -- much less clear to me, let me put it that way.

Q. So you don't know whether the traditional ratemaking principles like avoiding cross-subsidies would apply under an ESP.

A. Not really; because even the definition somewhat of cross-subsidy is kind of rooted in my ability to do a class cost-of-service study and those kinds of things and those really aren't tools in my toolbox in an ESP circumstance.

But I can see how some of those principles would still apply even though you're moving towards a market environment when you get into circumstances like if you do slice-of-system bidding and you have to say well, now that I've got a slice-of-system bid, how do I divvy that up among the various customer classes to set the prices for them.

So it's really an odd situation for me in Ohio these days; much fuzzier than it used to be.

Q. Now, on your Exhibit DMR-1, the transmission rates, the TCRR for the June 2012 to May 2013 period, those are -- are those the current rates on a merged basis?

A. And you're looking at DMR-1, the column under June 2012 to May 2013, merged transmission?

Q. Correct.

A. Those are the current TCRR rates by rate zone recomputed on a merged or unified basis. I believe we talked about this earlier and I may have failed to qualify that with one thing, that those values exclude any over or underrecovery that's in the current rate. So it's just the actual costs from the most recent TCRR filing excluding over and under.

Q. Would the same be true for the fuel number, that it excludes any over/underrecovery?

A. My recollection of the second quarter FAC was there was no over/underrecovery component.

Q. Now, with regard to the TCRR rate, the same is true for the next two time periods shown on DMR-1, they're the current rates recomputed on a merged basis?

A. Correct. For the June '13 to May '14 period and the June '14 to December '14 period, correct.

Q. Are you aware of any projection of TCRR rate levels over the term of the modified ESP?

A. I'm not aware of one because we make that filing annually and so we'll be filing not -- the filing date just got moved, so sometime in the next few months I think we have to file our projection for the coming year.

Q. Do you know how the TCRR rate used in your Exhibit DMR-1 compares to the previous one or two years of rates?

A. No, I haven't looked at it. I know that the TCRR can go up, can go down, I just haven't looked at it.

Q. Now, in your testimony on page 11, let's see, specifically on page 11, lines 15 through 17, you talk about adjusting the ESP generation prices to reflect the fact that there are certain generation costs included in AEP Ohio's TCRR. Now, is your understanding that the generation costs that you're referring to are related to ancillary services?

A. I think generally that's correct. I still struggle to remember all the elements that they are, but generally I think they're ancillary services.

And what I'm doing on -- what I'm discussing there on page 11 of my testimony is how I take the ESP prices and I'm trying to make the prices in Exhibit DMR-2 comparable to what Witness Thomas needs for her ESP MRO comparison.

So there are certain -- based on the history of the TCRR, which really goes back to its genesis as a PJM cost recovery rider, there were certain generation elements that are in the TCRR that I needed to identify and include in the generation prices I was giving to Witness Thomas.

Q. Do you have an idea of what any of the other generation costs might be in addition to ancillary service charges?

A. I may be mistaken, but I think there may be a congestion, I can't remember whether congestion's in there or not, I'm just not certain, it would all be in, you know, that annual TCRR filing. I just can't picture every line item right now.

Q. But, in any case, the adjustment you're making is so that you have an equivalent -- you have generation costs that are equivalent to what would be included in Miss Thomas's market generation price; is that right?

A. I think generally that's right. I'm trying to make sure we're doing an apples-to-apples comparison, and if I didn't identify these elements of the TCRR, I would be understating the generation price I was giving Witness Thomas.

Q. So on Exhibit DMR-2, which is what you provided to Miss Thomas, you have rows that show generation in TCRR, and what you have is the current

for AEP Ohio is $2.895 per megawatt-hour, right?
A. For June 2012 to May 2013, and I guess the other period is June '13 to May '14, and June to December '14 are a current value of $2, $2.95 per megawatt-hour.
Q. Then that would be for the proposed, it's $2.91 per megawatt-hour for each of the -- for each of the time periods, correct?
A. Yeah, for each of the three periods. And, again, I suspect this goes back to the same thing, is that I computed the merged TCRR rates based upon our last approved TCRR filing which would have had a -- I think it would have been a projected July of '11 to June of '12 volumes, perhaps. I may be off a month or so on that projection.
So when I computed the merged rate, I would have used that same data to compute the merged rate, and when I apply that to the projected connected load volumes, I get a slightly different answer for protected total AEP Ohio.
Q. But in terms of the TCRR costs that you're showing as current or proposed, are you starting with the same set of costs from the same time period?
A. Yes, that's correct.

Q. Now, the $2.95 per megawatt-hour that's on DMR-2, what would that compare to on Exhibit DMR-1?

A. It would be a subset of the value shown in either the current trans or merged trans columns and, I'm sorry, I like to do things in cents per kilowatt-hours, so the values in DMR-1 in cents per kilowatt-hour versus the ones in DMR-2 in megawatts per kilowatt-hour. So if you wanted to make them comparable you'd have to slide all the decimals one to the right.

Q. So if we were going to megawatt-hour on DMR-1, the AEP Ohio merged trans would be about $8 even?

A. Correct.

Q. So the --

A. Per megawatt-hour.

Q. So the generation component of that $8 per megawatt-hour that you've identified is the $2.95 per megawatt-hour?

A. Correct.

MR. LANG: I'll try one more exhibit, your Honor, if I could approach and have marked FES Exhibit No. 111, please?

EXAMINER SEE: Okay.

(EXHIBIT MARKED FOR IDENTIFICATION.)

Q. Mr. Roush, the exhibit that I've just handed you to be marked as Exhibit 111 for FirstEnergy Solutions, do you recognize this as the workpaper from your original filing in January 2011 that's equivalent to your Exhibit DMR-2 in your current testimony?

A. It looks like it, but I don't have it with me to cross-check.

Q. I just wanted to ask you a few quick questions, and in terms of the transmission adjustment that we were just talking about on your Exhibit DMR-2, can you see from Exhibit 111 how that generation portion of transmission has changed over the last year and a half, approximately?

A. Yeah, I can see that the values changed. And what I would assume, given that this is my workpaper from January 2011, would have been that it would have been based upon our spring 2010 transmission cost recovery rider filing; whereas, the data presented in my Exhibit DMR-2 would have been based on the 2011 transmission cost recovery rider filing.

Q. So there's, between those two time periods with regard to the transmission adjustment, it's increased from $2.14 to now $2.95; is that correct?

A. That appears to be correct, yes.

Q. And the fuel costs have -- also reflect increases; is that right?

A. Yes. It looks like on the FES Exhibit 111, the fuel costs were projected 2011 fuel costs; whereas, in DMR-2, as we've been discussing, they're second quarter 2012 FAC costs.

Q. So what has the increase been over that time period?

A. Looks like roughly $3.50 a megawatt-hour for fuel.

Q. Thank you.

Let me ask you about a different topic. At the top of page 5 of your testimony on line 7, you refer to Case No. 11-531-EL-ATA. Now, your understanding is that the company, AEP Ohio, filed a tariff proposal in that case, correct?

A. That's correct. My understanding is I think we may have filed more than one, maybe more than one tariff proposal dealing with the previous ESP which set forth that customers under the previous ESP could elect not to pay the POLR charge that was in place for some period of the previous ESP and, if they made that election, they were agreeing, should they return to SSO service, that they would return to market-based SSO service. And so the company filed a proposed market based set of tariffs in that proceeding. Lots of circumstances have changed since that time.

Q. Is it fair to say that you're not familiar with the particular terms of the market-based tariffs that were proposed in this separate case?

A. I know I looked at it at the time, but I don't remember the specifics today. It's been a long time.

Q. In either case that's something that's still pending in that separate docket, so whatever that market price would be is still undetermined, correct?

A. Correct. I'm not sure where the litigation position on all that stuff is. I know we made the filing, we may have even had some conversations with staff after the filing. I don't remember what other things have gone on in that docket since then, but it's still, from my view, still kind of hanging out there.

Q. Now, on page 12 of your testimony, new topic, you're referring to the generation resource rider here, and on line 9 you say "...the Company has no basis to prepare an estimate of the potential GRR rates," but that in terms of preparing an estimate of the potential GRR rates, that is what you then did with your supplemental testimony filed on May 2nd, correct?

A. Correct. In my view, when I wrote this original testimony, since the need for Turning Point hadn't even been determined, I really didn't have a basis to do a computation. Subsequently, the Commission ordered us to present an estimate, so we did what the Commission ordered.

Q. And the basis that you used was a net revenue requirement provided to you by Mr. Nelson; is that right?

A. That's correct. Mr. Nelson gave me a net revenue requirement for 2014 and January to May of 2015.

Q. Now, with regard to the data that he relied upon to develop the net revenue requirement, the specifics of what he relied upon is not something that you looked at or that you're familiar with; is that correct?

A. I looked at it. I can't pretend to say that I understand all the elements of it, that's for sure.

Q. Okay. Now, you took his net revenue requirement and then, in your Exhibit DMR-8 attached to your supplemental testimony, you show three possible rate designs; is that right?

A. That's correct. Because, again, since the design of the GRR won't be addressed until, first, the need for Turning Point's approved, second, the GRR's approved in this ESP, and then, third, another proceeding is held regarding the inclusion of Turning Point in the GRR, so I didn't want to prejudge any particular rate design in this proceeding because I have no clue. There's too many other conditions precedent, I guess.

Q. So of the three options you show on that exhibit, the energy allocation is a straight kilowatt-hour allocation; is that right?

A. Correct. It's just total revenue requirement divided by total kWh without any, you know, voltage differentiation or anything else, just that simple.

Q. And then the demand allocation uses the same 5CP demand allocation that you used for your RSR calculation; is that right?

A. That's correct.

Q. And then the base G allocation is done proportionately to the proposed base G rates; is that right?

A. Correct. And those were kind of three -- there's probably a million other variants -- but those were kind of three that I have seen used for Ohio Power Company. So it was done to try to quantify possible outcomes for the Commission to say this is ranges of the potential impact.

Q. So depending on which rate design the Commission might select, that shows the estimated impact of the Turning Point Solar project for at least 2014 and -- for at least 2014, correct?

A. Actually not correct. I went ahead and, to be conservative in the impact, I used the full impact through '15. Through May of '15.

Q. So to be clear, what time period are you calculating?

A. If you kind of look to Exhibit DMR-8, page 1, I show the -- take the revenue requirement to kind of compute a per kilowatt-hour rate for calendar '14, then I also compute the rate for January to May of '15. Since -- to present this as conservative as possibly, I used the higher January to May of '15 rate in my presentation on page 2 of DMR-8.

Q. So page 2 is the January to May 2015 impact using the estimated cost from that time period.

A. Correct. And the impact would be lower during 2014.

Q. Now, that impact is not reflected on your Exhibit DMR-1, correct?

A. That's correct.

Q. Now, if the costs of Turning Point were included in the GRR, do you know whether the capacity cost of Turning Point would be added to or in addition to the $255 per megawatt-day capacity charge that is proposed for the first five months of 2015?

A. Mr. Nelson could probably have said for sure, but I don't think it would be.

Q. Now, on your Exhibit DMR-3 you show a calculation of the retail stability rider, and on the first, I think it's the first three lines, you're allocating the cost of the RSR to customer classes based upon each class's average contribution to load using the five coincident peaks of PJM; is that right?

A. Yeah, that sounds right. It's the -- each class's contribution to the company demand or load at the time of the PJM 5CPs.

Q. And so, on this Exhibit DMR-3, that 5CPs in terms of megawatt-hours -- in terms of megawatts is 9,352.

A. That's correct. That's the total for all the retail classes for, I believe it's summer 2011.

Q. Okay. So that was the 5CPs for 2011?

A. That's my recollection.

Q. And is it your understanding that Dr. Pearce's capacity calculation that's been referenced other times in this case, he uses the 5CPs for 2010?

A. Could be.

Q. So you don't know?

A. I don't recall. I know he's filed testimony in that regards here, I think he's prepared calculations at FERC, so it just depends on the particular one.

Q. And you also have a separate calculation reflected in your workpapers for the IRP-D and that calculation also includes a 5CP allocation; is that correct?

A. It uses a 5CP value and my recollection was this was the same data we filed or most of the data there including that 5CP are the same data we filed back in January of '11. So I believe I pulled that from the 2009 data based on the 2009 -- or, 2009 data based on our original filing at FERC.

Q. So there you're using the 5CPs for 2009 which I think your workpapers show is 8,386 megawatts; is that right?

A. That's correct.

Q. Do you know whether the 5CPs for 2010 fell in between the 2009 and the 2011 5CPs that you've used in your different calculations?

A. I don't know. The one thing I would note is we were discussing workpaper DMR-5, that 5CP value, that's total company which is retail and wholesale versus the 5CP we were discussing on Exhibit DMR-3 is retail only.

Q. So the retail stability rider calculation is retail only?

A. Correct.

Q. Now, DMR-3 shows a rate design for the retail stability rider, is this based on a theoretical annual revenue requirement?

A. It's based upon a level annual revenue requirement from the calculations Mr. Allen did, so we chose to calculate the retail stability rider on a level basis across the period. I think Witness

Allen's numbers do vary by year.

Q. Is it your understanding that Witness Allen's numbers for the RSR increase year by year?

A. I think that's right, but I'm sure you could check that from I think it's his Exhibit WAA-6.

Q. Now, the revenue requirement that you're assuming here would be on line 5 is the 94.7 million; is that right?

A. That's correct. I think Witness Allen gave me a number of 280-some-million-dollars which I divided by three to make it a level charge over the three-year period.

Q. Do you know whether the 280-and-some-million-dollar number that he provided to you, whether that's a fixed number as part of the modified ESP or whether it's a number that could potentially change over the term of the modified ESP?

A. I think there's an underlying calculation to it so that I think the value can change, but I think it would be safer to ask Witness Allen because he did the actual calculation.

Q. Well, would you agree that the proposed rates shown in your Exhibit DMR-3 under the modified ESP could be higher than what you show here?

A. I couldn't agree with that in the first year.

In the second year, as I think I discuss in testimony, we'd have a annual reconciliation filing where we would, you know -- so the first year, June '12 to May '13, the rates, assuming the modified ESP is accepted, the rates would be the rates I've shown here.

Once that 12-month period was over, we'd look at the actual collection under the rider, we'd look at what the RSR costs are going forward and recommend a new rate for the coming year through a whole Commission process, or we'd make a filing and parties could review, whatever, you know, that whole process, so that would take some period of time.

So at least for the first years and for probably longer than the first year, the rates would be the rates as we've proposed them because we'd have to wait till that first year ended, go through the process to get the rates modified and that I can't imagine is going to be a terribly quick process. So at least for the first year and so-many-months they'd be the rates that we file.

Q. So are the proposed rates for the different classes shown on DMR-3, is that the actual rate proposed for -- that would be the starting 2012 rate?

A. Correct.

Q. Now, I think starting page 13 of your testimony you discuss using a competitive bid process to meet the SSO obligations starting, well, for delivery beginning on and after January 2015. Now, the details behind the rate design for that auction, for that first five months of 2015, that will be addressed in a future proceeding, correct?

A. Correct.

Q. Now, as the rate design person, is it fair to say that you would have preferred to have had those details filed in this proceeding?

A. I'm going to give you a wishy-washy answer: Yes and no. You know, any details that can be worked out you'd like to get them nailed down sooner rather than later.

The practical reality is I may have an opinion, other parties may have an opinion on what's the best way to do the rate design.

There are other circumstances, you know, we don't know the outcome of this proceeding as far as what the rates are going to be prior to that auction period to be able to anticipate necessarily if there are going to be any issues when we get to auction as far as customer impacts, things that we were trying to address in the previous version of the ESP of trying to say, well, when we get to auction, here's what the rates are going to look like, here's what our rates look like now, and how do we get between here and there.

And I think some of those issues are probably better flushed out in a separate proceeding that's focused on that once we know the outcome of this proceeding so we know what the rates look like that we're starting from and moving towards.

Q. Are you aware that there will be a separate generation company, AEP Generation Resources, that will be charging AEP Ohio $255 per megawatt-day for capacity during the time period of this first five months of 2015 auction?

A. That's my understanding, yes. The mechanics of it are a little weird. I don't think Gen Resources will actually charge -- the way the accounting works, I'm not sure how the money flows, but ultimately Gen Resources will be fulfilling the FRR obligation for Ohio Power Company.

Q. So on page 13 of your testimony, lines 17 and 18, you refer to new tariffs and riders to recover cost of power purchased through the competitive procurement process. When you're referring to that cost of power purchased through the competitive procurement process, do you understand that at least the capacity component will not be procured through the competitive process?

A. I guess that's kind of where I was saying some of it gets a little fuzzy for me as far as the accounting for it, and Witness Nelson probably could have talked to this a little bit too, but it's entirely possible that the 255 charge could go to the competitive provider and they include in their price to AEP Ohio.

I'm just not -- like I said, all the details haven't been worked out. My general statement here and what I was trying to reflect here is the cost of the auction, the competitive bid energy auction, the cost of capacity, the cost of generation total is going to be coming through this -- some new mechanism, new tariffs.

Q. So if the rate design does include that $255 per megawatt-day capacity price, would you expect that for rate design purposes that would also be allocated on a 5CP basis?

A. And I think you can go one step further. I think the rate design would have to -- the generation rate design would have to reflect the $255 a megawatt-day, and I would expect, you know, based on what I've seen of how capacity charges are handled in Duke and FirstEnergy, that a 5CP allocation would be the likely outcome, but until we go through the separate proceeding process, I can't say for sure.

Q. And since that would be for early-2015, if you're going to use the 5CPs, you'd probably use summer of 2013?

A. That sounds correct to me because summer of '13 peaks are used for planning year '14-'15.

Q. So with regards to the components of the retail rate that you would expect that I think you discuss a little here on page 13, it would include some kind of base generation charge that would reflect the auction results, correct?

A. I would hate to split hairs with you, but it may be more of a rider charge than a base generation charge, but I would expect that the end result of this, that there would have to be supply to collect the capacity, there would have to be something to collect the energy procured in the competitive bid, there would have to be a mechanism to collect things like we were talking about earlier, like ancillary services.

And whether that's through continuing the TCRR, whether it's part of the auction, I don't know at this time. And it's even possible that you can eliminate the TCRR entirely and that all be part of the auction process as well.

So there's -- all the details aren't worked out and that's where I think it's important to have folks in the room to have time to actually devote to it to work through all those details and make sure we get it right.

Q. And, again, as you reference here on page 13, that could also potentially include there would be a reconciliation rider?

A. Yeah, I would expect that there's going to be some over or underrecovery that has to be followed, that the auction comes in, you divvy out among rates and apply it to actual usage. You're not going to hit the amount right on the head so there's going to be some reconciliation that's going to need to be done.

Q. Then also potentially an uncollectibles rider.

A. Yes, potentially.

Q. And you mentioned the impact on the TCRR, if the auction product includes transmission, then the TCRR might be eliminated.

A. Correct. That's a possibility.

Q. Or if the auction product included only the generation components of the TCRR, then, you know, kind of as we discussed earlier, the difference between the $8 and $2-and-some, you typically bring the TCRR down to reflect the removal of the generation components; is that correct?

A. Yeah, that makes sense to me. You can't, you know, can't collect things twice, it's got to be one place or the other and that's why, again, we've got to slog through all the detail and make sure you get it right.

Q. Now, there's a discussion in Mr. Nelson's testimony in particular about pool modification. Do you agree there is not a pool modification rider that is included in the modified ESP?

A. I think that's right, and I think I was fortunate enough not to have any mention of it anywhere in my testimony or exhibits, so -- but my understanding generally is it's a provision that may or may not ever be invoked. If it's invoked, then there will be a separate proceeding regarding that and, depending on the outcome of the proceeding, there may or may not be a rider.

Q. So for purposes of your exhibits showing rates and rate impact, you know, there's nowhere in those exhibits would we find a pool modification rider, correct?

A. Correct. To my knowledge.

Q. Now, with regard to the base generation rates that you use in your testimony, those base generation rates are not cost based, correct?

A. Generally I'd say that's fair. Some elements of them were once upon a time or even more recently upon a time, but the proposed base generation rates are kind of, you know, they were the unbundled rates from back in the '99 ETP cases which at that time were based on cost studies from the '91 and '94 cases.

They've gone through so many transformations between rate stabilization plan and ESP I and the proposal here, to roll the environmental cost requirement rider into them which is based on costs, themselves, they're kind of a, I don't know, prego kind of thing I'm not sure what all's in them.

Q. So, for example, you wouldn't be able to say whether the base generation rates recover nonfuel variable energy costs, correct?

A. No, I can't say for certain any more what they are. You know, conceptually you would say -- conceptually you'd say well, way back then, the original unbundled rates back in '99 would have included some nonfuel variable O&M, but through all the transformations they've gone through over the years it's really hard to say what's in them. You know, you can maybe make an argument that they've got this, that, or the other, but they're kind of just rates.

Q. So because of the passage in time and all the changes that have occurred it's fair to say that as we sit here today we don't have a basis to disaggregate the base G rates into subcomponents in any meaningful way; is that right?

A. I think that's fair. In order to do that we'd have to go back to where I'm really comfortable which is traditional cost-of-service-world land and do class cost-of-service studies and everybody in the room would have their own version of that class cost-of-service study, and then we'd debate about all those methodologies about minimum system, 12CP versus 6CP and all those great things, and come to some conclusion of, well, these are the elements that make up the rates and that's just -- that's not where Ohio is anymore.

Q. I want to take you to page 4 of your testimony.

A. Now we're going backwards.

Q. Yes, but it's the last page for our journey today. Now, here you note that existing -- the existing switching charges are being retained in the modified ESP. I think that's around line 12. Do you see that?

A. Correct. Yes.

Q. Do you know what the existing switching fee is?

A. I do now. It's $10.

Q. That's something you checked on since our deposition?

A. Yes.

Q. Good.

Now, that $10 fee is not in the tariffs attached to your testimony; is that right?

A. That's correct. I only attached the standard tariffs to my testimony.

Q. And then -- because AEP Ohio has separate tariffs for shopping customers and your tariffs are the -- the tariffs attached to your testimony are the

SSO tariffs; is that right?
A. Yeah, effectively, because I think pretty much the only changes to that other entire book of tariffs are the things that I've discussed here on page 4, and we've killed enough trees in this proceeding.
Q. Now, is it your understanding that the switching charge is assessed both when a customer shops and when a customer returns to the SSO?
A. My recollection, and I didn't get a chance to check through all the nuances of this since my deposition, but my recollection is the first time a customer shops or switches, there is no switching charge, and then subsequent switches there is a switching charge.
Q. And so the subsequent switches would be in both directions?
A. I believe that's correct.
Q. Do you know whether suppliers are able to pay AEP Ohio directly for the switching charge?
A. No, I don't know. I didn't get a chance to check.
Q. Now, is it your understanding that there was a cost calculation done for the switching fee that would have been part of the electric transition

plan case?

A. That's my recollection is that there was some way back in the '99 ETP cases there would have been some basis for the charge, and then actually I think the company's proposed charge was modified during that time as additional obligations were developed around the rules for switching and all that kind of stuff.

Q. Now, to your knowledge, that cost calculation has not been updated since then; is that right?

A. I'm not aware of it.

Q. Is it also fair to say that you are not aware of whether AEP Ohio's switching processes have been updated since then?

A. No. The only thing I'm aware of is that, you know, all of us, you know, much of that involves computer systems and I would suspect the computer system we're using today bears no -- or, has been modified extensively during the course of the last 12 years, but I have no firsthand knowledge of that.

Q. So do you think the switching process may be much more automated than it was back in 2000?

A. I don't know whether it's more automated or not. I would just think that, you know, just like, you know, Microsoft Office we put on our computers, there's probably been five iterations between a 12-year period of the software.

Q. Now, still on page 4, you discuss modifications, and the first one starting on line 15 is a modification to the terms and conditions of service which is adding information to the master customer list, correct?

A. Correct.

Q. Now, other than the reference here in your testimony, you have not provided any documentation reflecting this change to the terms and conditions of service; is that correct?

A. That is correct. I would just, you know, upon approval of the modified ESP, when we file the compliance tariffs, I'd add those to the, I think it's the open access distribution terms and conditions, and it might even be in the supplier terms and conditions.

Q. So that's something else that would not appear in your Exhibit DMR-5.

A. I don't believe it does. That's that whole other book we were talking about.

Q. Now, on, let's see, starting on line 18, you identify another modification regarding the

12-month minimum stay requirement, and this is the one for certain large commercial and industrial customers. Is that something that's in DMR-5?

A. No. I don't believe so. For a couple reasons: One, I think it's in the OAD terms and conditions of service; and the other is it wouldn't even be in the original compliance tariffs in this case. They would be filed under our proposal sometime before January 1, 2015, but I think obviously that's clearly the company's intention that if the modified ESP is approved, these changes, as discussed in my testimony, will be made to the tariffs, the compliance tariffs filed with the Commission appropriate times.

Q. So that's the tariff book that applies to the shopping customers is where we'd find that; is that what you referred to as the open access distribution tariff?

A. Right. That's correct.

Q. And the proposal here is to eliminate this minimum stay requirement commencing January 1, 2015?

A. That's correct; coincident with the timing of the beginning of the auction. The energy auction.

Q. So if a large industrial or commercial customer returns to SSO service in November of 2014, would that customer be unable to shop until November 2015?

A. I don't believe that to be correct just based on what happened in January and February of this year. We eliminated that 90-day -- or the 12-month. I'm sorry, I got myself confused.

My expectation would be that the obligation would go away when it was removed from the tariff so that customer would be free to shop in January of '15 in your hypothetical.

Q. Now, what is the current purpose of the 12-month minimum stay requirement?

A. My recollection, and it's been there a long time, so my recollection is what it is I guess, was there was a lot of discussion back in the late-'90s/early-2000s around minimum stay issues and around the potential for seasonal gaming due to the fact that most utilities' rates did not have seasonal elements to them, they were set on an annual traditional, going back to good old-fashioned regulation, 12-month test year, set your rates, set an annual rate that covers the cost throughout the year even if your cost varied by season.

Most of our rates are not seasonal and Columbus Southern residential is probably one of the exceptions. Columbus Southern Power rates, residential rates, are one of the exceptions for Ohio Power Company. Most of our rates are seasonal.

So there was an issue around, well, wouldn't it just make good business sense, and nothing too nefarious involved, but wouldn't it make good business sense to say, well, I'll write a contract for you to serve you in what are the lower-cost months and dump you back on -- "dump's" not the right word -- switch you back to SSO service during the high-cost months to take advantage of the fact that that SSO rate's an annual rate and doesn't reflect the seasonal variations.

Q. Now, that was the discussion and the concern as you stated during the electric transition plan cases. Have you done any review since then to determine whether seasonal gaming has become an issue either elsewhere in Ohio or in other states that have competitive procurement?

A. I haven't done any research in that regard. It would be very hard from an AEP Ohio standpoint to evaluate it because the minimum stay kind of precludes that from happening.

Q. So you haven't looked at the experience that other Ohio utilities have had after they eliminated their minimum stays?

A. Not even aware that they have eliminated them.

Q. Have you looked at other default offerings in states outside of Ohio with competitive resale service to determine whether seasonal gaming has occurred or is occurring in those jurisdictions?

A. I have not. But as we have discussed earlier, Ohio's kind of got a unique construct, so each state is a little different.

Q. Other than the concern that people had back around the time of the electric transition plan cases, do you have any examples of seasonal gaming that actually did come to pass?

A. I don't have any specific examples. We discussed that earlier, it's kind of hard to experience an example with the minimum stay provisions in place.

The other part of it is kind of the condition precedent which is that AEP Ohio still does not have seasonal rates for the most part. So we're still kind of in that same situation that we were back when we were discussing this in the ETP cases.

Q. Now, you discuss a similar modification in your testimony starting around page 4, line 20, as to the current requirement, this is for the residential and small commercial customers, that if they return to standard service -- to SSO service during the summer, they must remain on the SSO service until April 15th of the following year. Do you know, when it says return during the summer months, do you know how "summer months" is defined?

A. My recollection is it's June to September.

Q. Does it include September or does it go till September 1?

A. I believe it includes September.

Q. Now, is this provision in your DMR-5 exhibit?

A. No. It would be in the open access distribution tariffs that are on file at the Commission.

Q. And is it your understanding that this provision also has a -- its genesis was because of a seasonal gaming concern?

A. That's generally my recollection, yeah, but they're kind of similar issues, just different-size customers.

Q. Have you seen any CRES provider offers to residential customers in Ohio that would be short-term offers that exclude the summer months?

A. I don't really look that closely at them because I don't have the ability to shop where I live, but the few times I've looked on the Commission's Apples to Apples site, I've seen offers that run different kinds of periods.

I think it seems like it can happen not just with a offer that only -- that's no less than 12 months, it could happen with an offer that's, say, 15 months or 16 months or 18 months and only includes, you know, one summer and two off-peak periods, but I haven't really looked that closely at what folks are offering.

Q. Are you aware that the cost to acquire residential customers needs to be recovered by the provider over time, if you know?

A. That's taking me somewhere where I don't deal with that side of the world.

Q. I think similar to the question earlier about the industrial customer and, you know, how the January 1, 2015, works, if the residential customer were to return to SSO service in August of 2014, does that mean that they can't shop until April 15 of 2015 or are they freed up on January 1, 2015?

A. My expectation would be once those provisions were removed from the tariff, they would be free to shop 1/1/15.

MR. LANG: Thank you, Mr. Roush.

That's all the questions I have, your Honors.

EXAMINER SEE: Let's go off the record for a minute.

(Discussion off the record.)

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

Mr. Serio.

- - -

CROSS-EXAMINATION

By Mr. Serio:

Q. Good morning.

A. Good morning.

Q. Or afternoon. I'm sorry.

You indicated that you allocated costs on the RSP based on the 5CP methodology; is that correct?

A. Allocated costs of the retail stability rider, RSR.

Q. Did you consider any other allocation factors other than the 5CP?

A. No, not really, because it was kind of the nature or the underlying nature of it, of the costs that we were collecting there were kind of fixed costs. So, in my view, fixed costs and the demand allocation kind of go hand in hand.

Q. Now, I believe that in your discussions with counsel for FirstEnergy Solutions, you indicated that the CP calculation changes from year to year.

A. Yes. That's correct. The 5CP is determined every year kind of on a lagging basis, so the 5CP for planning year '12-'13 which is June '12 to May '13, is based on the summer 2011 peaks.

Q. Now, to the extent that the CP changes from year to year and the switching changes from year to year, wouldn't it make sense to use an average of the CP from a number of years rather than any one particular year to do the allocation?

A. Not to me, but as we were kind of discussing earlier, the retail stability rider, this is the first year rates, first year and change rates, I would expect I'd use the updated to that summer 2012 5CP data to update the rate in the next annual filing.

Q. Do you understand the basis for the

company indicating a need to collect the RSR?

A. At a very high level. Witness Allen obviously is the expert on it, but at a very high level I think he's termed it as kind of like a generation to coupling mechanism to say, okay, here's our generation costs, he's computed them, and then there's a bunch of credits against those costs including revenue collections from SSO customers, I think there's revenue collected from capacity charges, there's some other offsets that go into that and it comes down to the number he gave me, but he's the expert.

Q. Is it your understanding that if there was no switching, there would be no need for the RSR?

A. Maybe. I haven't worked through that exercise and I'm not intimately familiar with Witness Allen's calculations, so you might be better asking him.

Q. On page 9 of your testimony, lines 6 through 9, you indicate that upon approval of the RSR the company is willing to increase the IRP-D credit to $8.21 per kilowatt month. Do you see that?

A. Yes, I see that.

Q. Now, if that's approved, this increased level of credit would reduce the base generation revenues, correct?

A. That's correct.

Q. Who's the direct and primary benefit of the IRP-D credit? What customer class, if you know?

A. There's kind of two beneficiaries of the IRP-D credit: There's kind of the direct beneficiary of the folks that are willing to accept the lower quality interruptible service, get a credit for being willing to accept that lower quality interruptible service; there's kind of a second-level benefit in that the way that interruptible benefits all customers having interruptible load is basically viewed as a resource from PJM's standpoint, so that resource, in conjunction with actual generation plants, the combination of those two together are used to meet the capacity obligations for all customers.

So there's a little bit of -- I mean that's kind of the genesis of IRP was, rather than having to build additional generation, having interruptible reduced costs for all customers and a credit was given to those customers who accepted that lower level of service.

Q. Now, when you said that there's the primary -- the primary impact, those customers that are willing to accept the lesser quality of service, is that available to all customers? For example, could I offer to take a lesser-quality service at my home and sign up for that service?

A. I'm trying to think. I think if you happen to reside in the gridSMART area, we've got a DL -- direct load control tariff in place there that would allow you to get credits for being willing to have your load reduced at certain times. There are some other gridSMART type tariffs.

I think from a residential standpoint there are kind of other ways to get that same benefit through some of the generally available time-of-day type tariffs where you reduce your on-peak usage and shift that usage to off-peak. The off-peak rate is a lower rate than the on-peak rate.

So there are some elements of that, but it's not, you know, obviously we were talking about complete comprehensive rollout of gridSMART, it is not part of this proceeding but is something that needs to be evaluated, that, you know, once we learn how that works for us in the gridSMART area, you know, that's one of the things that could be rolled out to potentially to all customers, but that's down the road.

Q. So today can the average residential or small commercial customer take advantage of the IRP-D credit?

A. The -- specifically the IRP-D credit, no. That's applicable to larger commercial and industrial customers. There are other provisions that we were discussing that are available to small residential and small commercial customers.

MR. SERIO: Thank you.

That's all I have, your Honor.

EXAMINER SEE: Mr. Maskovyak?

MR. MASKOVYAK: No. Thank you, your Honor.

EXAMINER SEE: Mr. Pritchard?

MR. PRITCHARD: Yes, your Honor.

\- - -

CROSS-EXAMINATION

By Mr. Pritchard:

Q. Good morning, Mr. Roush.

A. Good afternoon, I was just told.

Q. Oh, good afternoon.

Would you turn to page 4 of your testimony.

A. Yes, sir.

Q. Earlier during Mr. Lang's cross you had briefly discussed the peak load contribution information, the specific modifications that you had planned to make. Are these modifications going to be contained in any tariffs, in any compliance tariff filings you might make in this case?

A. Yes. Yes, those -- I believe it's on the open access distribution terms and conditions of service and may also be in the supplier terms and conditions, kind of as I referenced way back at the end of my testimony that we would file compliance tariffs, you know, upon approval of the -- of this ESP, we would file compliance tariffs to be effective for bills beginning with the first billing cycle of June 2012.

Q. And those compliance tariffs would include the PLC and NSPL information that you reference here?

A. I guess, and I don't want to get at cross-purposes with you. In the tariffs what it says is that this is the information, it would list, like, I believe it lists the information that's on the master customer list and we'd add those as elements that are added to the master customer list. I may be mistaken but I believe we've already done it, actually added the information to those lists, I believe.

Q. And so what I'm getting at is once the modified ESP would be approved, a customer could have access to their PLC information?

A. The only reason I'm hesitating is I'm not sure who all has access to that master customer list. I know suppliers have access to that. I'm just not sure whether an individual customer can have access to that master customer list.

As far as getting their own PLC, I don't know why a customer couldn't get their own PLC today. I may be wrong, though.

Q. And turning to your exhibit on the retail stability rider, DMR-3.

A. I'm there.

Q. Earlier you stated that you got a total revenue requirement number from Mr. Allen; do you remember that line of statements?

A. Yes, I do.

Q. And to develop your $94.7 million number you divided his three-year number by three to get your annual number, correct?

A. Correct; to get kind of a level charge for the whole three years.

Q. And is that $94.7 million number a fixed amount?

A. I think that goes back to the conversation I had with Mr. Lang. The rate will be fixed for the first year and so-many-months. There will be a kind of a reconciliation, an annual reconciliation kind of trueup proceeding where we'll look at the over/underrecovery for the prior 12-month period, what we think the value -- the projection of the costs are going to be for the coming period and then propose a new rate for that coming period.

Q. Are you going to be in that trueup or reconciliation proceeding, are you going to be truing up to a $94.7 million number?

A. I don't think so. I haven't done the math, but I would -- haven't put the trueup filing together because this plan's to be approved and we've got to be a year from now before we can even file it.

But generally I would think that we would be looking at what the actual collections under the rider were, what the actual RSR revenue requirement was, and doing that reconciliation, and also looking at what the RSR revenue requirement prospectively would be to set the rate.

So I think Witness Allen can probably confirm this for you, that his calculations, I think, will change based on what actually happens.

Q. So the $94.7 million is not the revenue requirement number for the retail stability rider?

A. It's the initial revenue requirement that established the first year and so-many-month rate, but then I think ultimately it will get reconciled based on actuals, but I just would just doublecheck with Mr. Allen to make sure that's the way he envisions it as well.

Q. So if I'm understanding you, the first year you projected a $94.7 million revenue requirement number, but in the reconciliation proceeding you would -- that $94.7 million number would be based on actual numbers and that actual number is the amount that you would be truing up the rider to prospectively set the rates the next year.

A. I think you're correct, but I'm just going to walk through it again just to make sure we're on the same page.

Witness Allen gave me a total number for the three-year period and we just -- and we chose to levelize the rate across the three years based on the projections during Witness Allen's testimony. How, say, first year, the actual RSR costs are 50 million and we collect a hundred million under the rider, we'd say, well, we owe customers $50 million during that period, but we think next year the rider costs are going to be 150 million, so we'd say, well, next year's going to be 150, I've already collected 50 this year so the new rider rate will collect a hundred.

That's kind of why we chose to levelize it to say let's try to keep this where we think it's going to be for all three years so that we don't see fluctuations in the rate over the period. Does that help?

Q. Yes.

Just one further question on the revenue requirement number. Was Mr. Allen's number that he gave you that you had divided by three, was that the total revenue requirement for the RSR or is his number he gave you subject to change to actual information that aren't currently known?

A. It's the total revenue requirement based on his projection of the three-year period, but I believe that the actual revenue requirement will be based on what actually happens during that three-year period. I think he has like a starting point number that's kind of fixed, I believe, and Mr. Allen can address this much better than I can, within the elements underneath of it like the actual base generation revenues are going to change based on actuals, those kinds of things.

Q. Thank you.

A second ago you had said that you were going to have to look at your actual RSR costs when I was asking you about truing up the rider. Could you identify what the RSR costs, as you used the term, were?

A. Sure. The way I was using the term was I was kind of describing the calculation that Witness Allen went through where he started with here's kind of a total dollar amount and then he backed -- of revenue requirement generation, decoupled revenue requirement, then he has a whole bunch of elements he subtracts off like base generation revenues and those kind of things, and kind of comes down to a residual.

And so I was talking about the RSR costs, I was basically talking about the calculated residual.

Q. And that residual amount, that's a revenue requirement amount, correct?

A. Yeah, I kind of would view that as that's the net revenue requirement that we were designing the RSR rider to collect.

Q. During Mr. Lang's cross you had discussed the open access distribution tariffs. As part of the modified ESP you've proposed the RSR and that would apply to the open access distribution tariffs, correct?

A. Correct.

Q. And, again, the exhibits attached to your testimony and specifically DMR-5, your revised and proposed exhibits, those don't contain any open access distribution tariffs, correct?

A. Correct. What you would do, what we would do in the compliance filing is the RSR rider that is shown in my Exhibit DMR-5, that same rider would just show up in the open access distribution tariff book.

So it's on Exhibit DMR-5, page 232, that -- basically that same rider sheet would show up in the open access distribution tariff book and I kind of laid that out in my Exhibit DMR-4.

Q. Thank you.

And then if you would turn to Exhibit DMR-5, page 39.

A. Yep, I'm there.

Q. This sheet is labeled 104-1, and this is the sheet that was the at-pool riders, correct?

A. Correct.

Q. And a -- the last rider on that page is the alternative energy rider, correct?

A. Correct.

Q. And that's a new proposed rider?

A. Correct. We're separating out the costs related to the alternative energy rider are currently in the FAC, we're separating those costs out and including them in a separate rider.

Q. And, to your knowledge, do you know if the current FAC, which includes the cost of the alternative energy rider, do you know if that is a specific line item charge on a customer's bill?

A. I don't think that the FAC is a line item on a customer's bill.

Q. And if approved and the AER is, the cost of the alternative energy compliance, if they're split out from the FAC as proposed, would those appear as a line item charge on a customer's bill?

A. I don't believe so, but it could be.

MR. PRITCHARD: No further questions, your Honor.

EXAMINER SEE: Mr. Sineneng?

MR. SINENENG: No questions, your Honor.

EXAMINER SEE: Ms. Kyler?

MS. KYLER: No questions, your Honor.

EXAMINER SEE: Ms. McAlister?

Mr. Pritchard, could you pass the microphone down?

\- - -

CROSS-EXAMINATION

By Ms. McAlister:

Q. Good afternoon, Mr. Roush.

A. Good afternoon.

Q. Okay. You talked a little bit about the PIRR and the delay in charging that charge to customers. During the period of time that you delay, will the PIRR continue to accrue carrying costs?

A. Yes, it will.

Q. Turning to interruptible service, do you know what the basis of the $8.21 per kW month credit is?

A. I actually computed it on my workpaper DMR page 5, as I was discussing with Mr. Lang. It's based upon the company's original filing at FERC which I think included 2009 data. It's basically our -- based on that information it's our full cost of capacity adjusted to reflect the difference between the fact that the charges apply to billing demand instead of 5CP demand.

Q. Do you believe that amount is a reasonable credit level independent of the RSR?

A. I think it's a reasonable credit level based upon our full cost of capacity, to the extent that our full cost of capacity is determined to be less, then potentially that credit should go down. I think as part of the company's modified ESP proposal our willingness to reduce our SSO base generation revenues is really contingent upon the RSR mechanism. So there's really kind of two parts to it.

Q. Okay. And then still on that topic, you mention that the company proposes that any customers with peak demand response attributes that cleared in the PJM market that are also receiving an incentive payment through a reasonable arrangement should commit the peak demand response attributes to AEP Ohio at no cost; that's on page 9 for you to reference.

Are there any customers with reasonable arrangements with peak demand reduction capabilities that are not already committing their demand response attributes to AEP Ohio at no cost?

A. I don't know. I haven't -- I apologize, I haven't kept up with all the nuances of every reasonable arrangement but -- so I'm not sure.

Q. You also say that this provision's not interpreted as modifying the specific terms of any of those agreements. I'm just wondering if, assuming there are customers who are not committing their peak demand attributes and you have reasonable arrangements, how would this not be expressly modifying the terms of the agreement?

A. I guess the way I look at it is if there's a reasonable arrangement that's approved and it doesn't -- that's already been approved and doesn't require such a commitment, that this wouldn't retroactively go back and modify that existing agreement. That's kind of my view of it.

Q. Okay. That helps, thank you.

Shifting your attention to page 13 of your testimony, you talked to Mr. Lang a little bit about incidental costs that are associated with the auction. Have you developed any estimate of what those costs may be?

A. No, I haven't. Just generally I know we probably will have to hire some -- an auction manager. I don't recall whether we have to pay for the consultant that staff uses or not, I don't recall that, but those are the kinds of things that I had in mind.

Q. Thank you. But no order of magnitude.

A. Not a clue.

Q. Okay. I'm going to turn you to page 14 of your testimony. There you're talking a little bit about the auction also and you talked about, with Mr. Lang, how your rates have been bundled since the early-1990s, and I think you said it was prego, you're not really sure what's all in there, but you did note that there may be some customer classes that are disproportionately impacted if you do move forward with an auction.

If you recall under AEP's initial proposal, the 29-month proposed ESP back from January of 2011, the rate design there had disproportionate impacts on larger industrial customers. You cite an example here but that's not the example that you cited. Do you anticipate the same type of disproportionate impact on large industrial customers as a result of a change in rate design?

A. Sitting here today I'm not sure. I think a big part of the impact that we were seeing back in the original filing back in January of '11 was related to the expiration of the fuel caps, but, you know, you raise a good point in that there may be other, and that's kind of what I was discussing later on page 14 is that there may be other issues we need to address as far as rate design when we get to that auction standpoint. And sitting here today I can't anticipate all of them, so could it happen? Possibly.

Q. Okay. And so it's fair to assume at this point you really haven't considered what potentially could happen or how you could potentially mitigate those disproportionate impacts?

A. No, not at this time, because I'm not even sure whether they'll exist or not at this point.

Q. Okay. On page 16 of your testimony you talk about Exhibit DMR-7 and it says that it assumes "...that shopping customers are currently receiving and will continue to receive a 10 percent discount from the current SSO price to compare."

Just for clarification, when you say "current," do you mean current as of today or then-current?

A. In the illustration I did in DMR-7 -- now I have to doublecheck. I thought I knew.

In the illustration I did in DMR-7, I started with a current SSO bill and then, to illustrate a shopping customer, I said, well, let's assume they get 10 percent off as the price to compare, so I discounted the current rate by 10 percent. And then I applied the elements of the modified ESP that would apply to a shopping customer prospectively, so the SSO discount is from the 10 percent SSO discount is kind of constant I think through the period.

Q. And what's the basis for the 10 percent?

A. It was just my attempt to illustrate the total bill impacts for a shopping customer, and I have no real basis for 10 percent, just --

Q. Easy math?

A. Yeah.

Q. Okay. And what capacity price was assumed for the shopping customers?

A. There was no assumption. I was just, again, the 10 percent saying if they're saving roughly 10 percent off SSO.

Q. Didn't you have to use a capacity cost to figure out the initial rate?

A. No. I just took whatever our current SSO rate is and said, well, if they shopped, they must have saved some money so I'm going to knock it down by 10 percent.

Q. Okay. I understand.

MS. McALISTER: I think that's all I

have. Thank you, Mr. Roush.

THE WITNESS: Thank you.

EXAMINER SEE: Mr. Sugarman?

MR. SUGARMAN: Thank you, your Honor.

- - -

CROSS-EXAMINATION

By Mr. Sugarman:

Q. Good afternoon, Mr. Roush.

A. Good afternoon.

Q. You were aware of rate design concerns for small commercial customers and residential customers in the former CSP service territory using more than 800 kilowatt-hours in the winter months, were you not?

A. I was aware that some folks had concerns around the impacts resulting from the ESP stipulation.

Q. And how did the rate design cause the concerns that were expressed by those customers?

A. I can't speak to what the -- what caused the customers to raise their concerns. What I can speak to is the stipulated -- obviously the company proposed a rate design and rider design in its original ESP. The stipulated ESP had, for lack of a better word, significant changes to what the company originally proposed but something that was ultimately agreed upon by the stipulated parties.

So that rate design was implemented beginning first of the year and it -- the combination of that rate design being implemented at the same time as the distribution case stipulation rate design changes being implemented did have varying impacts on any number of customer and customer classes, and a lot of that's not atypical.

You know, in a traditionally-regulated state, you know, like Indiana or Michigan or elsewhere where you file a base case and sometimes those base cases include significant increases, if you're doing anything to affect the things that we were talking about with Mr. Lang earlier as far as intra-class subsidies you can end up with some customers seeing -- will see larger increases than other customers.

So it was really kind of a confluence of events that at least I believe led to, you know, the concerns being raised.

Q. Okay. And with respect to the modified ESP that's been filed in this case, subsequent to the rejection of the stipulation, what specifically were the changes in that rate design to address the concerns for the small commercial customers or CSP rate zone residential customers using more than the 800 kilowatt-hours during the winter months? And you reference that on page 8 of your testimony, sir.

A. Thank you.

Q. And I'm reading from lines 9 through 11.

A. Thank you. Yeah, there were significant changes made in the modified ESP relative to what was in the stipulation. And I'll try to list them all but I'm sure I'm going to forget a few.

Q. I'm not asking for the -- let me just interrupt for a second maybe to short-circuit it. I'm not asking the differences between the stipulation and now more so just what were the specific ones that are now proposed to address the rate design concerns that you mentioned in your testimony.

A. Fair enough. I think I have to do it almost by deduction in that, in the stipulation --

Q. Sure.

A. -- a couple of the items that were issues for some customers were the load factor rider and the market transition rider, both of those elements are not in the modified ESP.

The other, at least one of the other

significant elements was the proposed redesign of the base generation rates to reflect kind of more market-based relationships, to reflect seasonal rates, those elements were removed by going back in this modified ESP to the current base generation rates and only rolling in the environmental rider.

I'm trying to think if I've forgotten anything else. I guess another element is the stipulated rates had a base generation rate increase in them. This modified ESP does not have a base generation rate increase. I'm sure I'm forgetting some but those are the ones that come to mind immediately.

Q. And so, in total, those are the changes that you believe create the -- or, eliminate the rate design concerns addressed in your testimony on page 8.

A. Those are all the elements I can think of at this time. I may be forgetting something.

Q. While you said there was no base rate increase, there is an overall rate increase that is expected to be experienced, a small commercial customer's GS-2, GS-3 class, is that not accurate based upon the modified ESP? Let me restate that perhaps.

I mean, your testimony, it's anticipated and expected that there's a rate increase to be experienced by customers if the modified ESP is approved by the Commission.

A. Yes. The retail stability rider is a charge that doesn't exist currently so that would be an increase. The distribution investment rider, a portion of that distribution investment rider I would view as an increase, the other portion of it is the amounts that were already credited against the authorized increase in the distribution cases. So those two elements I view as increases.

And then it's really not a product of the modified ESP, it's more a product of the previous ESP, under the -- we're proposing the phase-in rider that we're proposing to delay its implementation until June of '15, but really the phase-in rider is really a result of deferrals from the previous ESP.

Q. On the portion of the DIR that you just mentioned, you considered some to be an increase and some to be just a portion of amounts that were credited. Is that broken out in some percentage one way or the other? Have you done that?

A. I'm sure it's broken out in the distribution case stipulation, but my recollection is the distribution case established -- and I'm probably going to get the number wrong -- my recollection is it was somewhere around $60 million of warranted distribution rate increase that was offset because of the existence of the DIR.

So rather than the base distribution rates going up $60 million at the first of the year, base distribution rates did not change or did not -- we did not get an increase in base distribution rates, but we still haven't started collecting the DIR.

Q. Did distribution rates go up at the first of the year for small commercial customers as a result of the stipulation in the rate proceeding you mentioned?

A. There were two -- there were like three elements that -- I'm working from memory now -- there were three elements that changed the first of the year as a result of the distribution case stipulation: The general service or the commercial/industrial rates were redesigned to reflect the -- to remove a subsidy that existed within them currently which was that large commercial and industrial customers that were not served at distribution voltage were paying a significant amount of money for distribution costs, and so that cross-subsidy was eliminated.

So for lower voltage customers, for lower voltage customers, primary and secondary customers, their base generation rates went up. And the large commercial/industrial higher voltage customers' rates went down by an equivalent amount. That was one element.

The other element was the deferred asset recovery rider; we began collecting those costs. Those are previously deferred costs that had been deferred for upwards of 10-plus years, some of them, we began the collection of those under the deferred asset recovery rider.

The third element I recall was there was also a distribution credit to residential customers and all of those elements went in effect at the first of the year without the company getting the increased revenues. That was kind of the flip side of that for the distribution investment rider.

Q. Okay. And the DIR, is your understanding that that amount is not fixed on an annual basis during the term of the ESP?

A. It's not fixed. It's capped. But it's a direct function of the actual investment that the company makes in distribution during that period.

Q. And do you know the bases upon which the cap amount was determined for purposes of the DIR?

A. I'm sorry, I don't understand. The basis of time?

Q. No, just the bases upon which the -- the amount of the cap was determined.

A. My recollection is those cap values were actually laid out in the distribution case stipulation and we're continuing to abide by those in this modified ESP is my recollection.

Q. Would you agree that one of the attributes of the modified ESP that the company has put forth in this proceeding is that there is now certain -- rate certainty on the base generation rate? It's an attribute that is being touted for the approval of the modified ESP. Do you agree with that?

A. I don't know that I say that in my testimony. Someone else may say that. But I can say for certain that under the company's proposal the base generation rates are fixed for 20 -- you know, the beginning of the ESP through the end of 2014.

Q. And with the fixed, by contrast to the fixed base generation rates, now you have the addition of what I heard you say the RSR and the DIR which are not fixed but will fluctuate or may fluctuate from year to year during the duration of the modified ESP, correct?

A. The actual rate values of the RSR and DAR -- DIR could change during the duration of the ESP, but the DIR does have a cap.

Q. Right. So that it's fair to say that customers could experience rate fluctuations during the term of the modified ESP with the introduction of the RSR and the DIR that you've mentioned in your testimony.

A. Yes, it's fair to say that there will be rate fluctuations during this period, not -- customers' total bills aren't fixed.

Q. And that's true across all classes of customers in both rate zones?

A. Correct.

Q. Okay. Were you here for Mr. Kirkpatrick's testimony, sir?

A. Yes, I was.

Q. I believe up there, to your immediate right, are three exhibits that I think he handwrote on which I think were identified as NFIB-Ohio Exhibits 102, 103, and 104, if you can locate those and let me know when you've done so, please.

A. I have them.

Q. Great.

MR. SATTERWHITE: Let me interrupt for just one second to see if the witness took my copies.

MR. SUGARMAN: Perfect. I have extras if you need them, Matt.

MR. SATTERWHITE: Okay.

MR. SUGARMAN: Commissioner, I think I set some there on your table.

Q. Mr. Roush, if you would look first at RRG002 which is in Exhibit 102, the second page.

A. I'm there.

Q. Okay.

A. I'm sorry.

Q. I just wanted to be sure. It has a tariff 841, medium general service bill dated December 19, and it shows a distribution service charge of $5,549.25, correct?

A. That's what it shows, yes.

Q. If you would skip a page and go then to RRG004 and can you verify for yourself that this is the same customer account number?

A. It is.

Q. And it shows, one month later, a bill date of January 23, 2012, a distribution service of $13,546.21. Do you see that?

A. I see that.

Q. And do you know the reason for the increase of the distribution service from December 2011 to January 2012 from $5,549 to $13,546?

A. I have several items which would have contributed to that, the first of which is the base distribution rate redesign that came out of the distribution cases, that would be one element of it. Another element of it would have been the market transition rider from the now-defunct ESP. Another element of it would have been the load factor rider from the now-defunct ESP.

Other things that could have changed, generally the universal service charge changes around the first of the year so that could have been an element related to it that caused that change. There may be others, but those are all the elements that come to mind at this time.

But let me just check one thing. I'm sorry.

Q. Sure.

A. I'm glad I checked, I forgot the deferred asset recovery rider, that would have begun, we would have begun recovering those elements, those deferred assets, from years and years and years gone by, so that would have been included in that line item as well.

Q. Let me know when you've completed your answer.

A. Not yet.

Those are all of the elements that I can think of at this point, but, kind of as I described, the distribution service line item is potentially a little bit of a misnomer because it really includes distribution service items and nonbypassable items.

Q. Well, who selects the attribution of distribution service that appears on the bill?

A. I believe we have to get our bill formats approved by the Commission.

Q. So they're AEP's and approved by the Commission, but this is what the customer gets so -- you would agree with that.

A. I believe this is what the customer gets. I don't get an AEP bill.

Q. So the customer believes that it is paying $13,546.21 for distribution service; would you agree?

A. I don't know that I could put myself in the head of the customer.

Q. All right. So based on your testimony that I understood earlier, included in this charge -- I'm sorry, included in the distribution service charge on this bill, the load factor and the MTR would drop off if the modified ESP were approved?

A. The load factor rider and MTR have already dropped off as a result of the rescission of the approval of the previous ESP.

Q. And, in its place, if approved, we would have the RSR and the DIR, correct? Not in their place, even though they would drop off, you would now have the rate approved from the stipulation in the DAR that you talked about, you would have an RSR factor here, you would now have an DIR factor as well, correct?

A. Correct. And I believe I may have misspoken earlier. I believe for the period that we're looking at here, the DIR would have been in effect.

Q. The same as being proposed in the modified ESP in this proceeding?

A. Substantially the same I believe, yes.

Q. Do you know how much of this -- can you tell how much of this service charge is represented by that rider on this particular bill?

A. No, I cannot.

Q. Could you -- are you able to forecast, based upon any of your work that you prepared and prefiled along with your testimony, what this particular customer could expect by way of a distribution service charge if the modified ESP is approved by the Commission?

A. It's kind of a difficult question to answer since I don't have one of these based on what they're currently paying today because this -- the only bills I've got are a December bill and a January bill and not a bill since the rescission of the previous ESP.

Generally a customer -- and this customer looks like they have a metered usage, looking at the January bill of roughly 300,000 kilowatt-hours and --

Q. Is that the bill dated January 23?

A. Yes, sir.

Q. Okay.

A. Yeah, I was rounding, it looks like it shows meter usage of 282,600 so roughly 300,000 and roughly a thousand kW of demand. If you went to my Exhibit DMR-7, and looked for a GS-2 --

Q. Wouldn't I go to 6, as an SSO as opposed to a shopping customer?

A. This customer is a shopping customer.

Q. Okay. Just being sure. Go ahead.

A. The only thing I'm not sure about is whether they're a secondary or primary voltage, but I suspect they're secondary -- well, they could be either one.

But if you looked at Exhibit DMR-7, page 3 of 11, on the far left-hand side there are rate codes, GS-2 secondary or GS-2 primary, I'm not sure which one this customer is, but I have a calculation for a thousand kW, 300,000 kilowatt-hour usage customer that shows, based on today's rates, a current total bill for that particular customer would be roughly $35,000 and under the modified ESP the bill would go up to 35,241. And actually go down to 35,203 and then up to 35,241 for their secondary voltage.

If they're primary voltage, the closest level I've got in here is a thousand kW and 250,000 kilowatt-hours, it shows a current bill of 28,779, the proposed bill of 28,959 and change for an increase of about $180 and kind of work your way across there. So those are probably the closest ones I have.

Now, those calculations in Exhibit DMR-7, as we were discussing before, are based upon current rates and with the assumption that what the customer is saving for their SSO component of their bill is roughly 10 percent. So those are the two that are probably closest.

And in both of those instances we're seeing total bill increases under the modified ESP in the range of 1 percent in the first year, right around there, a slight decrease to a slight positive but still very small in the second year, and less than 1 percent in the third year as well.

Q. And is this customer in the CSP rate zone or the Ohio Power rate zone?

A. Thank you. I may have missed that. You're correct, yeah, I missed that, I apologize. The Ohio Power rate zone, so we actually need to go to Exhibit DMR-7, page 7 and 8.

Q. And if you looked at page 16 of your testimony as well, would this not be a customer that would fit right in your bottom half of your graph that appears there, the thousand kilowatt demand, 300,000-kilowatt usage on a monthly basis?

A. Yep. They're pretty doggone close to that, yeah.

Q. Okay. Thanks. You can set that aside.
Next is Exhibit 103.
A. I have that.
Q. And it's two months from the same customer, again, there's a December and January bill date, December 2011, January 2012. If I were to ask -- in asking you what the difference would be from the two months on the distribution service charge that appears on this bill, would your answer be the same as it was in explaining to us the differences on Exhibit 102?
A. Yes, they would.
Q. Okay. And we could determine similarly the proposed rates this customer would experience the same way utilizing either DMR-6 or DMR-7; would that be correct?
A. Yes, that's correct. And in this one's shopping, so I suspect DMR-7.
Q. Okay. If you would then turn to Exhibit 104, please.
A. I'm there.
Q. There are two months of bills for several different accounts for the same customer, again, in -- well, strike that.
There are -- this one has January of 2011

and January of 2012 as the comparisons for the two months for the several different accounts. That begins on RRG008 and continues through the end of the exhibit on --

A. I see that.

Q. -- RRG015. If I were to ask you the questions or to explain the differences in the distribution service increases that -- strike that.

You would agree that there is an increase in the distribution service that appears on these monthly statements of 2011 into 2012; would you not?

A. Just from my quick review that appears to be the case.

I apologize, I forgot one other thing that I may have failed to mention, which is when we were doing the comparison month to month.

Q. Okay. So if I were to ask you the same questions with respect to the question as to explaining the reason for the increase in the distribution charge that appears on these bills, would your answer be the same?

A. Generally yes. I just don't recall whether I mentioned there could be other differences due to just volume of usage. I don't recall whether I mentioned that previously or not.

Q. All right. We could compare the volume of usage on these bills rather than go through each one, and I don't pretend to do that now or want to, but just as a general question, if the volume of usage declined, would you expect the distribution charge to decline?

A. As long as -- and most of these customers are commercial customers so the volume of usage we're discussing would be both the kWh consumption and the kW peak demands, generally if both of those billing units declined, I would generally expect, if the rates were constant, then the total bill would decline.

Q. Would we be able to tell from these exhibits what portion of the kWh usage was attributable to peak?

A. The few that I looked at did identify both kWh usage and kW demand.

Q. If you would -- you can set those aside now, sir, and I'll ask you if you would turn in your prefiled testimony, and the Exhibit DMR-5, it is page 236 of 238. It's the distribution investment rider.

A. I'm there.

Q. All right. This indicates that "...customer bills subject to the provision of this

Rider, including any bills rendered under special contract, shall be adjusted by the DIR charge of," is that "14.20709 percent of the customer's distribution charges under the Company's Schedules, excluding charges under any applicable Riders"? Did I read that correctly?

A. Yes, I believe you read the first sentence correctly.

Q. Thank you. How do I know what the customer's distribution charge is that's going to be adjusted by a charge of 14.2 percent?

A. Probably the easiest way to illustrate that is by example. So let's stay in this exhibit, and go to -- let's do an easy one. Page 51, please.

Q. On DMR-5?

A. Yes, sir, Exhibit DMR-5, page 51.

This is Ohio Power rate zone Schedule GS-1 and it lays out that customer taking service under that schedule, their distribution charge is a customer charge of $13.17 and an energy charge of .27999 cents per kilowatt-hour. Those two elements would be their base distribution charges so would you calculate their bill based on their usage based on those charges and then compute the rider as 14 percent and change times that computation.

Q. And is that done on a monthly basis?
A. Yes.
Q. And that is after you take the customer -- the distribution -- well, let me make sure I understand. You take the monthly usage times the distribution and customer charge and energy charge that appears on page 51.
A. We'll even do an example to make it easy.
Q. Okay.
A. Let's say a GS-1 customer used a thousand kilowatt-hours, their distribution bill would be $13.17 plus a thousand times .0027999, so it would be 13.17 plus $2.80, would be $15.97. Then you would take that $15.97 times the 14 percent-and-change in the back and, say, the rider, the rider charge would be roughly 2 bucks. And so that would be how you would go through the calculation.
MR. SUGARMAN: Thanks very much, Mr. Roush. I have no further questions.
THE WITNESS: You're welcome.
EXAMINER SEE: Ms. Thompson.
MS. THOMPSON: Thank you, your Honor.

\- - -

CROSS-EXAMINATION

By Ms. Thompson:

Q. Good afternoon, Mr. Roush.

A. Good afternoon.

Q. During your cross-examination with Mr. Lang, you discussed modifications including eliminating the 12-month minimum stay requirement for large commercial and industrial customers in January 2015?

A. Yes, on page 4 of my testimony.

Q. Yes. And if I understood you correctly, the 12-month minimum stay requirement will decrease on a month-by-month basis beginning January 1st, 2014?

A. That's a neat way to look at it, but effectively if we're removing the minimum stay obligation effective 1/1/15, then effectively that obligation gets short -- becomes 11, then 10, then 9, yeah, I agree with that.

Q. You also discuss the modification eliminating the requirement for residential and small commercial customers returning to SSO during the summer months who then must remain on the SSO through April 15th the following year. That was a long-winded way of saying the second modification on page 4.

A. Yes, we discussed that.

Q. Okay. And if I understood you correctly, any customer switching to SSO from June 1st to September 30th, 2014, will only be required to remain on the SSO through January 1st, 2015.

A. That's my understanding, yes.

Q. Okay. Are you on page 4 of your testimony?

A. Yes, I am.

Q. Could you look at lines 14 through 15. There you testified that the modifications that you propose will benefit customers and CRES providers, correct?

A. Correct.

Q. And you believe waiting till January 1st, 2015, would benefit CRES providers and customers to eliminate those with stay requirements?

A. I believe it's better than waiting till June 1 of '15 on one hand; and then, in the deposition, Mr. Lang kind of asked me a question along this line and the other part of it that I believe is that potentially there could be a ramification of if you eliminate it sooner, eliminate those provisions sooner, it could have a kind of a circular impact and that it could impact the RSR calculation to the extent that we're moving that causes some seasonal switching, it could flow through and cause the RSR calculation to go up. So those are the two issues why I believe that waiting till January 1, '15, benefits both customers and CRES providers.

Q. Have you done any analysis to show how the RSR would be affected if the provisions were eliminated sooner?

A. No, I haven't. It was kind of a thought exercise we had.

Q. Okay. Now turning to the generation resource rider. The proposed GRR is a nonbypassable rider, correct? Page 12.

A. Thank you. Yes, it is a nonbypassable rider.

Q. And it's proposed to pay for new generation assets to serve SSO customers, correct?

A. Yes. I view it as generation assets owned by AEP -- owned or invested in by AEP Ohio and, I apologize, I haven't looked at that section of the Revised Code in a long time to be as precise as you might like me to be on this answer.

Q. I guess a better way to say this is if a customer's shopping, they will not be served by that generation asset under the GRR.

A. That's kind of the way I look at it. And I think it's consistent with what Mr. Nelson did in the Turning Point calculation was the SSO customers really won't be served by it either, it's effectively liquidated in the market and it's basically nothing more than a financial hedge for SSO customers.

Q. But the GRR is paid by both shopping and SSO customers.

A. That is correct.

Q. So would you agree that shopping customers will be subsidizing the generation assets benefiting other customers?

A. No, I wouldn't. I guess the way I view it is the GRR mechanism, if an investment is approved by this Commission to be made by AEP Ohio and included in the GRR, it's basically ensuring it's a, I'll use the term "financial hedge" or it's an insurance policy that benefits both shopping and nonshopping customers because a customer can change between those two states as a shopper or a nonshopper periodically.

So it's really kind of a Commission-approved hedge for customers taking SSO or a customer who may at some time either in the -- may at some time in the future elect the SSO.

Q. So if I understand you correctly, the only time a shopping customer would benefit from a generation asset under the GRR is when they switch back to SSO service.

MR. SATTERWHITE: At this point I'll object, your Honor, it extends beyond the scope of this witness's testimony.

MS. THOMPSON: Respectfully, your Honor, he testifies to the GRR and I think that he would be the witness most appropriate to answer questions on this rider.

MR. SATTERWHITE: I think Mr. Nelson also covered this area of how, this witness more designs on the design of the GRR and the zero placeholder for it, not the impact of what the generation resource is and the hardware that might go into it.

EXAMINER SEE: The objection is overruled. The witness can answer to the extent that he feels comfortable.

THE WITNESS: Can you read the question back?

(Record read.)

A. No, I wouldn't agree with that. I think the benefit -- obviously the Commission has to approve all of that, you know, they have to approve the modified ESP, they have to approve the appropriateness of an asset being included in the GRR, but I would generally think that the Commission, in that evaluation, would determine that it's beneficial to have that asset owned by the wires company or they wouldn't approve it so it would never get in the GRR. So I would presume their determination is it's beneficial to all customers to have that.

Q. I'll move along. Are you on page 12 of your testimony?

A. Yes, I am.

Q. Okay. On lines 6 through 8, you testify that "the rider is simply a placeholder until such time as the Commission approves costs to be recovered in a separate proceeding"; is that correct?

A. Correct.

Q. And during that separate proceeding is AEP planning to address the credits produced by the GRR funded assets, I'm sorry, the credits I'm referring to are the renewable energy credits, or RECs.

A. That would be my understanding.

Q. Okay. And if the GRR is approved as a nonbypassable rider for all customers, it would make sense for all customers to benefit from the renewable energy credits produced by GRR-funded assets.

A. To the extent it's a renewable facility, that makes sense to me that, I think it would also have been a good thing to ask Witness Nelson.

Q. Do you mind turning to page 237 of 238, to the actual GRR language in your Exhibit 5?

A. I'm there.

Q. When looking at the language proposed by AEP, is there any language concerning the renewable energy credits?

A. Not in this language because this language is kind of a placeholder like the whole rider itself. It's kind of the generic rider language that you can see on several of the rider pages in this book that more -- anything related to that would be in that later proceeding where we're seeking authority to include something in the GRR.

Q. And when you say "include something in the GRR," you mean actually amend the GRR rider language to include renewable energy credits?

A. It's kind of an interesting technical question as to whether upon the Commission -- if the Commission approved the placeholder rider in this proceeding, whether we'd actually put the tariff sheet in with a rate of zero or have no tariff sheet, until there's some point in time when something is actually approved and institute the tariff sheet in that time.

So I think any issue related to the actual rider language, other than just this very plain vanilla placeholder, to me would be addressed in that later separate proceeding.

MS. THOMPSON: That's all the questions I have. Thank you very much.

MR. SATTERWHITE: Could we go off the record for one second?

EXAMINER SEE: Yes.

(Discussion off the record.)

(Recess taken.)

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

Mr. Yurick.

MR. YURICK: Thank you, your Honor.

\- - -

CROSS-EXAMINATION

By Mr. Yurick:

Q. Mr. Roush, could you turn to page 12 of your testimony?

A. I'm there.

Q. I wanted to ask you some questions about the retail stability rider, okay. On line 11 you say the RSR, retail stability rider, is that right? That's what "RSR" stands for?

A. Correct.

Q. Is designed to recover AEP Ohio's proposed retail stability charges, correct?

A. Correct.

Q. Now, I apologize, but respectfully, I mean I don't understand what that means. AEP doesn't get a bill that says amount due for stableness, right? I mean what does that mean? What proposed retail stability charges are you talking about that you need to recover?

A. It's basically the amounts supported by Witness Allen.

Q. So let me ask you this: You're not testifying --

A. Excuse me.

MR. SATTERWHITE: Objection. Was the witness done? He was still speaking, I think, when you --

MR. YURICK: I'm sorry, I was trying to speed things along, Mr. Satterwhite.

MR. SATTERWHITE: I know; I just want to

make sure he's able to answer the full, not just part, of the question.

Q. I apologize. Were you not finished?

A. I think I was done.

Q. Let me ask you, so you're not really the person to talk about what those charges -- what retail stability charges really are comprised of; is that right?

A. No. Witness Allen would have performed the derivation calculation and then just provided the amount to me to design the rider.

Q. That's fine. But you're not -- my point is you're not really aware of exactly what that entails; is that right?

A. As kind of we were discussing earlier, I have a high level of knowledge and I think I itemized some of the elements of it, but not the depth that Witness Allen could address.

Q. I think what you said earlier was that this was a rider that was meant to recover fixed costs. Do you remember that?

A. Yes, I think it might be in my testimony, too.

Q. And you said that fixed costs usually necessitates or would indicate a demand allocation;

is that right?
A. Correct.
Q. And I'm guessing the variable cost as a corollary ordinarily would be not an energy allocation or -- I mean, it would be an energy allocation, not a demand allocation for variable costs, wouldn't it?
A. Correct; and a great example of that would be the FAC.
Q. And you also said earlier that rates should be designed to avoid cross-subsidies both between and within classes. Do you remember that?
A. I think that was in the context of a fairly lengthy discussion around traditional cost-of-service world, which I don't believe Ohio is quite in that paradigm for a generation.
Q. But to the extent you can, as a general proposition, you should design rates that avoid cross-subsidies both between and within classes, shouldn't you?
A. Again, I go back to that previous answer that in the traditional cost-of-service regulation environment those are principles that I would support generally that cross-subsidization between and within classes should be avoided.

Q. The retail stability rider, that's designed as a charge per kWh that varies by customer class; is that right? That's your testimony?

A. That's correct. The costs are allocated to the classes based upon demand and then converted to a rate per kilowatt-hour by class.

Q. And that kilowatt rate, that charge per kilowatt-hour, that's what's known as an energy charge, isn't it?

A. Well, it's a charge per kilowatt-hour, it depends on the context, some would call it a rider charge.

Q. Well, since the more energy you use, the more you pay, because it's a per kWh charge, it's an energy charge, right?

A. It's a charge per kWh. When I hear "energy charge," I generally think of base rates.

Q. So you say in your testimony "The first step of the design was to allocate the costs to customer classes based upon the class's average contribution to AEP Ohio's load during PJM's five highest peak loads." Right?

A. That's correct.

Q. And you're referring there to the contribution to capacity, right? The 5CP capacity.

Yes?

A. The 5CP that's used to determine capacity obligation.

Q. Right. So then your second step after you allocated the costs by capacity was to divide the allocated cost by the metered energy for each customer class to determine the rate per kWh for each customer class; is that right?

THE WITNESS: Could you just read back the very beginning of that question?

(Record read.)

A. Yes, I'd agree with that.

Q. But if costs are allocated pursuant to contribution to demand, shouldn't you have calculated that on the basis of a demand charge per customer?

A. It could be done that way for those classes that are -- include -- the entire population includes demand-metered customers, however, none of the classes set out in Exhibit DMR-3 include only demand-metered customers. Even the GS-2, GS-3, GS-4 class includes customers on time-of-day rates which don't have a demand meter.

Q. But there are other methodologies that you could use to compensate for that if you decided to go with a demand charge, isn't there?

A. If you're asking me could the rate be designed differently.

Q. Yes.

A. Yes, the rate could be designed differently. I proposed a methodology that I think is the most straightforward and simple for this rider design.

Q. Well, it may be simple, but the way that you've designed this RSR, don't high-load factor customers end up subsidizing low-load factor customers within their rate classification?

A. Not unless you assume that there is no correlation between load factor and coincidence ratio.

Q. I'm not saying that there's no relationship between the contribution to peak and energy, but that's an imperfect one, right? With the high-load factor customer versus a low-load factor customer. Isn't that right?

You might have a very high peak demand, but if your load factor is low, you're not going to pay as much in energy charges because you're not using as much power, right?

A. I think the problem with your statement you just made there is that if I have a high peak demand, that's not what's relevant. It's what your demand is at the time of the 5CPs and a low-load factor customer could have a high peak demand that's not coincident with the 5CPs, and therefore it doesn't warrant a higher allocation.

Q. Okay. But I guess what I'm saying is there could be customers, particularly low-load factor customers, who happen to not use much energy but might contribute to your higher demand levels at the 5CP measuring points, right?

A. There could be, and I think that's where anytime you design a rate for a class of customers, there are diverse -- there's a diverse population within that class, and to say that -- what you tried to state earlier is that high-load factor customers are subsidizing low-load factor customers, I can't agree with that because there are low-load factor customers who aren't coincident who deserve a lower charge, there are low-load factor customers that are higher coincident that may deserve a slightly higher charge, and then there are high-load factor customers that are higher coincident.

So when you put a class of customers together there's a certain amount of diversity among that class and any charge, whether it's a demand charge, an energy charge, a straight dollar-per-month charge, there are going to be imperfections in that design.

Q. So the fact that you allocated based on demand and then calculated kWh energy charge, you would consider that an imperfection in your rate design, correct?

A. No, I would not.

Q. I thought your testimony was that there could be customers in that rate class for whom that rate wasn't fair. Right?

A. No, that wasn't my testimony.

Q. Well, I think -- was it not your testimony that there could be high-load factor customers in a particular rate class that by paying an energy charge that's allocated on the basis of demand might be subsidizing low-load factor customers?

A. No, I think you're misconstruing my testimony. I said they could be either way. They could be -- under any design they could be theoretically, based on your premise, either overpaying or underpaying.

Q. Well, that's my point is that there are customers who could be overpaying, for example, high-load factor customers could be overpaying an energy charge and subsidizing low-load factor customers who contribute to the 5CP peak demand requirements on an equal basis, right?

A. Or the -- I guess I'm struggling with it because you're kind of assuming things within your statements.

Q. I'm asking a hypothetical, that's right. So I am assuming things within my statement. What I'm saying, as a general proposition, there are hypothetical high-load factor customers out there who may be paying more than they should because of your allocation, correct?

A. Or less.

Q. I understand that "or less," but "or more," right?

MR. SATTERWHITE: At this point I'll object, your Honor. I think we've belabored this point. The witness has stated his understanding. I think now he's just arguing with the witness.

MR. YURICK: I'll move on, your Honor. I apologize. I don't mean to argue.

Q. Would you agree that generally when costs are allocated on the basis of demand, they should be recovered on the basis of demand as a general proposition in rate design?

A. No; because I've proposed in numerous jurisdictions load factor type rates that have a demand cost recovered through a first block per kWh energy charge and I recall even making that same proposal in this proceeding back in January of 2011.

Q. So you think that it's fine, that your testimony is that you think -- I'm sorry, could you explain that? You're saying that you don't agree that generally, as a general proposition, when costs are allocated on the basis of demand, that they should be recovered on the basis of demand?

A. Correct. I think there are a number of rate designs that can accomplish the same thing without going to what you're describing as a full DEC rate where all demand costs are in the demand charge, all energy costs are in the energy charge, all customers costs are in the customer charge.

What I was referencing is in other jurisdictions and in this program back in January of '11, the rate design I proposed for the generation rates did not have a demand charge but had an energy charge that was tiered based on kWh per kW.

Q. But, sir, wouldn't you agree with me that in an ideal world the ideal rate would have all the customer charges in the customer charge, all the energy costs in the energy charge, and all the demand costs in the demand charge?

A. No, because I think that has the potential to unfairly burden low-load factor customers.

Q. But you don't see that there's a converse risk in doing it the way that you did it against high-load factor customers?

THE WITNESS: Can you read that back?

(Record read.)

A. I think there can be a risk in either of the designs. I think that there can be an argument made, which you've been making --

Q. I've just been asking questions, I thought. Go ahead.

A. -- that to the extent that a cost is allocated on a per kilowatt-hour basis, that that collection mechanism could disadvantage one set of customers versus another set of customers, but I think that is equally true of any collection mechanism including a full demand charge.

Q. Fair enough, sir.

Let me ask you, moving on to a different topic -- I know you're hating to move on to another topic -- but let me get to page 13. You talk about the distribution investment rider.

A. I'm there.

Q. Then you describe sort of the rider mechanism but you don't really describe what costs that rider is designed to capture, correct? That's another witness, right?

A. Witness Allen talks about it, but I do briefly touch on it in the very first line on line 4, page 13.

Q. Right.

A. It's a carrying charge on distribution net investment.

Q. Now, currently AEP Ohio is able to recover, through distribution rate cases, the investment that it makes in its distribution system; isn't that correct?

A. As a general construct we are allowed to file base distribution rate cases in Ohio. Currently we have the order approving the stipulation in the last base rate case which anticipated the collection under a DIR for which we're not collecting anything at the moment.

Q. Okay. Yeah, my point is just generally the company invests in its distribution system and normally files a distribution rate case in order to recover the costs that it incurs and the investment that it makes in its distribution system, right?

A. I don't know that I'd say "normally files," because we filed one in 2010 and that was the first one ever.

Q. Okay. But that methodology is available to you.

A. The filing of distribution base cases is permissible under current Ohio statute or rules.

Q. And that will allow you to recover your investment in your distribution system including things like carrying charges on distribution net investment, right?

A. I'm sorry to pick nits, but I don't know that that will allow us anything, it allows us the opportunity to come before the Commission and seek to recover.

Q. My point is you can ask and if the Commission thinks that your request is well premised, then it will allow you to recover those in rates, right?

A. I believe that was my point as well.

MR. YURICK: Thank you very much, sir.

I have nothing further at this point.

Thank you, your Honor.

EXAMINER SEE: Ms. Hand?

MS. HAND: Thank you, your Honor.

- - -

CROSS-EXAMINATION

By Ms. Hand:

Q. Good afternoon, Mr. Roush.

A. Good afternoon.

Q. Before we get started, do you have with you up there both a copy of your deposition transcript and a calculator?

A. No, I do not. I'll have to borrow a calculator.

Q. Okay.

MS. HAND: Permission to approach, your Honor? We have a calculator.

EXAMINER SEE: You may.

Q. Ready?

A. Yes, ma'am.

Q. Okay. I'm going to start on the PIRR. Now, isn't it true that in its application the company is proposing to blend the PIRR rates applicable to the Ohio Power zone and the Columbus Southern zone into a single PIRR?

A. That's correct, the company's proposing to implement the PIRR in June of '13 on a merged or unified basis.

Q. Now, isn't it true that the deferred balances to be collected through the PIRR reflect amounts that have not yet been paid by customers for their energy use during the first ESP period of 2009 to 2011?

A. Generally the amounts in the PIRR relate to deferred FAC costs.

Q. So those are costs that relate to energy consumption during a prior period.

A. I guess they relate to uncollected costs of the condition during a prior period related to the FAC, so I'm not sure I directly tie it to energy consumption of any particular customer.

Q. So isn't it true, then, that of the approximately 150 million PIRR annual revenue requirement, about 1.9 million comes from costs that were incurred by Columbus Southern to serve its customers during the prior period, while about 148 million comes from costs that were incurred by Ohio Power to serve its customers during the prior period?

A. If you're looking at workpaper DMR-8, page 8, the annual revenue requirement, those look like about the rough round numbers, 1.9 million for the CSP rate zone, 148.4 million for the OP rate zone.

Q. So you would agree that the overwhelming majority of the PIRR balance arises from the Ohio Power rate zone.

A. Yes, I would agree with that.

Q. So then isn't it true that if the PIRR is merged or unified and those costs are recovered from both zones, Columbus Southern customers will ultimately pay for costs that Ohio Power incurred to serve its customers during the 2009 to 2011 period?

MR. SATTERWHITE: Objection, your Honor. This case is about the delay of the effectiveness of the PIRR. There's a whole other case dealing with the merger of the PIRR and what goes into that PIRR. It's simply not part of the modified ESP, it's beyond the scope of this case.

MS. HAND: This goes directly to the rate impact on the customers, your Honor.

EXAMINER SEE: I'll allow the witness to answer the question. The objection is overruled.

THE WITNESS: Can you read me back the question, please?

(Record read.)

A. I would say that the deferrals, as we've discussed, relate to each rate zone or to the previous companies prior to merger.

After merger, the regulatory asset is basically a single regulatory asset for the now-merged Ohio Power Company and, as such, the collection of this merged value, consistent with the merger of the FAC, produces -- holds basically both Columbus Southern Power and Ohio Power Company customers -- rate zone customers neutral.

Q. But isn't it true that the FAC reflects costs that are being incurred by the company to serve its entire load as one load going forward; whereas, the PIRR reflects costs that were incurred by each of the two separate companies in a prior time period to serve their then-existing customers?

A. I guess I don't view that as particularly relevant. And I recall the Monongahela Power acquisition timeframe where Columbus Southern Power acquired Monongahela Power, and costs related to that acquisition were paid by all Columbus Southern Power customers, so the -- wherever you were before is really not so relevant, it's what are you now when they became Columbus Southern Power customers, at that time Monongahela Power customers as well as all other Columbus Southern Power customers paid a fee at that time. So I view this situation very similarly.

Q. But whether or not you believe the question was relevant, was the statement true that Columbus Southern customers or customers in the previous Columbus Southern zone -- I'm sorry, I went back one question too far.

Isn't it true that the FAC is looking at costs going forward to serve the company on a unified basis; whereas, the PIRR is looking at recovery of costs incurred in a previous time period to serve the customers of the two separate companies during that time period?

A. That's a long sentence for me to remember. Can you read that back?

(Record read.)

A. I would agree that the FAC is an ongoing look at current and future costs, and the PIRR is a collection of previously incurred and deferred costs.

Q. Thank you.

Moving on to the IRP-D. AEP Ohio's proposed interruptible tariff service is a form of demand response, isn't it?

A. I think you could generally categorize it that way, yes.

Q. Okay. And it's true, is it not, that AEP Ohio uses interruptible load as part of its FRR plan to meet its capacity needs?

A. Yes, and I think we talked about that earlier, that there are two types of resources effectively, that I'm aware of; there's generation, actual power plants, and capacity or emergency demand response, and those two resources are used as part of the company's FRR plan to meet its capacity obligation.

Q. So isn't it also true that when AEP Ohio counts such interruptible load as part of its FRR requirement, the customer taking interruptible service is unable to also sell that capacity into the PJM market?

A. I think that's correct that a customer who elects schedule IRP-D currently or proposed rider IRP-D during the term of this ESP, their commitment under rider IRP-D, the company uses that as a resource in its FRR plan.

If it's being used as a resource in the company's FRR plan, PJM rules will not allow them to also sell that same resource into the RPM auction. And so -- but.

Q. That answers the question.

A. I think that's fully appropriate.

Q. Now, it is also true, is it not, that under rider IRP-D as proposed, a customer must contract for the electrical capacity sufficient to meet its normal maximum requirements?

A. Yes. On Exhibit DMR-5, page 196, it says "Customers shall contract for electrical capacity sufficient to meet normal maximum requirements but not less than 1,000 kW of interruptible capacity."

So they'll contract for their firm service -- for their entire needs under the firm tariff and then to the extent they offer -- want to offer up interruptible capability, they'll specify how much interruptible capability they're offering up under rider IRP-D.

Q. Now, does that mean that a customer must commit all of its load to interruptible service -- that it may not elect to take only part of interruptible service for only part of its load.

A. Oh, no, absolutely not. Because I described in the previous answer they contract under the applicable firm service tariff for their normal maximum requirements, and then they specify how much of that, but not less than a thousand kW, that they want to offer up as interruptible.

Q. Now, if a customer enters into either a reasonable arrangement regarding interruptible service with the company or it takes interruptible service under the tariff for a portion of its load, is there anything that would prevent the customer from offering a different portion of its load into the PJM market?

A. I believe, depending on the particular product you're talking about within the PJM market, there are rules against having multiple curtailment service providers for the same entity that are PJM rules.

So to the extent that we were -- that a customer signed an interruptible agreement with us for a certain amount of capability, that my understanding is PJM would not allow, effectively, two curtailment service providers, so someone else couldn't register another portion of their load for the capacity market.

Q. But your understanding is that nothing in the AEP tariff would prohibit that, that that is caused solely by PJM's rules?

A. I believe that's correct. I can't think of anything in the tariff that would preclude such an action. It's really a function of PJM rules is my understanding.

Q. Now, is it true that AEP Ohio does not intend to take the megawatts that are signed up as part of the proposed rider IRP-D and offer those megawatts into the PJM RPM base residual auction for the planning year 2016-2017, 2017-2018, or the 2019-2020 auction?

A. No, I do not believe we would do that because, first and foremost, rider IRP-D is only for the term of this ESP which runs through the term 2015. So to make a commitment into those base residual auctions wouldn't make sense, given we have no certainty of having IRP-D customers after May of '15.

Q. Okay. So turning to the FAC rates, with the significant shopping load expected and the number of customers anticipated to leave the system, would that in any way affect the FAC rate to the remaining FAC customers?

A. I don't think so, but I'm not the FAC expert. That would probably have been better asked of Mr. Nelson.

Q. So you would not know whether, if customers leave -- as customers leave the AEP Ohio system, whether the remaining customers pay an increasingly higher percentage of the FAC?

A. That wouldn't make sense to me. FAC being primarily fuel costs, it's, you know, if I'm serving 20,000 megawatt-hours or 10,000 megawatt-hours, the cost per megawatt-hour generally is going to be in the ballpark pretty close. I mean, there's going to be some nuance differences, but --

Q. Okay. Do you know whether the AEP generators operate any differently, more or less efficiently, with a significantly reduced load?

A. I don't know, but I would -- I wouldn't think so because of the PJM dispatch that all units in PJM are dispatched by PJM, so, I mean, there's kind of the real-world operation of the system, which is what PJM's taking care of, and then there's, for lack of a better word, the accounting of, well, who's responsible for which load.

So the fact that a customer shops doesn't -- I can't see how it makes much difference on the dispatch of the broader PJM footprint.

Q. Okay. Thank you.

MS. HAND: Your Honor, the remainder of my questions pertain to confidential information. I'm happy to go into it now or to hold it until the completion of all the cross. Whatever's easier.

EXAMINER SEE: You can hold that.

MS. HAND: Okay.

EXAMINER SEE: Ms. Kaleps-Clark?

MS. KALEPS-CLARK: Thank you, your Honor.

EXAMINER SEE: Let's go off the record.

(Discussion off the record.)

(Thereupon, a lunch recess was taken at 2:42 p.m. until 3:30 p.m.)

- - -

Tuesday Afternoon Session,
May 22, 2012.

- - -

EXAMINER SEE: Let's go back on the record.
Ms. Kaleps-Clark?
MS. KALEPS-CLARK: Thank you, your Honor.

- - -

DAVID M. ROUSH
CROSS-EXAMINATION

By Ms. Kaleps-Clark:
Q. Good afternoon, Mr. Roush.
A. Good afternoon.
Q. Can you please turn to page 4 of your testimony.
A. I'm there.
Q. And here you state you will be continuing a number of provisions in your current tariff including the switching charge or fee. Have I stated that correctly?
A. Yes. Yes.
Q. Okay. And I'm going to ask you a few questions about the switching fee following up on Mr. Lang's discussion earlier.
Now, the switching fee or charge is the

fee that AEP Ohio assesses to SSO customers who opt to switch to a CRES supplier and you also assess those to SSO customers that -- or, shopping customers that return to the standard service offer; is that correct?

A. I believe that's with the clarification that with the first switch, there's no charge for the first switch of an SSO supplier to a CRES supplier.

Q. And you stated previously that the fee is $10.

A. Correct.

Q. Okay. Now, do you know what the switching fees are in the other Ohio service territories, that is, the DP&L, FirstEnergy service companies, and Duke?

A. No, I do not.

Q. Would it surprise you if the switching fees in these other service territories are half the price of AEP Ohio's switching fee?

A. I don't know if it surprises me, I have no basis to know one way or the other.

Q. Now, can you tell me, and again, you said briefly AEP Ohio's switching fee is a cost-based charge; is that correct?

A. That's my recollection, that the original basis for it was a cost calculation done back in like '99 timeframe and then I think the value may have been updated during the course of that proceeding based on the development of some of the activities and responsibilities defined in the rules for switching.

Q. Now, when you say it was updated during the course of that proceeding, you mean during the course of that '99, I believe it was an ETP case?

A. That's my recollection, yes.

Q. So it was updated during the course of that proceeding.

A. That's my recollection, yes.

Q. Okay. And can you tell me specifically what costs the switching fee is intended to recover?

A. Not really. I know there are elements dealing with, you know, the actual transactional work that's done, I assume there are elements related to like letters that have to be sent to customers or notices or rescission-type activity, but I don't have anything specific beyond that of what all went into it.

Q. Okay. Could I refresh your memory with a discovery response? I'd like to mark as RESA Exhibit 101, Ohio Power Company's responses to RESA's discovery requests in the modified ESP. It's the first set and we're looking at -- we're initially going to look at discovery responses 1 and 2, but we'll also attach, though, 3 and 4 which we'll discuss later.

MS. KALEPS-CLARK: Your Honor, may I approach?

EXAMINER SEE: Yes.

(EXHIBIT MARKED FOR IDENTIFICATION.)

Q. Mr. Roush, do you have what has been marked as RESA Exhibit 101 in front of you?

A. Yes, I do.

Q. And can you go ahead and take a look at the first two pages, we'll start with what is interrogatory 101 -- or, I'm sorry, 1-1.

A. I see that.

Q. And here I'm asking, please provide a detailed explanation of what costs the switching charges that are referred to in your testimony are meant to recover, and below you have the explanation you just gave regarding the ETP cases as well as a list of charges that the switching charges intended to cover, or a list of costs that the switching charge is intended to recover. Do you see that?

A. Yes, I do.

Q. Okay. And if you look at the second page, there's a similar question asking to provide a detailed explanation of how the costs of the switching charges detailed in interrogatory 1 were determined, and you reference again your answer on the first page. Do you see that?

A. I see that.

Q. Okay. Now, this is, again, a little bit more detailed list of what you just provided; is that accurate?

A. Looks like it includes some things that I couldn't remember off the top of my head.

Q. Okay. Now take a look at this list, and I'm just wondering, can you -- can you specifically tell me if there are any factors listed here that are unique about AEP Ohio's switching costs that you believe justifies the higher $10 rate?

MR. SATTERWHITE: Objection, your Honor. I don't think it's been established that the rates -- you're referring to the other jurisdictions?

MS. KALEPS-CLARK: Correct.

MR. SATTERWHITE: I don't think there's been anything to establish the other jurisdictions are higher.

Q. Let me rephrase the question, then.

When you look at these costs that you listed here, are there any costs that you would consider an extraordinary cost, costs that perhaps other utilities wouldn't have?

A. Specifically other utilities in Ohio?

Q. Specifically Ohio, or if there's anybody -- even broader than that, if there are other specific costs in here that you believe are extraordinary.

A. Like a utility in Indiana would have none of these costs, but as far as a utility in Ohio, I presume they're under the same rules as we are, but I don't know how they've chosen to collect their costs between what's in a switching fee and what might be in their base distribution rate.

Q. So there's no specific cost factor in here that you can point to that would perhaps justify a higher switching fee?

A. I think, as I said previously, I don't know how the other utilities set their switching fee, let alone what the number is, so I can't speak one way or the other. I don't even know if they're an apples-to-apples comparison.

Q. Again, you discuss in -- as you state in your response here, that the switching fees were determined as part of the ETP cases in 1999.

A. That's correct, that's my recollection, they were established in the ETP cases.

Q. And since that time have the costs been updated or has the charge been updated?

A. The charge has not been updated to my knowledge since that time.

Q. So then, again, you haven't looked or reevaluated at these costs that are listed here that were the basis of the original $10 fee?

A. I have not done that analysis, no.

Q. Okay. Now, you've described the costs that the switching fee is intended to recover and those costs all relate to the switching process, the process of moving an SSO customer to a CRES provider and vice versa, correct?

A. Just looking at the list here, it appears it says they "generally recover a portion of the costs related to items including," and then it lists a bunch of activities that all appear to me to be related to the switching process.

Q. And can you describe briefly or generally how that process works? Are you familiar with the switching process?

A. At about a 50,000-foot level. It's not part of my day-to-day responsibility. Generally I understand there would be some kind of enrollment received and processed, there's some duties we have to do related to notifying customers of their rescission rights and that kind of thing, but -- and I assume there's some kind of interaction between the provider and the company, but other than that I can't really go into any more detail.

Q. Okay. So since the year 2000 when the switching fee was established, or I believe it was 1999-2000, since that time period when the switching fee was established, do you know whether there have been improvements in the technology that's used for the switching process?

A. I think we had that discussion earlier. I would assume that software and whatnot that was built back in '99-2000 has probably been updated, modified, all that kind of stuff, because technology just doesn't last that long anymore, but I don't have any specific knowledge of it.

Q. Okay. Do you know whether it's true that an automated switching system has been implemented since the ETP cases in which the switching fee was determined?

A. Only by answer to the fourth page here, I guess.

Q. Okay. Well, you beat me to it. Can you go ahead and look again, then, at the third and fourth pages here starting with the fourth page. Have you -- are you familiar with this response?

A. I think I may have seen -- this was the response last week, but I didn't write it and didn't prepare it.

Q. Now, to the best of your knowledge, though, is it true that you have an automated rather than a manual system for switching?

A. That's what the response says, and I have no reason to doubt its validity.

Q. Okay. So, again, taking a look at this interrogatory on page 4, the question asked "If Ohio Power Company uses an automated switching system, please state when the system was put into operation."

And tell me if I'm reading this correctly, "The automated switching system was in place in 2000." And "the first effective date of switching was January 2, 2001."

MR. SATTERWHITE: Your Honor, at this point I'll object. This witness didn't prepare this; the witness that did is still coming up. I think Mr. Roush has answered what he's known, but I don't think we need to ask him to read another witness's statement when that witness can be asked about it.

MS. KALEPS-CLARK: That's fine, I'll withdraw the last question.

EXAMINER SEE: Thank you.

Q. Okay. Moving on, Mr. Roush, also on page 4 of your testimony you discuss how you will be adding peak load contribution information, PLCs, and net service peak load, NSPL's to the master customer list.

A. Yes.

Q. Do you know how this information will be provided? For example, will there be electronic data interchange transactions or EDI transactions used to provide the information?

A. I don't know. My recollection of the language in the tariff says that the master customer list is available on, I suspect it's DVD or something. I don't know about EDI transactions at all.

Q. Okay. And do you know what the format of that information would be, then? Would it be provided in 867 HU or 867 HI or, again --

A. I don't even know what those are.

Q. So the answer is no, then; is that

correct?

A. Correct.

Q. And do you know how often that information would be provided?

A. My recollection is the master customer list is updated quarterly is my recollection.

Q. Okay. And then my last set of questions here. Now, could you tell me how much the RSR, which is the rate stability rider, will add to the bill of the typical, let's look at the residential customer, commercial customer, and industrial customer?

A. I can do typical residential because we use a nice round figure of a typical residential customer uses a thousand kilowatt-hours, so for my Exhibit DMR-3, the RSR would be for a residential customer using a thousand kilowatt-hours, $2.66 a month.

I don't really know for a typical commercial or industrial customer because I'm not sure what they are in my testimony. I kind of identified kind of a select sampling of customers on the table on page 16.

If we were to use that information, let's say a small business customer as shown there using a hundred thousand kWh per month, that would be roughly $1,695, which as shown in kind of the exhibit on -- or, page 16 of my testimony, the LSR component would be $1,695 for that customer, their monthly bill would, net of all the changes proposed, would only be going up $290 or 2 percent in the CSP rate zone and $738 or 5 percent in the OP rate zone.

So the RSR in isolation is for that hundred-thousand kWh customer is $1,695, but net of all the other changes they actually see lower increases than that.

I could do the similar thing for an industrial customer if you wish for me, but it's a little harder because I don't have nice round numbers there.

Q. But we would use that same methodology that you just described to determine the industrial customers?

A. Yeah, you would use the RSR rate times the kWh usage to say this is the amount of the RSR and then put to put it in further context you say, well, the RSR is only one element of the whole plan, so the rest of the changes that are shown on page 16 would be the other elements.

Q. And that response, is that for the first year of the RSR?

A. Since we proposed kind of a levelized RSR over the period based on the forecast that Witness Allen did, that amount, subject to reconciliation trueup that we talked about earlier, is what we were expecting it to be for the three-year period.

Q. Okay. And also if AEP Ohio, I'm wondering if you've identified a point beyond which it would be inappropriate to charge the RSR. And let me give you a little context for this question. My understanding is in order to meet I believe what's the 929 million annual revenue, is that -- that's the ultimate goal would be RSR to meet that 929 million annual revenue; is that correct?

A. That sounds right, but probably better asked to Witness Allen.

Q. Okay. But, essentially, the RSR fills in the gap between the revenues that you're granted in the -- or, that you're asking for in the ESP terms with the 929 million ultimate annual revenue goal; would you say that's accurate?

A. From my limited understanding that sounds right, but, again, I'd suggest you talk to Witness Allen.

Q. Okay. I'll ask another question; again, if this is something better for Witness Allen, just let me know.

So let's say that you're expecting to charge, I believe it's -- is it 44 million for the first year with the RSR?

A. I'm sorry, I'm having trouble hearing you. Did your mic die?

Q. Are you expecting to charge 44 million with the RSR?

Can you hear me now?

A. Yes, thank you.

Q. So is it true that you're expecting to charge approximately 44 million in the first year with the RSR, that's what you're expecting to recoup through the RSR?

A. I don't think so. That number sounds vaguely familiar like it might be in Witness Allen's exhibit as part of the three years of numbers that add up to the 284 or 280, I think it's 284.1 or something like that, million dollars.

But what we proposed is to set the RSR on a levelized basis across the period based on that projection so that the charge would remain stable through the three years subject to the trueups and stuff that we had discussed.

So if that number, I'm not sure that's

the number or not, I don't remember, if we got to that first annual trueup and the actual RSR revenue requirement was 50 million for the first year, the rider collected a hundred million for the first year, we'd say, well, we're overcollected by 50 million, we owe that to customers, but we think next year the RSR might be 150 million revenue requirement so we'll say, well, the revenue requirement's 150, we got it over 150, we're back to a hundred, so that's pretty close to the levelized charge that we're proposing.

Q. But, again, as we discussed previously, the RSR, the goal is to basically fill in the gap between the ultimate revenue goal which is 929 million what you will be able to recoup under the ESP terms, correct, that you proposed here? I think you stated that earlier, I just wanted to --

A. I think that's my general understanding from a thousand foot, but Bill can tell you in detail how he did it. Or, Witness Allen. I'm sorry.

Q. All right.

MS. KALEPS-CLARK: That was my last question. Thank you very much.

THE WITNESS: Thank you.

EXAMINER SEE: Mr. Stinson?

MR. STINSON: Yes.

CROSS-EXAMINATION

By Mr. Stinson:

Q. Just a few questions, Mr. Roush. You were talking with Mr. Lang earlier and I believe you indicated that AEP Ohio has not performed a generation class cost-of-service study since the early-'90s; is that correct?

A. That's correct. The last class cost of service that I'm aware of we did was back in the last bundled cases for the companies which were in '91 and '94. We used those same studies to unbundle the rates in the '99 ETP cases.

We've done class cost of service for distribution only in the 2010 cases, but I'm not aware of a class cost of service that included generation since those '91/'94 cases.

Q. The various rate classes you have listed on Exhibit DMR-3, were those developed at that early-1990 time or at different times? I'm trying to get a feel for that.

A. Most of those rate classes, and actually I think all of those rate classes existed prior to those cases, so they were in existence for years and years and years.

I remember looking at some historical

tariff sheets, I would assume residential's been there for -- some type of residential rate has been there for as long as the company existed there.

Q. What about the GS-2 and GS-3 rates?

A. You're testing my memory as far as whether they all existed prior to the '91 and '94 cases or whether some of them were created through merging and disaggregating some other tariff classes. I vaguely remember Ohio Power used to have an LP tariff or something like that, but that's a real test of my memory.

I think we would have done, if we were doing that kind of realignment of tariffs, generally we would have done a study based on the existing rate classes and then another study based on the proposed rate classes.

Q. So does that mean the 1990 timeframe would have been correct for those rate classes?

A. They all existed at least since the '91-'94 cases; many of them I think existed far prior to that.

Q. And have Ohio's primary and secondary schools always been included in rate classes GS-2 and 3?

A. Actually, I would say that schools in our service territory would have fallen in a number of different rate classes. Some of the facilities that their locations could have been on GS-1, I would say the vast majority are probably on GS-2 and GS-3.

There are also a couple tariffs that have been in the process of elimination for a number of years in the Ohio Power rate zone that would have also had schools EHS and SS, there may be schools on some of the other tariffs as well, I assume if they have any lighting facilities, they might be on the lighting tariffs as well.

But I would say the vast majority are probably generally on the GS-2/GS-3 schedules.

Q. The rate schedule SS, I believe you said in the Ohio Power rate zone is in the process of being phased out?

A. Yes. It's been in the process of elimination for as long as I can remember.

Q. How many schools are on that rate?

A. Looks like, rough ballpark, between 150 and 200, somewhere in that range.

Q. And for as long as you can remember -- let me put it a different way.

When did Ohio Power stop taking customers onto that rate?

A. I was hoping the tariff sheet would give me a clue, but it doesn't. At minimum, since their last rate in the '94 case, there haven't been any new customers placed on there since the '94 case for sure. It may have been prior to that, I just don't recall.

Q. You indicated there were between 150 or 115 and 200 schools on that rate schedule?

A. Between 150 and 200 was my rough ballpark.

Q. And am I correct that AEP Ohio does not maintain peak days for primary and secondary schools in its service territory?

A. We don't have a load research sample specifically for schools other than potentially that SS class that we were talking about previously. To the extent that a school is above 200 kW and has shopped, they've got an interval meter so that interval data would be available.

Q. Turning back to your DMR-3, I believe we've already been over the allocations are based upon the class's average contribution to AEP Ohio's five-day peak; is that correct?

A. Yes, that's correct, based on their -- the average of their contributions during each of those five hours, yes.

Q. And classes that placed a higher demand on the customer's system on those peak days would be allocated a higher percentage of the cost of the RSR?

A. Yes, that's correct. The higher the contribution during those five hours, the higher amount of costs that would get allocated to that particular class.

Q. I want to direct your attention next to DMR-3 again, line No. 6, where you talk about all metered megawatt-hours. What do you mean by that?

A. It's -- all metered megawatt-hours in lines 6, 7, 8, that's basically the total energy usage of all customers within that class as measured by their meters.

Q. For what period of time?

A. My recollection is that was based on projected 2012, the same data that I would have used to prepare Exhibit DMR-1 except for this would have included shopping customers as well.

Q. So that's for the entire calendar year 2012?

A. That's my recollection, it's a projection for calendar year '12.

Q. Now, turning to DMR-1, and that's a

summary of proposed rate increases, and are those average rate increases?

A. Yes. Everything I present in Exhibit DMR-1 is a -- are averages for the class of customers.

Q. Did you develop any document that shows the range of increases from a minimum to a maximum percentage increase of the rates?

A. Yes, in Exhibit DMR-6 and 7, if I can take you to Exhibit DMR-6, page 1, for example, the very first section, I show for schedule R-R-1 customer during the summer at the range of possible usages which are from zero to 700 kilowatt-hours, I show their current total bill, their June 2012 bill in the proposed ESP, the dollar increase and the percent increase.

You can see from that example it ranges from 6.22 to 9.12 percent, and I keep going across for 2013 and the range is from .34 to 2.01. Then when I get to 2014, I show it again and the range is from .45 to 1.22.

And I've done similar things for virtually all of the other rate schedules showing kind of a range of usage characteristics and what the bill impacts would be.

Q. So those would be the outliers, then, as presented on there, the upper range there would be as much of a rate increase as any customer would experience.

A. For summer -- for example, for the R-R-1 summer customer, yeah, the highest increase in 2012 is for a customer that uses no energy whatsoever. So you can really clearly, for like that example, you can define the entire range.

For some of the other tariffs similarly, you know, for an R-R-1 customer in the winter, I show usage from zero to 5,000 kilowatt-hours and the range of impacts from 5.08 to 9.12 percent, and, again, that happens to be the 9.12 is for a customer that has no usage whatsoever.

Q. Do you have that minimum/maximum range as well for the GS-2 and GS-3 customers?

A. Yeah, if you keep moving forward through Exhibit DMR-6, on page 3 of 11, I've done that for a range of usage levels starting with a very small customer using 10 kW, up to a customer, I'm looking at GS-2 secondary customer using 2,000 kW, and then at a range of kWh usage and you can see there the impacts for those customers for GS-2 secondary in 2012 are all less than 1 percent.

The other thing I did, and that was when I was here and Commissioner Porter asked the question the other day, was we looked at -- for GS-2, GS-3 and GS-4 customers we took a month and took all of those customers and did a bill analysis.

Just took one month for all those customers, ran a bill analysis and looked at the range of impacts that those customers would see in 2012, and that's roughly 65,000 customers between the two companies served on those tariffs.

And when we looked at that, there were, I think, a total of nine customers within that population that saw an increase of greater than 10 percent in 2012. And all nine of those customers were customers with basically no usage where all of their increase was the customer charge -- and the customer charge and the DIR. So it was a very small dollar amount of that increase but the percentage was like 12 percent for those customers.

So, you know, based on Commissioner Porter asking that question, I've actually got a table and a graph that shows that, that there were only nine customers, and that was both looking at bundled and shopping customers. And I kind of did the same thing I did with Exhibit DMR-6; I was looking at a shopping customer. I assumed for simplicity they were getting a 10-percent savings off of our SSO rate.

And, again, out of that whole population, there were only nine customers above 10 percent and all nine of those were customers with virtually no usage, so they were seeing very small dollar increases as a result of the DIR related to their customer charge.

EXAMINER SEE: Mr. Roush, what are you looking at? Is that something that's -- that's not in your current testimony?

THE WITNESS: No. It's something I put together based on the question I heard the other day.

EXAMINER SEE: Okay.

THE WITNESS: Which I'd be happy to share.

EXAMINER SEE: Thank you.

Q. (By Mr. Stinson) Moving along then.

MR. STINSON: I'm sorry, were you finished?

Q. Your testimony is outside of those nine outlying customers with little usage, that the maximum increase you'd expect for a customer in 2012, GS-1, 2, or 3, would be 10 percent or less?

A. Yes. I was just confirming because the data I looked at was GS-2, 3, and 4, I was looking at the typical bills in my testimony for GS-1, and other than those nine customers those are the only ones we identified with an increase over 10 percent and the vast majority are in the 4- to 5-percent range.

Q. I want to follow up on one of Ms. McAlister's questions that had to do with DMR-7, and I believe she asked a question that the rates you have in DMR-7 did not include capacity charges and you indicated that they did, I believe. Can you clarify that for me?

A. Sure. What I did in DMR-7 was I wanted to present information as far as DMR-6 shows what an SSO customer's increases are going to look like and I said, well, I want to present information on what a shopping customer's increases are going to look like under this plan, and I can't say what competitive suppliers are offering so I used a simplifying assumption that shopping customers are getting a 10 percent discount off of our SSO rate. So all I did was take our SSO rate, take 10 percent off of that, so that's what they're paying for the generation component.

And then for the other elements of the

plan that they would pay, like the retail stability rider, like the distribution investment rider, those are all factored in there so, yes, is there a specific value for capacity in there? Not really. It's just whatever our SSO rate is less 10 percent.

Q. Well, I think you answered my question that you really can't tell what a CRES provider is going to be offering.

A. I have no idea what a CRES provider offers. I just used a simple 10 percent based on we talked earlier about the Apples to Apples chart, that seemed like a decent representative number.

Q. So you didn't do any analysis as to what capacity charges the CRES provider would be charging their customers?

A. I did no analysis of what CRES providers are charging their customers. I have no way to know that.

Q. And you made no analysis of whether CRES providers would be passing through the increased capacity charges to their customer in making your analysis at DMR-7.

A. The reason I'm struggling with that --

Q. Well, there's an issue at least to the schools in the case that the company is requesting an increase in capacity charges for CRES providers. There's an issue of whether that sum will be passed through to the CRES providers' customers.

My question to you is just whether you made any analysis or assumptions that that capacity charge would be passed through in making DMR-7.

A. No, I did not make any assumption one way or the other regarding that because I don't know what the provisions of CRES contracts are.

MR. STINSON: Thank you. No further questions.

EXAMINER SEE: Mr. O'Brien?

MR. O'BRIEN: No questions, your Honor.

EXAMINER SEE: Mr. Margard?

MR. MARGARD: No questions, your Honor. Thank you.

EXAMINER SEE: Mr. Satterwhite, Ms. Hand has requested a closed session, I need you to determine --

MR. SATTERWHITE: Take roll call.

EXAMINER SEE: -- who cannot be in the room.

MR. SATTERWHITE: All right. Thank you. Off the record for a short second then?

EXAMINER TAUBER: Sure.

(Discussion off the record.)

EXAMINER SEE: Let's go back on the record to begin a confidential portion of the transcript.

(Confidential portion excerpted.)

(Open session.)

EXAMINER SEE: Mr. Satterwhite, do you

need time for --

MR. SATTERWHITE: No, your Honor.

EXAMINER SEE: Go ahead.

MR. SATTERWHITE: Should I go forward?

EXAMINER SEE: Yes.

- - -

FURTHER REDIRECT EXAMINATION

By Mr. Satterwhite:

Q. Mr. Roush, you also referenced in cross-examination -- I'm not sure who it was to at this point. That's all right.

Mr. Stinson asked you some questions about some rate impacts on some customer classes, and you referred to some work that you had done after hearing a question that Commissioner Porter had mentioned previously in the proceeding. Did you prepare a document reflecting the testimony that you gave?

A. Yes, I did.

MR. SATTERWHITE: Your Honor, at this point I'd like to mark AEP Exhibit 113. May I approach?

EXAMINER SEE: Yes, you may.

(EXHIBIT MARKED FOR IDENTIFICATION.)

Q. Mr. Roush, is the document I just placed in front of you as AEP Exhibit 113, the document you were talking about?

A. Yes, it is. And it's basically looking at one month of all GS-2, GS-3 and GS-4 customer impacts for 2012 using the same assumptions that I used in DMR-6 and 7.

MR. SATTERWHITE: Thank you.

That's all I have, your Honor.

EXAMINER SEE: Recross-examination, Mr. Serio?

MR. SERIO: Nothing, your Honor. Thank you.

EXAMINER SEE: Mr. Maskovyak?

MR. MASKOVYAK: No questions, your Honor.

EXAMINER SEE: Mr. Lang?

MR. LANG: No, thank you, your Honor.

EXAMINER SEE: Mr. Pritchard?

MR. PRITCHARD: No, your Honor.

EXAMINER SEE: Mr. Sineneng?

MR. SINENENG: No questions, your Honor.

EXAMINER SEE: Ms. Kyler?

MS. KYLER: No questions, your Honor.

EXAMINER SEE: Mr. Siwo?

MR. SIWO: No questions, your Honor.

EXAMINER SEE: Mr. Sugarman?

MR. SUGARMAN: If you please, your Honor.

- - -

RECROSS-EXAMINATION

By Mr. Sugarman:

Q. It may be me, but Exhibit 113 that you were just handed, could you help me understand percentage increase in what is being reflected on this exhibit?

A. Certainly. If you look across the bottom below the bars, there is a less than -- the percentage increase is kind of shown less than 0, 1, 2, 3, 4, 5, 6, 7, 8, 9, greater than 10, that's the percentage increases represented in each bar, and then below each bar are the numbers of customer bills that fell into that category.

So, for example, for the 1-percent range, there were 8,110 bundled customer bills and 5,051 shopping customer bills for 2012, under the assumptions in DMR-6 and 7, would see a 1-percent increase, so you can kind of see the vast majority of customers are in the 5-percent increase or less range which kind of ties back to what was in Exhibit DMR-1 and Exhibit DMR-6 and 7.

Q. And is the percentage increase over the total on DMR-1, page 1 of 2, the $8.79? Is that the base number from which this increase is calculated, Mr. Roush?

A. Not quite since this is only GS-2, GS-3, and GS-4 customers. It was actually the -- each customer, their bill under the rates for -- that are comparable to the average of 8.79 so the rates are comparable to the 8.79 but it's each individual customer's actual bill under those rates versus their actual bill under the rates comparable to the 9.19.

Q. And this is just the percentage increase through the end of 2012; is that correct?

A. I guess technically the calculation is really for June '12 to May '13 to be comparable with Exhibit DMR-1.

Q. And did you prepare a similar analysis for years beyond the 2013? Have you done so?

A. Actually, yes, I did, year over year.

Q. Did you bring that with you today?

A. Yes, I do.

MR. SUGARMAN: I guess if we could make those available at an appropriate time.

THE WITNESS: Yes, we could.

MR. SATTERWHITE: We can mark that as AEP Exhibit 114 if that helps the Bench.

MR. SUGARMAN: This is just one

additional page then, Mr. Roush?

THE WITNESS: There are two additional pages, one for 2013, one for 2014.

MR. SATTERWHITE: Why don't we just mark them all as 113, as the set.

EXAMINER SEE: 113.

MR. SATTERWHITE: Good idea.

Q. (By Mr. Sugarman) So to move things along, it will probably be helpful, are the last two pages of what will be comprised of Exhibit 113 calculated in the same fashion as you've just described for this first page, GS-2, GS-3, and GS-4 customers for 2012?

A. Yes, sir.

Q. And percentage increase that you're showing on the last two pages of this exhibit, what is the base rate from which those percentage increases have been calculated?

A. In the same way I did Exhibit DMR-1, so the chart labeled 2013 is really the comparison of June '13 to May '14 over June '12 to May '13, and then the June to December '14 is relative to the percentage relative to June '13 to May '14. So it's entirely consistent with the presentation in DMR-1, and DMR-6 and 7.

Q. And for the record do you know what the base rate actually that you utilized for year-over-year comparison going to 2013 and 2014 would be?

A. It would be the values comparable, as we were kind of discussing before, it's the -- to the the 9.54 shown on Exhibit DMR-1, page 2, over 9.19 it would be that kind of comparable comparison, and then for the 2014 one would be the 9.56 relative to the 9.54, that comparable comparison.

Q. And did you keep the FAC number constant in your analyses for each of the three pages on AEP Exhibit 113?

A. Yes, sir, AEP Exhibit 113 uses all the same assumptions that were in Exhibit DMR-1 and DMR-6 and 7.

MR. SUGARMAN: Thank you very much, Mr. Roush, no further questions.

THE WITNESS: Thank you.

EXAMINER SEE: Ms. Thompson?

MS. THOMPSON: No questions, your Honor. Thank you.

EXAMINER SEE: Ms. Hand?

MS. HAND: No questions, your Honor. Thank you.

EXAMINER SEE: Mr. Petricoff?

MR. PETRICOFF: No questions, your Honor.

EXAMINER SEE: Mr. Stinson?

MR. STINSON: No questions, your Honor.

EXAMINER SEE: Mr. Margard?

MR. MARGARD: No questions. Thank you.

EXAMINER SEE: Commissioner Porter?

- - -

FURTHER EXAMINATION

By Commissioner Porter:

Q. Yes, thanks for the exhibit. You just saved about 50 questions from me.

If you could briefly look at DMR-1 and at the bottom of the page, sorry, if you could briefly look at DMR-1, at the bottom of the page. Are you there?

A. Yes, sir, I am.

Q. Okay. At the bottom of the page beneath the total numbers there's that language that says "Increase due to Previous ESP Deferral" and then beneath that it says "Increase due to Proposed ESP." If you could explain to me what those, what you mean by "Increase due to Previous ESP Deferral"?

A. Basically I was separating out and identifying the fact that the phase-in rider is really the result of the previous ESP, the deferrals that were created in that previous ESP, and of the 3.77 percent increase in that June '13 to May '14 period, virtually all of it is due to that, starting the collection of those deferrals with very little of it due to the proposals in this ESP. Specifically the -- I think the rest of it is due to the step up in the distribution investment rider.

Q. Okay. So there's no portion of this -- of the request for rate tiers due to rates that AEP Ohio would have previously requested recovery for. In other words, is any portion of this increase due to previous ESP deferral, you know, to be retroactive for portions of time that should have -- that in the company's mind should have previously been recovered? Let me make it more clear.

During the timeframe that the Commission might have otherwise approved or considered, is any portion of what we're discussing in response to your prior answer for recovery that might have previously been recovered -- I'm sorry, rates that might have been previously recovered?

A. No, sir. That previous ESP deferral or the phase-in recovery rider is entirely made up of deferred costs, cost deferrals out of the previous

ESP that weren't collected during that previous ESP term. And I think, as we discussed earlier, the vast majority of that is deferred FAC costs, there are a couple other elements in there that we discussed previously, the Ormet deferral item, and all of the amounts in that deferral category are subject to a separate proceeding as far as prudency reviews, all those and everything before they're collected.

COMMISSIONER PORTER: I don't have anything else.

- - -

EXAMINATION

By Examiner Tauber:

Q. Mr. Roush, on page 14, you mention rate design matters that might need to be addressed in the future, particularly in light of going towards an auction and market-based rates.

A. Yes, sir.

Q. Do you know, are there any plans at all -- if the Commission were to approve this modified ESP, would there be any plans at all during the ESP period to at least have a study or some type of work group or something because obviously there may be issues with seasonal rates and everything to try to transition it through, is there any type of, anything at all right now that would help move toward a transition?

A. I guess there are kind of two parts to that answer. In the company's original filing back in January of '11, we kind of attempted to do that.

Q. Right.

A. And that produced some, you know, ultimately in the stipulation produced some things that ended up getting the stipulation undone.

So the plan at this point is that when we have the separate proceeding addressing the implementation of the auction and the rate design of the results of the auction, that as part of that -- part of that review of the implementation of the auction, one of the factors that will be looked at is well, when you translate the auction price into rates to customers, does that cause rate-design issues and what mechanisms may need to be put in place in that. I haven't prejudged, I'm not sure what they all would be.

I think that proceeding and the evaluation -- in setting up the auction process and the translation of the auction into rates to customers is where we should really look carefully at -- determine if there are things that need to be addressed to manage the transition.

Q. So then the idea is, before auction, coming into it with, you know, here's what we're going to have issues with, these are things that we want to address in this proceeding and this is where we're going to go next? Is that a fair summary of your --

A. I think that's fair. I think we may be able to pre-identify certain issues like the couple I mentioned, like the residential winter rate.

Q. The seasonal issue.

A. Right. And if there are some issues we can kind of pre-identify, some of them may ultimately either be an issue or not be an issue depending on the actual outcome of the auction. So it's hard sitting here today what all may come of that.

Q. Right.

A. But that was kind of the process I would envision, yes.

EXAMINER TAUBER: Thank you.

EXAMINER SEE: Thank you very much, Mr. Roush.

THE WITNESS: Thank you.

MR. SATTERWHITE: Your Honor, there was one other matter that I think I mentioned to the parties on a break when the Bench was out, but counsel for EnerNOC had requested that we stipulate to a couple of the discovery responses, I think he sent an e-mail out earlier and copied the Bench.

I'm in the awkward position of offering EnerNOC 101 which are those interrogatories. I've distributed them to the parties, but may I approach?

EXAMINER SEE: Yes, you may.

MR. SATTERWHITE: And I've marked as EnerNOC 101, AEP Ohio's responses to a number of interrogatories. Does the Bench want to look at those at all before I move everything and Mr. Roush leaves the stand? I don't want to cut it short in case you wanted to look at those.

EXAMINER SEE: This is a subset of the interrogatories that were attached to Mr. Poulos's e-mail?

MR. SATTERWHITE: Those are the ones, I believe it was 2, 4, 5, and 6 are the ones that I think he wanted to put in.

EXAMINER SEE: Okay. EnerNOC Exhibit 101, it's marked Exhibit 101, EnerNOC 101.

(EXHIBIT MARKED FOR IDENTIFICATION.)

MR. SATTERWHITE: At this point I would move for admission of AEP Ohio Exhibits 111, 112 and

113.

EXAMINER SEE: Are there any objections to the admission of AEP Exhibits 111, 112, and 113?

(No response.)

EXAMINER SEE: I note that IEU had a motion to strike a portion of Mr. Roush's testimony, that motion is denied, and if there are no other objections, AEP Exhibits 111, 112, and 113 are admitted into the record.

(EXHIBITS ADMITTED INTO EVIDENCE.)

EXAMINER SEE: Mr. Lang?

MR. LANG: Thank you, your Honor. FES moves Exhibits No. 110 and 111.

EXAMINER SEE: Are there any objections?

MR. SATTERWHITE: One second, your Honor.

No objections from the company.

EXAMINER SEE: FES Exhibit 110 and 111 are admitted into the record.

(EXHIBITS ADMITTED INTO EVIDENCE.)

EXAMINER SEE: Mr. Petricoff?

MR. PETRICOFF: Yes, thank you, your Honor, move for the admission of RESA Exhibit 101.

EXAMINER SEE: Are there any objections to RESA Exhibit 101?

MR. SATTERWHITE: Your Honor, the company has no objection to the first two pages that were sponsored by the witness.

The second two pages, though, the witness said he was familiar with the subject area overall but none of the details. I believe all the questions just dealt with him reading portions of what was on here, so he really didn't answer anything responsive to here. I think this would be more appropriate if brought in through the witness it applied to.

So page 1 and 2 are fine, page 3 and 4 we would object to.

MR. PETRICOFF: Your Honor --

EXAMINER SEE: You wanted to respond, Mr. Petricoff?

MR. PETRICOFF: Yes, your Honor. The witness did indicate that he was familiar with -- that he had seen it before, and at this point I think that -- and he indicated that to the best of his knowledge it was correct. I think that's probably enough of a foundation.

If that's not, then, your Honor, I suggest that maybe we hold this exhibit out until Mr. Allen takes the stand and we can ask him about that. That's all that's required.

MR. SATTERWHITE: That's fine with me,

your Honor. I just want to make sure the appropriate witness has a chance to give his perspective.

EXAMINER SEE: We'll take RESA Exhibit 101 under advisement.

Ms. Hand?

MS. HAND: Yes, your Honor, at this time I would move Ormet Exhibit 101 which is a confidential exhibit, into the record.

EXAMINER SEE: Any objections?

MR. SATTERWHITE: No objection.

EXAMINER SEE: Then Ormet Confidential Exhibit 101 is added into the record.

(EXHIBIT ADMITTED INTO EVIDENCE.)

EXAMINER SEE: Let's go off the record.

(Discussion off the record.)

EXAMINER SEE: Let's go back on the record for a minute.

Mr. Sugarman?

MR. SUGARMAN: Yes, thank you, your Honor. At this time I'd like to offer NFIB Ohio Exhibits marked as 102, 103, and 104.

EXAMINER SEE: Are there any objections to the admission of NFIB Ohio Exhibits 102, 103, and 104?

MR. SATTERWHITE: No objection, your

Honor. I guess before we leave I should move admission of EnerNOC 101. Just trying to do a professional courtesy.

EXAMINER SEE: Yeah, yeah.

Are there any objections to the admission of EnerNOC Exhibit 101?

MR. PRITCHARD: Yes, your Honor.

EXAMINER SEE: Mr. Pritchard?

MR. PRITCHARD: The first interrogatory response, No. 2, is not a request for admission, therefore, it's not a proper basis for a stipulation.

The party -- AEP's response here is their opinion and it's not a statement of fact to stipulate to. We don't have any objections as to the other responses.

EXAMINER SEE: And the Bench will take the admission of EnerNOC Exhibit 101 up at a later time when Mr. Poulos is here. So we'll take it under advisement.

Is there anything else?

Let's go off the record.

(Discussion off the record.)

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

Mr. Satterwhite?

MR. SATTERWHITE: Mr. Conway.
EXAMINER TAUBER: Mr. Conway.
MR. CONWAY: Thank you, your Honor. At this time AEP Ohio calls Laura Thomas.
EXAMINER TAUBER: Ms. Thomas, please raise your right hand.
(Witness sworn.)
EXAMINER TAUBER: Thank you.

- - -

LAURA J. THOMAS

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

DIRECT TESTIMONY

By Mr. Conway:

Q. Ms. Thomas, could you state your name for the record, please?
A. My name is Laura J. Thomas.
Q. And by whom are you employed?
A. I'm employed by American Electric Power Service Corporation.
Q. And what is your position?
A. My position is the Managing Director of Regulatory Projects and Compliance.
Q. Ms. Thomas, did you prepare direct testimony in this proceeding that's been prefiled?

A. Yes, I did.

Q. And did you also prepare supplemental Commission-ordered direct testimony for this proceeding?

A. Yes, I did.

MR. CONWAY: Your Honor, at this time I would like to mark as AEP Ohio Exhibit No. 114, Ms. Thomas's direct testimony that was prefiled on March 30th, 2012.

EXAMINER TAUBER: It shall be so marked.

(EXHIBIT MARKED FOR IDENTIFICATION.)

MR. CONWAY: And then, your Honors, I would also like to mark as AEP Ohio Exhibit 115, Ms. Thomas's supplemental Commission-ordered testimony that was prefiled on May 2nd.

EXAMINER TAUBER: It shall be so marked.

(EXHIBIT MARKED FOR IDENTIFICATION.)

Q. (By Mr. Conway) Now, Ms. Thomas, do you have with you on the stand copies of your direct testimony and your supplemental Commission-ordered direct testimony?

A. Yes, I do.

Q. And, first, with regard to your direct testimony that was prefiled on March 30th and we marked as AEP Ohio Exhibit No. 114, do you have any additions or corrections to make to that testimony at this point?

A. Not that I'm aware of.

Q. And turning your attention to what has been marked as AEP Ohio Exhibit No. 115, your supplemental Commission-ordered testimony, do you have any additions or corrections to make at this time to that testimony?

A. Not that I'm aware of.

EXAMINER TAUBER: Mr. Conway, could the Bench get an extra copy of the supplemental?

MR. CONWAY: Yes.

Q. Miss Thomas, if I were to ask you the questions posed in your direct testimony, AEP Ohio 114, today, would your answers be as they appear in that document?

A. Yes, they would.

Q. And would your testimony and your answers be true and accurate to the best of your knowledge and belief?

A. Yes, they would.

Q. And also with regard to your supplemental Commission-ordered direct testimony, AEP Ohio Exhibit No. 115, is the answers to the questions in that document, your testimony that you provide there, is it true and accurate to the best of your knowledge and belief?

A. Yes, it is.

MR. CONWAY: With that, your Honor, Ms. Thomas is available for cross-examination.

EXAMINER TAUBER: Thank you.

Before we get into cross-examination, there is one outstanding motion to strike from Industrial Energy Users and we're going to deny that. As always, any issues with content may be addressed during cross-examination.

Start with Mr. Kutik.

MR. KUTIK: Thank you, your Honor.

- - -

CROSS-EXAMINATION

By Mr. Kutik:

Q. Good afternoon.

A. Good afternoon.

Q. Ms. Thomas, as part of your testimony you present an aggregate MRO test, correct?

A. That's correct.

Q. And that appears at Exhibit LJT-1, correct?

A. That's correct.

Q. And you tried to quantify the benefits and describe the nonquantifiable benefits of the proposed ESP versus an MRO, correct?

A. That's correct.

Q. And by "benefit" we're not to consider benefits to the company, right?

A. The benefits here are the benefits to CRES providers and to the customers and the things that allow the company to offer those things to the customers and CRES providers.

Q. So the benefits, again, are to the customers and the CRES providers, correct?

A. Yes, that's what we've captured here.

Q. Now, the availability of, quote, discounted, end quote, capacity is the largest quantified benefit, correct?

A. Yes, it has the largest numerical value of the things that were quantified.

Q. And that $989 million figure is based upon shopping assumptions that were provided or that were derived by Mr. Allen, correct?

A. Yes. Mr. Allen provided that number to me.

Q. Because this discounted capacity would be a benefit to CRES providers and potentially to shopping customers, correct?

A. That's correct.

Q. The higher the assumed shopping, the greater the benefit would be for this, quote, discounted capacity offering, correct?

A. Mr. Allen calculated that number. I believe that it reflects his shopping assumptions; shopping assumptions, if they change, would change that number, yes.

Q. So if there was more shopping, there would be a greater benefit, and if there was less shopping, there would be a smaller benefit, correct?

A. That's correct. Mr. Allen could give you the magnitude of any changes.

Q. Now, Mr. Allen made a similar calculation of the, quote, benefit, end quote, from, quote, discounted, end quote, capacity in the stipulation hearing, correct?

A. That's my recollection, yes.

Q. And he derived those calculations using shopping assumptions in that proceeding, correct?

A. That's my recollection.

Q. And Mr. Allen assumed, as far as you know, shopping only to the extent of the set-asides that would have been provided under the stipulation, correct?

A. I don't recall the shopping assumptions that Mr. Allen used in his calculation previously; that's a better question for him.

Q. So you don't know.

A. I don't recall.

Q. Now, I think you agree with me that this benefit, in quotes, of, quote, discounted, end quote, capacity is something that nonshopping customers wouldn't be able to enjoy, correct?

A. Well, I think they would not receive necessarily a direct benefit, but because a discount to CRES providers would provide additional shopping opportunities, I think it benefits all customers in that it provides additional shopping opportunities for all customers.

Q. Well, a customer can't be a shopping customer and a nonshopping customer at the same time, correct?

A. That's correct, they can't be both at the same time, but by providing additional shopping opportunities that benefits all customers and then they have that opportunity to choose to take advantage of any shopping opportunities.

MR. KUTIK: Your Honor, I just asked if a customer could be a shopping customer and a nonshopping customer at the same time, so I move to strike everything including the word "but" and after that word.

MR. CONWAY: Your Honor, he asked the question, somewhat flippantly, and she gave him an honest answer and explained it, and I think she's entitled to do that.

EXAMINER TAUBER: The motion to strike is denied.

Q. A customer who would be nonshopping would not be paying a CRES provider, correct?

A. That is correct.

Q. And then the price that the CRES provider would -- so a nonshopping customer would not get the direct benefit of a lower price by discounted capacity because that customer was not receiving the price from a CRES provider, correct?

A. That would be correct if the customer chose not to take advantage of shopping opportunities.

Q. Thank you.

Now, without the benefit of the discounted capacity in your calculation, the quantitative MRO aggregate test would be negative, correct?

A. The mathematical would be negative for the quantifiable portion, but that is not the complete aggregate test.

Q. Now, you did not look at the Commission's December 14th, 2011 order in this case in preparing your testimony; is that correct?

A. Not when I prepared my testimony, no.

Q. And at the stipulation hearing, AEP Ohio presented witnesses to the effect that the true cost of the company's capacity was $355 per megawatt-day or thereabouts.

A. Yes. There were company witnesses regarding the full cost of capacity.

Q. And as we mentioned earlier, there were company witnesses who indicated that there should be a benefit quantified by the discount of capacity that was going to be offered to CRES providers, a discount off of the 355, correct?

A. That's correct.

Q. And it's true that the Commission found that AEP Ohio's capacity price, being something that wasn't certain, cannot be considered either as a benefit or a meaningful number for purposes of evaluating the ESP versus MRO, that's what the Commission determined in its December 14th order; is that correct?

A. I don't have or recall the words that the Commission used in its order.

MR. KUTIK: All right. May I approach, your Honor?

EXAMINER TAUBER: You may.

Q. Ms. Thomas, I've handed you a document, do you recognize that document?

A. I believe it is the Commission's order that was issued on December 14th, 2011; it appears to be a copy of that.

Q. Okay. Let me refer you to page 30 of that order. Are you there?

A. Yes.

Q. At the bottom of that page, third line from the bottom, there's a sentence that reads as follows: "Third, we believe the Signatory Parties in AEP-Ohio cannot claim the discounted capacity price to CRES providers as a benefit. As Mr. Fortney appropriately stated in his testimony, AEP-Ohio's requested capacity price in its application was never certain, and, therefore, it cannot be considered as either a benefit or a meaningful number for purposes of conducting the statutory test."

Does that refresh your recollection,

ma'am?

MR. CONWAY: Your Honor, I object to the line of questioning. The context is completely different. It's misleading to be using this order in the fashion that Counsel is using it.

EXAMINER TAUBER: The objection is overruled.

Q. Does that refresh your recollection, ma'am?

A. That's what the words say on these particular pages.

Q. Thank you.

Now, to calculate the MRO price test for inclusion in the aggregate MRO benefit test, you took the difference between the ESP price and the MRO price and you multiplied that by AEP's connected load, correct?

A. I utilized connected load in the calculations in the price test.

Q. So you're comparing all of the customers that you have and saying all those customers, if they paid ESP price, versus all the customers -- and if they pay the MRO price and you're calculating that difference, correct?

A. I used the connected load to calculate that difference because every customer can take SSO service. At any given point in time it will be a different amount, but every customer can take SSO service from the company.

Q. Right. And customers who aren't -- who are shopping aren't taking SSO service, correct?

A. That's correct. A customer who's shopping is not taking SSO service at that particular point in time.

Q. So with respect to the $250 million number that you calculate, you made no deduction for customers who might shop, correct?

A. No, because that would not be appropriate.

Q. Now, customers -- well, under the proposed ESP, a customer can get the benefit of the discounted capacity if they shopped, or they can get the below MRO ESP price if the customer doesn't shop; is that correct?

THE WITNESS: Could you repeat that, please?

(Record read.)

A. I would say that that is correct, although every customer still has that opportunity to have the SSO rate, so while at a given point in time a customer may shop or not shop, they all have that opportunity to go to the SSO rate should they choose to do so.

Q. But they can't simultaneously have both benefits, correct?

A. They can simultaneously be shopping and still have that option to return to SSO service at any time.

Q. But they aren't going to be having the SSO price or a shopping price at the same time, correct? They have one or the other.

A. They would only be charged one price at the same time, but they always have -- if they're shopping, they have that opportunity to return to the SSO price.

Q. But they're only receiving one benefit at a single time, correct?

A. They would only be charged one price either from a CRES provider or the company at a time.

Q. Now, if we wanted to show the benefit in terms of what a customer was directly receiving for nonshopping customers, it would be fair, then, would it not, to deduct the shopping customers or the shopping load from your $250 million figure, correct?

A. No, I don't believe that's correct.

Q. Well, if we did that -- well, first, are you familiar with generally what Mr. Allen assumed in terms of total shopping load?

A. Just generally.

Q. About 68 percent?

A. I don't recall the average number.

Q. Does that sound about order of magnitude correct?

A. It may be, I don't recall the number.

Q. Okay. Well, do you recall any number that he assumed for shopping?

A. He provided me with the megawatt-hours of shopping that I show in my Exhibit 4.

Q. Do you know what that is -- and are you saying that you don't know what that is as a percentage of total load?

A. I didn't specifically calculate that, I had no reason to.

Q. I didn't ask you if you specifically calculated it, I asked you if you knew.

A. I have not calculated that, I don't know the specific number.

Q. And so you don't know whether it's on the order of magnitude of 68 percent total load.

A. I don't recall.

Q. All right. And if we assume for purposes of my question that it was on the order of 68 percent, and we applied that to your $256 million number, we get a number of $882 million in terms of nonshopping customers who would get the benefit, correct?

A. Could you repeat that, please?

Q. Let me try it again.

If we wanted to deduct, from your number, shopping customers, and assuming that shopping customers represent 68 percent of the load, the benefit just to nonshopping customers would be $82 million as opposed to $256 million, correct?

A. It could be in that ballpark. I've not calculated the number.

Q. Similarly, if we took the numbers in your alternative calculation where you come up with an $81 million number for the ESP or the MRO price test and we applied a 68 percent deduction, we would be down to $26 million, correct?

A. If you did those calculations, I believe that would be in the ballpark, but, again, it would not be appropriate to do those calculations.

Q. All right. Now, I want to talk to you a little bit about the MRO price test. You did this calculation before as part of the stipulation here, correct? Or a similar calculation.

A. Yes, I did.

Q. And you believe that the methodology that you used in the stipulation hearing was an appropriate methodology, correct?

A. It was an appropriate methodology that reflected the stipulation.

Q. But it was an appropriate methodology, correct?

A. It was an appropriate methodology that reflected the provisions of the stipulation.

Q. Are you saying that using that methodology today would be incorrect?

A. No; what I'm saying is that, you know, the --

Q. Can you answer my question "yes" or "no"?

MR. CONWAY: Your Honor --

Q. Would it be incorrect?

MR. CONWAY: -- he's interrupting her. She's entitled to provide her answer. If he doesn't like it, he can follow up or ask for an instruction at that point, but I think she's entitled to provide her answer before he continues on.

EXAMINER TAUBER: Mr. Kutik, if you could let Ms. Thomas finish, please.

MR. KUTIK: Sure.

EXAMINER TAUBER: Thank you.

MR. KUTIK: I would like a "yes" or "no" answer to my question.

EXAMINER TAUBER: If you can answer your question with a yes, no, or I don't know, you're able to provide a brief context, but please answer the question.

THE WITNESS: Could you repeat the question, please?

(Record read.)

A. Yes, I'm saying it would be incorrect for the purposes of the company's proposal in this case.

Q. So when you came up with the various elements of the -- or you identified, rather, the various elements of the competitive benchmark price and you used the same ones here, that was an appropriate thing to do in both cases, correct?

A. I used the same competitive benchmark prices, the same methodology in both the stipulation and in this case.

Q. And the competitive benchmark price includes elements that are shown on your Exhibit LJT-2, correct?

A. Yes, for this case those are the prices, the competitive benchmark prices that were used.

Q. And although your numbers are different from what you presented in the stipulation hearing, those are the same elements, same components, that you used in the stipulation hearing, correct?

A. Yes, they're the same 10 components.

Q. Now, it's your view that a wholesale bidder would not construct a bid without including these 10 elements, correct?

A. That's correct. I believe that these are the components that would go into a full requirements product.

Q. And you would think that it would be logical that each of these components would be treated as a cost by the wholesale supplier.

A. I would think that's correct; although, I can't speak to the specific of what a wholesale supplier might consider a cost or there might be elements that are not cost but are actually profit for the supplier.

Q. So the answer is yes, you would think it would be logical, correct?

A. With the caveat that I just mentioned that some of these may not be costs if the supplier has built in more than its cost and includes its profit such as in the transaction risk adder which would include a profit margin.

Q. Well, so you would believe, then, that we could then perhaps deduct those out of the competitive benchmark price if those are just profit, right?

A. Those are elements -- I don't think that's correct for the competitive benchmark. I believe that those elements of the competitive benchmark would be included in a competitive bid.

Q. And something that a wholesale supplier would want to recover, correct?

A. Again, I can't speak to what a specific wholesale supplier might add in in addition to this, beyond these, or if they would scale back some of these elements. To the best of my knowledge these are the components that would be included for a competitive bid.

Q. Right. And you think that, at the very least, it would be reasonable to assume that a wholesale supplier would want to include these elements in a bid and recover these elements, correct?

A. For a competitive bid, yes.

Q. Now, these same components would generally apply to a CRES provider too, correct?

A. I would expect so, yes.

Q. Now, in LJT-1 for the period for the planning year 2012 and 2013, would it be fair, then, that you think that the price a CRES provider would charge would be $69.36?

A. That's correct.

Q. And that is higher than the ESP price of $62.12, correct?

A. That is correct.

Q. So if these were the prices, it would be difficult for a customer to shop because there would be no savings, correct?

A. Well, this would be -- this is an average, and again not every customer pays the average. Customers pay --

Q. So at least on average there would be no savings, correct?

MR. CONWAY: Objection. He's interrupting her again.

MR. KUTIK: I'm sorry, I thought she was done.

A. Customers do not all pay the average. You have some customers who would pay more than the average and some that would pay less than the average, and depending upon each customer's specific situation with what they pay, as well as the offers from a CRES provider, would determine whether or not they shopped.

Q. But on average there would be no savings, correct?

A. That would only be true if -- I believe that there would be savings for customers because some customers would shop because not everybody pays the average; those who are paying above average may shop.

MR. KUTIK: Your Honor, I move to strike, that wasn't responsive at all. I said on average there would be no savings.

EXAMINER TAUBER: Ms. Thomas is providing context for her answer. Motion to strike is denied.

Q. It's also true, is it not, Ms. Thomas, that your competitive benchmark price and your ESP price, if we compared those two, for 2013 and 2014 we would see that the competitive benchmark price that a CRES provider might charge would be higher than the ESP price, correct?

A. On average that would be the relationship.

Q. And that would also be the same for June through December of 2014, correct?

A. That's correct.

Q. Now, you did a calculation of a competitive benchmark price for -- using a capacity price of $255, correct? You made that calculation.

A. I did make that calculation, but that's not what is used in Exhibit LJT-1.

Q. I just asked you if you made the calculation. You made that calculation, correct?

A. Yes, I did.

MR. KUTIK: Your Honor, may I approach?

EXAMINER TAUBER: Yes.

MR. KUTIK: Your Honor, I would like to have marked at this time as Exhibit 112, FES Exhibit 112, a two-page document entitled "AEP Ohio Electric Security Plan Competitive Benchmark Prices by Component and Customer Class, Capacity Cost $255 Per Megawatt-Day."

EXAMINER TAUBER: So marked.

(EXHIBIT MARKED FOR IDENTIFICATION.)

Q. Ms. Thomas, I've handed you what's been marked for identification FES Exhibit 112. Do you recognize that?

A. Yes, I do.

Q. And that includes your calculation of a competitive benchmark price using a capacity cost of $255 per megawatt-day, correct?

A. Yes. This was included in my workpapers.

Q. And we can see the various competitive benchmark prices that you have on a weighted total average for each of the first two planning years, correct?

A. That's correct.

Q. And you also did one for the planning year of 2014-'15, correct?

A. That's correct.

Q. And would it be fair to say that comparing these prices to the ESP prices in LJT-5, the ESP prices, again, are lower than the competitive benchmark prices that you used at 255?

A. You're comparing them to which exhibit, I'm sorry?

Q. LJT-5.

A. In LJT-5 in some years it's higher, some years it's lower.

Q. Now, you used, in LJT-1, let's go over that one, you use a capacity cost of $355 per megawatt-day in one of those calculations, correct?

A. That's correct.

Q. And you use a weighted combination of $146 and $255 per megawatt-day in your calculations on LJT-5.

A. LJT-5 would also include the capacity cost of -- effectively at 355 for nonshopping customers.

Q. So that includes 146, 255, and 355 on a weighted basis.

A. That's correct.

Q. And that weighting is shown, I believe, in LJT-4?

A. Yes.

Q. Now, would it be fair to say that the $355 figure and the $255 figure are not market based?

A. I guess it depends on what market you're talking about. The 355 is the company's cost of capacity during this period, and the 255 is a reduced price.

Q. So they're not, for example, RPM-based prices, correct?

A. That's correct, these are not RPM prices.

Q. And the 146, that would not be an RPM price during the proposed term of the proposed modified ESP, correct?

A. That's correct. None of these are RPM prices because RPM does not apply to the company.

Q. Now, we'll talk about why you use these numbers in a second, those capacity numbers, but would it be fair to say that you used market-based numbers for your energy components of your competitive benchmark prices?

A. For the energy component I used the simple swap market prices for the ESP period.

Q. Those would be market-based prices, correct?

A. That's correct.

Q. Now, would it be fair to say that you believe that AEP Ohio is required to supply its own capacity as an FRR entity?

A. That's my general understanding of FRR, yes.

Q. And that the $355 price is appropriate to use in a competitive benchmark price because that's AEP Ohio's cost.

A. It's appropriate to use because that cost, the FRR, during the period when the company is in FRR, that would be its cost of capacity that it supplies to serve the customers regardless of who is actually serving the customer, the company is providing the capacity.

Q. Now, if the Commission determined that as an FRR entity AEP Ohio was only allowed to charge -- was only allowed to charge a lower price, not 355, but say at 146, would it be fair to say that an appropriate competitive benchmark price calculation would be lower than what you show?

A. I think it would still be appropriate to use the 355 cost for the company and then the -- I think it would still be appropriate.

Q. So even if the Commission said that your cost wasn't 355, it was some other number, you still think 355 is the right number to use, correct?

A. Yes, I do.

Q. So is it your belief, then, that the Commission has no say as to what the proper level of AEP Ohio's capacity costs are? Is that your view?

A. I don't believe that's what I said.

Q. All right. So, for example, let's say the company said that their capacity costs weren't 355 but, say, $710, would that be the right number to use according to you?

A. I can't speak to 710. I can speak to the company has presented it costs at 355, that's what the company's cost will be for this period of time.

Q. Well, you believe that that's what the

company says that its costs are, correct?
A. I believe those are the company's costs that have been done on the analyses in these proceedings.
Q. And you're aware that the proper amount of the charge is something that's presently being adjudicated before the Commission, correct?
A. That's correct.
Q. And one potential issue that might be adjudicated is what the proper level of capacity cost is, correct?
A. I believe that is one of the issues before the Commission currently.
Q. And if the Commission, in weighing all the evidence said, you know what, AEP's numbers, they're wrong, their analysis is wrong, their costs aren't 355, but their costs are really $146 or whatever. You still believe that the proper number to use in a competitive benchmark price would be 355; fair to say?
A. Yes.
Q. Now, you did provide, as we talked earlier, testimony in your stipulation -- testimony in the stipulation hearing where you used capacity prices, correct?

A. That's correct.

Q. And you used a -- you had two analyses and the first analysis that you did, did not use 355, correct?

A. The first analysis represented the stipulation and the second one reflected the company's cost as I've done here.

Q. So, again, you did an analysis and the first analysis that you did in the stipulation did not use 355, correct?

A. That's correct, because it was a stipulation.

Q. Now, would it be fair to say that the Commission has never approved a capacity price for AEP of $355?

A. Not in these proceedings, but I believe that Mr. Allen shows in his testimony that 355 is approximately the level of capacity that is embedded in the current rates which have been approved by the Commission.

Q. Well, all Mr. Allen actually showed was that the revenues were the same, he didn't say that SSO customers were paying a 355 capacity price, did he?

A. I would have to go back and look at the exact words as to what he said, but I believe -- my recollection is that --

Q. Well, Mr. Allen's testimony will speak for itself. But my question to you is with respect to CRES providers and what AEP could charge CRES providers. It's true that the Commission -- the Commission has never approved a capacity price of 355, correct?

A. I believe that that is what is pending currently before the Commission.

Q. And they've never approved that so far, correct?

A. It's pending before the Commission.

Q. Have they approved it or haven't they?

A. If it's pending before the Commission, I think the logical conclusion is it's not yet approved if it's pending before the Commission.

Q. Right. And did they approve it in any prior proceeding, the 355 price for CRES providers?

A. As it relates specifically to CRES providers, not that I know of.

Q. Okay. And did the FERC, is it true that the FERC has never approved a $355 per megawatt-day capacity charge for CRES providers?

A. That is also pending before the FERC.

Q. So, again, they haven't approved it, correct?

A. Not approved it because it's pending before the FERC.

Q. And they didn't approve it in any prior proceeding, correct?

A. Not to my knowledge.

Q. And would it be fair to say that either the Commission or the FERC or both might have a say in what the proper charge for capacity by AEP Ohio should be to CRES providers?

A. I believe that there are cases pending currently before this Commission and before the FERC regarding that issue.

Q. So you would agree that they would have a say, correct?

A. Given that there are cases before the Commission, I don't know what they're going to say.

Q. Okay. Now, I think you said earlier that you believe that the 355 is required because AEP Ohio -- the cost of AEP Ohio's FRR obligation, correct?

A. That's correct.

Q. And fair to say you don't know much of the details of what the FRR obligation entails.

A. I believe we have other witnesses who are responsible for that topic.

Q. So you don't know.

A. I know just very generally.

Q. And you don't know, for example, if the FRR obligation requires AEP Ohio to use its own generation. Fair to say?

A. I rely on the testimony of the other witnesses regarding exactly what FRR requires.

Q. Is it fair to say you don't know?

A. Fair to say that I rely on the testimony of the other company witnesses who are more knowledgeable in those areas.

Q. So is it true, then, that the FRR obligation does not require AEP Ohio to use its own generation?

A. I can't speak to that. That's a question for Witness Nelson.

Q. Okay. Because you don't know.

A. Because that's his testimony.

Q. And because you don't know.

MR. CONWAY: Your Honor, I object.

EXAMINER TAUBER: Ms. Thomas, could you please answer the question.

A. I believe I did. I rely on the testimony of these other witnesses because I am not the expert in that area.

Q. And you don't know.

A. I'm not the expert in that area.

Q. So you don't know.

EXAMINER TAUBER: Ms. Thomas, the Bench instructs you again to answer a question. You can say I don't know, yes, or no, and you're able to provide a context, but if you can please answer the questions that are posed to you.

A. I don't know the details of the FRR. I rely on the testimony of other witnesses in this case.

Q. So you don't know whether the FRR obligation requires AEP Ohio to use its own generation, correct?

MR. CONWAY: Your Honor, I object. It's been asked a number of times and the witness has done her best to provide Mr. Kutik an answer and I think it's been provided and it's now not productive.

MR. KUTIK: She's done everything she cannot to answer my question.

EXAMINER TAUBER: Mr. Kutik, she answered the last question with "I don't know the details."

Q. Do those details include whether AEP Ohio

must use its own generation?
A. You would have to ask Mr. Nelson.
Q. The details that you don't know about include those, right?
A. To the -- the question that you asked, you would have to ask Mr. Nelson for the details.
Q. Because you don't know.
A. Because I don't know because I rely on the testimony of Mr. Nelson --
Q. Thank you.
A. -- who is the expert in that area.
Q. Thank you.
Now, prior to the current application, by that I mean the one that was filed before the stipulation. Are you with me so far?
A. Could you clarify which application you're talking about?
Q. Sure. This case number has, among many, 11-346.
A. Yes.
Q. So the application that started what I'll call the 11-346 case. Are you with me with that?
A. Made in January of 2011.
Q. Yes. So there was an ESP in place at the time that application was filed, correct?

A. That's correct.

Q. And that was the first ESP that AEP presented, correct?

A. I believe that's the case.

Q. And that was presented through an application, correct? That first ESP.

A. Yes. I was not involved in that case.

Q. But Mr. Craig Baker from AEP presented testimony on the ESP versus MRO test, correct?

A. Yes, he did.

Q. And for the competitive benchmark price for capacity he used the RPM prices, correct?

A. I believe that's the case.

Q. And it would be fair to say that when that application was filed, AEP Ohio was an FRR entity; was it not?

A. Yes. AEP was an FRR entity at that time and it still is.

Q. Thank you.

Now, generally, would it be fair to say that utilities, such as AEP Ohio, do sensitivity analyses when they're trying to determine a future course of action?

A. That's a pretty broad statement. I would have to think about more the specific context.

Q. Well, would it be fair to say that sometimes AEP -- utilities, such as AEP Ohio, do sensitivity analyses when they're trying to determine a future course of action?

A. Again, I think I would need more specifics, a course of action around what specifically or, you know, this is a very broad statement, I don't think I can say always that there would be sensitivities.

Q. I said "sometimes."

A. That there might be, again, I would need some context.

MR. KUTIK: Your Honor, may I approach?

EXAMINER TAUBER: Yes.

Q. Well, let me ask you, Ms. Thomas, what do you have -- do you have on the stand with you a deposition that I took of you on August 10th, 2011?

A. No.

MR. KUTIK: May I approach?

EXAMINER TAUBER: Yes.

(Discussion off the record.)

Q. Ms. Thomas, let me direct you to page 221 of that deposition. Are you there?

A. Yes.

Q. Now, it would be fair to say that I have put in front of you the deposition transcript of a deposition that was taken on August 10th, 2011, correct?

A. That's what's on the cover page of the document.

Q. And I was one of the attorneys that questioned you on that date, correct?

A. To my recollection, yes.

Q. Right.

And now specifically directing you to page 221 of that transcript on page, excuse me, on line 10, am I correct to say that you testified as follows: "Question: What kind of -- would you agree with me generally that utilities like AEP-Ohio do sensitivity analyses when they're trying to determine the future course of action?

Answer: There are some times when it might be appropriate to do sensitivity analyses and some times it may not be needed."

That was your testimony, correct?

A. That's what it says, yes.

Q. Okay. Now, in this case you did calculate a set of competitive benchmark prices using a capacity price of $146, correct?

A. For the purposes of Exhibit LJT-5.

Q. Right. But, again, you did produce, in other words calculate, a competitive benchmark price using that capacity value, correct?

A. Yes, for the purpose of Exhibit LJT-5.

Q. And you did not calculate the results of an MRO price test using a competitive benchmark price using $146 per megawatt-day for capacity, correct?

A. That's correct.

Q. Nor did you do a calculation of the MRO price test using a competitive benchmark price that included RPM-based capacity prices, correct?

A. That's correct.

Q. Even though you did such a calculation for the stipulation hearing, correct?

A. My recollection is that I did not -- that what I did for the stipulation was the blend of the various prices of the stipulation.

Q. Isn't it true that you did a calculation of the MRO price test for the stipulation hearing using RPM-based prices, but you then threw that calculation away?

A. I believe I may have, but I don't recall.

MR. KUTIK: May I approach, your Honor?

EXAMINER TAUBER: Yes.

Q. Ms. Thomas, I'd like to hand you a

document that is the deposition transcript of a deposition taken on September 22nd, 2011. And let me refer you to page 16 of that deposition. Are you there?

A. Yes.

Q. Did you testify at that time as follows, starting at line 13: "Question: Did you do a calculation of a comparison of the MRO price and ESP using competitive benchmark price that uses capacity only at the RPM price?

Answer: I believe I looked at that.

Question: Okay. Is that in your workpapers?

Answer: No. I did not use that in my testimony.

Question: Okay. Do you still have that calculation?

Answer: No.

Question: So you got rid of that calculation?

Answer: I think I just plugged in a number and looked at it and didn't save it."

That was your testimony, correct?

A. That's what it read up to that point, but then it also says that I didn't save it because I didn't need it for my analyses.

Q. But you did do a calculation last time, correct?

A. That's what this says.

Q. And you didn't do the same calculation this time, correct?

A. That's correct.

Q. Now, would it be fair to say that you recognize that the result of your MRO, the result using a competitive benchmark price including a $146 per megawatt-day capacity price would show less of a benefit than the competitive benchmark price that you show?

A. I believe mathematically, yes, that would be the direction.

Q. And that would be the same if we used a competitive benchmark price that used RPM-based prices for capacity.

A. That's correct.

Q. If we used a capacity price that was less than half of the $355 price that you use in LJT-1, would it be fair to say that the MRO price test would be negative?

A. I don't know. I've not done those calculations.

Q. Well, let me shift gears. If there was an MRO, there would not be an RSR, correct?

A. I believe that's the case, yes.

Q. And for purposes of calculating the MRO test, if we were to include the RSR, we would put in the ESP price and not on the -- in the MRO price, correct?

A. That's correct. That amount is included in Exhibit LJT-1 as a negative amount to account for that.

Q. All right. So if we included the RSR in the MRO price test, the ESP would fail that test, correct, because it would be a negative number?

A. It would just be moving that charge from one part of the test to the other and what you have to look at is an aggregate. So if you move that to the price test, yes, that portion may fail, but, again, you have to look at the overall aggregate results and not just the price test.

Q. But if we included the RSR in the MRO price test, the MRO price test would fail, correct?

A. I believe that is just -- is what I just said, that if you move that from one location of the test to the other part, to the price test, that portion would fail, but you have to look at the aggregate and it has been accounted for in the test on page 1.

Q. Let me shift gears again. You include base generation in both sides of your MRO price test, correct?

A. There is base generation in the current ESP price and there is base generation in the proposed ESP price.

Q. And both the base G on both sides include energy and capacity, correct?

A. That's correct.

Q. And also ancillary service, correct?

A. That's correct.

Q. Right. Now, there's also a fuel factor that appears on both side of the equations, correct?

A. That's correct.

Q. Both sides of the equation, correct?

A. Yes. Both under the current rate and under the proposed rate there would be a fuel adjustment clause.

Q. Now, for the MRO price the fuel factor appears in the legacy ESP portion of your calculation, correct? The total generation service.

A. The FAC would be a portion of the current legacy generation price and fuel would be basically an element of the competitive benchmark price as well.

Q. But with respect to company's fuel cost, that would appear in the legacy ESP portion of the MRO price, correct?

A. That's correct.

Q. And certainly for the ESP, the fuel charges would be part of that price as well as developed by Mr. Roush, correct?

A. Yes. Fuel is included in both the legacy and the proposed ESP prices provided by Mr. Roush.

Q. And with respect to the MRO, what you did is you kept the fuel factor, essentially, constant through the period that you were analyzing, correct?

A. Correct. I did not increase the fuel factor over the period. I also did not increase the environmental over the period. I kept all of those things -- I did not increase any of those things.

Q. So you, again, you kept it relatively constant, correct?

A. Yes, I kept the fuel constant as well as other elements such as the environmental rider constant. If you increased one, you would basically increase all of those.

Q. And the numbers you received, you

received those from Mr. Roush, correct?

A. Yes, the fuel factors that I used were provided by Mr. Roush.

Q. In fact, what you used was Mr. Roush's Exhibits DMR-2, correct?

A. That's correct.

Q. I'll get to that in a second. Now, would it be fair to say that through the period of the proposed ESP it's unlikely that the fuel factor will be constant?

A. That's correct. I believe, as Mr. Roush testified, that the fuel factor changes quarterly.

Q. And you're now using a fuel factor of between $36.32 to $36.39, correct?

A. Yes. It just varies because of the different kilowatt-hours at the different rates.

Q. And your testimony that you prepared for the stipulation hearing, you used a fuel factor price of around $32.86, correct?

A. I used the current fuel factor at that time.

Q. Would that be $32.86?

A. I don't recall the exact number.

Q. Would you accept that subject to check?

A. It sounds in the ballpark.

Q. Thank you.
Now, you did not hold other parts of the MRO price constant, correct?
A. I held the other components of the legacy generation price constant.
Q. That wasn't my question. You didn't hold other parts of the MRO price test constant, correct?
A. When you refer to the "MRO price," are you referring to the weighting of the market price and the legacy price?
Q. No, I'm talking about the various elements that make up the MRO price test. MRO price in your MRO price test.
A. Well, the components of the MRO price is a weighting of the legacy ESP price and the expected bid price.
Q. All right. For example, in your competitive benchmark price you didn't hold all of those things constant, correct?
A. Some elements were held constant.
Q. But some elements were not.
A. That's correct.
Q. All right. For example, your energy prices were not held constant.
A. The energy prices were taken from the --

they were not held constant, they were taken from the simple swap for those particular periods.

Q. And those represented forward prices, correct?

A. That's correct.

Q. And those forward prices would be in the nature of forecasts, correct?

A. No, those are not forecasted prices, those are prices that people are actually transacting at for those future periods.

Q. So would it be fair to say that because they occur in the future, these prices could be considered to be a form of forecast?

A. I guess on one hand you might consider them a forecast because they are in the future, but the simple swap prices are prices that people are actually doing transactions at and so, you know, when I go back and I think about that, I would say they really aren't a forecast because actual transactions are taking place at those prices.

MR. KUTIK: May I approach, your Honor?

EXAMINER TAUBER: You may.

Q. Ms. Thomas, I'd like to hand you the transcript from the stipulation hearing, Volume XIII.

Let me refer you to page 2342. Are you

there?

A. Yes.

Q. And did you testify as follows at line 16: "Okay. So you don't view the forward prices as a forecast of prices, fair to say?

"Answer: In some ways you might consider them a forecast, but they are also prices which people are willing to transact for those periods."

That was your testimony, correct?

A. I believe you didn't read that exactly.

Q. All right. Let's try it again.

"Question: Okay. So you didn't view the forward prices as a forecast of prices, fair to say?

"Answer: In some ways you might characterize them as a forecast, but they are also prices at which people are willing to transact for those periods."

That was your testimony, correct?

A. Yes, that is what I said and I believe that, you know, my statements here in terms of that, you might characterize them as a forecast, but the more that you think about that, because people are actually transacting at those prices, they are real prices, not necessarily forward -- I mean, forecasts, they are forward prices as opposed to forecast prices and I think that that would be a more correct answer, is that they're forward prices not forecast prices.

Q. But you did testify as I read, correct?

A. That's what I said --

Q. Thank you.

A. -- back in -- back some time ago.

Q. Right.

Now, you used, or you got your fuel forecast number from Mr. Roush as we talked earlier, correct?

A. I got from Mr. Roush the current fuel factors.

Q. Okay. And that was from the DMR-2, correct?

A. That's correct.

Q. Do you have DMR-2 with you, ma'am?

A. No, I don't.

MR. KUTIK: May I approach?

EXAMINER TAUBER: Yes.

Q. And on DMR-2 we see, do we not, the FAC numbers? Correct?

A. Yes.

Q. And would it be fair to say that the AEP Ohio numbers that we see on DMR-2 are lower than the numbers you used?

A. I would disagree.
Q. All right. Well, let's put it this way: They're different than the numbers you used, correct?
A. No.
Q. Well, look at LJT-1. The fuel factor that you used for the planning year 2012-2013 is the same as the proposed number that Mr. Roush has for that period, correct?
A. No. The current fuel factors in line 5 are the same as the current fuel factors that Mr. Roush shows on DMR-2.
Q. That's not my question. My question is it's different than the proposed factors.
A. It is different -- it is not the same as the proposed factors --
Q. Thank you.
A. -- because these are the current factors as labeled in line 5.
Q. So you didn't use the proposed factors that Mr. Roush used to calculate the SSO price, correct?
A. I used --
Q. The ESP price. Excuse me.
A. The proposed ESP price shown in line 13 uses the proposed FAC numbers that Mr. Roush used.

Q. So the numbers we see, as you understand it, proposed FAC were the numbers that Mr. Roush used to calculate the ESP price that you used, correct?

A. So that I --

Q. Correct?

A. Well, I'm not sure that that's correct. I used Mr. Roush's current fuel factors in the current fuel factor portion of my test. I utilized his proposed fuel factors as part of the proposed ESP price so I've matched those up.

Q. I guess it's a question of what you match because you didn't use the same numbers on both sides of the equation, correct?

A. I used the current fuel factors on the current side and I used the proposed fuel factors on the proposed side, and I believe that Mr. Roush explained those slight differences.

Q. And if you used the proposed fuel factors with respect to the MRO price, the MRO price test figure would be less than what you calculated, correct?

A. If I did that mathematical calculation, that would be -- the numbers would move in that direction, but that would not be correct. You use current fuel factors on the current side, you use proposed fuel factors on the proposed fuel side.

Q. And you're proposing what the MRO price would be in the future, correct?

A. I've used the current fuel factors and the current environmental factors to calculate the legacy generation service price which goes into the MRO price that you've asked about. And all of those pieces of the current utilize the current factors. I did not forecast any of those. If I had forecasted them, I would have forecasted not only fuel but also environmental increases as well.

Q. Well, that wasn't my question. My question is: The MRO prices that you're calculating, they're not current MRO prices, they're proposed MRO prices; are they not?

A. No. The MRO is really not a current or proposed. The MRO calculation to get to an MRO price, you take your legacy price and weight it with a competitive benchmark. So it's not a current, it's not a proposed price, it's a calculation that weights the legacy ESP price with the competitive benchmark.

Q. So you don't need to figure out what a proposed MRO would be during any period of the proposed ESP; is that your testimony?

A. A proposed MRO --

Q. Is that your testimony?
A. No.
MR. CONWAY: Your Honor, I object to the continual interruption.
EXAMINER TAUBER: Mr. Kutik, you need to let Ms. Thomas begin to answer the question and --
MR. KUTIK: But I'd also like --
EXAMINER TAUBER: Right, you can ask if you feel -- if you're not happy with the answer then you can ask, but you need to let Ms. Thomas have an opportunity to answer first.
MR. KUTIK: I would like answers that can be answered "yes" or "no" "yes" or "no" and of course I know she's allowed to explain, but I at least would like to get that much where the question fairly calls for it.
MR. CONWAY: Why don't you let -- your Honor, he can let her answer the question and, if he's dissatisfied at that point, then he can proceed.
EXAMINER TAUBER: Let's do that.
Ms. Thomas, please answer the question.
THE WITNESS: Could you repeat the question, please?
(Record read.)
Q. So you don't -- so you don't --

MR. CONWAY: Just a second.

MR. KUTIK: I thought she answered.

MR. CONWAY: I thought she was collecting herself. And let her tell us when she's done, but, once again, you're interjecting before she has an opportunity --

EXAMINER TAUBER: Let's move on. Come on, let's move on.

MR. KUTIK: I think she answered "no."

EXAMINER TAUBER: Yes, Mr. Kutik, if you have another question, go ahead.

MR. KUTIK: Thank you, I do.

Q. (By Mr. Kutik) Would it be fair to say that whether it's proposed, whether it's current, you did not use Mr. Roush's proposed FAC numbers in your MRO price calculation, correct?

A. That's correct, I used the current fuel factors because what the MRO price is is a weighting of current prices and the competitive benchmark.

Q. And the proposed prices are lower than the current price or cost, correct?

A. I believe the numbers may be slightly lower, but I believe that Mr. Roush explained why that is and that it really is the same except, because of the weightings, the number comes out slightly different.

Q. Well, the numbers aren't the same, are they?

A. I believe they're slightly different because of the weightings, but it's not because of a reduction in the fuel cost.

Q. I didn't ask you what they were caused by. I just asked you if the numbers that Mr. Roush used, the proposed numbers, were lower than the numbers you used.

MR. CONWAY: And, your Honor, I object. She explained why the numbers are different, that they are different and why they're different, and now it's -- we're continuing to beat a dead horse.

EXAMINER TAUBER: The objection is overruled.

Ms. Thomas, you're directed to answer Mr. Kutik's question. If you need it repeated, we can repeat it.

THE WITNESS: Could you repeat the question?

(Record read.)

A. The answer to that would be no. The numbers that I used -- I used the current numbers on the current side, I used his proposed numbers on the proposed side, so my numbers are consistent with what Mr. Roush has on DMR-2.

Q. The numbers that Mr. Roush has for the proposed fuel adjustment clause numbers are $36.35, $36.02, which is repeated, and then $36.32, correct?

A. Yes. Those are the numbers on DMR-2.

Q. And you use, for your MRO price, $36.35, correct?

A. That's correct. I used the current fuel for the current side of the MRO price.

Q. And just as a matter of comparing those numbers, the numbers that I've read off of DMR-2 are either equal to or lower than the number you used for the current FAC in your MRO price calculation.

A. Yes. The numbers that Mr. Roush has for his proposed rates are slightly different than the numbers that I have for the current rates.

Q. In your -- I want to talk to you now about the GRR.

A. Okay.

Q. In your supplemental testimony you show a value for what it would cost if one included an estimate of the Turning Point project's cost in the GRR, correct?

A. That's correct.

Q. And you believe that including those costs in an MRO price test would essentially be a wash because you believe that the GRR would be recoverable through an ESP or an MRO, correct?

A. That's correct as I've been advised by counsel.

Q. And your view is based solely on advice from counsel, correct?

A. Yes, that's based on my -- advice from counsel.

Q. Now, it would be fair to say that you didn't include a GRR or anything in the GRR as a cost in the MRO price test the last time for the stipulation hearing, correct?

A. That's correct.

Q. And would it be fair to say that the Commission found that that was an error?

A. I don't recall.

Q. All right. Do you have the opinion in front of you, ma'am?

A. Yes.

Q. Let me refer you to page 30.

A. Okay.

Q. In the second-to-last paragraph: "We believe there are several material flaws in

AEP-Ohio's testimony for determining whether the proposed ESP meets the statutory test. First, we believe Ms. Thomas erred by failing to include a cost in the GRR in her price comparison." Do you see that?

A. Yes, I see that.

Q. Now, it would be also fair to say that in this case the Commission determined that Turning Point costs were an important consideration in the statutory test under Section 4928.143.

A. I'm sorry, what's the question?

Q. Did the Commission also determine in this case?

A. I'm sorry, I don't understand this question.

Q. Let me try it again, then. Isn't it true that in this case the Commission also determined that the Turning Point project costs were, quote, an important consideration in the statutory test under Section 4928.143, end quote?

A. I believe that that was the language that the Commission did in requesting us to provide the supplemental testimony.

Q. Now, given what the Commission determined last time in the stipulation hearing, given the

Commission's comments in this case, would it be fair to say you didn't question your lawyer's advice as to whether the GRR would be appropriately recovered in an MRO as well as an ESP?

A. I believe that, at the advice of counsel, we included in the testimony on page 3 that if the Commission determined that a GRR would exist only under an ESP, then it would result in a change of approximately $8 million which is what is reflected in my Exhibit LJT-1 TPS alternative that was filed.

Q. Right. That's not my question. My question is: You said you relied on advice from counsel to come to the view that the GRR would appear on both sides of the ESP MRO price test, right?

A. That's correct.

Q. And I asked you given what the Commission determined in the stipulation hearing and given what the Commission said in this hearing, did that cause you to question your lawyer's advice?

MR. CONWAY: Your Honor, I object. Now he's simply arguing with her as to whether or not she has relied or should rely or whether she should question her lawyer's counsel. It's a legal debate. The company's position with regard to this item is what it is and we respect the Commission and we pursue our positions with respect to a conclusion. And so I --

MR. KUTIK: Your Honor, I'll move on.

MR. CONWAY: So I think it's overbearing and it's not necessary. It's inappropriate.

MR. KUTIK: It's hardly overbearing. It's an appropriate question, but I'll move on, your Honor.

EXAMINER TAUBER: Let's move on. Thank you.

Q. (By Mr. Kutik) Now I want to talk to you about how this proposed ESP compares to the stipulation. Would it be fair to say that the proposed ESP would have less customers paying tier 1 capacity prices than the stipulation would have?

A. I don't recall. I believe that's a question for Mr. Allen.

Q. Would it be fair to say that compared to the stipulation ESP, this proposed ESP would have a higher tier 1 capacity price?

A. My recollection is that the tier 1 was at RPM prices and, in this case, the company's proposal is for $146.

Q. Which is higher than the RPM price.

A. That's correct.

Q. Would it be fair to say that compared with the stipulation ESP, the proposed ESP would have a new $284 million cost in the RSR?

A. That's correct. There is an RSR in this case.

Q. And compared to the stipulation ESP, the proposed ESP would totally eliminate grants to the Partnership With Ohio and the Ohio Growth Fund.

A. Yes, I believe that's the case of one of many differences between this and the ESP -- and the stipulation, but I believe that there are a number of other things that, like there is no base rate, base generation rate increase in this proposal which was in the stipulation.

MR. KUTIK: May I have one moment, your Honor?

EXAMINER TAUBER: Yes.

MR. KUTIK: I have no further questions. Thank you, Ms. Thomas.

MR. CONWAY: Your Honor, can we take a short break?

EXAMINER TAUBER: Sure, let's take a five-minute recess. Let's go off the record.

(Recess taken.)

EXAMINER TAUBER: Let's go back on the

record.

Mr. Serio? Ms. Grady?

MS. GRADY: No questions, your Honor.

EXAMINER TAUBER: Mr. Darr?

MR. DARR: Thank you, your Honor.

EXAMINER TAUBER: I'm sorry, Mr. Maskovyak.

MR. MASKOVYAK: I do have a few questions, your Honor.

(Discussion off the record.)

- - -

CROSS-EXAMINATION

By Mr. Maskovyak:

Q. Good evening, Ms. Thomas?

A. Good evening.

Q. I want to talk a little bit on some ground that Mr. Kutik already covered where you talk about the MRO test is not just about numbers but it's about a measure that's in the aggregate and that's a point of emphasis in your testimony as I understand it; is that correct?

A. That's correct.

Q. In fact, on page -- start on page 4, we have about two-and-a-half pages explaining what I think have been labeled as the "Not Readily

Quantifiable Benefits" which also are the ones that appear on your Exhibit LJT-1 at the bottom of that page in a composite fashion.

A. Yes, that's correct. I talk about it in the testimony and then try to show those elements, the other elements of the aggregate test in that exhibit on page 1.

Q. And as stated on page 6 at the top, one of those benefits is the advancement of state policies.

A. That's correct. Company Witness Dias testifies to those.

Q. I understand that.

Among the state policies that you enumerate that are a benefit here are the protection of at-risk customers; is that correct?

A. Yes. This comes from Witness Dias's testimony.

Q. I understand. Can you tell me how this ESP application protects at-risk populations?

A. I believe it provides all customers with a -- with these various benefits that we've listed here including, you know, the no base rate increase, the elimination of the environmental rider, things like that, which -- and then also the number of things that were discussed with Mr. Roush in terms of managing bill impacts, that all of those things would be to the benefit of such customers.

Q. But that is a benefit for all customers to the extent they are a benefit; is that not correct?

A. That is correct, that would include those populations.

Q. And is there anything that you can think of that would make them a special benefit for at-risk populations?

A. Not that I can recall, but I would suggest a question to Mr. Dias on that.

Q. And can you tell me what the definition is of "at-risk populations" as it's used here?

A. Again, I'm just referring back to Mr. Dias's testimony.

Q. So is Mr. Dias the only person who would be able to answer these questions?

A. I believe he would be the person because he's the one who testifies to how this meets the state policies and objectives.

Q. If I were to ask you about -- I'm sorry. Can you please turn to your Exhibit LJT-1?

A. Yes.

Q. And, again, I'm referring to the bottom, the "Not Readily Quantifiable Benefits."

MR. CONWAY: Are you at page 1?

MR. MASKOVYAK: Yes, I'm sorry, page 1 of 3.

Q. At the bottom of the chart.

A. Yes.

Q. In each of those categories that AEP lists as the nonquantifiable benefits and where there are names listed at the far end, are those the only folks that could describe how those are benefits?

A. Other than the general characterization that I have here, these are the witnesses who have -- that testified to the specific details of each of those and what I've done is summarize here the benefits that they have provided to me that they testify to.

Q. But you don't have particular knowledge about any of these categories where your name does not appear.

A. Just in general, and I have captured those benefits as provided to me by those witnesses.

MR. MASKOVYAK: Thank you, Ms. Thomas.

No further questions.

EXAMINER TAUBER: Thank you.

Now we'll move on to Mr. Darr.

- - -

CROSS-EXAMINATION

By Mr. Darr:

Q. Ms. Thomas, is it correct that AEP Ohio, as of July 1, 2008, owned directly operating generating facilities?

A. I believe that's correct, yes.

Q. And these facilities were considered used and useful in the state at the time of July 1, 2008; is that correct?

A. I believe so.

Q. Are you familiar with the fact that AEP Ohio asked for authority to conduct a slice of the system energy auction as part of its 2008 ESP application?

A. No, I'm not. I was not involved in that proceeding.

Q. Now, with regard to your background, is it fair to say that, at least in the positions that you've held with AEP Ohio over the last ten years, you have not been engaged, or through the personnel that you've managed, those people have not been engaged either in the process of forecasting?

A. That's correct. I've not been involved in forecasting.

Q. With regard to the prices that you have discussed at length with Mr. Kutik, is it also fair to say that you reviewed these prices and tested them against the results in the Duke case?

A. I did review the results of the -- you know, in terms of what market prices were utilized in the MRO test in the Duke stipulation that was approved by the Commission. So I don't know that I tested them, I just, you know, did a comparison of how do these look relative to those prices.

Q. Did you do anything else with regard to testing the results of your ESP versus MRO test in terms of comparing it to available market information?

A. No. These prices were developed based on market information and I didn't do any further comparisons with anything else, no.

Q. Is it fair to say that you did not review it against the prices that are offered by any competitive retail electric service providers?

A. That's correct; because that would not be appropriate unless you had all possible offers that were out there. Typically offers that are made to customers are made to specific groups of customers or at least the ones that I've seen a lot of them have, you know, various periods of time that they're only effective for, for the first so many customers would get this, and there's a lot of differences between, you know, what might be offered to a portion of the population versus what would be offered to all customers under an SSO rate.

Q. Based off your answer, it seems you're relatively knowledgeable in all these offers. Did you make a comparison against those offers that you were aware of?

A. I have seen offers, but I did not make a comparison for the reasons as I just explained.

Q. Did you solicit, from any other department, information to test the competitive benchmark prices that you provided here today?

A. Other than the fact that I worked with our Commercial Operations folks on the development of these prices and that is part of the function of what that group does is pricing in the market, and so I worked with them and relied also on their expertise.

Q. Was that not for collecting the information you needed for the various elements in your benchmark price?

A. Yes, for collecting the various elements and ensuring that those were reasonable elements.

Q. Did you test that aggregation of information against any other -- any other competitive markers that you might -- that might be available to you?

A. No, because this is really the only thing that would be applicable to AEP Ohio.

Q. Now, with regard to the Duke stipulation, which apparently you did use, do you know when that Duke price was put together?

A. I know that it was put together sometime prior to when we filed this ESP and, like I said, I just kind of used it just to kind of see where did that come out.

Q. Was that not, in fact, was that price not put together before the first of the year 2012, the Duke price I'm referring to?

A. Yes, it was.

Q. Now, with regard to the calculation of the aggregate benefits, did you make any adjustment for the benefits for the effects of delaying the implementation of the phase-in recovery rider?

A. No, I did not include that.

MR. DARR: That's all I have. Thank you.

EXAMINER TAUBER: Thank you.

Ms. Kingery?

- - -

CROSS-EXAMINATION

By Ms. Kingery:

Q. How are you this evening?

A. Fine, thank you.

Q. I have just a few questions for you.

A. Okay.

Q. On Exhibit LJT-1 you identify competitive auctions commencing January 2015 as a benefit of the modified ESP; is that correct?

A. Yes, it's a benefit as shown in line 5 because it occurs sooner than it would otherwise happen under an MRO.

Q. But isn't it true that there is no statutory restriction under SB 221 that would prevent AEP Ohio from conducting such auctions prior to January 2015?

A. I guess that's really a legal question. However, I'm not aware of anything, but there are company obligations as talked about by other witnesses that relate to that particular date.

Q. But there are no statutory restrictions on such auctions at an earlier date, correct? That you're aware of as a layperson.

A. Not that I'm aware of.

Q. Thank you.

If we turn to page 3 of your testimony, starting on line 20, you list a number of what you call "key considerations," which you then spell out in more detail later; is that correct?

A. That's correct.

Q. And one of these which talks about the impact on customers and customer shopping, you go into more detail on page 4, if you would turn to there.

A. Yes.

Q. On approximately line 21 you seem to be saying that charging CRES providers for capacity at prices higher than RPM will lead to increased shopping. Is that correct?

A. No, that's not correct. The statement there refers to the fact that CRES providers are being charged a discount to the company's capacity price during a period it's an FRR entity and that should lead to increased shopping opportunities for customers.

Q. And yet it is higher than RPM.

A. Mathematically that rate is higher than RPM, but the company is under FRR.

Q. Regardless of whether you believe that the FRR status allows you or requires you to charge cost, nevertheless it is higher than RPM, correct?

MR. CONWAY: Objection. It's been asked and answered.

MS. KINGERY: I'm trying to get her to tie all the pieces together.

EXAMINER TAUBER: Can you please answer the question.

A. Yes, the company's proposed rate is higher than the RPM rate currently.

Q. And the capacity rate that you are proposing you believe will lead to increased shopping.

A. The discounted capacity rates will lead to increased shopping than there has been previously, yes.

Q. What you have designated as a discounted rate, but the rate you believe will lead to increased shopping.

A. I believe that's covered by Mr. Allen and as -- that information comes from Mr. Allen.

Q. Thank you.

And I believe you're also suggesting that the existence of a nonbypassable retail stability rider will support expanded shopping opportunities; is that correct?

A. Yes. The RSR allows the company to offer the balanced package that is offered here and therefore would lead to more shopping.

Q. So the existence of an additional nonbypassable charge will benefit shopping, in your opinion.

A. The existence of that charge is what allows the company to offer the balanced package which will then lead to shopping.

Q. Is it true that you are -- you do not know whether amounts collected under the RSR will increase if shopping levels in AEP Ohio's territory increases?

A. That would be a question for Mr. Allen.

Q. I asked whether you're aware of that.

A. I don't recall the specifics of exactly how that calculation works. I know there's a number of moving parts and so exactly what moves with what parts I think would be a question for Mr. Allen.

Q. But it is your expectation that the amounts collected under RSR will be trued up, correct?

A. It's my understanding there's a trueup, but I don't know the details of that.

Q. That's fine.

As another benefit, is it correct that you believe the risk of increased environmental costs being borne by AEP Ohio should be considered?

A. Yes, I do.

Q. And if we look at your testimony on page 5, line 7, you have a reference there to "the company," and by the name "the company" are you referring to AEP Ohio?

A. Yes.

Q. And are you referring to AEP Ohio even after asset transfer?

A. That would depend upon the specifics of the agreement which Mr. Nelson testifies to between AEP Ohio and AEP Generation Resources. So depending on how that's structured, it might, but Mr. Nelson would have to clarify that.

Q. So you believe that depending on the terms of that agreement, AEP Ohio itself might still bear some environmental risks.

A. Again, I think it depends upon the provisions of that contract.

Q. And am I not correct that that risk would also be offset by the RSR?

A. I think you'd have to ask Mr. Allen, but I don't believe the calculation takes into account that increased cost of environmental.

Q. We'll ask him. Thank you.

Now, a little while ago you spoke with Mr. Kutik about the in-the-aggregate test, do you recall that conversation?

A. Yes.

Q. And for purposes of that test you need to quantify, as a part of your test, both the proposed ESP and the expected results under an MRO, correct?

A. Yes, as part of the aggregate test.

Q. Yes. And I'm only talking right now about the quantification.

A. Okay.

Q. Just so we're clear.

So the former, the first piece of that, that is the quantification of the proposed ESP, is a quantification of all of the terms and conditions of the proposed ESP over its term, correct? And again I'm only --

A. Those that you can quantify, yes.

Q. Yes, I'm only talking about the quantifiable part.

So, in other words, AEP Ohio needed to

calculate the dollar amounts applicable to the riders and other pricing provisions under the modified ESP for the entire term, correct?

A. Could you repeat that, please?

Q. Sure.

MS. KINGERY: Can you read it back?

(Record read.)

A. No, I think that the way that the test works, it allows you, you know, whether or not you forecast fuel, forecast environmental over the entire period, that that has not been required by the Commission in the past.

So I think, you know, you include the impacts of the additional items which we have quantified here, but you don't necessarily have to forecast every provision for the purposes of the price test.

Q. I don't believe I used the word "forecast." Perhaps I did. If I did, let's try it again.

So the goal is to look at the entire term of the proposed ESP and determine the dollar amounts, to the extent quantifiable, that would be charged under the ESP, correct?

A. I think it's to look at all of the

provisions and, again, I think it's looking at all of the provisions of the ESP and quantifying where you can.

Q. For the life of the ESP.

A. For the term of the ESP, yes.

Q. Yes. And the second piece of information that you're going to compare that to is the expected results under the MRO provisions, correct?

A. You would compare it to an MRO annual price, yes.

Q. Yes.

And as you've discussed previously, given the fact that AEP Ohio owns generation as of July 30, 2008, the expected results under the MRO provision would require a blending of market or bid prices with the most recent standard service offer price, correct?

A. That's correct.

Q. Okay. And AEP Ohio's current ESP does not involve any kind of a competitive procurement process, correct?

A. That's correct; currently there is no competitive procurement.

Q. And for purposes of this test, you identify the most recent standard service offer pricing as the ESP rates effective March 30, 2012, correct?

A. Yes. We used the rates that were in effect at the time that this was prepared.

Q. Yes.

So those March 2012 ESP rates are to be blended with the competitive benchmark or market price, correct?

A. Yes, you blend the legacy price with the expected bid price and compare that to the proposed ESP price.

Q. Right. And arriving at -- in arriving at the blended price, you did not use RPM-based prices for capacity as you discussed earlier, correct?

A. That's correct.

Q. Rather, you used AEP Ohio's proposed prices which are above the RPM rates, correct?

A. Yes, I used AEP's cost of capacity which is greater than the RPM rate.

Q. And is it your testimony that in arriving at the blended rate, the law allows a utility to incorporate cost that it is not actually charging?

A. I believe that you're allowed to, in the determination of what that expected bid price is is not dependent on what you're charging or not charging, but it is what is the expected bid price for the duration of the ESP.

Q. But nevertheless, AEP Ohio currently has no authority, as you discussed earlier with Mr. Kutik, to charge those rates.

A. That's correct. Those rates are pending before the Commission.

Q. So you are -- your test incorporates rates that are not approved for charging.

A. That's correct that it uses rates that are not approved. It uses rates that are pending before the Commission.

Q. Thank you.

And when you completed your analysis, that was accomplished on or prior to March 30th, 2012 when your testimony was filed, correct?

A. That's correct.

Q. And at that time were you aware of the Commission's March 7th order providing that AEP Ohio's interim tiered capacity price would be in effect through May and that AEP Ohio was to revert to RPM pricing for capacity effective June 1, 2012?

A. I was aware of that particular item as -- but it's my understanding that that was because the case was currently being -- in process and the

Commission expectation of an order by the end of May.

Q. Do you have some inside knowledge of why the Commission ordered that date, or did it say that in the order that that was why? I'll move on.

Are you also aware that it was not until after March 30, 2012, when your testimony was filed, that AEP Ohio requested an extension of that date?

A. I recall it -- the company requested an extension. I don't recall when that occurred.

Q. If we look at page 18 of your testimony, Table 2, let me know when you're there.

A. Yes.

Q. Table 2 summarizes the statutorily-required blending percentages applicable to the first three years of an MRO, correct?

A. That's correct.

Q. And absent Commission approval otherwise, a utility owning generation assets on July 31, 2008, and is serving customers under an MRO is required to blend, according to those percentages, correct?

A. Yes, these are the blendings that would apply.

Q. But you did not use those blending percentages for the entire period, correct?

A. Well, I did use those blendings and I believe that what I show in my Exhibit No. 3 is that what I used was equivalent to a 70/30 blend for the period of January through May of 2015. I showed that those were mathematically equivalent so I believe that what I did did meet the standard.

Q. To be clear, the statutorily required blend, as we've discussed earlier, includes the prospective market or bid prices and your historical ESP price with certain adjustments, correct?

A. That's correct.

Q. The blend does not require any calculations with regard to the proposed ESP in the blended price, correct?

A. The blended price allows you to make adjustments for things like purchased power and fuel and for this period that there would be a significant change in terms of what the purchased power would be and so I made the adjustment to the current rate for that purchased power during that period.

Q. But the manner in which energy is procured under the new ESP is immaterial.

A. No.

Q. I want to move on to one final -- couple questions on pool termination costs. Am I correct that the proposed ESP includes a pool termination

rider?
A. It includes a pool termination rider only under certain conditions as testified to by Mr. Nelson.
Q. But you did not include the costs associated with that rider when projecting the costs of the proposed ESP, correct?
A. That's correct. If there were to be a pool termination rider, it would be determined in a separate proceeding before the Commission and, therefore, to include anything but a zero would be speculative.
Q. But it, nevertheless, would have a cost in the event that it comes to pass.
A. In the event that there's a request by the company before the Commission for a pool termination rider, the Commission at that time would determine what cost if any that there would be.
Q. But it, nevertheless, would have a cost in that case.
A. And if there was a cost, then the Commission would consider the cost at that time.
Q. Which would make the ESP more expensive, correct?
A. I can't say whether, you know, it would

be more expensive or not. I don't know what may or may not be approved by the Commission. It's also the company's proposal that, you know, that there not be a pool termination rider in the event that the ESP is approved.

Q. You said it might or might not be more expensive. Do you think there's a chance it might be negative?

A. No; it may have a zero impact.

Q. Right. But if it is charged, if one is approved, it would make it more expensive, correct?

A. Well, I think by definition a non-zero charge would add to it, but, again --

Q. Thank you.

A. -- it's subject to another proceeding before the Commission, and the Commission could determine what costs or impact on the ESP at that time.

MS. KINGERY: Thank you. I have no more questions. Thank you.

EXAMINER TAUBER: Ms. Kyler?

MS. KYLER: No questions, your Honor.

MR. D'AURORA: No questions.

MS. THOMPSON: No questions, your Honor. Thank you.

MS. HAND: Just a couple, your Honor.

- - -

CROSS-EXAMINATION

By Ms. Hand:

Q. Good evening, Ms. Thomas.

A. Good evening.

Q. Turning to LJT-1 on the first page, looking at line 2, I believe we've already had some discussion of the $988,700,000 being the amount of the discount that's provided to the CRES providers, correct?

A. That's correct.

Q. Okay. And if a customer is unable to shop due to a prohibition in a unique arrangement, you would agree that that customer would be unable to receive any of the benefit reflected in that $988,700,000 figure; is that correct?

A. If a customer does not shop, there would be no direct benefit from a CRES provider, but, again, this is a component of a balanced package, you know, to be -- as part of the ESP.

MS. HAND: Okay. This next line of questions I'm going to attempt to do without moving into a confidential session, your Honor. But if counsel for AEP Ohio is concerned that we're heading in a confidential direction, I would encourage counsel to please speak up and I'll be happy to accommodate.

MR. CONWAY: And I would encourage the witness to speak up if she thinks we're treading on confidential territory also.

Q. On page 2 of LJT-1 in your calculations, I believe we've already established that you relied upon the fuel prices or the fuel values provided by Mr. Roush.

A. That's correct.

Q. And were you present for the confidential portion of Mr. Roush's testimony this afternoon?

A. Yes, I was.

Q. The numbers that you've used that you received from Mr. Roush do not estimate any potential changes in the level of costs recovered through the FAC, they assume a stable price in the fuel cost; is that correct?

A. That there was no forecasted increase that was used, that's correct.

Q. If Mr. Roush's numbers were to be changed to reflect fluctuations in the fuel cost, that would also require that your numbers in this analysis be changed as well; is that correct?

A. It's correct that I would adjust both the current fuel factor for that forecast as well as the proposed rates for that forecast, and then, in addition, I would also forecast environmental increases as well under the current riders.

Q. Okay. But none of that has been done at this time; is that correct?

A. That's correct. The Commission has ruled on a number of previous occasions that that was not required.

Q. Okay. And if the FAC rate were to increase, it would be reasonable to expect that that would have a greater impact on the proposed ESP price than on the MRO annual price in your table; is that correct?

A. Only by a small amount because the, you know, the changes in the FAC would occur regardless because they would occur under the current ESP that we're currently under, it would occur under the proposed ESP, and then it would have an impact on the MRO as well. So it would impact everything.

Q. Right. But you could expect the impact to be greater on the ESP price than on the MRO price; is that correct?

A. That's correct for the fuel, but the

opposite would be said of the environmental increase, that there would be less impact on the proposed ESP price than there would be on the MRO price, so they would work in opposite directions, the fuel and the environmental.

Q. Okay. But sitting here today, you have -- you don't know one way or another how that would play out; is that correct?

A. I have not forecasted all those numbers or included a forecast of those numbers, no.

MS. HAND: Thank you, your Honor. That's all I have.

EXAMINER TAUBER: Thank you.

Mr. Beeler?

MR. BEELER: Just a few, your Honor.

\- - -

CROSS-EXAMINATION

By Mr. Beeler:

Q. Good evening.

A. Good evening.

Q. Just a couple questions here on MRO price test, and this may have already been covered but I just want to make sure here. Your MRO price test reflects your best estimate of what the likely outcome of a market rate offer would be given the information you know now; is that correct?

A. That's correct.

Q. Okay. Have you attempted to test the validity of your methodology by comparing your predicted MRO rate to any other generation rate that has been established based on market outcomes such as a procurement auction either within Ohio or within PJM?

A. No. I've not looked at that outcome based on auctions because they're really not directly comparable.

Q. Any other empirical way to validate?

A. Like I said earlier, I looked at the market prices that were utilized in the Duke MRO test approved by the Commission and these are -- our market prices were actually lower than those that were utilized in the Duke MRO test.

Q. And that was it?

A. Yes.

MR. BEELER: That's all, your Honor.

EXAMINER TAUBER: Thank you.

Mr. Conway, redirect?

MR. CONWAY: Just if I could have a minute, your Honor.

EXAMINER TAUBER: Sure. Let's go off the

record.

(Discussion off the record.)

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

Mr. Conway.

MR. CONWAY: Your Honor, the company has no redirect for Miss Thomas, and at this point we would move for the admission of Company Exhibits 114 and 115.

EXAMINER TAUBER: Are there any objections to AEP Ohio Exhibits 114 and 115?

(No response.)

EXAMINER TAUBER: They shall be admitted into the record at this time.

(EXHIBITS ADMITTED INTO EVIDENCE.)

MR. KUTIK: Your Honor, we move for the admission of FES Exhibit 112.

EXAMINER TAUBER: Any objections to FES Exhibit 112.

MR. CONWAY: One moment, your Honor.

No objection.

This is it the workpaper, right?

MR. KUTIK: Yes.

MR. CONWAY: No objection.

EXAMINER TAUBER: FES Exhibit 112 shall

be admitted at this time.

(EXHIBIT ADMITTED INTO EVIDENCE.)

EXAMINER TAUBER: Seeing nothing else, we'll reconvene tomorrow morning at 8:30.

We'll go off the record.

(The hearing adjourned at 7:37 p.m.)

- - -

CERTIFICATE

I do hereby certify that the foregoing is a true and correct transcript of the proceedings taken by me in this matter on Tuesday, May 22, 2012, and carefully compared with my original stenographic notes.

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

My commission expires June 19, 2011.

(MDJ-4016)

\- - -