COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) APPROVAL OF TARIFFS AND RIDERS; (3) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES (4) APPROVAL OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY; AND (5) ALL OTHER REQUIRED APPROVALS AND RELIEF	CASE NO. 2020-00174

VOLUME II

Transcript of November 18, 2020, hearing before Chairman Michael J. Schmitt at the Kentucky Public Service Commission, 211 Sower Boulevard, Frankfort, Kentucky 40602-0615, with Vice Chairman Kent A. Chandler, Commissioner Talina R. Mathews, counsel, and witnesses attending via GoToMeeting.

LAURA J. KOGUT, RMR, CRR, CRC
DANNIELLE COPELAND, RMR, RDR, CRR
McLendon-Kogut Reporting Service, LLC
2525 Nelson Miller Parkway, Suite 204
Louisville, Kentucky 40223
(502) 585-5634
lkogut@mclendon-kogut.com
dannielle.cox@gmail.com
www.mclendon-kogut.com

C O N T E N T S

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APPEARANCES

FOR KENTUCKY POWER COMPANY (Via Videoconference):
Mr. Mark R. Overstreet
Ms. Katie M. Glass
Stites & Harbison PLLC
421 West Main Street
P.O. Box 634
Frankfort, Kentucky 40602-0634
(502) 223-3477
moverstreet@stites.com
kglass@stites.com

and

Ms. Christen M. Blend
Mr. Tanner Wolffram
Mr. Hector Garcia-Santana
American Electric Power
1 Riverside Plaza, 29th Floor
Columbus, Ohio 43215
(614) 716-3410
cmblend@aep.com
tswolffram@aep.com
hgarcia1@aep.com

FOR KENTUCKY ATTORNEY GENERAL (Via Videoconference):
Mr. J. Michael West
Mr. Lawrence (Larry) W. Cook
Mr. John G. Horne II
Commonwealth of Kentucky
Office of the Attorney General
Office of Rate Intervention
700 Capitol Avenue, Suite 20
Frankfort, Kentucky 40601-8024
(502) 696-5300
michael.west@ky.gov
larry.cook@ky.gov
john.horne@ky.gov

APPEARANCES
(Continued)

FOR KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC. (Via Videoconference):
Mr. Michael L. Kurtz
Ms. Jody Kyler Cohn
Boehm, Kurtz & Lowry
1510 URS Center
36 East Seventh Street
Cincinnati, Ohio 45202
(513) 421-2255
mkurtz@bkllawfirm.com
jkylercohn@bkllawfirm.com

FOR WALMART, INC. (Via Videoconference):
Mr. Barry Alan Naum
Ms. Carrie Harris Grundmann
Mr. Don C.A. Parker
Spilman Thomas & Battle
110 Oakwood Drive, Suite 500
Winston-Salem, North Carolina 27103
(336) 725-4710
cgrundmann@spilmanlaw.com
dparker@spilmanlaw.com

FOR KENTUCKY SOLAR INDUSTRIES ASSOCIATION, INC. (Via Videoconference):
Mr. David E. Spenard
Mr. Randal A. Strobo
Strobo Barkley, PLLC
239 South Fifth Street, Suite 917
Louisville, Kentucky 40202
(502) 290-9751
rstrobo@strobobarkley.com
dspenard@strobobarkley.com

FOR MOUNTAIN ASSOCIATION KENTUCKIANS FOR THE COMMONWEALTH KENTUCKY SOLAR ENERGY SOCIETY (Via Videoconference):
Mr. Tom FitzGerald
Kentucky Resources Council
P.O. Box 1070
Frankfort, Kentucky 40602
(502) 875-2428
fitz@kyrc.org

APPEARANCES
(Continued)

FOR SIERRA CLUB (Via Videoconference):
Mr. Joe F. Childers
Ms. Bethany N. Baxter
Childers & Baxter
201 West Short Street, Suite 300
Lexington, Kentucky 40507
(859) 253-9824
joe@jchilderslaw.com
bethany@jchilderslaw.com

and

Mr. Matthew E. Miller
Sierra Club
2528 California Street
Denver, Colorado 80205
(517) 230-7420
matthew.miller@sierraclub.org

FOR SWVA KENTUCKY, LLC (Via Videoconference):
Mr. Michael A. Frye
Jenkins Fenstermaker, PLLC
P.O. Box 2688
Huntington, West Virginia 25726
(304) 523-2100
maf@JenkinsFenstermaker.com

FOR KENTUCKY PUBLIC SERVICE COMMISSION:
Ms. Nancy J. Vinsel
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602
(502) 564-39404
nancy.vinsel@ky.gov

ALSO PRESENT:
Ms. Candace Sacre, PSC Court Reporter

* * *

(Hearing commenced at 9:05 a.m.)

MS. SACRE: Okay, sir, you're on. You're on, Chairman.

CHAIRMAN SCHMITT: We may be on the record, but I don't have a screen that --

MS. SACRE: Okay.

CHAIRMAN SCHMITT: -- shows anything.

MS. SACRE: Okay. Just a second, then.

CHAIRMAN SCHMITT: Is your screen working?

MS. VINSEL: No, it's the same as this.

MS. SACRE: I'll text Jim.

MS. VINSEL: There we are.

MS. SACRE: Okay.

CHAIRMAN SCHMITT: Is your-all's screen working? Mine isn't, but --

MS. VINSEL: Yes. Yes, mine is working now.

MR. GARCIA-SANTANA: Good morning, Your Honor. This is Hector Garcia with Kentucky Power.

MS. SACRE: Here comes Jim.

CHAIRMAN SCHMITT: No, it doesn't work. Oh, it does work. It finally made it. Okay.

All right. The parties and counsel are all present. I guess we won't know until we start, right? Okay. As we left off yesterday, we had finished, I think, the testimony of Mr. Satterwhite.

And so at this time, Mr. Overstreet, are you ready to call another witness?

MR. GARCIA-SANTANA: Good morning, Your Honor. This is Hector Garcia with Kentucky Power. Just confirming that you can hear me.

CHAIRMAN SCHMITT: Yes, Mr. Garcia. Do you have an idea of a witness to call at this time?

MR. GARCIA-SANTANA: Yes, Your Honor. The Company would like to call Dr. Kelly Pearce.

CHAIRMAN SCHMITT: Okay. Thank you.

Would you please raise your right hand? Okay. Do you solemnly swear or affirm under penalty of perjury that the testimony you are about to give will be the truth, the whole truth and nothing but the truth?

MR. PEARCE: I do.

CHAIRMAN SCHMITT: Okay. Counsel, you may ask.

MR. GARCIA-SANTANA: Thank you, Your Honor.

KELLY DOUGLAS PEARCE, having been first duly sworn, testified as follows:

DIRECT EXAMINATION

By Mr. Garcia-Santana:

Q. Good morning, Dr. Pearce. Can you hear me?

A. Good morning. Yes. I'm turning up my volume

just a little bit. Okay.
Q. Yeah. During the examination, it's possible that we may be instructed to speak clearly. Since we are in a virtual environment, it's a little harder to take down the record, so just to give you a heads up.
Would you please state your name, business address, who you work for, and what title for the record?
A. Certainly. My name is Kelly Douglas Pearce. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I work for American Electric Power Service Corporation. I am managing director of transmission asset strategy and policy.
Q. Thank you. And in this case did you cause rebuttal testimony to be submitted on behalf of Kentucky Power?
A. Yes, I did.
Q. And subsequent to that rebuttal testimony, did you also cause to submit supplemental corrected testimony?
A. Yes, I did.
Q. Okay. Were those pieces of testimony prepared by you under your supervision?
A. Yes, they were.

Q. Okay. And did you also cause discovery responses to be submitted on behalf of Kentucky Power?
A. Yes, I did.
Q. And those also were prepared by you and under your supervision?
A. Yes, they were.
Q. Okay. Dr. Pearce, if you would be so kind, would you describe briefly, what's the nature of the corrections that were filed as the supplemental corrected testimony?
A. Certainly. On a couple of pages of my revised rebuttal testimony, at pages R7 and R8, there were a certain of the numbers that required refiling, and there was an additional question and answer regarding those revisions.
In the course of doing an analysis of what would be the impacts on Kentucky Power of leaving the transmission agreement and going from 12CP to a 1CP basis, I determined that the incorrect values had been pulled, basically from the roughly 15 percent nonaffiliate loads within our zone, and so that was discovered last week and corrected and filed last Thursday, the 12th, I believe.
Q. Okay. And just to clarify, those

nonaffiliates in the zone, can you describe what those are?

A. Certainly. That is within the AEP load zone. That's the approximately 15 percent of the load within the AEP load zone that represents various municipalities and cooperatives that are not affiliates to AEP but take transmission service from AEP within the AEP load zone.

Q. Thank you. If I were to ask you the same questions today regarding the discovery answers and your corrected supplemental testimony, would you provide substantially the same answers today?

A. Yes, I would.

MR. GARCIA-SANTANA: Your Honor, the witness is tendered for cross-examination.

CHAIRMAN SCHMITT: Thank you, Mr. Santana.

Ms. Vinsel, questions?

MS. VINSEL: Your Honor, Staff does not have questions of Dr. Pearce.

CHAIRMAN SCHMITT: Okay.

Attorney General, counsel for Attorney General, any questions?

MR. WEST: Mr. Chairman, we don't have questions for this witness. Thank you.

CHAIRMAN SCHMITT: Mr. Kurtz, questions on behalf of KIUC? Mr. Kurtz, we can't hear. You may be on mute.

MR. KURTZ: I was. Thank you. Can you hear me now okay?

CHAIRMAN SCHMITT: Yes.

MR. KURTZ: Even if the connection is bad. Okay. Yeah, I do have a few questions.

CROSS-EXAMINATION

By Mr. Kurtz:

Q. Good morning, Mr. Pearce.

A. Good morning, Mr. Kurtz.

Q. Under the transmission agreement, Kentucky Power gets its revenue requirement as a transmission owner; is that correct?

A. Yes, it does.

Q. Okay. And then Kentucky Power pays its 12CP allocated share of the AEP zonal cost as an LSE or transmission user; is that correct?

A. Yes, it does.

Q. And the return on equity authorized by FERC for all the entities within AEP, which would be Indiana Michigan, Indiana Transco, Kentucky Power, Kentucky Transco, etcetera, is 10.35 percent; is that correct?

A. That is correct. 9.85 base ROE and 50 basis

points for RTO participation; that is correct.
Q. Okay. Then the transcos' equity authorization -- equity ratio is authorized up to 55 percent for the transcos; is that correct?
A. That is correct.
Q. All right. Now, you filed rebuttal testimony against AG KIUC Witness Mr. Baron; is that correct?
A. Yes, I did.
Q. Okay. Mr. Baron calculated in his initial testimony that if Kentucky Power were a stand-alone entity, transmission entity, it would pay $19 million per year less in 2020 than as a member of the AEP transmission pool. Is that your understanding of his testimony?
A. That's my understanding of what he represented.
Q. Okay. You did not challenge that $19 million number, did you?
A. I have not reviewed it. I will say that, just to clarify the scenario he's describing, it is not just Kentucky Power leaving the transmission agreement and being part of the zone. That was under a scenario where Kentucky Power could, in theory, leave both the transmission agreement and create its own load zone within PJM.

Q. All right. And all that would require a change to the PJM rules is your understanding; is that correct?
A. Yes. Right now there's specifically a portion of the Consolidated Transmission Owners Agreement, which is FERC-approved Rate Schedule 42, that specifically disallows that.
Q. Okay. Are you aware that Mr. Baron updated the $19 million number to $27.689 million based upon AEP's '20-'21 PJM filing?
A. I looked at an updated version of what he did. I did not go through the number specifically.
Q. Are you aware that the new number changed from 19 million to 27.689, at least his testimony?
A. I'm aware it increased. I'll accept your number.
Q. Okay. Is it correct that over the five-year period 2021 to 2025, AEP plans to spend 10.1 billion on transmission within PJM?
A. Based on, I believe, the exhibit that we were talking about yesterday, I believe that is the case.
Q. Okay. And under the current transmission agreement, Kentucky Power would be allocated about 5.6 percent of that 10.1 billion, 5.6 percent being its 12CP share of the AEP system; is that correct?

A. That, I believe -- I don't think you can do the math that straightforwardly in the sense that, you know, some of those projects would be part of the regional expansion plan and could get allocated to other zones. The allocation based on 12CP in the AEP zone would only be how much of that got charged back to the AEP zone under the current rules, and then the allocation between the nonaffiliate and the AEP companies under the current transmission agreement, then that bucket then would be further allocated with Kentucky Power paying its 12CP share, which currently is running around 5.7 percent.

Q. Okay. Are you familiar with the Certificate of Public Convenience and Necessity process in the AEP East jurisdictions for transmission?

A. Somewhat.

Q. Can you describe the process in Kentucky versus -- I'll pick just one at random. Versus Indiana?

MR. GARCIA-SANTANA: Your Honor, I would like to object to the question to the extent it calls for a legal opinion.

CHAIRMAN SCHMITT: Overruled. You may ask.

A. Could you repeat the question?

Q. The Certificate of Public Convenience and

Necessity process for transmission line certification in Kentucky versus Indiana.

A. The CPCN process varies across all of our states. I believe I&M has -- does not have a substantial CPCN process. Kentucky, of course, has one. Ohio, on the other kind of end of the spectrum, has a very stringent CPCN process.

Q. So it's easier to build transmission in Indiana than Kentucky because of the difference in the CPCN process?

A. I would say the CPCN process may be somewhat lighter, but I don't think that is a significant, you know, driver in addressing the needs in the state. We work through whatever regulatory processes we have in each one of our states to address the needs.

Q. Would AEP make more money investing in a transco transmission project with a 55 percent equity and 10.35 percent return on equity versus Kentucky Power at 43 percent equity?

A. The earnings are going to be tied to the capital structure of the company, I will agree with that.

Q. So the higher the equity capitalization, the more profit?

A. Well, the more earnings. But, again, also, the flip side as far as the customer value, the higher the equity, normally, the lower the debt rating. For example, I believe Kentucky Transco has a lower debt rating than Kentucky Power does. So the net WACC, weighted average cost of capital, for the customers can be blended together from these two pieces.

Q. Still, the net weighted average cost of capital for the transco is higher than for Kentucky Power, correct?

A. The earnings based on the investment can be higher.

Q. Because the equity has to be grossed up for federal and state taxes and debt is not, among other things?

A. Yes, you do have to do an adjustment for the taxes.

Q. And a return on equity is -- even after taxes, is higher than the cost of debt, correct?

A. Well, I mean, let me be clear. The adjustment for taxes on the equity piece would be true of the opco or the transco, if that's what you're asking.

Q. Well, yeah, that's true. And I'm also

asking: Isn't the equity component higher than the debt component? You're asking for ten percent after taxes --
A. Well --
Q. -- here versus four, five percent for debt; is that your understanding?
A. Yes, the equity component is allowed up to 55 percent for the transcos, that is my understanding.
Q. Are you familiar with the process that KPC or some other complainant would have to go through at PJM to change the PJM rules?
A. Which PJM rule are you defining?
Q. The one that prohibits Kentucky Power from being its own transmission zone.
A. Under Article 7.4, to modify that, as referenced in my testimony?
Q. Yes.
A. As far as all the steps within the process, no, I'm not sure I could describe them all today. But I think even through that process, then eventually you would have to make -- it would probably culminate in a required FERC filing to attempt to make that change at FERC.
Q. One last bit of questions, Mr. Pearce.

MR. KURTZ: Can -- Ms. Vinsel, could we have on the screen Company Hearing Exhibit Number 7?

MS. VINSEL: Yes, Mr. Kurtz, we're getting that displayed.

MR. KURTZ: Thank you. Thank you. Could we go to page 8 of 20? That's it.

Q. Mr. Pearce, I assume you're familiar with this Company exhibit, this PJM document?

A. I'm sorry, it's cutting off on my screen. I only see the top of the exhibit. I don't know if others see it that way.

Q. I think it's better now. Can you see the exhibit?

A. Yeah. Okay. I can see it. Hang on. My top --

Q. Okay. I assume you're familiar with --

A. Bear with me here. I'm just trying to pull it up where I can -- on my screen it's showing very small in the up left, and then it's showing just the top of the graph. But I think I can see it here. Okay.

Q. Okay. This -- are you familiar with Company Exhibit 7? It's a PJM 2005 --

A. Yes, I believe I have seen a version of this.

Q. Okay. Now, if we look at AEP, it is page 8, Baseline and Supplemental Project since 2005. So we're seeing -- what does it show for AEP? How should I read this graph?

A. Yeah. Like I said, I'm trying to expand it, and when it expands, it only gives me a quarter of it. Hang on.

Q. Okay. It shows for baseline 4,942,000,000 --

A. Oh. Yeah, I'm -- hey, what you just did was better. Could you re-shrink it further to, like, 75 percent? Is there any way -- I apologize. Is there any way to scroll down on the exhibit?

VICE CHAIRMAN CHANDLER: So, Mr. Pearce -- sorry. This is Kent Chandler. You can control the actual screen with your cursor, the portion of the document that's being presented, and then at the top of the entire dialogue box, there -- you have your own zoom button as well. It's everyone, web cams, then the third item at the top is zoom.

THE WITNESS: Okay. I apologize. I see a dialogue box that's got the microphone.

VICE CHAIRMAN CHANDLER: On the primary screen that has the document and the video boxes, do you see that?

THE WITNESS: Yes.

VICE CHAIRMAN CHANDLER: Directly above the video boxes there's an item that says Everyone. Beside that it says Web Cams. Do you see those?

THE WITNESS: I see Sharing the Webcam.

VICE CHAIRMAN CHANDLER: Yeah. To the right of that, do you have a zoom button?

MR. GARCIA-SANTANA: Your Honor, if I may. Dr. Pearce, do you happen to have a freestanding copy of this document? You can follow on your own copy and then probably we can just discuss the document that is being presented, but you are following on your own direct copy. I don't know if you have one available to you.

THE WITNESS: I don't believe that I have a copy of this. Let me --

MR. GARCIA-SANTANA: Dr. Pearce, actually, you probably have one that we submitted to you by e-mail.

THE WITNESS: Okay.

MR. GARCIA-SANTANA: Thank you, Your Honor.

THE WITNESS: Okay. Yes. Thank you. I have it open now.

Q. (By Mr. Kurtz) Great. How about page 8? 8.

A. Okay. Sorry for the delay. Okay.

Q. So if we go to AEP, do I read this as the amount of spending on baseline and supplemental by

AEP since 2005?

A. That is correct. That is those statistics.

Q. Okay. And these are the transmission rate based numbers that Kentucky Power pays as part of AEP, correct?

A. That is correct.

Q. Okay. Can we compare that to EKPC? Do you see EKPC, East Kentucky Power Cooperative, who has spent really just a fraction of the dollars on transmission since 2005?

A. That is true, you can, but I believe that is an apples-to-oranges comparison. On the very document that we're on, if you scroll to the -- this is the total spend on a dollar basis. If you move to the very next page.

Q. I was just going to go there. East Kentucky --

A. Okay.

Q. -- all the utilities in AEP, so it spent less dollars. It's not really descriptive. But the next page is the amount spent since 2005 adjusted by peak load, to put it more on apples to apples?

A. That is correct. And furthermore, if you -- we have to recognize the AEP system is a fairly broad area with a low population density. So if you

scroll to the page after this one, which identifies it by line miles --
Q. I was going to ask you about that page next, but we still have --
A. Okay.
Q. -- we still see the trend in East Kentucky, adjusted by peak load or by line miles, as a less expensive transmission system than AEP. Would that be fair to say?
A. Yes. It has a -- somewhat less expensive, as do many utilities, though, have more expensive on a dollar-per-mile basis, which I think the is fairest comparison.
Q. And, in fact, yesterday, I don't know if you saw the -- my discussion with Mr. Mattison about the NITS charges by PJM load zone, where East Kentucky was 20 percent, $20,000 per megawatt -- per megawatt year versus about 80,000 per megawatt year for East Kentucky -- for Kentucky? For AEP. Did you see that exhibit?
A. Yes, I did.
Q. East Kentucky operates in basically the same service territory as Kentucky Power, doesn't it?
A. Could you elaborate?
Q. Same topography, same customer base, probably

similar density per transmission mile. I mean, the service territories overlap. Your lines go over their service territory and vice versa, that's what I meant.

A. I haven't done that comparison. I don't think I can comment on that.

Q. Does a cooperative utility, if you know, have the same earnings growth requirements as an investor-owned utility?

A. I'm not sure about earnings growth requirements. I mean, cooperatives and municipalities operate under basically a completely different set of rules, in my mind, than investor-owned utilities.

MR. KURTZ: Thank you, Mr. Pearce. Mr. Chairman, I have no further questions.

CHAIRMAN SCHMITT: Okay. Thank you.

Ms. Grundmann, any questions on behalf of Walmart?

MS. GRUNDMANN: No questions, Your Honor.

CHAIRMAN SCHMITT: Mr. Spenard or Mr. Strobo, questions?

MR. STROBO: No, Mr. Chairman, no questions for this witness.

CHAIRMAN SCHMITT: Mr. FitzGerald, questions?

MR. FITZGERALD: No, Mr. Chairman, thank you.

CHAIRMAN SCHMITT: Sierra Club, Mr. Miller, questions?

MR. MILLER: Good morning, Mr. Chairman. No questions from Sierra Club. Thank you.

CHAIRMAN SCHMITT: Mr. Frye, any questions of this witness?

MR. FRYE: No questions, Mr. Chairman.

CHAIRMAN SCHMITT: Vice Chairman Chandler, questions?

VICE CHAIRMAN CHANDLER: Thank you, Chairman. Can you hear me?

THE WITNESS: Yes.

EXAMINATION

By Vice Chairman Chandler:

Q. Dr. Pearce, how are you?

A. Good. How are you? I appreciate you helping me through the technical difficulties a minute ago.

Q. That's all right. We're all in the same boat here.

Let me ask: Your rebuttal focuses only on the allocation of NITS from a 1CP to a 12CP basis, correct?

A. Yes.

Q. Yeah. So were you watching the hearing yesterday?

A. Yes, I was.

Q. Okay. So you saw my questioning of Mr. Satterwhite and Mr. Mattison on the subject?

A. I did.

Q. Okay. So let me just ask again, because I know that you deal more directly with this than Mr. Satterwhite does. My hope is that after these questions that I can maybe have a better understanding of how everything works together in the AEP East system regarding transmission.

A. Okay.

Q. So there are operating companies and there are transmission companies, correct?

A. That is correct.

Q. Is there a -- ignoring, and I don't mean this to be mean to our friends in the south, but ignoring Tennessee for a minute, does every state that has an operating company in the AEP system have a transmission company?

Well, let's just go through them. So Tennessee does not, right? They do not have a transmission?

A. That's correct, they do not.

Q. Okay. And I'm trying to -- work with me here, I may forget a state here. Kentucky does have a transmission company?

A. It does.

Q. Virginia?

A. Yes.

Q. West Virginia?

A. Yes.

Q. Ohio?

A. Yes.

Q. Indiana?

A. Indiana and Michigan have I&MT jointly.

Q. And so the Indiana and Michigan are together?

A. That's correct.

Q. And that's the entire AEP East system, correct?

A. Yes.

Q. So only Tennessee doesn't have a transmission company?

MR. GARCIA-SANTANA: Your Honor, if I may interject for a second, just to clarify the record before this goes any further. If I can ask really quickly, Dr. Pearce, Appalachian Transmission Company covers both Virginia and Tennessee, sir, if you know?

CHAIRMAN SCHMITT: I'm sorry, Mr. Santana, I'm not sure I understand you.

MR. GARCIA-SANTANA: It covers the Appalachian?

VICE CHAIRMAN CHANDLER: Yeah, so I can -- I think I can take care of this.

Q. There's a singular transmission company for -- that Appalachian, it covers West Virginia and Virginia, correct?

A. I'm sorry?

MR. GARCIA-SANTANA: Tennessee and Virginia, Your Honor.

Q. Tennessee and Virginia?

A. Tennessee and Virginia, yes. Excuse me. Yes.

THE WITNESS: Thank you for that clarification.

Q. Okay. So West Virginia has its own?

A. Yes.

Q. Okay. So I just want to make sure I understand. The operating companies don't own the transmission companies, correct?

A. No, they do not.

Q. Okay. And the -- just to make sure we're also clear, the transmission companies don't own the operating companies, correct?

A. No, they do not.
Q. Okay. So let's look at it for a second from the operating company perspective. Kentucky Power, you heard that -- from Mr. Satterwhite and Mr. Mattison about them attempting to attract as much capital as possible for Kentucky Power Operating Company to invest in a transmission system.
Do you remember Mr. Satterwhite's testimony on that point?
A. Yes, I do.
Q. Okay. So Kentucky Power invests, we'll just make up money. Let's make up numbers here for the purposes of illustration. They invest $10 million in transmission, right? And they file that as under the -- the costs recovered of that $10 million transmission investment is recovered by the transmission of -- the transmission agreement, correct?
Oh, I apologize, Mr. Pearce, you're on mute.
A. Your Honor, I apologize. That kind of (indiscernible). Kindly repeat that question.
Q. Yeah, let's wait one minute for the latency issue to go away. Can you hear me now okay?
CHAIRMAN SCHMITT: There's something wrong,

Mr. Pearce. We can't hear you.

MR. GARCIA-SANTANA: Actually, Your Honor -- this is Hector.

THE WITNESS: Can you hear me now?

MR. GARCIA-SANTANA: It may be a timing problem with the Internet.

CHAIRMAN SCHMITT: Oh, okay.

Q. So let me --

CHAIRMAN SCHMITT: Like an old foreign movie, right? You see the lips move and ten seconds later you get to hear the words. Let's try it and see how it works.

Q. Yeah. Can you understand -- can you hear me now, Mr. Pearce?

A. I can. Can you hear me?

Q. Okay. Yeah, there's just a short delay, which is probably better for everybody, including the court stenographer.

Kentucky Power, let's just say hypothetically invests $10 million in the transmission system in year X. In order to recover that investment, they include that -- they recover that investment through the transmission agreement that we were discussing yesterday, correct?

A. You said Kentucky Power?

Q. Kentucky Power.

A. Yes. Well, if Kentucky Power invests $10 million in transmission, the revenue requirement for that would actually go into their transmission formula rate, and they would initially get recovery of that revenue requirement directly from PJM.

Q. Okay. So how does that happen in practice? What form is that filled out on? Who is that filed with? Does it go through AEP first? And does AEP then do it, or is it filed directly with PJM by AEP on behalf of Kentucky Power? I just would like for you to explain to us, in practice, how that recovery -- how -- let me just ask it this way: How the request for rate recovery occurs from the Kentucky Power perspective.

A. Certainly. Certainly. So the -- based on the FERC-approved tariffs, part of the PJM tariff is Attachment H. So as the process is approved, Kentucky Power is one of the companies that on an annual basis develops its projected revenue requirement for the next year. So they have to make an annual filing of that by the end of October each year, looking ahead to the next year.

So that is filed, provided to PJM, posted. There's a webinar held, and those rates go into effect January 1 of that year. And then PJM effectively does the billing. And then what happens is, the revenues come back in for our zone to our Transmission Settlements Group.

Q. Mr. Pearce, can we wait just a minute on that? I just -- the going up isn't the question, but the how they seek recovery is what I want to clarify first.

So they file the request to approve those through their projected revenue requirement as laid out in Attachment H of the PJM Open Access Transmission Tariff, correct?

A. That is correct.

Q. And is that the case for all of the transmission -- well, I guess, let me withdraw that.

Is that the case for all of the AEP operating companies? Is that the same process?

A. It is the same process. All of those are under Attachment H. For the op-cos, it's Attachment H14.

Q. H14?

A. Which, as a traditional cost of service, has effectively been approved by FERC, but the protocols then require that we go through, we update all the information on an annual basis, and then it's

submitted as I described.
Q. Okay. And so that's the projected revenue requirement for the next year. I assume at some point there's a true-up to that, correct?
A. You are correct. What happens is --
Q. Can you --
A. Go ahead.
Q. I think you're going to already do it, but can you explain to me what the true-up is as it relates to the operating companies?
A. Absolutely. So what happens is, for example, for 2019, okay, we were required to do a true-up by the end of -- by around the end of May is when we have to have that completed. It is all tied to the FERC Form 1 data.
AEP, we complete our FERC form 1s for each of the op-cos around the middle of April. And so by the end of May, then, we submit that. And the same thing, we basically post it, we will have webinars. Our protocols allow for extensive discovery of that, as they actually do for the projection as well.
And then that true-up, that over/under, is included back in the next year's rate. So it's actually for -- the 2019 true-up will be included as a line with our 2020 -- so, I'm sorry, 2021

projection that will go into effect this year.

So we only collect what we actually spend. That's how we get back the over/under with interest at the FERC rate.

Q. Okay. And it's the 2021 because the 2020 actually would have been filed the previous October, and you haven't gone through the entire year yet to find out what the true-up needs to be, correct?

A. Yeah, that's exactly right.

Q. Okay. So that's the operating companies. That's how they seek recovery of the revenue requirement, correct?

A. Yes.

Q. Okay. The transmission companies, is that H20A?

A. Yes.

Q. Okay. So the transmission companies -- so the operating companies are on H14, an attachment to the Open Access Transmission Tariff. The transcos are H20A. Is it the same situation just with a different tariff?

A. It is. It is. The templates are nearly identical, standard cost of service, and all those time frames that I laid out are precisely the same.

Q. Okay. And the same projection revenue

requirement and then true-up two years later, correct --
A. That is --
Q. -- or year and a half?
A. That is correct.
Q. Okay. So we have -- that's the way that all of the transmission investment done by AEP in the AEP East system is recovered is through those two attachments to the Open Access Transmission Tariff, correct?
A. You are correct.
Q. Okay. And then we go from requesting recovery of the revenue requirement to recovering the revenue requirement.
Now, are you aware of the transmission agreement that was referred to yesterday? And I believe it was -- well, it was one of the PSC Staff's exhibits that had the chart as AEP as an LSE and AEP as a transmission owner?
A. I am.
Q. Okay. So in regards to the conversation that we just had regarding H14 and H20, would you agree that that transmission agreement applies only to those utilities, only to those companies that file under H14, in terms of AEP as a transmission owner?

Let me ask that differently. That applies only to the operating companies and not to the transmission companies, correct?

A. Yeah, the -- only the operating companies are members of the transmission agreement.

Q. Okay.

A. For clarity, I'll only add, though, that when it talks about how they allocate the costs coming in that's applicable to the operating companies, that is all of the costs that they get billed. So it would include their -- billing to them as an LSE, whether it was, you know, basically pieces of the opcos or pieces of the transcos.

Q. Yeah, and that's the next step of what I want to ask you about. So the -- they get filed with FERC, right? And then can you walk us through the process whereby FERC then charges -- this -- maybe this is not the correct term, but effectively charges those transmission revenues back to load? Can you walk us through that process?

A. Certainly. So for net service throughout the year, all load-serving entities within our load zone are going to be charged more for their transmission service. They're going to pay their bill. And then, you know, PJM is a clearinghouse, so basically, at the end of the day, they'd be revenues that they are collecting that come back into -- for the AEP zone, that make their way into our Transmission Settlements Group.

Q. All right. So we're going to have to go a little more granular than that. I understand that -- my take on PJM is always be -- going to be the transmission owners -- it's a transmission owner organization and load always pays. So I get that -- I get that it all gets allocated to LSEs --

A. Yeah.

Q. -- but the question I have is the mechanisms by which that is done.

A. Okay. So the mechanisms by which that is done is the transmissions group, the settlements group is going to basically identify, based on the network service peak load contribution, all of the nonaffiliate responsibility and allocation for those bills, and then AEP, which is one collective account under Appalachian Power, I believe, that's the first operating company in alphabetical order, it gets allocated to the AEP companies on that basis.

Q. Okay. That's great. So all the NITS costs, right, which we -- okay. Let me take a step back.

You would agree that there are additional LSE

OATT expenses in a -- above and beyond NITS?
A. That's correct.
Q. Okay. So we'll just talk about NITS for the time being. The NITS costs are broken out first, when they're billed, between LSEs that are not part of AEP and AEP as if it's an entire LSE itself, correct, on a 1CP basis?
A. That's correct.
Q. Okay. So you -- let me ask this: So let's just make it the city of -- and this is a real city, but it may not be in your district. The city of Kalamazoo, right? Let's say it's an LSE within the AEP East system. Is it going to get allocated NITS on a 1CP basis?
A. Yes, it would.
Q. Okay. So it gets allocated on a 1CP basis. So you break -- you get the big picture on how PJM charges on a 1CP basis. You break out everybody who's not an affiliate of AEP, or not a load-serving entity of AEP, and then for AEP, you get the bill on a 1CP basis.
Now, that is the bill, as I understand it, for all -- for everyone except for those nonaffiliated LSEs, right?
A. That is correct.

Q. And so let's just -- for an illustration again, even if you allocated those out to AEP LSEs in the east, Kentucky Power Operating Company, Ohio Power Operating Company, Appalachian, even if you allocated all of those out on a 1CP basis, that is materially different in terms of the ultimate costs than if you allocated only the costs of each operating company on a 1CP basis if they were billed separately, correct?

A. Okay. Could I ask you to repeat that one more time?

Q. Sure.

A. I just want to make sure I follow it all.

Q. Sure. And maybe I can make it a little more definitive. Is the -- is there a difference, right, between allocating Kentucky Power's 1 CP contribution from the whole AEP residual bill, or, if you just allocated Kentucky Power, Ohio Power, we -- you know, all the different operating companies on their own single CP before -- if the bill was sent directly to Kentucky Power on a 1CP basis instead of being sent to AEP and then being broken out on a 1CP basis.

A. It -- let me say this, and if I don't answer your question, please let me know. I think what you're asking is, is if each of the operating companies, for example, was -- the calculation was being done within transmission settlements as though the transmission agreement did not exist, each one would be allocated on a 1CP basis. I think the sum of all the companies together would add up to the same amount as is being collected, as is being allocated in the block that we were just talking about.

Q. I think the sum would be, but would the individual allocations to the operating companies be the same?

A. Well, the individual operating company allocations would all be tied to their individual contribution to the entire zone's network service peak load.

Q. But the -- but the percentage is then applied to the costs allocated to the entire AEP East zone for affiliates, correct?

A. That is correct.

Q. So my question is: Is the same -- let's just -- again, let's just make up a number. So say the allocation was a hundred million dollars, and we know it's way more than that because the -- it's more than a hundred million dollars, right, that's being allocated to AEP after you carve out the nonaffiliated LSEs?

A. Correct.

Q. But let's say it's -- a hundred million dollars is the residual amount that has to be recovered from all the different AEP operating companies. And then let's say the transmission agreement doesn't exist and it's just going to be reallocated on a 1CP basis, right?

A. Yes.

Q. And let's say Kentucky Power's is six percent. Okay?

A. Okay.

Q. So under that, Kentucky Power gets a $6 million allocation?

A. Yes.

Q. Okay. Compare that situation to, instead of the AEP East zone being treated as a singular LSE, instead think of it, if each AEP operating company was its own separate LSE, right? And it was allocated -- AEP, Kentucky Power, was allocated its 1CP and got a bill directly from PJM instead of it running through AEP first, and Ohio Power Company got allocated a 1CP based off the transmission in their -- you know, if -- I guess what I'm saying is:

If each one was a separate zone, if each LSE was its own separate zone, you would agree that the outcome from that 1CP allocation is different than the first one I described, whereas everybody just is part of the same TO zone, but they get the 1CP after it comes to the AEP East's companies?

A. Oh, Your Honor, I mean, I need to clarify. The scenario we're talking about, I thought, is the transmission agreement doesn't exist but they're all still apart of the same zone. Okay.

Q. Okay. What I --

A. So --

Q. What I -- go ahead.

A. Okay. So, yes. And I think, if I understand your question -- let me -- maybe this will help, if I just walk through it. And this is actually in my rebuttal testimony, referring to page 7.

Q. Okay.

A. So what we looked at is, if -- and I think this is the scenario you're describing is, if, for example, Kentucky Power was not part of the transmission agreement anymore, it would be allocated like the nonaffiliates. It would just basically look at the entire bucket of dollars allocated to the entire zone --

Q. Right.
A. -- and then it'd be allocated a percentage based on its contribution to that one (indiscernible). Then on page 7, on line 8, for the seven-year period we looked at, that is the percentages. The 4.42 percent up to 6.63 percent would be the amounts that would be allocated to Kentucky Power. It would just basically look like a nonaffiliate in our zone. And that's the basis for the allocation to Kentucky Power.
Q. Yeah. I know that.
A. Does that answer your question?
Q. What I want to ask, though, is: For Kentucky Power, for instance, is there a difference between an allocation under that scenario? If the transmission agreement didn't exist, right? Compare that example that you put in your testimony --
A. Yes.
Q. -- compare it to an example where, instead of all of the operating companies belonging to their own TO zone, if they were all their own TO zone themselves. If Kentucky Power only got allocated, right, the transmission that's located in their territory, would the calculation be different than under the scenario you laid out on page 7?

A. In the hypothetical -- so you're talking about, if we went this route that I believe Mr. Kurtz was talking about, is if we attempted to create a new -- entirely new load zone for Kentucky Power itself, as -- instead of it being part of the PJM load zone?

Q. That's what I'm trying to understand. It -- is that -- yes. That part of that -- that effectively, that's the area. If all the opcos, or even if just -- I was thinking about all the opcos, but if Kentucky Power was its own zone --

A. Yeah.

Q. -- would you agree that the allocation to it under 1CP would be different than under the allocation if, for instance, just the TA -- just the transmission agreement didn't exist?

A. Yeah, it would be assigned a certain dollar revenue amount to the zone, and then under the -- under the default, I'll say, for PJM, then it would be the 1CP. So the contribution of that zone, that new Kentucky zone, would be allocated to all the loads in the zone. And obviously, if Kentucky Power was pretty much the only load in that zone, then it would effectively be all allocated to Kentucky Power, with perhaps a few munis or co-ops in there.

But I think -- but I do need to clarify something. And I do think that the thinking that, under that scenario, if Kentucky Power became its own -- its completely own zone, okay, if somehow, despite the reference to Article 7.4 specifically, explicitly saying that FERC does not desire that to happen, so personally, I do believe it would be an uphill battle, but on top of that, I don't know that it would necessarily be as easy as saying what the dollar revenue obligation would be for Kentucky Power to be able to just add up Kentucky Power, Kentucky Transcos, the revenue obligation under that zone.

Up to this point in time, we have had an integrated system. I mean, we had it for decades, even when we joined PJM and revised the agreement around the 2010 time frame, you know, we still proposed to have an integrated system. So I do think, you know, if such -- and I am speculating here, but if such -- if such filings were even attempted at PJM and at FERC to try to adjust that provision, and it's basically buying an exception, I mean, we'd all agree that there's going to have to be just and reasonable support for that.

And I think the problem is, as Kentucky Power being part of an integrated system, is the other companies can look and say, hey, if we have built assets, transmission assets over time in West Virginia, in Virginia, in Ohio, that are clearly supporting Kentucky Power load, I mean, Kentucky Power has a generation asset outside the state, then I think folks could come in with a very strong argument and say, even if they're going to try to create their new zone -- their new zone, that they should be on the hook to pay for some of those legacy -- those legacy investments.

Q. And --

A. So the dollar amounts -- and, you know, yes, I agree with as far as the peak load contribution, but the dollar amount could change substantially different than just looking at what's the revenue requirement of Kentucky Power and Kentucky Transco together. There could be more charges for that, plus there could be some other issues in the future.

Company Witness Ali is, I believe, taking the stand after me, and I think he could talk further about if you really had this scenario where Kentucky Power was its own load zone, even if you could get there, what implications there might be, its negative consequences for Kentucky Power's customers going forward, and how we would have to do this planning between the rest of our integrated system and now Kentucky that's stand-alone.

Q. Yeah. So those are all great considerations. So I would ask: Does anybody at AEP talk about these things?

A. I mean, I think -- and up to this point we have seen the benefits of the integrated system across our entire system. The Company Witness Ali may have more to add as far as how he looks, but he looks at the needs in all the -- all the opcos, all the states, and basically does a prioritization, shares that with the operating companies, and between them, they make the decisions.

But yes, they are looking at it holistically, as an integrated system, to improve the power flows, and reliable power flows across our entire AEP load zone, Kentucky customers included.

Q. No, what I'm asking is: I appreciate that there's a steadfast interest by the Company, as evidenced by the testimony, to continue to look at AEP as a holistic entity or as an integrated system. What I'm asking: Is there anybody at the different operating companies or anybody at the AEP Service Company looking out for the concerns of the individual operating companies as part of that goal?

A. Oh, that's a great question. Yes. And, I mean, I do think -- at least my personal experience has been that when the transmission organization has met with the various operating company leaderships, that's exactly the type of questions they are asking, that they are making sure they are looking out for their customers and making sure, is it a fair allocation across all the companies.

Q. And it's --

A. I do get -- go ahead.

Q. Excuse me. Go ahead, Mr. Pearce.

A. Just to say, I -- 'cause, personally -- I think the term, you know, is one company subsidizing another, and personally, I think that in this context, I think that's somewhat of a misnomer.

You know, for years, under the old transmission agreement, Kentucky Power was surplused, and they were -- because they were getting payments from the other operating companies. But, I -- you know, I would have been one of the first ones to argue that in no way are those companies, you know, subsidizing Kentucky Power. Kentucky Power was investing for the good of the system. And then when you blended all that together and you looked at everybody's load obligation, or load contribution, that's a fair allocator. I mean, it's one that's used, you know, time tested in both retail and wholesale rate making.

So, you know, I think -- I would not classify that as cross-subsidization. And I also do think, obviously, that these are dynamic and change over time. You know, as we've all discussed, if the scenario we go down, at the least would take three years from the notice, from the transmission agreement, plus there may be some other three-year capacity planning and everything, every attempt to align Kentucky Power assets on load zone.

You know, so in that amount of time, you know, if you get to the end of that three-year period and then you start looking out, well, what Kentucky investments are going to have, you know, post three years out, you know, it could be a situation where now Kentucky is starting to ramp up its investment. And if it has managed to climb this hill of becoming its own load zone, then suddenly it's on the hook for a hundred percent of all the investment, whereas under the current mechanism, it would pay less than -- less than six percent of that investment that would be made in the state of

Kentucky. So --

Q. But --

A. -- I mean, there's just -- I think there's some long-term concerns with potentially trying to do that that would argue that the climb may not be worth the view at the top.

Q. Let me ask this question: If that was the case and Kentucky Power was significantly investing in their transmission system, wouldn't you agree that those would be costs within their control?

A. Kentucky investing in its own system? I mean, Kentucky investing in its own state, in the -- would have some control over that, to the extent that PJM doesn't require specific projects, part --

Q. Sure.

A. -- of the expansion plan. Company Witness Ali can speak to the specifics of who has the ultimate authority on the various decisions.

Q. Yeah, and I'm pretty aware of the differentiation between supplemental and baseline projects, but you're aware of the testimony in this case that the argument for the -- for increasing the tariff PPA from 80 percent recovery to a hundred percent recovery of LSE load expenses is that the Company has no control over those expenses. But under the scenario you described, the Company would then have complete control over the increase in those expenses, correct?

A. I'm going to defer that to Company Witness Ali. To the extent that there are some nationwide standards like NERC or other things that may be required, that Kentucky has to comply with, it would be a better question for him.

Q. Well, and I can appreciate it would be a better question. And I'll withdraw that, at least the portion that says "complete control."

But wouldn't you agree that under that scenario, they would have much more control over their transmission expenses, over PJM LSE OATT expenses, than they do under the current scenario?

A. I would think that they would tend to have some more level of control.

Q. They would. Okay. And let me just ask: Given that, do you think that that's a consideration a utility should have when deciding what agreements it should be in, what level of control they have over the increase or decrease in expenses?

A. That could be one event.

Q. And that's one event --

A. But I do know -- oh, go ahead.

Q. I was going to say: And once you -- once you enter into an agreement, that would be most likely a consideration you would keep in mind as the agreement goes along as to whether or not the agreement continues to be in your best interest, right?

A. Yes. Yes. You would definitely look at all of that.

Q. Okay. So who is looking at that on behalf of Kentucky Power now?

A. As far as the -- I don't know that anybody has done a comprehensive review of, you know, what would be the potential implications for unwinding it. I don't know that somebody at the Company has specifically looked at that. Obviously, if that was a request, and I did hear Company Witness Satterwhite yesterday talk about discussions with Company Witness Mattison about, you know, following this proceeding, additional discussions around these areas, these topic areas. And I think that would be a good forum to perhaps look at that.

Q. Yeah. So this agreement is approximately, we'll just use -- this transmission agreement is approximately ten years old, right? Have you been in and around the transmission -- in and around areas of the Company that deal with this transmission agreement since its inception?

A. Yes.

Q. Okay. And so in that time, has anybody discussed or quantified or attempted to study whether or not the operating companies and the customers of those companies were better off as part of the current agreement as the -- with the agreement amended, with the agreement changed, or with the agreement continued? Has anybody looked at those on a holistic basis or on behalf of any of the individual operating companies within the AEP system?

A. Okay. Let me say this: I would say as far as -- there's -- again, there's -- I'm trying -- there's a very (indiscernible) between Kentucky Power leaving the transmission agreement and staying part of the AEP zone, which would require a notice, a FERC filing, it could require some level of approvals, but as far as the impacts at Kentucky Power, that's what I believe I did with my rebuttal is I went through in this case to show in that scenario, it would be -- I believe it would be worse for Kentucky Power and its customers to attempt to leave the transmission agreement.

Going the next level of saying, well, what if Kentucky not only left the transmission agreement and tried to become its own zone, I am not aware of any specific hard looks at what that -- what that -- somebody in the Company has done with that.

I think -- I think when we saw the language in the tariffs specifically not allowing that from a FERC perspective, kind of stopped there at this point.

Q. But let me just ask: Your testimony was provided in response to a suggestion made by a party in a proceeding at a state level. What I'm asking is: You and your group, on behalf of the different operating companies that depend on AEP Service Company to direct them -- we heard from Mr. Mattison the other day, that he depends on you-all, right, for particularly the transmission planning and the transmission cost recovery. And we heard from Mr. Satterwhite that the operating companies and the transmission group depend on his group to make the filings to get the cost recovery.

Prior to it being raised and providing some sort of, you know, calculation in response or in defense of the status quo, I'm just asking, in your-all's daily work on behalf of these operating companies, have you-all looked -- and I assume that the answer would be the same, but have you-all looked at that in any given year of just taking a step back and saying, is this in our customers' or is this in our operating company's best interest to continue with the status quo?

Would you say that your response indicates that that hasn't been the case, you haven't looked at that up until now?

A. Well, and I appreciate the question. And let me say this: Yes, on a regular basis, I believe we look at the settlements, we look at how it's impacting the various operating companies. And consistent with the discussion yesterday, if I ever saw a situation, in transmission in general, where we felt like there was an inherent bias, you know, for whatever reason, that that was -- that was disfavoring one of our operating companies, I do believe we would raise it to that -- we would raise it up, up the service core chain and we would raise it to the operating company.

This allocation discussion that we're having I don't see as an inherent bias. As I discussed, it can move around over time. And there could be areas that Kentucky Power is in that payer that would be -- at times, that Kentucky is in that receiver.

So cost allocation, by definition, whenever you develop a form of revenue requirements for its -- for the various entities, you sum them and then you allocate them out. By definition, that's always going to be a zero-sum game. So you're always going to find periods where roughly half of the group could say, you know, I am having to pay more than my revenue requirement, so am I being taken advantage of? And I disagree with that, as I said, in the form of a subsidy. It just -- cost allocation is always going to be a zero-sum game.

So this broader context, you know, we've looked at it, not necessarily with the laser lens that we've talked about here over the last half hour or so, but we would, I believe, you know, look at the operating companies and make sure: Are we addressing the needs in the state: Are they paying a fair share of the cost? And if we felt like there was a situation that was inherently biasing any of the opcos, then yes, we would bring it to Mr. Mattison's attention.

Q. So Mr. Pearce, if the Company's belief -- and I've heard this now from the three witnesses, that this is an integrated system and this is a fair way to allocate costs of an integrated system. If you always believe that it's an integrated system and you take that at face value, then how is -- wouldn't you agree that taking that position, you're never going to see that there's an inherent bias under this current allocation?

A. That's a good question, and I think -- I think, again, it comes back to are all the entities receiving a reasonable benefit that is consistent with their total cost? If, at the end of the day, you know, there could be some situation -- and I'm not saying that that couldn't happen, I'm just saying up to this point I haven't seen it. And I do, though, I'd say a reasonable amount of inquiry in that, where, hey, Kentucky Power is truly being disadvantaged in this situation and we need to -- we need to do something about it, then that's what we would do.

Q. Okay. So are you aware of, I think it was the DC Court of Appeals opinion regarding the Dominion 715 projects and the allocation of those costs?

A. Somewhat.

Q. Somewhat, yeah. That makes two of us. So let me just ask: When that matter was remanded back

to FERC and FERC required PJM to rerun the -- rerun those allocations, that instead of those 715 projects being allocated solely to the Dominion zone, that they be allocated on a regional basis with some sort of consideration of DFAX, did that change the allocation to -- did that start to allocate a portion of those costs to AEP? Is that your understanding?
A. It would potentially allocate a piece of the 715 as baseline projects, yes, I believe.
Q. Yeah. And did you-all support that allocation, that regional allocation?
A. No. We questioned that, that allocation that Dominion was using for that project.
Q. Well, wouldn't you agree, then, that -- obviously AEP is an integrated system, right?
A. Yes.
Q. They are -- excuse me. AEP is an integrated system, PJM is an integrated system, correct?
A. That is correct.
Q. Okay. And it is planned on a region-wide basis, that's the -- that's the underlying of the RTEP process, right? It's the regional transmission enhancement, I think that's the right -- but it's the RTEP process, right?

A. That's correct.

Q. Okay. And running those scenarios that FERC required on remand, AEP was being allocated a portion of those costs, or being proposed to be allocated a portion of those costs, because the DFAX came back and said that you-all were getting benefits from those, correct?

A. Okay. If I recall correctly, the Dominion system that we're talking about is 500 kV, and the allocation that PJM uses in that context is 50 percent on load ratio share for everything that's 345 kV double circuit and above, and the other 50 percent is on DFAX. So some of that would be allocated across the entire zone, the entire PJM, based on load ratio share, the other half would be on DFAX.

Q. Right. But you would agree that some of those came back and indicated that AEP was showing up as certain percentages on the DFAX runs, correct? Is that your understanding or your memory?

A. I vaguely recall that there might have been some DFAX allocated to our zone. Company Witness Ali may be able to confirm that.

Q. So I guess I would ask: You-all don't propose, as I understand it, in the process of allocating all transmissions, then, across the entire PJM system, even though you agree it's integrated and it's planned on an integrated basis? But that's the basis for the transmission agreement and the steadfastness, right, is that the AEP zone is an integrated system? So why is it -- why is one thing that's good for the goose not good for the gander?

A. Your Honor, that is a great question. And let me be clear here. On that project that we're discussing, that was a completely different set of circumstances. PJM, on any new project -- a new project, okay -- they are going to allocate costs as I just described. If it's a 345 kV double circuit or above in voltage, half is going to be allocated to load ratio share. So anywhere within PJM that such a project went, AEP would get a portion. Similarly, if AEP did some new refilled 765, we would get the benefit of it being allocated other places.

The problem, and part of our frustration, was when, you know, AEP had its own AEP OATT before we joined PJM. When we joined PJM, unfortunately PJM has made the distinction that legacy assets that were there before aren't subject to region-wide cost allocation.

So the set of circumstances in this and the distinction with the Dominion issue is, that is a rebuild of legacy assets that up to that point have not been allocated subject to those rules. They have been assigned to the Dominion zone.

So in the sense that you're taking an existing asset that only your zone was paying for, and now you're doing nothing but rebuilding that, but now you're seeking to allocate it across all of PJM we felt like was unfair to our customers, and that's what we've been fighting for. So --

Q. And --

A. So that is different. I would not -- I would not challenge if it was a prior allocation that was continuing, and I think that's what we're talking about in the context of the AEP system.

Q. And what if --

A. Were it the result -- rules on a new project, I would not -- I would not -- believe I would not challenge that right now under the current rules.

Q. Well, let me -- I think this may help me understand your position a little better. So you would say that because Kentucky was always paying for -- let's say it was almost a fully depreciated transmission line in Michigan, that Kentucky should continue to pay for a portion of the replacement for that transmission line?

A. I would say that it is appropriate, to use your example, the same way I would say that as Kentucky has lines that depreciate down and need rebuilt, that I&M should pay a portion of that line. We are a fully integrated system, as we have been for a long time, and I do feel there's benefits in that.

Q. So the -- I believe in your testimony you referenced a nearby page a minute ago about this allocation. So we've talked about it's maybe a little more than just 1CP versus 12CP, it's also 1CP versus 12CP versus 1CP as if AEP East was its entire zone and if each opco was its entire zone? Those are all distinctions to make, correct?

A. Yes.

Q. Okay. So when you looked it at just on the 12CP versus 1CP basis, as if the transmission agreement didn't exist, that for '19 and '20, Kentucky paid more under the 12CP, is that -- is that right, that they paid more under the 12CP than they would have been under the 1CP, correct?

A. '19 and '20. I'm just looking here. Yes, Kentucky Power would have paid more under a 1CP than the 12CP. They benefited for 2019 and 2020. Yes, they did.

Q. They paid --

A. They had that benefit.

Q. (Indiscernible) Kentucky Power --

A. They paid -- they would have paid more under 1CP than they did under the current transmission agreement 12CP.

Q. Okay. And so my other question is, forgetting the allocation of those costs for a minute: What percentage -- for these new investments Kentucky Power is being allocated approximately -- we'll say it's six percent, but I think it's 5.7 percent is the most recent 12CP allocation, right?

A. Okay.

Q. Is Kentucky attracting -- is Kentucky Operating Company, Kentucky Power Company, is it attracting six percent of the transmission investment?

A. I have not looked at that. I think we provided the numbers of the forecasted capital spend for Kentucky Power. I don't know exactly how close it is. I would say, based on revenue requirement, as far as comparing Kentucky Power to the other operating companies, it is attracting more than its load ratio share. The transcos is where it's probably going the other way.

Q. What do you mean by "going the other way"?

A. Meaning that if you look at -- if you tried to take the transco times 5.7 percent, I believe Kentucky Transco would be -- would be less than that percent.

Q. So that --

A. It's a little bit more for the opco and a little less for the transco.

Q. Yeah. So that's fair. So would you agree that Kentucky -- well, based on the comment, would you agree that Kentucky, then, as a state, between the transco and the opco, and compared to all the other states' transcos and op -- transcos and opcos, that Kentucky Power is getting less than six percent of the new transmission investment over the last few years?

A. I would -- subject to check, I think that sounds right that they have for that specific period of time.

Q. Okay. And at what point -- to your comment earlier about the fairness of the agreements and the recovery of costs, at what point does that have to be so disproportionate that it's unfair?

A. Well, that's a great question. And again, I think the question is, is if Kentucky Power is receiving some benefits from the investment of the other companies, and I believe it is, then I am not sure that's the fair -- that's the fair comparison.

Again, I think that takes me back to my point, that the calling a payment that Kentucky may not have quite as much as the others a subsidy, I don't necessarily agree with that. Just as I would defend Kentucky Power if it had invested a little bit more than the 5.7 and effectively, you know, some of the other companies were questioning the same way. But cost allocation like that is always going to be zero sum.

Q. Right. If you --

A. Now, if there was a -- if there was a -- to answer your question, if there was some set of circumstances where this is biased against Kentucky Power, they can never catch up, it can never be -- and it's very clear that they are getting very little benefit, then that may be something we need to look at, but, you know --

Q. You --

A. -- I can't say that I have seen it yet.

Q. You keep using the word "benefit," and I don't know -- you know, if I think of benefit, I think of something like DFAX, right, a quantifiable measure of the flow, right, that you're actually getting use out of it.

What do you mean by "benefit," because earlier when you used it, it was exclusively in the context of building the integrated system over the last hundred years, but we're here today and we're trying to move forward with tomorrow, and we talked about that $36 billion capital plan that the Company has.

So what do you mean when you keep saying "benefit," and how are you measuring benefit versus something else we can measure, which is the amount of cost coming to Kentucky Power customers?

A. That's a great question. And I do believe that when I say -- what I mean by "benefit," it is -- is they are receiving the benefit of the AEP system in terms of delivering reliable power to load consistent with the amount of dollars they're paying in in total of the total cost responsibility. So not necessarily their own system, but their portion of the total cost of all the companies together.

If I may use an example, and I did note in my -- in my rebuttal that I'll be the first one to say that there's never any perfect allocator, but in PJM's perspective across the entire system, the 345 kV double circuit and above is allocated at 50 percent of load ratio share, so that's regardless of where you are.

So you can be on the very western edge of PJM, and if it's a line that's higher than that on the very eastern side, you're paying 50 percent -- you're paying on 50 percent of that investment, half based on that load ratio share. And the philosophy is, is that the entire PJM RTO, everybody is benefitting in some concept. You know, it -- somebody could go in and argue, no, I want everything on DFAX, everything has to be beneficiary pay is tied to a DFAX calculation. And there's even different ways to do the DFAX calculation.

So admittedly, I agree with you that benefit can be hard to define sometimes, and you can argue it different ways, but at least I think bringing the PJM system into AEP, when I say "benefit," I say it's part of an integrated network. I do believe that to the extent that, you know, saying we're going to kind of just seal off the borders of Kentucky, and that, you know, they'll pay for the investment in this state and we'll not necessarily look at, well, are there flows coming into the state, and then, by definition, off somebody else's transmission lines? How much are they benefitting from that?

I would say if there's -- if there's imports to our service territory from out of state to Kentucky, then that is a benefit they're receiving thanks to that investment that's made by another company.

But I agree with you a hundred percent, there's a lot of ways you can argue about benefits and cost allocation. I mean, that can be its own discussion.

Q. Yeah, and I appreciate your example, but you're using an example of a bulk electric transmission system and not the 69 kV and 138 kV system that is the basis for a lot of Kentucky Power -- well, not Kentucky Power's, a lot of AEP's investment in these other states. I mean, you are aware of these hundred-, 90-year-old steel lattice poles that they're replacing throughout Ohio and Michigan on the 138 kV system, right?

A. Yeah, I'm aware that -- I'm aware that we have some in -- yes, in -- built in the 1930s --

Q. Yeah. And --

A. -- and they are --

Q. And that's a big project, right, and -- but that's not necessarily the BES, is it?

A. I'm sorry, the --

Q. That's not -- that's not exactly the interstate transmission highway of electricity, the 138 kV system, right? That's why 345 is the threshold for, a lot of times, of those allocations you're talking about, is because at 345 and above there is a systemwide benefit, but we're talking about 48, 69, 138 kV, right?

A. Yeah. Let me -- let me defer you to Company Witness Laizar Planner (phonetic). I think he's going to be the best one to describe, at those lower voltages, how much Kentucky can benefit from like, to use your example, the 138 kV system coming in from out of state.

Q. Okay. So let me just ask: When you're looking at whether something is fair or not, are you looking at it from the perspective of AEP Service Company, or the AEP generally, or on behalf of general -- of individual operating companies?

A. I think we're looking at it that -- I will say both. I think we're looking at it collectively in terms of all the operating companies, but I do think we also consider it on an individual operating company by -- or operating company basis, to make sure that, you know, there's no one that is -- you know, again, my example was biased in some way, that they are paying for something, it's not clear that it's going to be naturally biased this way for some long period of time without some reasonable expectation that they are getting benefits from.

Q. And you're -- in the aesthetic above that we talked about earlier, have you come up on any situation that you can provide me to where you found that the interests of the operating company did not align with AEP on the transmission front?

A. You're asking me to really pull my memory here. I do recall, and this was several years ago, for the true-up cost allocations, so that the way that the -- and it's been updated relative to what we've talked about earlier, but the way it used to work, when we did the true-up, the allocation of that true-up back to the companies, it was such a way that it wasn't quite being made whole for the companies. They were just basically the revenue --

the true-up revenues were being allocated, I think, on, like, the next year's projection. So it was close, but it wasn't getting all the companies back to perfectly made whole.

I don't remember which side of that Kentucky Power was on, but we just said it was inequitable. So we actually used the mechanism in the transmission agreement for the operating committee, and said, hey, we can refine this calculation to make sure each of the operating companies is made whole precisely on their -- on their -- on their true-up, receiving the dollars of the true-up if we go through that.

So that's -- off the top of my head, that's one example that I can recall that we used the transmission agreement in a positive way to make sure all the operating companies were being treated equitably.

Q. So have you seen the increase in the PJM LSE OATT expenses that were discussed yesterday between 2014 and the test year in this case?

A. I'm not sure which exhibit.

Q. Yeah. So Mr. Satterwhite was referred back to Mr. Vaughan's testimony on page 32 and 33, and I believe on page 33 of Mr. Vaughan's testimony, it indicated that in the 2014 case, the PJM LSE OATT expense was approximately, I think, 53, 54 million dollars, and that Mr. Vaughan indicated the test year amount was 96.8. That 96.8 was the number that Ms. Vinsel asked Mr. Satterwhite to remember. Do you remember that portion of the testimony?

A. Somewhat, yes.

Q. Okay. I'd be happy, if -- to bring it up if you'd like.

A. Okay.

Q. I'll ask it -- well, so let me -- one second here. All right. Please let me know when you can see my screen, Mr. Pearce.

A. Oh, there we go.

Q. All right. Perfect. Do you see that, that in the 2014 case that it was 53.7 million --

A. Yes.

Q. -- on line 10? And then on line 9 it says the test year amount was 96.8?

A. Yes, I see that.

Q. Okay. That's Vaughan. I can't see the numbers. Vaughan 33, correct?

A. Yes.

Q. Okay. So let me just ask: Given your role, if you-all were being allocated a significant cost from a neighboring transmission owner and the amount had doubled in six years, would you be alarmed by that?

A. I would certainly make inquiries, just to get an understanding of are these -- are these really needed, are these drivers? Yes, I would do -- I would make inquiries.

Q. Okay. And have you made inquiries on behalf of Kentucky Power for the PJM LSE OATT expenses as to why it's doubled in six years?

A. Well, we've reviewed the expenses, and I've been in several presentations by Company Witness Ali, who's up next, to describe those needs. And I do think as we -- what I do recall yesterday in one of the exhibits was that -- was that histogram showing how many of our assets, exactly how old they are. And while we don't replace assets just strictly on age, it is -- correlates somewhat with condition, condition, performance, and risk, that he can walk through that's driving the needs of the system.

If you notice from that exhibit, there was a substantial trough, if you will, from about 1980 to about 2010. Why? Well, the capital requirements of the companies was going to generation at the time.

That's where the -- that's where the needs were, that's where the drivers are, adding flue-gas desulfurization scrubbers, adding SCRs. So the system progressively kept getting older without the level of investment.

So we're at a point now where this infrastructure, yes, needs rebuilt. I appreciate it is driving up a portion of the bill in these ways, but is it needed to keep reliable power in place? You know, I believe it is, but Company Witness Ali is the head of our planning department and would be the perfect one to walk through those, those examples.

Q. So you -- so the amount has doubled in -- almost doubled in six years and now represents 16 percent, as Mr. Vaughan says in his testimony -- we just saw that on page 33, 16 percent of the company's revenue requirement in this case, or the company's revenues. Based off -- or based on the 35 or 37 million dollar -- billion dollar investment expectations at the AEP level and the amount of that to pinpoint -- I think the EEI document referenced yesterday was something like ten and a half billion of that's on transmission alone. What, in five or six years, can Kentucky Power customers expect the

PJM LSE OATT expenses to be?

Well, let me ask this: You would agree that 90 percent of the PJM LSE OATT expense is from affiliates, correct?

Well, let me -- let's --

A. I think it's -- the majority -- the large majority certainly would be.

Q. Well, I want to make sure. At AEP 5 yesterday, do you remember that, when it was the 96.8 and Ms. Vinsel added up to $88 million, that was almost 91 percent of the PJM LSE OATT expense in the test year. So 91 percent of the current test year bill was from affiliates, those lines that said, you know, PJM affiliated transmission NITS costs 41.6 million, PJM NITS expense-affiliated 39.4 million.

In five years, given the capital plan, how much is Kentucky Power going to be allocated of those affiliate amounts?

A. Its capital spend? I believe we provided that in a discovery request regarding the amounts of capital forecasted over the next few years.

Q. And the revenue requirement impact -- and under the current perspective, or the current expected allocation of those costs of Kentucky Power specifically?

A. The revenue requirement of the -- no, we don't have any forecast out that far that I'm aware of what our revenue requirement is going to be.

Q. You've got a five-year --

A. Capital spend.

Q. You got a five-year capital plan, but you don't know what the impact of that is to the customer?

A. I mean, right now, I know we've done our 2021 projection and filed it. Beyond that, as far as the revenue requirement, impact to customers, I'm not aware of a specific allocation, because obviously it's not just, you know, the capital piece, but it's the O&M and the other costs, which as we did see yesterday (indiscernible) for the O&M portion.

Q. So if the Commission wanted to know in five years, for instance, if Kentucky Power filed a rate case for the test year in five years, and based on that five-year capital spend, how much of it AEP intends to spend on transmission expense, could you-all at least give us an idea of what you think the affiliated transmission costs are going to be in year five for the PJM LSE OATT expense?

A. Five years, and for the transmission expense?

Q. Sure. You know what you're going to invest, right?

A. Yeah. We've got a forecast for it. I'm not sure how accurate that calculation could be on a forecast basis out that far, but there's quite a bit of complexity to the formula rate. I mean, you get into things like taxes. There might even be -- you know, the next administration, who knows what tax changes are going to be and everything. So --

Q. I'm not looking --

A. -- it would be -- I'm sorry. It would be -- it would be pretty back of the envelope.

Q. Yeah, and I'm perfectly happy for the Company to provide whatever caveats they would like in terms of the assumptions they make. But what I'm asking is: Is it -- are you able to?

A. On a reliable basis, I don't know. I don't know how reliable we could calculate that number out five years.

VICE CHAIRMAN CHANDLER: Chairman, I just have just a couple more questions.

Actually, I think that's all I have, Chairman. I appreciate Mr. -- Dr. Pearce. Thank you.

THE WITNESS: Thank you.

CHAIRMAN SCHMITT: Dr. Mathews, questions?

COMMISSIONER MATHEWS: I don't have any. Thank you.

CHAIRMAN SCHMITT: Mr. Santana, any redirect examination?

MR. GARCIA-SANTANA: Yes, Your Honor, just a few, but we have been going for about 90 minutes, and I'm wondering if there would be time for me to just go ahead and do the redirect now or should we take a break?

CHAIRMAN SCHMITT: Well, if you -- yeah, if you don't mind, if we could complete your redirect, then I thought we'd take a break before the next witness was called.

MR. GARCIA-SANTANA: I'm sorry, Your Honor, I didn't follow that. Would you like me to proceed with the redirect now or --

CHAIRMAN SCHMITT: Yeah, I'd like you to proceed with the redirect of Mr. Pearce.

MR. GARCIA-SANTANA: Sure.

CHAIRMAN SCHMITT: And after you're completed, we'll take a break before the next witness.

MR. GARCIA-SANTANA: Perfect. Thank you.

CHAIRMAN SCHMITT: Okay.

MR. GARCIA-SANTANA: Thank you, Your Honor.

REDIRECT EXAMINATION

By Mr. Garcia-Santana:

Q. Dr. Pearce, if I can impose on you and on Staff, if we could turn to KIUC Hearing Exhibit 1 as submitted. Oh, I'm sorry, I am sorry. I apologize. I got my -- it was from questioning from Mr. Kurtz, but it's Company Hearing Exhibit 7. I apologize. And specifically I would like to draw your attention to page 10 of the document.

A. I'm sorry, I'm not sure -- Company Hearing Exhibit 10. Okay. Is that it?

Q. Yes. That's the document. Thank you.

A. Yes.

Q. That is page 10. Can you see it?

A. Yes, I do.

Q. Okay. Dr. Pearce, I was under the impression that you were trying to provide some explanation in the context of what you were being asked about the costs associated with the transmission investment by AEP, and I think you were trying to refer to this page. Could you explain to us, please, what is it that we have in front of us, and what the significance?

A. Certainly. This is just -- as it shows it, it is for various PJM utilities, and calculated by PJM itself, but it's -- as it says, it's the estimated cost of each utility's transmission system on a dollar-per-mile basis, circuit mile. So AEP is the largest transmission owner in the United States. We have well over 20,000 miles in our -- in PJM.

And so as you see, you know, due to the nature of our system -- well, you know, understandably, people will look at the dollars, the revenue requirement, but we feel like, you know, being as cost conscious as possible, investing only as we need to, that on a dollar-per-mile basis, we actually are coming in, you know, relatively low side.

You know, I can't speak for EKPC. You know, they may have a system that is fairly depreciated and with not a big revenue requirement, and they may be coming up on some necessary infrastructure investment themselves. I just can't opine on them. But I think we do pay careful attention to these type of statistics to manage the cost for our customers on a dollar-per-mile basis.

And Company Witness Ali can speak in much more detail to that, to the extent that there's any specific questions on it.

Q. Thank you, Dr. Pearce. You may recall that you were also asked about the formula rates of Kentucky Power at FERC, through which Kentucky Power recovered its transmission investment.

Do you recall that line of questioning, sir?

A. Yes.

Q. Yeah. It's your understanding that Kentucky Power and Kentucky Transco have formula rates that are essentially the same from what's filed with FERC?

A. Yes. Kentucky Power and Kentucky Transco have similar formula rate templates at FERC. Is that your question?

Q. So, for example, they have the same authorized ROE for their FERC rates, correct?

A. Yes, they do.

Q. And if I can clarify something, Dr. Pearce. Turning our attention to the transmission agreement, am I correct that the parties to that agreement, the members of that agreement, are only the load-serving entities in the AEP East system?

A. You are correct.

Q. Okay. And just for clarification, the transmission-only companies like Kentucky Transco, are only transmission owners; is that correct?

A. That's right. They're under FERC jurisdiction, and which is why they're not in -- and they are not load-serving entities, so that's why they're not part of the transmission agreement.

Q. Right. In other words, they are not load-serving entities because they don't have retail customers, they only have transmission customers?

A. You are correct.

Q. And then turning for a second. You were asked a series of questions about -- I'm going to call it the possibility or the scenario in which Kentucky Power became its own zone within PJM. Do you recall those questions?

A. Yes, I do.

Q. Do you have a sense of whether Kentucky Power would be required to pay for essentially its membership, its fair share, if it became its own zone? And if you could describe a little bit what that would look like if -- to extend that you know.

A. Well, I mean, again -- and this is a hypothetical because, as we said, there's a provision in the rate schedule that specifically says you can't do this, but just saying from a -- from a filing, you know, arguing that it's just and reasonable to do so, I think a natural line of questioning is going to be -- is identifying potential assets that are known by Kentucky Power and Kentucky Transco but for which loads in the state of Kentucky are benefitting from and were effectively built in part for their benefit. Again, Company Witness Ali can probably provide some more color around that.

And so, you know, identifying at the end of the day, you know, beforehand, whether Kentucky Power would pay, you know, less or more is unclear to me. If there was additional legacy charges picked up from those -- from such facilities, you know, it could be that a -- that there are additional costs.

Q. And it's your understanding that considerations related to Kentucky Power becoming its own zone, to the extent that it were to be something that could be accomplished, would have considerations related to things other than transmission, and what would those be, if you can say?

A. Well, you know, one thing I don't think we even touched on is obviously the generation agreement between the companies, the power coordination agreement that Kentucky is a member of.

You know, it's kind of our cool light now, but it is through, you know, that agreement, the companies can get -- basically, if a Company has a capacity need, given the FRO plan, there's hedge sales, there's various benefits to all the companies, and I think that would require a fresh look and potentially put Kentucky Power's participation in jeopardy as well if it was attempting to peel off -- again, not just break out of the transmission agreement but actually try -- attempt to form its own load zone.

Q. And this may be a better question for Mr. Ali, but let me ask you this: To the extent that it would have to do with the interrelationship with PJM and others, but from the position that Kentucky Power is in right now with its generation and its transmission assets, do you have a sense of what Kentucky Power would need to pay for if it was in a stand-alone zone in order to provide service to its customers?

A. I mean, what -- it would have to pay, obviously, still the -- a portion of the regional transmission expansion plan. Again, other costs that could be directed. It would be -- again, it would be forging new ground here. So as far as --

Company Witness Ali may have some firsthand knowledge of some of the -- you know, the -- and he may not, but as far as some of the specific assets or something that would come into play here.

Clearly we all know that, you know, Kentucky Power has generation that's even outside of Kentucky, outside of the state of Kentucky, and it would require transmission service to import it to its load.

Q. Okay. And just to wrap up that topic, sir, let's -- actually, let -- I can come back to that.

You provided some testimony regarding the level of control that Kentucky Power has over its transmission investments, if I recall correctly. Do you recall that?

A. Yes.

Q. And to the extent that you were testifying -- I just want to clarify the record. Were you at all referring to the control, for example, that Kentucky Power has over the timing of needs or the location of needs or transmission investments that may be required for serving Kentucky Power customers, or is that something that would be more on the planning side for Mr. Ali?

I'm just trying to figure out what you were referring to when you were indicating that Kentucky Power may or may not have any control over its transmission investment.

A. Yeah, I said as far as the level of control in that scenario, I think as far as still the PJM obligations, the NERC obligations, all of that would be probably questions better for Company Witness Ali to describe.

Q. Okay. Let me get into specifics for a second. But you were also providing some testimony about tests, I understand it's called DFAX; is that right?

A. Yes.

Q. Okay. And is DFAX a reliability measure, or does it take into consideration the normal reliability benefits of transmission, if you know?

A. Yes. I mean, DFAX is going to be the use of a new project between the zones. But yeah, that's an important distinction that you're making, is yes, from a PJM standpoint -- and, again, Company Witness Ali can go into more detail, that when PJM does its modeling, it basically assumes all assets are in perfect working condition. So unlike our supplemental work, they consider, you know, a brand-new asset the same as an 80-year-old asset in terms of their modeling.

Q. Okay. And one last question, then, in that context, Dr. Pearce. We were talking about the scenario in which Kentucky Power would become its own zone. Do you think that that type of decision or scenario would be something that would need to be considered in a long-term -- with a long-term view, or rather based on circumstances in the short term?

A. I think that would need to be considered in the context of a very, very long-term view. There could be certainly a lot of unintended consequences with Kentucky attempting to go its own, as its own zone, if you could even get there.

MR. GARCIA-SANTANA: Your Honor, if I can have a second, please.

CHAIRMAN SCHMITT: Sure.

MR. GARCIA-SANTANA: Thank you, Your Honor. I don't have any further redirect.

VICE CHAIRMAN CHANDLER: Chairman Schmitt, can I -- can I ask two questions based on that redirect?

CHAIRMAN SCHMITT: Yes.

VICE CHAIRMAN CHANDLER: Thank you.

* * *

REEXAMINATION

By Vice Chairman Chandler:

Q. Just very quickly, when you said -- talking about importing generation, Mr. Pearce, you would agree that if Kentucky Power was its own it TO zone, it would be part of PJM and would not need transmission service in order to be provided generation, regardless of where it's located in the PJM zone -- or PJM, correct?

A. I don't think I can completely agree with that, because I -- as I said, the reason I say that is because of this: Because of the scenario we're talking about where, if you are proposing to take an existing zone -- an existing zone, existing TO to join PJM as a block, as others have historically, as EKPC, as Dayton, others that have been pointed to, and now you're trying to go down this path to further split it, I don't know that PJM will -- I appreciate what you're saying, but I'm not sure PJM would necessarily look at it that way when you're further carving up.

I mean, we have to ask ourselves, why is that Article 7.4 in there in the first place? And I do think, where is -- if you took on any party -- let's say you took a muni or a co-op that had a small amount of TO, a lot of load in a local area, it was getting benefits from the bigger zone it was in, but it did the math and it suddenly realized, hey, I could call myself my own zone, only pay my share and still get the benefits of all these imports surrounding me.

I think -- I think taking that a step further and trying to drill down the -- to the zone on that, I think that's part of what probably drove the desire, through that formation of the Article 7.4, is so we don't start having entities within PJM sort of gaming it to see, well, I'm getting allocated more than I could if I became my own zone.

So to attempt to go down that path, I'm not sure you would get the same set of rules applied to you as you would to your point. You know, if Kentucky had always been its own entity, affiliate or not, and never joined PJM and then walked in, I think the rules might apply differently than the situation we're having. So to me, that would be to be determined.

Q. To be determined, but you're not aware of any instance that's actually occurred, where a transmission owner or an LSE in a zone has to get some sort of different transmission service when it's a full member of PJM and located within the PJM zone?

A. I'm not aware of that because, to the point I'm making -- I'm not aware of that, correct, because -- but I'm not aware if this scenario that we're trying to go down has ever been attempted before, so --

Q. And that's fair. That --

A. -- both of those.

Q. I just want to make sure, there's no rule about transmission service that you were referring to, you're just expressing a concern about a hypothetical?

A. I'm expressing -- I'm expressing if you attempt to forge new ground here, you know, taking an existing zone exclusively excluded today and attempt to break that up, what could the parties argue over in terms of, well, you're leaning on me but you're trying to carve out some small period, still take the benefits but basically get out of some, perhaps, historic costs that you were paying for.

And again, I think, as I've said, this is not a specific instance that I think Kentucky is necessarily always going to be here. As counsel just asked me, it's definitely going to be a long-term view, I think, should Kentucky -- would be the best look for Kentucky Power and its customers if there's going to be additional discussions on attempting this.

Q. But to be fair, nobody's had that discussion before this case?

A. Not the full, what if we split up. It just went against this because of the article. I know I have not been in conversations about what if we tried to overcome Article 7.4 and do something.

Q. Well --

A. And again, I -- and I don't see any -- I still don't see any specific automatic benefits to Kentucky Power as a result of doing that, but I appreciate that it may be worthy of additional discussion, I think as someone discussed yesterday.

Q. And the other question I had, and I appreciate -- because I did forget it. And I do appreciate Mr. Garcia's redirect on it, because I asked Mr. Satterwhite yesterday and he pushed it up to you.

The offset -- do you remember yesterday me asking Mr. Satterwhite about the difference in investment in a state's transco versus a state's operating company and that the benefit to the operating company is that the revenue requirement from the transmission investment would be an offset?

Do you remember that?

A. Somewhat.

Q. So I was going to say: For a million dollars in revenue requirement, or based on -- let's just make up a $10 million investment, so short life, a million-dollar revenue requirement coming back to the trans -- if it's made by the transmission company, it just comes right back to the transmission company, goes to AEP, you know, it -- I don't know how it works -- pays the dividends, whatever it may be, right? If it's done at the operating company level, there's a million-dollar revenue requirement come back, that is an offset to rates, correct?

A. In the context of what amount goes in, like, if it's in a test year, but that would be -- that would be an offset to rates, you know, the amount.

Q. And -- and --

A. Between rates you could have a tracker. I was going to try not to refer to them, but I will -- part of that I will refer to Company Witness Vaughan, because it's the retail tracker.

Q. Yeah. But as I said -- so let's talk about a test year tracker, it doesn't matter. It is an offset if the operating company makes the investment, and that's a benefit that the customers would get, for instance, by having lower rates, as opposed to if the transco makes the investment?

A. The revenue coming in, to the extent it is an offset, that's correct. But, of course, in that context, Kentucky Power had to cash out money. They had to come up with the cash. And obviously, you know, if they have to come up with -- let's say a number. If it's a $20 million investment, and, of course, the revenue requirement. So they have to come up with 20 million, capitalize that. The 20 million is going to result in a, you know, much smaller revenue requirement. I'll just say 3 million, for example.

So they have to -- so as far as how it affects their credit metrics and all that, so they had to cash out like they have the -- but then they would have the revenues coming in.

If the transco, by comparison, made the same investment, either way Kentucky Power gets the same charge as an LSE, but then they avoided -- they don't get the revenue, as you said, but then they didn't have to also come up with the cash outlay either.

Q. Okay. And then finally, as it relates to control, and we can talk -- you can defer to Mr. Ali if you'd like, but I think you'll understand the concept and be able to help me here. If the Kentucky Transco becomes the one that owns the vast majority, and the maybe eventually the entirety of the Kentucky transmission system owned by AEP affiliate, then Kentucky Power then would have no control over the needs, the timing, the solutions for transmission investment in the state, correct?

A. I'm going -- I'm going to -- I'm going to really defer -- to me that's almost a legal interpretation, as far as what level of legal control, I mean, when it goes into CPCNs and -- and I understand there was an order issued, you know, quite a few years ago regarding the Commission's view on their jurisdiction over Kentucky Transco, so it would be consistent with that order and --

Q. Yeah. Let me ask it -- let me ask it this way: Does Brett Mattison control the amount invested in Kentucky Transmission Company?

A. Brett Mattison is a strong input into those discussions, yes.

Q. Yeah. But he does control the investments made in the Kentucky Op -- Kentucky Power Operating Company, correct?

A. Absolutely. Absolutely.

Q. Okay. So it may be a distinction in degree, but it's certainly a distinction, correct?

He may have input into the investments made to Kentucky Transmission Company, but he's in charge of the investments made to Kentucky Power?

A. Yeah, and I will -- I don't want to speak for Brett. I think it's too -- I mean, when we say "input," I mean, that could be -- obviously he's the company president, he's going to have very strong input into investment in the state of Kentucky --

Q. Okay. And --

A. -- regardless whether it's Kentucky Power or Kentucky Transco.

Q. And I just want to make sure we're clear. There is no ownership interest either way between Kentucky Transmission Company and Kentucky Power Company?

A. That is true.

VICE CHAIRMAN CHANDLER: Okay. Thank you Mr. Chairman.

CHAIRMAN SCHMITT: Mr. Santana, anything

else?

MR. GARCIA-SANTANA: Thank you, Your Honor. No. Thank you.

CHAIRMAN SCHMITT: Okay. We will now be in recess until ten minutes after 11:00 o'clock, at which time Kentucky Power can call another witness.

(Recess from 10:50 a.m. to 11:13 a.m.)

CHAIRMAN SCHMITT: Okay. We're now -- we're now back on the record.

Ms. Blend, are you taking the next witness?

MS. BLEND: I am, Your Honor.

CHAIRMAN SCHMITT: Okay. Thank you. If everyone else is on and ready, then, Ms. Blend, please call -- please call Kentucky Power's next witness.

MS. BLEND: Thank you, Your Honor. The Company calls Kamran Ali.

CHAIRMAN SCHMITT: Okay. Mr. Ali, please raise your right hand. Do you solemnly swear or affirm, under penalty of perjury, that the testimony you are about to give will be the truth, the whole truth, and nothing but the truth?

THE WITNESS: I do.

CHAIRMAN SCHMITT: Okay. Thank you. You may proceed.

MS. BLEND: Thank you, Your Honor.

KAMRAN ALI, having been first duly sworn, testified as follows:

DIRECT EXAMINATION

By Ms. Blend:

Q. Good morning, Mr. Ali.

A. Good morning.

Q. Would you please state your name and business address for the record?

A. Kamran Ali. Business address is 8500 Smith Mill's New Albany, Ohio 43054.

Q. Thank you. By whom are you employed and in what position?

A. I'm employed as managing director of transmission planning for the American Electric Power Service Corporation.

Q. Did you cause to be filed rebuttal testimony in this case?

A. Yes.

Q. Did you also cause to be filed data responses?

A. Yes.

Q. Do you have any changes or corrections to any of those documents today?

A. No, I don't.

Q. If I were to ask you the same questions today, would your answers be the same?
A. Yes.
Q. Thank you.
MS. BLEND: Your Honor, Mr. Ali is available for cross-examination.
CHAIRMAN SCHMITT: Okay. Thank you. Before cross-examination, Mr. Ali, it is a little difficult to hear, so I would ask you to perhaps get closer to the microphone or speak up. We have a court reporter here who sometimes has difficulty hearing, and it's important that she be able to have a complete understanding of your answers.
Ms. Vinsel, any --
THE WITNESS: Yes, Your Honor.
CHAIRMAN SCHMITT: Okay. Any cross-examination?
MS. VINSEL: Yes, chairman.

CROSS-EXAMINATION

By Ms. Vinsel:
Q. Good morning, Mr. Ali. Why don't I let you have a moment to say something so that we can make sure that we've got the volume correct?
A. Yes. Can you guys hear me better now? I moved the mic up.

MS. SACRE: It's terrible.
Q. No.
CHAIRMAN SCHMITT: You're still too low.
MS. SACRE: He's terrible.
CHAIRMAN SCHMITT: You may have to speak into your pocket, hold your microphone.
THE WITNESS: How about this? I'm going to switch mics here.
CHAIRMAN SCHMITT: That's better.
THE WITNESS: Better?
CHAIRMAN SCHMITT: That's much better.
THE WITNESS: Okay. Awesome. Thank you, Your Honor.
Q. Excellent. Okay. I think -- I think we're good to go now. Can you hear me okay?
A. Yes, I can.
Q. Okay. Again, good morning, Mr. Ali. I have a question or two for you about the PJM Attachment M3 process.
Before I begin, can I have you give me just a wee bit of explanation. What is the attachment M3 itself?
A. Sure. Good morning. So the attachment M3 is the process that oversees engagement and review of projects, mostly supplemental projects. These

supplemental projects, in essence, are really, if you think about the PJM project, project buckets, there are three categories of projects in PJM. One is baseline. Those are projects that are driven by bright-line criteria. One is upgrades. Those projects are driven by generation interconnection or changes in their capacity. And then the third bucket is the supplemental projects.

The M3 process outlines the process that transmission owners must follow to ensure that these supplemental projects are transparently reviewed with the stakeholders as per the FERC-approved data.

Q. Thank you. As the M3 -- and as the attachment M3 process relates to Kentucky Power in supplemental projects, can you provide me just a little more detail? And I appreciated the overview, but if you could give me greater detail about that process in regards to Kentucky Power and supplemental projects.

A. Absolutely. I'll be very happy to do that. So, in essence, my organization, the transmission planning organization, is responsible for determining what are the needs across the transmission grid, which also includes the Kentucky Power corporate and the region. And what we do is, on a yearly basis we determine what are the grid, you know, needs based on assessments. You know, some of these assessments are load-flow-type analysis, which is very bright line in nature. You take a line out of service and you see what happens to the rest of the system.

Q. Uh-huh.

A. Some of the needs are driven purely by the condition, performance, and risk that the assets pose to the grid. So it's my job that we go and collect all those needs across the system, we vet and validate those needs internally, and we vet and validate those needs with our customers. And that happens also on a yearly basis.

And then as the needs get vetted and validated, meaning -- I'll give you an example of that. So let's say that my radar shows that there is a line that has 5 million customer minutes of interruptions over a year, then what I want to do is I want to make sure that that is indeed the case, so make sure the data is correct, and, number two, understand why we have so many minutes of interruptions. And the reasons could be, you know, weather. It could be, you know, poor condition of the asset.

So once that need is validated, that's when we take that need to the stakeholder forum at PJM. So we then share that with all the stakeholders at PJM, that here is a need on the grid that has resulted in poor performance, poor condition, or it poses a risk to our customers and the grid in the future.

Once that is done, the stakeholders then have the ability to comment on that. They have the ability to then provide us maybe additional needs that they are seeing that we have not seen on our radar. And then we have to wait at least 25 days, and in some cases it can take as long as a year to bring back a mitigation plan.

So the next meeting that happens with the stakeholders at PJM is the review of the mitigation plan. Again, the stakeholders have the ability to provide alternate or recommend alternate or, you know, if they have questions concerning the project, we have -- you know, we answer those questions during that process.

After that, the stakeholders can still send questions to us. We are e-mailed. And then, on a quarterly basis, projects that have been reviewed at PJM, they get published in the local plan. So that's the final step, when PJM publishes the needs and the solutions in the local plan on a quarterly basis.

Q. Thank you very much. I very much appreciate -- you answered exactly what I needed. Very thorough. Thank you.

MS. VINSEL: Zach, can I ask you to display PAF -- excuse me -- PSC Exhibit 15. Thank you.

Q. Just to explain what this is, this is created by AEP. It is --

MS. VINSEL: Thank you, Zach.

Q. -- the M-3 needs and solutions presentation, and it's titled Sub Regional RTEP Committee: Western AEP Supplemental Projects.

MS. VINSEL: Zach, can I have you scroll through three or four pages so I can show this to Mr. Ali? And if you'll go to the next page. There.

Q. The remainder of this presentation contains similar slides. This presentation has about 87 different transmission projects that sets forth the project driver, assumptions, and identified problems at each site. And again, as you can see from the upper-left corner, this was created by AEP.

Mr. Ali, have you seen this document before?

A. Yes, I have seen this document. We prepared this document, my team does, on a monthly basis, in collaboration with PJM.

Q. And is this -- and if you need us to scroll through a couple more pages, please let me know. But I would ask if this is an accurate representation of an ordinary sub regional RTEP presentation from AEP, and in that sense it has both solutions and needs?

A. That is correct. So this is -- this is a correct representation of the process that I mentioned earlier. And you can see there are -- in a given meeting, there are needs that we're bringing forth, and then we are bringing forth needs and solutions for needs that may have been discussed in previous meetings. So it has -- it has both the needs, new needs, and solutions to needs that have already been discussed in previous meetings.

Q. Thank you.

MS. VINSEL: Zach, you can take that document down. Staff has no further questions, Chairman.

CHAIRMAN SCHMITT: For Office of Attorney General, any questions?

MR. WEST: We have no questions for this witness, Your Honor.

CHAIRMAN SCHMITT: Okay. Mr. Kurtz,

questions?

MR. KURTZ: Thank you, Your Honor.

CROSS-EXAMINATION

By Mr. Kurtz:

Q. Okay. Great. Good morning, Mr. Ali.

A. Good morning, Mr. Kurtz.

Q. In your rebuttal testimony, you opposed the AG KIUC recommendation that incremental transmission expenses be recovered solely through base rates, correct?

A. Can you please refer me to that, just to refresh my memory? I don't -- I'm not recalling opposing --

Q. Well, let me say it the opposite way. You recommend a hundred percent tracker recovery of incremental transmission expenses through PPA, correct?

A. That is correct.

Q. Okay. And the AG KIUC proposal was a hundred percent recovery through base rates. Were you aware of that?

A. Yes. I remember seeing that.

Q. Okay. If the Commission accepts your proposal, how big will the rate increase be for calendar year 2021?

A. Mr. Kurtz, that would have been a good question for Company Witness Pearce, because I do not do rate calculations, so I really can't answer that, the impact of that.
Q. And I guess you don't know probably what the rate increase would be in 2022 either, correct?
A. That is correct, sir.
Q. Okay. Well, how do know if your recommendation is reasonable if you don't know how big the rate increase would be?
A. So, Mr. Kurtz, we work as a collective team here at AEP. So, of course, my job responsibility is to determine what are the needs across the grid, as I explained earlier, what risks those needs pose, what are the best solutions that are cost effective, reliable, and safe for our customers, and then get those to the stakeholder process to make sure their opinions and feedback is accounted for.
And then, of course, that gets, you know, visited with -- you know, with folks like Brett Mattison, Company Witness Brett Mattison, so that they can look at the other aspects of it, as to what are the rate impacts, you know, how much investment can the Company afford.
So really, those decisions are made

collectively, and I'm just playing the part of the planning aspect of that.

Q. Okay. One basis for your recommendation was your belief that Kentucky Power does not really have effective control over these transmission expenses, correct?

A. Yes, that is -- that is correct. I mean, Kentucky Power, or for that matter, any transmission owner or load-serving entity across North America, I mean, they don't have really the control over the needs. The needs are what those are. Some of those needs are determined by the age of your system and the performance and condition of that system and how it is being used. Some of those needs are determined by regulation from the RTOs or NERC or other regulatory bodies, and some of them are, you know, state regulations, as well as customer obligations.

So really, there is no control that the transmission owners or LSEs have on the needs. They may have some control on the timing of how and when to address them.

Q. Well, between Kentucky Power and its ratepayers, who has more control over the timing and the need for these transmission rate increases?

A. I'm sorry, I don't quite get that question, Mr. Kurtz. Could you please repeat that?

Q. Well, the ratepayers have no -- zero control over the timing and the level and the need of these transmission rate increases. Certainly, I would expect, Kentucky Power has some --

A. Well --

Q. -- (indiscernible) consumers?

A. Mr. Kurtz, like I said, I mean, you know, the needs are what they are on the grid. And again, if they're not addressed, they pose significant risks down the road to our customers and the reliability of the grid. So, I mean, nobody has, I would say, control over those needs. Now, of course, a company like Kentucky Power has to make sure that the investments are made in a way that is, number one, taking into consideration the impact on customers as well as taking into consideration the financial health of the company.

And I know I heard Mr. Mattison talk about that. I think he would be the right witness to answer that question concerning, you know, who has more control, whether it's customers or Kentucky Power. Like I said, where I sit, looking at the needs, really, those needs are outside the control of anyone.

Q. Well, just to close up, you're aware that the Attorney General KIUC position is that Kentucky Power should get, could get, would get 100 percent recovery of all its transmission expenses; however, it would be through a rate case, not through an automatic tracker? Is that your understanding of our position?

A. Mr. Kurtz, you mentioned that earlier, and I remember seeing that. Yes, I'm aware of it.

MR. KURTZ: Chairman, no more questions.

CHAIRMAN SCHMITT: Thank you. Ms. Grundmann, any questions for Walmart?

Ms. Grundmann, cross-examination?

VICE CHAIRMAN CHANDLER: Chairman, can you -- can you wave your hand if you can hear us?

CHAIRMAN SCHMITT: Yeah.

VICE CHAIRMAN CHANDLER: Yeah, we can't hear the hearing room.

CHAIRMAN SCHMITT: You can't hear me? You can't --

MS. VINSEL: No, they can't hear you.

CHAIRMAN SCHMITT: Well, let's see if we can find some way to get it fixed.

Nancy, can they hear you, do you think?

MS. VINSEL: No, I don't think so.

VICE CHAIRMAN CHANDLER: Chairman, we can hear you now.

MS. GRUNDMANN: Loud, Chairman.

CHAIRMAN SCHMITT: You can? Oh, okay. I'm sorry. I don't know what happened. The system's failures are rampant.

Ms. Grundmann, do you have any cross-examination on behalf of Walmart?

MS. GRUNDMANN: I do. I just have some very brief questions.

CROSS-EXAMINATION

By Ms. Grundmann:

Q. Mr. Ali, are you familiar with the Virginia Clean Economy Act that was effective -- it went into effect July 1st, 2020, of this year?

A. Yes, I have -- I have read it at a high level, I would say executive summary level, so that that's my level of familiarity with it.

Q. And just from that high level, do you anticipate there being a need for transmission projects associated with the requirements that are imposed on APCo as a result of the VCEA?

A. We have actually not done any analysis to substantiate that, so I really can't answer that.

That would be -- that would be speculative on my part, without having done any analysis concerning that.

Q. But you understand that there is an obligation on the part of APCo to either acquire or purchase certain renewable power, whether or not there's an actual need for it, in order to meet certain renewable and carbon free goals by 2050?

A. Yes, Ms. Grundmann, I understand that. I guess your question was, would there be transmission investment. And like I said, I don't know where that renewable is going to come from, where it would be located, so I can't really answer if there will or there will not be any transmission investment in regards to that.

Q. Well, and I guess just my question that sort of flows from that is: I think you made a statement about the grid and the transmission and that the needs are what they are on the grid, right?

A. That is correct.

Q. And just to the extent that APCo were obligated to undertake a transmission project as a result of an obligation imposed with the VCEA, that's not exactly the typical type of need that we would associate with a transmission project, is it?

A. Ms. Grundmann, it really depends, because, you know, the tariff, the way it is written in PJM, generation interconnection is a cost that is borne by the generator. So if the renewables that are being acquired are within the PJM zone, which I'm assuming most likely they will be -- and again, that's an assumption on my part, so I want to clarify that -- then those generators need to be deliverable to begin with, and those costs of the transmission upgrades to ensure deliverability will be already part of the generation interconnection cost.

So again, like I said, we would really need to know where the exact location of that generation is. If it's outside PJM, yes, there could be -- there could be costs, but that -- again, without doing any analysis, I can't speculate on that.

Q. Well, just as an example, I believe the VCEA does require that at least some amount of this new load be located within the Commonwealth of Virginia. Are you familiar with that?

A. Yes, I am. And, Ms. Grundmann, my -- I guess what I'm not familiar with or I don't have an answer on is where is the remaining coming from? If the remaining is also coming from the PJM region, then the expectation that there will be a transmission investment needed I think is wrong, because that generation is already deliverable within PJM and it has already gotten connection to the transmission grid.

If it's coming from outside PJM, then, of course, depending on where it's coming from, you may or may not need transition investment.

MS. GRUNDMANN: Okay. No further questions.

CHAIRMAN SCHMITT: Mr. Spenard, Mr. Strobo, questions for Kentucky Solar?

MR. STROBO: No, Mr. Chairman, no questions on behalf of KYSEIA.

CHAIRMAN SCHMITT: Mr. FitzGerald, questions?

MR. FITZGERALD: No, Mr. Chairman. Thank you very much.

CHAIRMAN SCHMITT: Mr. Miller, Sierra Club, questions?

MR. MILLER: Thank you, Mr. Chairman. No, no questions from Sierra Club.

CHAIRMAN SCHMITT: Mr. Frye, any questions?

MR. FRYE: No, Mr. Chairman, no questions at this time.

CHAIRMAN SCHMITT: Vice Chairman Chandler, questions?

VICE CHAIRMAN CHANDLER: Thank you, Chairman.

EXAMINATION

By Vice Chairman Chandler:

Q. Mr. Ali, how are you?

A. I am doing well, sir. How about yourself?

Q. Good. Yesterday I referred to you as the Alex Vaughan of transmission, that -- the joke has been around here about a couple of hearings we've had, everybody always pushes their questions off to Mr. Vaughan, but now that we're talking about transmission, everybody is pushing their questions off to you, Mr. Ali.

A. Your Honor, I must -- I must tell you that that that was very character-limiting move for me by naming me Alex Vaughan, so I may have to change my name.

Q. Yeah. Well, maybe Mr. Vaughan can be the Kamran Ali of everything else.

Let me ask here: Until a comment by Mr. Pearce and then your testimony a minute ago in response to KIUC, the testimony in this case, at least in regards to Mr. Vaughan about the need for a hundred percent recovery of tariff PP -- of the LSE OATT costs and tariff PPA have been that the costs -- that LSE OATT expenses are outside the

Company's control because they are pursuant to a FERC-approved rate schedule and that the -- yeah, just that the annual -- this is Vaughan, line 6 at 32, (Reading) The annual level such as charges and credits can vary greatly from year to year and are largely out of the -- of the Company's control. Also" -- and this is the portion that Mr. Satterwhite read in the testimony yesterday. (Reading) Also, as the Company expected, PJM transmission owners have continued to increase their investment in the transmission grid. The increasing level of investment which is necessary to maintain and improve the grid will increase transmission charges allocated to LSÉ and PJM, including Kentucky Power.

So as I understood it up to now, the out-of-control was that, hey, FERC said these are the costs, other people are imposing these costs, they're the drivers of it, it's out of Kentucky Power's control, let us recover it through the tariff PPA.

But what you're saying is, even if these weren't allocated costs and these were solely the costs of Kentucky Power alone, that you still consider them out of their control. Am I understanding that correct?

A. Yes, Your Honor. So I am focusing on the needs aspect of it, right? I mean, so really, all these investments are driven by needs across the grid, and those needs are, in essence, outside the control of anyone, and so that's what I was referring to. I think what you are talking about is even beyond that, the allocation piece of it. And you're right, there is a -- there is a FERC-approved tariff for that that I know Mr. Kelly Pearce talked about in detail.

Q. Okay. So let me ask this question: Who is the final arbiter of need?

A. I mean, at the end of the day, the decision as to which need gets addressed and which need gets deferred -- so, first of all, we have to address all of them. There is no question about it, because if you don't -- if you don't address them, then eventually you address them as a failed equipment, right, which is more costly for our customers, not to mention all the customer interruptions it adds.

So really, as far as the needs are concerned, all of them need to be addressed, but who determines the timing of it? That is a decision that the operating companies have to make for their -- for their needs on their system. And I know Mr. Mattison talked about that yesterday. And, you know, that depends on many factors, which I -- which I think he's the better witness to talk about what factors he considers when making that decision.

But like I said, the needs themselves have to be addressed, they are outside the control. As to how many can a company afford in a given year, that is the -- that's the financial factor that Mr. Mattison had mentioned yesterday.

Q. So if the need -- you would agree that the transmission, whether it's at the state level or at the federal level, is regulated in some degree, correct?

A. That is --

Q. Transmission --

A. -- my understanding, yes.

Q. Right. Transmission rates. So FERC, for instance, there's a process by which people can oppose or challenge the prudency of projects, right, whether it's that the project isn't needed or whether it's more expensive than it needs to be, whatever it may be, there's a process by which they can challenge the underlying need for a project, correct?

A. That is correct.

Q. And then at the state level, and I know you've got 11 -- or you don't have 11 -- you're just in the East zone, correct? You just operate in the East?

A. No, Your Honor, I oversee planning function for the entire AEP system.

Q. Okay. So great. So 11 jurisdictions, right?

A. That is correct.

Q. Yeah, same as Mr. Satterwhite. So you got the 11 jurisdictions and then the federal review. So would you agree that insofar as maybe FERC doesn't have the -- you know, whether it's -- well, like I say, a CPCN process in Kentucky. We'll just talk about a very simple example. Kentucky ultimately determines the need for a project when you bring in front of them for a CPCN, correct?

A. I think, Your Honor, that maybe the right way for me to point that out would be the need is what it is. Kentucky Commission may be the -- as far as require CPCN, the Kentucky Commission is the one that is validating it and agreeing with it and ratifying it or disagreeing with it, right?

Q. Right. That was my question earlier about the final arbiter. Kentucky Power can assert that there's a need, but as far as the CPCN, the standard, as I understand it, is that the Company must prove need and wasteful duplication. So insofar as the Commission doesn't find that there is a need, would you agree that their -- like, for instance, in that example, in Kentucky, they are the final arbiter to determine, factually, on a legal basis, whether there's a need? And I'm not asking you for a legal opinion, but that's your understanding of the need determination, correct?

A. If you're -- Your Honor, if your question is can Kentucky Commission deny a filing for CPCN if they don't find a need, then the answer is absolutely they can. And similarly, the stakeholders have the ability, and they exercise that ability, to bring forth any prudency issues that that when we file the pro forma 1 filing.

And to my experience, you know, so far, we haven't had an instance where FERC said there was -- a project was not prudent. We had one instance where the cost was -- you know, was booked as transmission and should have been booked at distribution, so we made that change thanks to our stakeholder engagement.

But again, you're right, FERC -- FERC has the ability during those proceedings to say if there was something prudent or not prudent.

Q. Okay. So FERC has that ability. We do agree Kentucky has the ability when it's actually being requested to be built, right, in terms of the Kentucky Power Company.

You operate in 11 jurisdictions. Let's just focus on the AEP East system. Is that -- is that -- well, let's call it a safeguard, because I want to give myself a little more -- maybe make myself a little more important than I am. But say there's that safeguard as a determination of need in Kentucky in the CPCN process. Can we walk through a couple of the AEP East states and can you tell me whether the -- whether or not you're aware of whether there is that ultimate need, or you've experienced that ultimate need arbitration or determination at the Commission level or deciding board level?

So like in Ohio, for instance, is there any determination, is there any sort of CPCN process, either on the operating company or the transmission company side, where there's ever a situation to where, the state level, somebody is the ultimate arbiter of need?

A. Your Honor, that's a very loaded question, so I'm going to take it apart a little bit. I hope you don't mind.
Q. Take it however you want it.
A. So, you know, when it comes to Ohio, let's take that as an example. Does Ohio have a siting process? Absolutely, it does. Is the siting process for Ohio the same as Kentucky? No. There are differences, and those differences are defined very clearly in the state statutes. You know, similarly, Virginia, they have a siting process. You know, states that don't have siting processes, they have other permitting processes. They have rate cases that, you know, you gotta go through, and again -- and to your question, is there an ultimate entity that you can go to and say, okay, I don't agree with the prudence, you know, in my opinion, what is common to all of these jurisdictions, that one entity that anybody can go to and say I don't agree with the prudence of a certain investment, that is FERC.
Q. Yeah. I don't want to get off on words like reasonable, just -- you know, just and reasonable or fair or prudent. I didn't anticipate asking questions about this, but your answer specifically

was the need is what it is, right? The need is the need?
A. (Witness nodded head.)
Q. But you-all are regulated on the transmission front on -- well, you're regulated on the trans -- on transmission on all fronts, right, either at the state or the federal level. And what I want to make sure of is that I understand, there is ultimately some degree of somebody saying what the need is, right, or to -- the word you used earlier was "validate" the need, right?
A. (Witness nodded head.)
Q. You would agree that there's some -- you-all aren't -- let me ask the question this way: You-all aren't the sole determiner in -- the sole determining entity in deciding whether there is need or not? There are checks along the way, correct?
A. That is correct.
Q. Okay. And so do you-all -- and that's the same case for all transmission owners. Let's just use an example. Other transmission owners in PJM, correct?
A. That is correct.
Q. Okay. And so do you-all ever challenge other PJM transmission owners, FERC formula tariff -- FERC

transmission formula filings?

A. Not to my -- not to my knowledge, we haven't. And again, Your Honor, you know, for us to challenge it, first of all, we need to know that there is an adverse impact to our customers or our systems for us to do that. I'm unaware of any such case where we needed to.

Q. Okay. And then -- and then, have -- are you aware of any operating company within AEP challenging any other AEP affiliates' FERC formula filings?

A. Well, Your Honor, I'm not aware of it. Like I said, there has to be a basis for something like that. And, I mean, I'm not sure, do you -- do you have some example that you are -- you are thinking about? Maybe I can answer that more completely.

Q. I don't. I'm asking -- I'm asking, are there examples of it?

A. No.

Q. Okay. So do -- these questions -- I don't want to go out of order, Mr. Ali.

VICE CHAIRMAN CHANDLER: Can I ask if Staff could bring up that PSC Exhibit Number 15, which is the supplemental planning document?

Q. And so, Mr. Ali, we're both aware of this document. These are the near monthly filings made at the sub regional -- sub regional RTEP western meetings, correct?

A. That is correct, Your Honor.

Q. There are a couple of -- or a few, I forget. There's two or three sub regional RTEP committees, right? There's a western, maybe a southern, and an eastern, mid-Atlantic?

A. You're right. It's the mid-Atlantic one. Yes, it is.

Q. Okay. And so the sub regional RTEP western -- and I'm just now realizing the R and the regional are the same thing. But the sub regional RTEP western committee is, help me out here, Dayton Power & Light, right, East Kentucky Power, AEP? Is there anybody else in the western?

A. So, Your Honor, so we have in the western also part of the FirstEnergy system --

Q. Okay.

A. -- and APF, and, of course, ComEd of the -- you know, the footprint in Chicago, that's part of it.

Q. Of Exelon, right? It's a subsidiary of Exelon?

A. That's right.

Q. Okay. So you-all bring these. And let's take a step back. One thing that Ms. Vinsel didn't ask about and that you maybe covered. There are needs and solutions as part of the process, right? There are times frames between when you can bring those needs and solutions, and then every year there's an update as to the basis, effectively, the information and quantifications that you use as a basis to determine those needs, right?

A. That is correct.

Q. Okay. And so just very quickly, can you explain that annual filing?

A. Yeah. So on an annual basis -- and as a matter of fact, we'll be doing that, Your Honor, in December, sub regional RTEP. What we bring forth to our stakeholders are the assumptions, the criteria, the guidelines that AEP and other transmission owners utilize in determining the needs across the system.

Q. It's the assumptions, criteria, guidelines, and then the word escapes me right now. The models that you use to also drive those needs, right, or to determine those needs?

A. Yes, sir. For the load flow and short-circuit analysis, those models are utilized.

Of course, those models don't -- they are not able to -- they are not adequate enough to capture anything beyond that. But really, those are -- those are the models that we have to create, and we utilize the same model.

Q. Okay. And so let's talk about just a couple of these.

VICE CHAIRMAN CHANDLER: Could Staff turn to pagination page 6. It may be PDF page 7, we'll find out. Yeah, so it is just page 6.

Q. And so this is just an example that AEP would bring, and this is a project in -- well, it's not a project. It's a need, correct, in Greenup County?

A. That is correct.

Q. And the need number is identified in the left-hand side, and then the process stage. Do you see that?

A. Yes, I do.

Q. And that's just -- so this is the February 21 meeting. So that's just saying that this is the first time this has come before you. So this is the needs meeting being presented on February 21st; is that right?

A. Yes.

Q. And then in your annual filing, what do you call that, your assumptions document?

A. Yes.

Q. Okay. So in your assumptions document you lay out the different types of drivers, right? And so this one is customer service. Do you see that?

A. Yes, sir; I do.

Q. Okay. And so you-all had the assumptions, criteria guidelines for customer service connections in that assumptions document each year, and that's what leads you to mark this as a customer service document -- a customer service need?

A. So the document, the assumptions document, Your Honor, that you are referring to, it talks -- it focuses on internal -- internally driven needs, or I should say internally recognized needs that AEP has the ability to recognize. Customer service is not an internal recognized need, because any customer can come and say, okay -- a steel mill can comment and say, I want connection, I want service.

So those are not explicitly discussed in the assumptions document, but we have another document that we share with our stakeholders on annual basis that's called a Customer Interconnection Requirement for the AEP System. And the customer projects are discussed in that document in detail, and as to what requirements that AEP has for connecting customers to the grid.

Q. Okay. And so, just so we're all clear here, we get -- what was that document called again?

A. It's a -- and subject to check, Your Honor. I may not have the exact, you know, name spelled out, but it's call Customer Interconnection Requirements for the AEP System.

Q. Okay. So we've got that. We've got that and we've got the assumptions filing each year. We've got the attachment M-3 process, which is an attachment to the Open Access Transmission Tariff. All of those sort of drive this document as well as the -- to a degree, the PJM business practice manual, Manual 14B, right?

A. That is correct, Your Honor. And just for completeness' sake, we have the FERC 715 filing that is part of that, right, which is the planning criteria for the AEP system. And, yeah, I think that -- and the models, like you mentioned earlier. Just for completeness' sake, the models are identified in that -- in that assumptions document as well.

Q. And that 715 is the same 715 that me and Mr. Pearce were discussing earlier as it related to the Dominion issue that was remanded from the DC Court of Appeals, correct?

A. It's not --

Q. It's not the same document, but, I'm sorry, it's the same PJM order that the documents have come out of, right, for the --

A. It's the --

Q. -- FERC order?

A. That's right. It's the same document for AEP. Of course, each transmission owner has their own FERC 715 document.

Q. Okay. And those set forth criteria, certain planning criteria that drive needs as well, right?

A. Yes, Your Honor. Those are more bright line in nature, because, you know, NERC transmission line standards are applicable to the bulk electric system, BES, which is 100 kV and above. So there is, of course, a gap there for the load system. So the transmission owners are expected, and we all file the standards and criteria for the -- even the sub transmission systems in the FERC 715 document.

Q. Yeah. And some transmission owners even allow PJM to identify those needs pursuant to their 715, in lieu of the transition owner themselves, right?

A. Your Honor, all 715 needs PJM identified and verified for all transmission owners.

Q. Okay. So we'll go down this. The other one is the specific assumption references, that's a reference to the assumption document, the annual assumption document; is that correct?

A. Yes, Your Honor.

Q. Okay. And then the problem statement. And can you explain to me just, and I know it's intuitive, but what the problem statement is intended to do?

A. Your Honor, it is explaining the detail, so the detail of the need, as to what is -- what is the need. In this particular case, you know, it's a very simple need. We have a request from the distribution company to establish a new service point. And as you can see if you go through the document, some of the needs are more elaborate in nature, because they are more complicated.

Q. Okay. And this is a February 21st document. Can you -- last thing, can you explain to me here this model reference?

A. So that is the RTEP model year that we are using to analyze the impact on the load flow and short circuit aspects of the grid. So the -- so PJM puts models together roughly five years ahead. So in 2020, we are using a 2024 RTEP cycle. So what it is referring to is that the analysis that was done or will be done to assess this need and the impact of this on the grid will be using a 2024 regional transmission expansion planning model.

Q. Okay. And those are updated annually by PJM, correct?

A. Yes, that is true. And, Your Honor, I must say that, you know, it's a collaborative process, because, of course, PJM does not have the load information at each of our distribution substations or the appearances of the line or the configurations of the substations, so we are working collaboratively with PJM to update those models on a yearly basis.

Q. And you provide them a significant number of input for your load area, right?

A. Yes, sir; that is correct.

Q. All right.

VICE CHAIRMAN CHANDLER: And so if Staff can turn to page 7 of this document.

Q. This is another Kentucky need. Do you see this?

A. Yes, I do.

Q. Okay. And so we'll go down. It says the -- there's the need number, the process stage, it's the first time this has been brought, right, the February 21st needs meeting. Do you see that?

A. Yes, I do.

Q. And the driver, which as I understand from your testimony will have been in the assumptions document, the driver -- a number of drivers mentioned, equipment condition, performance, risk, operational flexibility. Do you see that?

A. Yes, I do.

Q. Okay. And then the need here is the Elwood 46 kV station. Now, 46 kV is, in the world of transmission, pretty low voltage, correct?

A. Your Honor, it's still pretty dangerous, but yeah, I would say that compared to 765, you can say it's low voltage.

Q. Yeah, I'm not saying it's safe to grab on to, but comparatively, it's -- you know, it's even significantly lower than -- you know, it's lower than 69 K -- let me ask this: Is there a transmission voltage, and I think there -- I don't know the answer to this, that's why I was curious. Is there a transmission voltage that AEP operates that's lower than 46 kV?

A. Yes, Your Honor. We do have some 23 kV equipment, and we have 34 kV equipment, as well as 40 kV. I think maybe the question is, is there a voltage that AEP doesn't operate? And I think there is -- there is not. Across our 11 states, we have transmission voltages spanning from 23 kV all the way to 755 kV.
Q. Okay. But in terms of the span, this is towards the low end of the voltage, though, right?
A. Yes. Yes, that is correct.
Q. And so -- because I will not get it right, do you mind to walk us through the needs or the -- let me say this: The drivers or the conditions or the performance or risk identifications listed there in the bullet, the bullet points, could you walk us through those and explain those to us as it -- as it drives this need?
A. Your Honor, I'll be very happy to do that. Would you like me to do that verbatim or would you like for me to summarize -- for me to summarize it like I would at our sub regional RTEP?
Q. I would actually love if you could read each bullet point and then tell us what the heck it means.
A. Sure. Absolutely. So starting with Elwood

46 kV station, 46 kV circuit breakers A, B, and C. So really, we have identified -- identified through our needs vetting and validation process that these three breakers need to be addressed. And the reasons for them, number one, 1960s vintage FZO-69-1500P type oil circuit breakers. So what we're mentioning here is the vintage. It's, as you can see, a 60-year-old circuit breaker. Circuit breakers typically have a lifespan of 40 to 50 years.

It's an oil type circuit breaker. Oil type circuit breakers, of course, pose another risk for us, especially if they are before 1973, when they -- back in the day, in the 1960s, there were not a lot of environmental regulations, and all the transmission owners had these circuit breakers used that were the in technology, if you will, at that time. But at that time we didn't have any oil containment built around these breakers.

So the reason for mentioning this, and I know our stakeholders understand that, whenever you see oil breaker, that right there is a flag for them; because in some cases, as these breakers get old and if they fail, the cost to mitigate oil contamination, the environmental costs, can even, in some cases, exceed the cost of that entire substation, because these breakers typically -- and again, I'm -- you know, not specifically for this type of breaker, but they can carry at least a thousand gallons of oil each.

The next one is fault operation CB --

Q. We're going to move on --

A. Sorry, Your Honor?

Q. We're going to move to the next one real quick.

On that item -- and it -- you-all have internally, at AEP, prioritized the replacement for the -- at least addressing the concerns surrounding these oil circuit breakers, correct?

A. Your Honor, I'm sorry, there was some -- there was some background noise there. I couldn't completely get your -- get your question.

Q. Has Kentucky Power, AEP, prioritized the replacement or addressing these oil circuit breakers?

A. Your Honor, yes, we are. We are addressing these through our system. And yes, we have -- we have prioritized the replacement of these breakers. Now, one thing I will mention to you, Your Honor, around priority, is that we have a -- what I call a radar for every single asset on our grid. So every single substation, every single transmission line, we have a dashboard that tells us what is the health of that. Now, that's just a radar, because it's telling me, as the transmission planner for the grid, that here are the assets you need to go and pay more attention to.

What then happens is -- so it is a priority. That's the priority that you're reporting to. So all of these are in that list. As we go through that, we have the obligation to vet and validate every single one of them, because, you know, in some cases, you know, failure has happened. For example, a line went out, and that's what my radar tells me, that this line has gone out ten times in the last year. Now I need to vet and validate it because there is a possibility that the last time it went out, our tree service individuals did something to repair it to a point where it should not be a concern in the future. So then the needs gets vetted and validated.

And the timing of how that happens, Your Honor, is very different, because some assets we can validate in a month; some assets may take us a year to validate, because we may need to do more analysis, like side boring and, you know, ground grid analysis, things like that. So as soon as a need gets vetted and validated, as soon as that happens, in the next meeting, stakeholder meeting, we bring it forth to the stakeholders.

Q. Yeah. And what I wanted to make clear was that that prioritization or that indication of concern around the oil circuit breakers is indicated in your assumptions documentation, right?

A. Your Honor, like I said, yes, it is indicated, and it is in the radar, but the one point I'm trying to clarify here is that, but that's not the order of mitigation, because it still needs to be vetted and validated. It may fall off in that process or it may become a high priority in that process.

Q. Right. Okay. Can you go to the next one now? Thank you.

A. Sure. Thank you, Your Honor. So the next one is fault ops CB A. Circuit breaker A has 33 fault operations. Circuit breaker B has had 83 fault operations. Circuit breaker C had 105 fault operations. Your Honor, the manufacturers for these breakers recommend that a breaker be completely overhauled. It's like, you know, your car engine getting rebuilt or reviewed. After 10 fault operations, because those fault operations has a lot of energy, so you can think about, you know, the context of the breakers are closed and power is going through that, and then when there is a fault, the fault energy, depending on the short circuit and depending on where that breaker is on the system, could be thousands of amperes, and that takes a lot of energy to open that, clear that, and that will wear down the contact very quickly.

So the manufacturers recommend after ten fault operations, you gotta go overhaul it. And we have been doing that. We have been overhauling these breakers. But now they are at a point where you can't even find replacement parts for them to overhaul them.

So that's what we are showing here, that these have gone through significant fault operations through their lifespan, and way beyond the manufacturer's recommendation.

Q. Can I ask on that, the overhaul, is that a -- and I know this isn't your -- what you do, necessarily, but I'm just curious, is that a capital expense or an O&M expense when you do those overhauls?

A. Your Honor, it really depends. Mostly it is O&M, because most of the time it may require very small parts replacement, but if it becomes a bigger item, like maybe a whole portion needs to go away or, you know, you need to replace a major component, then it can be capital as well.

Q. Okay.

A. Your Honor, the next ones are the -- so there are some other issues that are identified. Damage to the bushings. Like I mentioned earlier, the spare part availability is typically mostly our concern with these types of breakers. You know, it's like having a 1960 vintage car and nobody, you know, has parts. If they have it, they are going to sell you that at a very high cost, more than probably a new breaker would cost.

And then, you know, lack of vendor support. I mean, a lot of these breakers, you know, the vendors don't even have people, resources that know how these operate anymore, because they have all transitioned to new technologies.

There are only eight of these remaining on our system, so again, you can -- you know, in the past, Your Honor, what we did -- and again, that's the benefit of being part of that big, integrated system, right, because you can -- you can imagine that we are using the same equipment pretty much all over our footprint. And as equipment becomes obsolete, we have spare parts available because we are retiring stuff, but we are cannibalizing equipment as we retire it, and we keep that in our -- in our stores so that we can get longer lifespan from -- for the rest of the equipment.

So we -- as a whole, we have a lot more. And as a result of it, you can see our lines, you know, they are lasting 70, 80 years. This breaker has a lifespan recommended 40, but it's sitting there for 60 because we are able to do that.

Now, the other thing is, when you only have eight of them left, then, of course, there is not a lot of spare parts even from failed breakers that we can utilize. So that's an important distinction, I think, we are making here.

And the last one, Your Honor, is 86 percent of the relays at the station are electromechanical. Electromechanical relays, Your Honor, are -- nobody makes them anymore. Everything is now digital. And they are really, the -- they really base -- you can think about it, it's like an old watch, so they ar very -- all the -- all the functions that they are performing are based on mechanics and tolerances. So really, the weight increases this much and then the relay will operate, but the tolerances are very, very, very small.

So these electromechanical relays, number one, they don't -- they don't talk to the new relays anymore. And, number two, they don't -- they have a lot of misapprove -- misoperations because over the years, the tolerances have become very thin. So there are 86 percent of the relays, protective relays, which are protecting the grid, telling the breakers when to open, when to close, those are electromechanical.

And I think that pretty much, Your Honor, summarizes the need here.

Q. Okay. I appreciate that, Mr. Ali.

VICE CHAIRMAN CHANDLER: Mr. Chairman, I have still a number of questions for Mr. Ali, but I noticed at that last response, we're at 12:04. Would you like me to push through or do we -- can we come back to Mr. Ali after lunch?

CHAIRMAN SCHMITT: Okay. I guess it's, what, after noon? Why don't we take a break and come back at 1:00 o'clock and finish up? Can we do that?

All right. We'll be in -- we'll be in recess until 1:00 p.m.

(Recess began at 12:06 p.m.)

CHAIRMAN SCHMITT: We're back on the record. Over the lunch hour, we've been undergoing some technological repairs, and hopefully they -- hopefully they'll work. So Mr. -- or Kentucky Power, Ms. Blend, are you ready for Vice Chairman Chandler to begin his continued cross-examination of Mr. Ali?

MS. BLEND: We are, your Honor. I have just one clarification that I wanted to offer before we resume, if that is okay.

CHAIRMAN SCHMITT: Okay. Can you speak up? You're difficult to hear.

MS. BLEND: Can you hear me better now?

CHAIRMAN SCHMITT: Yes.

MS. BLEND: Thank you, your Honor. We are ready to resume. I wanted to address one minor issue before we continue, if that is okay.

CHAIRMAN SCHMITT: That's okay.

MS. BLEND: Thank you. Small clarification. I believe earlier the vice chairman asked Mr. Ali about rate impacts associated with the company's PJM LSE OATT expense or the year one and year two rate increase. Mr. Ali testified I believe that Dr.

Pearce may have been able to answer those questions.

I just wanted to point out that Mr. Vaughan, in his rebuttal testimony, addresses the first year, the 2021 rate increase. So I just wanted to mention that in case it's helpful for later witnesses. Thank you.

CHAIRMAN SCHMITT: Okay. Vice Chairman Chandler, are you ready to continue your cross-examination?

VICE CHAIRMAN CHANDLER: Yeah. Thank you, Chairman. Can you hear me okay?

THE WITNESS: Yes, sir, we can.

VICE CHAIRMAN CHANDLER: That's never been my problem, so I don't think it's going to start today.

Q. (By Vice Chairman Chandler) So we -- Mr. Ali, do you remember we were talking about the -- if Mr. Ripy can bring it up on the screen, I believe it's Staff's PSC Exhibit 15. And we'll wait for -- for Mr. Ripy to bring that document up.

And do you remember this -- this is the page that we were discussing?

A. Yes, your Honor.

Q. Okay. And so, big picture, this is -- we walked through the assumptions document that is -- the assumptions document as following the attached

M-3 which is an attachment to the open access -- PJM's Open Access Transmission Tariff.

And these -- these needs proposals, these subregional RTEP presentations are in accordance with all of those -- or proposed -- presented in accordance with all of those in addition to, to some degree, the manual -- I want to make sure I get this right -- the PJM Business Practice Manual, Manual 14B, correct?

A. Yes, your Honor. That is correct.

Q. Okay. So we talked about all those documents. This is -- this is sort of the culmination of all those different processes, all those different roles. There is a -- this documentation is a needs and a solutions presentation by AEP, correct?

A. Yes, your Honor. That is correct. The only -- only other clarification, the 14B process, it also, you know, covers baseline projects, and so we go -- and so the baseline projects are under the matter of 14B.

Q. Yeah. And so I guess I was just trying to say: There are portions of 14B that govern these presentations --

A. Yes.

Q. -- govern -- or maybe governing is wrong because they're not technically governing documents, but that provide guidance on how these processes should actually occur in reality, right?
A. Yes, sir. You are correct.
Q. Okay. And then -- and just for -- I'm not going to ask you to remind me, but I'll try to go back to 14C in a minute. So we've got 14B.
So this is a need, and if we can -- I don't --let me just say, Mr. Ali -- well, I'm going to go to solution here in a second. It is 60 pages away. Can we -- can we go straight to it? And if you see it, you'll know that's it's a solutions presentation; is that fair?
If you see it, you'll know whether it's a needs or a solution presentation?
A. Yes, sir. That is fair.
Q. Okay. Can we go to the pagination -- the PDF pagination 67?
And while he's going, Mr. Ali, the reason I ask, is: This document is a presentation that you would agree is broken up between a needs -- which we saw that maybe on page 2 or 3 where it says "needs," and then later there's a break in the pages that says "solutions."

Everything after "needs" is a need; everything after "solution" is a solution, right?

A. Yes, sir. As I explained earlier, you know, we present the need for service portion of the grid during these meetings, and then also we take the opportunity to present solutions during this meeting for needs that had been previously discussed with the stakeholders.

So -- so that's why the presentation is divided into two different sections, if you will.

Q. Okay. So this is -- it's page 67. Do you see the document on page 67? It's on the screen.

Is it the same one that's in front of you?

A. Yes, your Honor. It is -- it is for Floyd County, Kentucky. So it's a -- it's a different need for a -- and a different solution. But yes, I see it.

Q. It's the same area, right, a county -- a county or two over from Pike?

It's the AEP Kentucky Power service territory still, but this is a different need number than that need we looked at on page 7, correct?

A. Yes, sir.

Q. Okay. So process stage solutions meeting is this meeting that we're talking about, the February

21st meeting. Do you see that?

A. Yes, sir.

Q. And this was brought -- the solution was brought about eight months after the needs meeting. Do you see that?

A. That is correct.

Q. Okay. And so the -- we'll skip over the supplemental project driver, the assumptions reference. We were just talking about those. We'll go down to the problem statement. We were just talking about that.

That lays out the actual conditions or the -- the specifics on -- on how the criteria in the assumptions -- criteria document were implicated, right?

A. Yes. Criteria or guidelines.

Q. Or guidelines. All right. Yes, sir. Assumptions criteria guidelines.

Okay. So we'll skip on to go to --

VICE CHAIRMAN CHANDLER: Mr. Ripy, do you mind going to the next page, page 68?

BY VICE CHAIRMAN CHANDLER:

Q. So all that -- all that -- all that information is on the needs side, and on page 68 there's just additional needs statements, right?

A. Yes, your Honor. This is -- this is pretty much the needs in that particular area that are recorded and validated. And of course these needs were originally shared with the stakeholders, like you said, in June of 2019. And then it took us roughly eight months to come up with a feasible solution, and now we are refreshing the stakeholders' memory on the needs that we had originally presented, and we're also now sharing with them the solution, which is starting on 69.

Q. And so we move to 69. And so you restate the needs so that everybody is -- you know, people have context for what you're about to give them.

VICE CHAIRMAN CHANDLER: And if we can move on to page 69, Ms. Ripy.

BY VICE CHAIRMAN CHANDLER:

Q. This is, you would agree, the presentation of AEP's or Kentucky Power -- the proposed exclusion to that identified need, correct?

A. Yes.

Q. Okay. And -- and I'm not going to ask you to -- to do anything verbatim or anything, but just so that we understand the document, to the left, these are all different solutions for a multitude of the needs identified, correct?

A. Yes, sir. So these are -- I would -- I would say that these are categorized based on assets. So a transmission line is an asset, and a transmission substation is an asset.

So -- so what we are looking at is overall, what does it take to solve of these needs individually and holistically to see what is more cost effective and robust. Once we have made that determination, then we lay out the -- our by-asset scope and cost of that solution.

Q. Okay. And so that's what these -- these are a description of the solution by sort of asset type or -- or defined sort of project, right, as a piece of the bigger solution and a cost of that -- those individual parts, right?

A. That is correct, sir.

Q. Okay. And so they vary here, just going through, $35.3 million, $11.5, $1.3. This screen is really small, but 1. something, half a million dollars. Do you see all those down the page?

A. Yes, your Honor. I do.

Q. Okay. And then if we'll -- just for full context, we'll go to page 70 just for a minute.

This finishes those identified assets or portions, right? And then it gives the total estimated transmission cost.

That's the capital cost, right?

A. Yes, that is.

Q. Okay. And then what's the next thing there, the ancillary benefits of -- you removed an obsolete 25 miles of a 40- -- is that 46, 48 kV network?

A. Yeah, 46 kV. That is correct.

Q. Can you explain that just for a minute?

A. Yes, sir. So I know you mentioned earlier that 46 kV is the lower end of the voltage spectrum. And you're exactly right, that is the lower end of the voltage spectrum. And these voltages, 43 kV, 34 kV, 40 kV, 46 kV, and 88 kV, they were -- they're pretty predominant across the Appalachian region, including Kentucky, but these are obsolete in the sense that if we were to go out there today and buy -- try to buy transmission equipment, at 46 kV, nobody sells that. All the equipment is at 69 kV or higher.

So, of course, our goal is that as we are replacing this infrastructure, there are areas where we can't get rid of 46, to be very frank with you, because the load is served off that network, and it's not just a matter of AEP taking that investment in the grid. It's also the customers -- you know, the industrial customers, for example, they'll have to make investments on their side to get to a higher voltage.

So what we do is in these cases where we are able to get rid of that voltage, we would get rid of it by retiring it and moving the load to a different voltage like a 69 or 138 kV, such as in this case.

Where we cannot get rid of it, your Honor, we would at least design the new assets that we're building to a higher voltage, but we'll still operate it at a lower voltage until such time that everybody else in the -- in the region is ready to make investments on their side to get to the next level of voltage.

So, you know, just to kind of give you an example, if you go to the SPB region of AEP footprint or the unmarked region in Texas of AEP footprint, we don't have anything less than 69 kV. Those voltages have already -- the lower voltages have already been phased out over the years, and we are now trying to do that here in the eastern regions as well, where we can.

Q. Okay. So we -- so we get the proposed total cost. We know what the need that identified -- that AEP identified that this solves, and then in

addition to solving that need that is proposed, AEP has indicated there are ancillary benefits of getting rid of what it believes to be an obsolete 46 kV network, right?
A. Yes, sir. That is correct.
Q. Okay. And then these are -- to the right of that, these are existing assets and proposed assets. I'm sure there's a correct engineering term for -- for -- but they look to me like individual -- I guess a map of the circuits.
can you explain what those are?
A. Yes, your Honor. So each -- each dot represents a substation. So each dot represents a load, if you can think of stepping down to residential or industrial customers or coal mines, for example. So each dot is reflecting a delivery point to -- to an end user, if you will, and the line segments are representing the transmission circuits that are connecting them.
So as you can see, if you look at the -- the box that represents the existing infrastructure, all the yellow lines and yellow dots are 46 kV. And of course, that's where all the needs are that we mentioned on the slides beforehand.
And then you see the red dots and red lines

are the existing 138 system in the area, and -- and there are, of course, some needs identified on that as well. Especially as you can see there's some major customers, and our goal is that, How do we holistically solve that?

Now, we can look at it individually, your Honor, and that will be us going by every single substation, every single line, or we can look at it more holistically.

And that is what we have done here, is where we can -- some of these stations because they're close proximity -- in close proximity to the 138 system, we're just able to move that load onto 138 with some 138 infrastructure, and then get rid of a significant portion of the 46 kV network, which as you can see on the proposed section, a lot of the yellow dots are now not there anymore because now they're moved to the 138 kV network.

And we still have three stations at 46 kV left, but, you know, a significant portion of them are already being recommended to move to 138 kV.

Q. Yeah. So just one of the changes to that point, the existing, the proposed is that the -- I can't say it -- but we'll say it's the Allen to Beaver Creek; is that right?

A. Sorry, your Honor -- your Honor, I'm not following you. Are you talking about the --

Q. What is the substation to the far right of the existing --

A. Oh, yeah. Yes, your Honor. You're right. So the Allen -- Allen to Beaver Creek -- you know, we -- Allen, McKinney, and Beaver Creek are still left on the 46 kV network.

Q. Yeah.

A. And the remaining stations, Garrett, as well as Saltlick and Spring Fork -- all of them are either moved or consolidated on the 138 system.

Q. And that's what I want to make sure that I understand that -- is that McCreary or McKinney? McKinney.

A. Yes, sir.

Q. The McKinney to Spring Fork Tap is the portion that you're talking about being retired; is that correct?

A. Yes, sir. That is correct. 25 miles of --

Q. Beaver Creek. Yeah. Okay. All right.

So you proposed all of these. You bring this forth -- you bring forth the need. You bring forth the solutions, and -- and this may -- please tell me if this is a distinction without a difference or a difference without a distinction: Is this Kentucky Power -- is this -- are these Kentucky Power's needs or are these AEP's needs?

A. Sir, these are the -- the needs on the AEP transmission grid, and they happen to be in the Kentucky region.

So these -- if your question is who owns the needs and who owns the solutions? I mean, I, as the AEP service corporation employee, am the one who is looking at these needs, prioritizing these needs, and developing the solutions.

But when it comes to actually approving them and implementing them and funding them, of course that is made in collaboration with Kentucky Power because this is in Kentucky. These investments will be in Kentucky.

Q. Yeah. That's what I do -- I do want -- if there is a distinction, I do want to make it here, or at least understand it here.

Insofar as the frames in the middle of the screen, the existing assets, right, and the lines and the substations -- insofar as those are Kentucky Power's assets located in Kentucky Power's service territory, is -- is this -- is this -- the page 67/68, that's their need, and you or your team is bringing that need on their behalf through the M-3 process, and that's -- just so I understand it; is that correct?

A. Yes, sir. That is correct.

Q. And the reason, I would assume -- and I want to ask it so I -- you can tell me I'm right, that's always fun.

The reason is you-all can do a consolidated transmission team at AEP. Instead of having one at each one of the individual operating companies, you get -- you get economies of scale and scope by doing that?

A. Your Honor, that is partially correct, but the other part of the answer is that the transmission system has always been designed as an integrated system, as an integrated network, so we have to do it this way so we're fair and equitable to all of the operating companies within AEP. Right?

So my job is regardless of where the needs are, whether it's in Kentucky or Ohio or I&M, I am going to prioritize them based on severity, based on the risk they pose, based on how deteriorated the condition is of the assets.

And then I'm going to fix that -- you know, the mitigation plan I'm going to come up with is to address that in a very cost-effective and reliable and safe manner; and I'll then take it back to the operating companies of AEP and say, "Here are the needs, here are my recommendations, here are the risks if you don't address them."

And then, of course, like I mentioned earlier, they have to make decisions around how much can our customers afford, how much can the company afford, and then -- and then those needs move forward through the execution process based on it.

Q. Yeah. And I -- I didn't mean to indicate otherwise.

I guess what I was asking is: The presentation of them in the inquiry process is what I'm asking about because to your -- to your point just then, the AEP transmission group can still identify and prioritize and consider all of the projects in totality in terms of ranking and still go back and present those to the operating companies, like you say.

But then the operating companies could then take those, take your recommendations, and then bring those themselves to the M-3 process, right?

I'm more asking about that -- that second half of what you were describing, is after the decision has been made, you're then presenting it, effectively, on behalf of the operating company, right?

A. Yes -- yes, your Honor. And the reason for that is, like you mentioned earlier, that, you know, we have a pool of resources that all operating companies use for planning purposes, number 1, to make sure that the grid is being designed on an integrated basis in a fair manner, and number 2, to reduce the burden of resources you will need if one of the operating companies was doing it individually.

Q. Okay. And so all of these fairly leading questions are getting to -- I'm trying to move as fast as possible to set this foundation for the -- the part that I need to learn, right, or need to understand.

The -- the solution -- or the need is the -- or operate -- or the asset owner's needs, right? They're the ones that own the asset, if it's driven by reliability, if it's driven by whatever may be -- in terms of the these supplemental projects, it is the -- it is the transmission owner's need, is what we just discussed.

In the solution side, is it necessarily -- in this M-3 process, is it the transmission owner's solution?

A. Absolutely. As a matter of fact, your Honor, it's not just only the transmission owner's solution, it's the solution that all of the customers that are served on that infrastructure have to also agree with, and they have to help us achieve it.

I mean, those stations that I mentioned that are moving from transmission 46 kV network to 138, those are distribution substations that will also need to be a significant investment in to move them.

So really, my team works very closely with Everett Phillips, who I know is going to be on the stand later on, on the solution to come up with what is the right solution for the Kentucky customers because we own them together as the Kentucky Power transmission solution as well.

Q. And so that's what I'm trying to get to and understand.

Where is the distinction made, then, between ownership of the assets of the solution between, for instance -- in a Kentucky Power example here, between Kentucky Power and Kentucky Transmission

Company?

If the need is of the asset owner, then how does someone other than the asset owner in the M-3 process end up owning a portion of the solution?

A. Your Honor, I can -- I can absolutely answer that question.

So in essence, there are what we call transmission company operating guidelines, and we call them project selection guidelines, or PSGs in short, and those guidelines were established by transmission as well as the operating companies across the AEP footprint as to which assets need to or pre-qualify to the print as Transco, or transmission company assets, and which assets need to stay within the operating company.

And of course, you know, there are also some exceptions because each AEP substation has their own rules, and you have to abide by those rules as well.

So there are some exceptions that are carved out there, but that guideline is what guides us to figuring out which assets will go into AEP Transco, Kentucky Transco, and which assets will go into Kentucky Power Company transmission books.

And I will tell you, your Honor, that, you know, there is -- of course the purpose behind the

Transco was to be able to provide a financial mechanism to the operating companies so that they're able to, you know, more efficiently invest dollars to address needs.

But the transmission companies, they can determine, at the end of the day, that if they -- they need to make any changes in the level of investment, you know, that that is going into that infrastructure.

So the guidelines are the ones that guide us, but at the end of the day, you know, the Kentucky Power has the ability to say, you know, this asset, I would want it to go in Kentucky Power for -- for reasons that -- that would be laid out, you know, in a -- in a -- in their business plan. Make sense?

Now, you could not do it the other way around. My understanding is that we can't move assets from Kentucky to Transco that are not in the guidelines, but we could from Transco to Kentucky. And that does happen, if that makes sense.

Q. Well, and just so that I'm clear, you're not necessarily moving assets because moving assets would likely require -- and I'm not asking for a legal opinion, but is it your understanding that moving the assets from a regulated utility -- or in your experience that moving those assets would require commission approval in many of the states, including Kentucky?

A. Your Honor -- your Honor, my apologies. Bad choice of words there.

So what I meant to say is let's say we're building a new asset, brand-new asset. The Transco guideline, which I believe when the Transcos were formed in Kentucky, those guidelines were also filed as part of the approval process, and the Commission I believe has a copy of that.

(A DISCUSSION WAS HELD OFF THE RECORD.)

CHAIRMAN SCHMITT: Thank you, Mr. Ali. If you would please try to repeat from the beginning of your answer so the court reporter can pick it up. Thank you.

THE WITNESS: Thank you, your Honor. So, Mr. Vice Chair, as I was stating earlier, just in the -- you know, for the sake of making sure that the record is clear, what I was stating earlier is that the existing assets, let's say to start with our own by Kentucky Power, right, those are already in the rate base.

And now we're enhancing that grid. Maybe we're rebuilding some lines, maybe we're rebuilding some substations, we're maybe building new lines. The Transco guidelines, which are the guiding principles for what assets can or cannot be part of the transmission company, are what we use up front to determine which assets will be owned by Transco and which assets may be owned by operating companies.

Of course, they are subject to the approval of the operating company as well as -- you know, if it requires a CPCN filing or something like that, approval of the Commission, but we are using the project selection guidelines for new assets that -- to determine which ones will go in the AEP Transmission Company and which will go in AEP Kentucky Power Company.

Q. And so I'm unaware -- and I plead my ignorance on it.

I'm unaware of whether this document has been filed with the Commission. Is it something that if requested in a post-hearing data request, you could provide the -- as I understand what you said it is called the transmission company operating guidelines?

A. I'm sorry. Project selection guidelines.

Q. Project -- PSG, project selection guidelines.

VICE CHAIRMAN CHANDLER: Is that something that the company can provide in a post-hearing data request?

MS. BLEND: Yes, your Honor. I believe, subject to check, that it was produced in discovery. We'll confirm that and either provide the reference to the appropriate data response or we will provide it as a post-hearing data request.

VICE CHAIRMAN CHANDLER: Okay. Thank you very much.

MS. BLEND: Thank you.

BY VICE CHAIRMAN CHANDLER:

Q. So as you -- well, let me ask about enhancements for a second so we have a very clear record.

Enhancements, rebuilds, are those just -- do you just mean the solutions in general to the needs, whatever they may be, or do you mean enhancements -- or let me ask this way: Do you mean enhancements in terms of the archive -- or like the baseline projects, or do you just mean sort of replacements and the solutions to the needs identified in the inquiry process?

A. Your Honor, the project selection guidelines cover all projects. So really whether it's a baseline project or a supplemental project, depending on what configuration is being -- recommending -- recommended as a part of the solution, we will apply the project selection guideline to then determine which components are the Transco components and which components are Kentucky Power components.

Q. Okay. And okay. And does the -- does -- well, let's just say Kentucky Power -- because that's who we're here with.

Does Kentucky Power indicate anywhere in the M-3 process that they will not be the entity that owns the entirety of the solution?

Let me ask the question differently.

Is there anywhere that you're aware of in the M-3 process whereby a Kentucky -- Kentucky Power would indicate that a transmission company or some other entity will own a portion of the supplemental solution?

A. Off the top of my -- my head, I -- I -- nothing comes to mind where we -- we state that explicitly. But like I said, the project selection guidelines when we made filings for the Transcos at all jurisdictions, that was the guiding document as to what assets can and cannot go into the Transcos.

And so that is, I know, available, and we will -- we will make it be available, also, as the counsel mentioned here. But I'm not familiar where we explicitly go out in the M-3 process and -- and explain which assets are going in which companies.

Q. Okay. And so is it your understanding that -- that most of the other transmission company -- well, so were you watching the hearing yesterday?

A. Yes, your Honor, I was.

Q. And did you see the portion of the hearing where -- where Mr. Satterwhite was asked about the S&P document or the S&P story from 2014 that discussed the -- the proposals around the AEP territories regarding Transcos?

A. Your Honor, I -- I don't recall it. If you don't mind maybe refreshing my memory on it so that I don't --

Q. So do you -- are you aware that the Kentucky Public Service Commission, in a June 10th -- I think maybe it was referred to yesterday maybe a June 10th, 2013, order disclaimed jurisdiction over the Kentucky -- AEP Kentucky Transmission Company, that they found that it was not a utility as defined by Chapter 278? Are you aware of that?

A. Yes, your Honor. I am.

Q. And so we -- let me ask this: When you were describing earlier about the filings made with jurisdictions regarding the allocation of projects between the Transco and the operating company, would that inherent -- given that being the situation, is that inherently different than -- than your experience or of the experience of other states regarding the insight they may have into the allocation or these -- these project selection guidelines between transmission companies and operating companies?

A. Yes, your Honor. So I'll maybe clarify it. It's a little bit maybe complicated because each jurisdiction is somewhat different.

But really the project selection guidelines mentions what assets can qualify for Transco. But what it also clearly states is, is that the -- that the operating company can still choose to put those assets in the operating company because really the purpose of the Transco was to help the operating company with their financial burden, so it gets us where -- where they don't need that help , they have the ability to put those assets in the operating company.

So in case -- I think what you're asking -- the question you're asking just to make sure I get it right, is that are the Transco guidelines, the way they are being implemented in Ohio the same as they are being implemented in Kentucky?

Is that your question, your Honor? I just want to make sure I get it right.

Q. To a degree, yes.

A. Okay. So like I said, in Ohio right now, we are following the Transco guidelines the way they -- they are stated. In Kentucky we do the same thing. My team would follow the guidelines, and we will assume that these assets will go in Transco, probably, and these assets will probably go in the Kentucky Power Company.

But then of course, you know, the Kentucky Power makes the final determination in collaboration with the transmission policy group if that is indeed the case to satisfy, like you said, you know, certain additional requirements that we may have in Kentucky.

Make sense?

Q. Yeah, it does. And this is what I -- this is really what it was all culminating to, is to understand this better, is that when it comes to the solutions, presented in the M-3 process, for instance, and the implementation of those solutions with investments in the system and the allocation -- or the -- let's just say it this way -- whose books those investments end up on, right, and who owns those solutions.

I want to make sure I understand, that is still, for instance, in this situation, 100 percent up to the Kentucky Power operating company president?

A. Your Honor, I -- I will be very honest with you. I don't think I can answer that and say definitely -- definitively that it is 100 percent, you know, a call of the operating company.

My presumption is that it is, but I think Witness Mattison or Witness Pearce are probably the better witness because this is more of a policy cost allocation question.

But what I can assure you is that when I'm developing a solution, I really don't care if the Transco will end up owning it or Kentucky will end up owning it or Ohio will end up owning it. My job is to come up with the most cost-effective, holistic solution for a customer.

So that's what I look at, and then of course these guys have to look at other things around cost recovery, cost allocation, things like that.

So I think if your question is that -- who makes that final determination and how much authority somebody has or does not have, I think Witness Pearce or Witness Mattison will be better witnesses for that.

Q. So I just asked Mr. Pearce a very similar question, attempting to find out what input Mr. Mattison had, for instance, on investments in the transmission company, and I think his response was something like that they have input, but they had -- the ultimatum decision lies in the operating company.

VICE CHAIRMAN CHANDLER: So, Ms. Blend, do you know if Mr. Mattison is the best person to ask about that? Because I would like to understand and have a definitive answer in that regard.

MS. BLEND: Thank you, your Honor. I believe Mr. Mattison would be able to speak to that question.

VICE CHAIRMAN CHANDLER: All right.

MS. BLEND: I don't want to speak for him and promise you that he will provide an answer that you think to be very definitive, but I do believe that he will be able to address that question.

VICE CHAIRMAN CHANDLER: No, I think it's an important part of our inquiry on this issue, particularly the PJM LSE OATT expenses.

And so if -- I would just ask if Mr. Mattison cannot give a definitive answer, that maybe we can discuss after Mr. Mattison comes back so we can find a witness that can do so.

Is that -- are you amenable to that?

MS. BLEND: Yes, your Honor. Thank you.

VICE CHAIRMAN CHANDLER: Thank you.

BY VICE CHAIRMAN CHANDLER:

Q. So -- so in terms of a deviation from the guidelines under the project collection guidelines, when you're planning, you are -- and I don't mean this in a derogatory sense, but you're indifferent to who -- whose books it ends up on, right?

You're there -- you're there from sort of an engineering perspective, that, here is the engineering need, here is the engineering solution, and then the finances necessarily are up to somebody else.

Is that -- I don't want to boil it down too much, but is that effectively what -- is that a fair characterization?

A. Yes, your Honor. And that is very fair, that my job is -- I am looking at a solution. But one thing I want to clarify is that one thing in finding a solution is to ensure that it's cost effective, it's reliable, it is safe.

So all of those things are part of my job but not to the extent that, you know, what those solution components may fall into.

Q. And the reason I ask that is because is it fair to assume that at this point when these solution -- solution presentations are happening in M-3, no one may have made the decision yet as to who the ultimate asset owner is going to be of any of these different parts of the project, right?

A. Yes, your Honor, that is correct. The only thing I would clarify there is, like I said earlier, we have an idea, right, based on the project selection guidelines.

And -- and these solutions, your Honor, are very long-term solutions in the sense they take four to five years to -- it's not something we can just go address tomorrow.

So what we have to do is we not only have to build a solution, we also have to build a cash flow as to what will it take from an -- from an investment perspective.

So when we go to the operating company leadership like Brett Mattison, then they have that picture available, that here is a solution, you know, here are the arguments we looked at, here are the risks that we are trying to mitigate.

And we believe based on the project selection guidelines that this solution -- you know, which -- which companies that solution resides in and what the cash flows are so that they will have a full picture of what it's going to take and can we -- can we afford it or how much of that we can afford.

Q. That's fair.

A. So we do that, but it's not definitive, to your point.

Q. And just so I understand, so -- so to your answer, when these are presented, the assumption is that the guidelines will be adhered -- and I know they're guidelines. They're not requirements necessarily, under you're all -- but that they will be strictly adhered to?

And so, you know, this transformer X would be -- and generally, in terms of just your planning, you're indifferent as to the decisions of the operating company for planning purposes.

A. Yes, sir. That is -- that is correct. So you're right. We -- we look at the guidelines. We apply them, and we are indifferent to whether that -- those components change, if needed.

Q. Okay. So part of the -- the question yesterday -- and I don't remember who -- who it was asked of or who answered it, but I'll provide you in its context -- regarding how in terms of the rate of return, the ROE, of AEP's different operating companies Kentucky Power historically has been a laggard -- or at least in recent history has been a laggard.

Are you aware of that?

A. No, your Honor. Like I said, I don't deal with financials or regulatory cost recovery and those -- those type of mechanisms.

Q. Okay. And so -- and let me ask this: Have you ever -- either directly or in a roundabout way, have you ever been aware of investment decisions being made at AEP with regards to transmission that -- that prioritize investments in jurisdictions that earn a higher return on equity?

A. Not -- not to my knowledge, your Honor.

Q. Okay. And -- and have you ever heard, either directly or in a roundabout way, an interest in prioritizing transmission investments in jurisdictions that -- back to our earlier conversation -- may have different regulatory processes for implementing transmission -- you know, transmission build, rebuild investment that may have less oversight or more simpler processes?

A. No, your Honor. I haven't gotten any such direction from anybody. And I think -- I think -- if I may, your Honor, you know, I think maybe you're referring to the slide deck that was being shared yesterday -- yesterday where there were some references to which states have what recovery mechanism.

I think what I will tell you, the role I play in that, my role is to determine what are the needs on the grid, what are the right solutions regardless of which bucket those solutions go in, and -- and then making sure that they rationalize or justify the prudent -- or stakeholders that engage in developing them.

And then of course it's the job of our leadership to go and acquire capital at the most effective rates for our customers. And I think that's what you were seeing, what -- I have never received direction that we are investing dollars in a certain company because of -- of their ROE.

I'm sorry. I'm not aware of that.

Q. And you remember Mr. Pearce's testimony today where -- where he agreed that at least in recent history, the investment in other states -- the investment in Kentucky has been shy of its allocation of costs in the last couple of years when you combine, you know, operating companies and transmission companies for the state.

Do you remember that?

A. Yes, your Honor, I absolutely remember that. And -- sorry.

Q. No, I was just going to ask: So is that an indication that on a -- at least as it relates to on a 1 CP basis or a 12 CP basis, that the needs of other states -- that other states just effectively have more transmission needs than Kentucky?

A. Your Honor, that is -- you know, based on where I sit, I don't see it that way. You know, of course, you can -- you can appreciate that these allocations, they do change over time, right?

I mean, I can go back to 2012, and I know we had to make -- we had to make a significant investment into Baker Substation which is a critical station to serve the Kentucky customer base, extra high voltage. And so during those years, if you go back and you look at it, I'm assuming we will see that the investment allocation was different.

I get it that if you look at the data right now, you know, the investment allocation between Kentucky and other operating companies have changed, but that is not to say that it will not change again in the future based on the needs.

Now, your question -- the other question, and I want to address the answer to that, that do we have less needs in Kentucky than other operating companies. The answer is no. We do have needs in Kentucky, and I see significant needs in Kentucky in the future years coming up as -- as the system gets more aged.

But, at the end of the day, like I said, the line is drawn based on, you know, how much can a company afford, as well as how much distribution investment can also be made.

I mean, it will be very irresponsible for us to go and -- say let's go and replace the entire transmission network you're seeing on the map there in front of us in the exhibit and not have the distribution investment to go along because then we're not delivering that benefit to the customer.

So it's more complicated than that because it's not -- you've got to have the distribution investment also available. You've got to have the financial, you know, expense to be able to do that, and, like I said, it is volatile over here so we can't just look at a static view and assume that is what the future will hold as well.

Q. So there's a -- you remember yesterday that there was a discussion around a $37 billion investment plan, five-year investment plan. Do you remember that?

A. Yes, sir. I do.

Q. And that 10 and a half million of it was dedicated to transmission?

A. Yes, sir. That is correct.

Q. And at least referred to in the S&P article a significant portion of it allocated to -- to renewables, right?

A. Yes, sir. That is my understanding.

Q. Okay. So I just want to make sure that I understand that you're not directly discussing or -- I want to make sure that I understand that you're not discussing the -- the capital allocations or the capital available from the Kentucky Power standpoint to make the necessary investments in its system to meet its obligation of service.

That's not necessarily your -- your job, correct?

A. Yes, your Honor. My -- like I said, my job is to tell Kentucky Power where the needs are, what the solutions are. What would those solutions take from an investment perspective because, at the end of the day, they need to understand the dollar value of those solutions.

One thing I do want to clarify, your Honor, you said 16 billion had the renewable --

Q. I don't think I said -- I didn't mean to if I did. I apologize.

I just remember it being about 37 overall, and 10 and a half for transmission. Is that your understanding?

A. Yes, roughly 16 for transmission, but that doesn't have the renewables. That's a separate piece. I just wanted to clarify that for the record.

Q. Okay. 16 for transmission is your understanding?

A. Yes, sir.
Q. Okay.
A. It is entire -- entire network, your Honor. So it's not just PJM region. So it is the entire transmission network of the AEP system, which includes four RPOs.
Q. I appreciate it. Maybe the 10 and a half in the EEI presentation may have been PJM footprint, is that -- is that your understanding?
A. Yes, your Honor.
Q. Okay. That's the distinction. I appreciate it.

So in terms of -- of whether adequate capital is being made available to Kentucky Power to meet the needs that you bring to Kentucky Power, right, the identified needs, that would be a question for Mr. Mattison?
A. Yes, your Honor. I think that would be a good question for Mr. Mattison.
Q. And the last question I have pending -- it may be in dispute whether it's in the record or not: Does the project selection guidelines apply to baseline projects in addition to supplemental projects?
A. Yes, your Honor. They apply to all project

drivers across the -- across the system.
Q. Okay. I appreciate it. Mr. Ali, those are -- before I -- before I hand it -- I don't want to have to come back like I did Mr. Pearce. I hate to ask the Chairman for a favor twice. Let me just check one second, make sure I have no more questions.
Oh, yeah. The last set of questions I had, Mr. Ali: I wanted to come back to manual 14C. So 14B is the planning for projects, effectively, right, supplemental and baseline?
And do you -- do you -- are you aware of the purpose of manual -- PJM Business Practice Manual 14C?
A. Yes, your Honor, I am.
Q. Okay. And what's your understanding of -- at a very high level, the purpose of manual 14C?
A. Your Honor, I may be -- I may mix those two up, but really, in essence, it is -- it is discussing, at a high level, the protocols for, you know, evaluation and review of needs, projects, publishing of them in the subregional RTEP and what avenues the stakeholders have if they want to raise more comments concerning the portfolio.
Q. And at least a portion of 14C, as I remember

it, is sort of the backside of some of the stuff the 14B talked about.

And would you agree that there are portions of 14C that talk about the tracking of -- or the updates that transmission owners or designated entities, I think they're referred to -- that they provide to PJM on an ongoing basis for transmission projects?

A. Yes, sir. That also includes that. So after the projects have been submitted, there are regular updates that the transmission owners have to make to cost and service.

Also as the project goes into execution, they have to provide -- we have to provide information for project planners who are working on it, so PJM can visit, especially, the baseline project.

So I believe all of that is discussed there as well.

Q. And what I wanted to make sure of to our discussion earlier about the designation of let's just say whose books it ends up on, right, a transmission project.

I just want to make sure that during that tracking process, do you know whether or not -- you answered earlier sort of on the planning side maybe.

But do you know during that tracking process of the projects as they're being built, whether they're in construction or scoping or whatever they may be -- does -- does anybody give an update or indicate in those filings who the ultimate asset owner is going to be, whether it's going to be a Transco or another affiliate or the initial owner of the -- of the transmission system that identified the -- the need?

A. Your Honor, I do know that for baseline projects, we have to sign what we call a designated entity agreement with PJM. So for those projects, yes, that has to be clearly stated as to who the designated entity is. As you know, supplemental projects don't require a PJM board approval, so there is no such agreement for those.

Q. Okay. And so on that subject, if Kentucky Power -- let's say there's a baseline need in the most recent run of -- of the RTEP, right, that the CETL values go crazy and there's a number of violations and it ends up being a baseline need identified by PJM and Kentucky Power is the asset owner for all of the transmission systems identified in the need, right?

Do you understand the scenario I'm setting up?

A. Yes, sir, I do.

Q. And -- and Kentucky Power -- let's say somebody wants to bid on it. It's a designated entity that's not the incumbent transmission owner, right? And Kentucky Power wants to bid on it.

If there's going to be an allocation, according to the project selection guidelines, when Kentucky Power files the -- you know, once the bid for the -- it's a competitive project, sorry. It's five years out. It's a competitive project.

Kentucky Power wants to bid for it. Do they have to indicate in their designated entity agreement that, for instance, AEP Kentucky Power -- AEP Kentucky Transco is also going to be one of the developers and own a portion of it?

A. So, your Honor, this is -- just let me break it down a little bit because I don't want to misstate something here.

So, number 1 is that we don't need to identify who is going to own a certain asset at the stage of the need as well as when we're presenting the solution to PJM. We -- that is not a requirement because there will be multiple solutions PJM will have to go and evaluate during that scenario.

Once PJM has evaluated and picked the right solution, the cost-effective and robust solution, then PJM is going to ask the entity to sign the designated entity agreement. It is at that time that we have to identify as to who will be the owning entity, and in cases where both Transco Kentucky and Kentucky Power Company own an asset, both of them will be signatories of that agreement.

Q. And it's your understanding -- and I'm happy to ask him here in a minute, but it's your understanding that Mr. Mattison would be the -- for instance, in the example provided, would be the one making the determination, correct?

A. Your Honor, like I mentioned earlier, I mean, I don't know if I can say 100 percent. I think he will be the better one to answer, but -- but, like I said, we would -- I would be presenting to the operating company the cash flows to undertake that project.

And then based on that and see if we can meet the timeline, you know, that determination will be made, you know, by -- by the operating company, and we will then present that to PJM.

Q. Yeah. And I -- I hated to put you on the 100 percent.

But I guess what I'm really asking is: It's your experience that the operating company president makes that ultimate decision?

A. Yes, or his designee or her designee. I mean, you know, of course we're working with their teams on a regular basis, and they're involved in it.

So yes, they would be -- or their designees will make that determination, that if we're okay with making this investment, are we able to afford this investment.

VICE CHAIRMAN CHANDLER: Okay. I appreciate it, Mr. Ali. Thank you very much.

CHAIRMAN SCHMITT: Dr. Matthews, questions?

COMMISSIONER MATTHEWS: I don't have any.

CHAIRMAN SCHMITT: Ms. Blend, would you like the opportunity to provide redirect examination?

MS. BLEND: Yes, your Honor. Thank you.

And before I begin my redirect, Vice Chairman Chandler, the project selection guidelines that have been referenced during Mr. Ali -- during your questioning of Mr. Ali were produced in response to Staff Request Number 2 and Staff 5, so Staff 5, 2 Subpart B, as in boy.

VICE CHAIRMAN CHANDLER: And just so I'm

clear, that's the responses on behalf of the company, the staff's fifth item request, item 2B?

MS. BLEND: Yes. Thank you.

VICE CHAIRMAN CHANDLER: Thank you very much.

REDIRECT EXAMINATION

By Ms. Blend:

Q. Mr. Ali, I want to follow up quickly on the last -- quickly on the last items or topics that Vice Chairman Chandler asked you about.

Do you recall the question about M-3, the M-3 process and the identification of a -- the owner of the solution?

A. Yes. I do.

Q. Did I understand your testimony correctly that there is no requirement through that process that a solution owner be identified in that process?

A. Yes. That is correct.

Q. Are you aware of transmission projects for which Kentucky Power Company has obtained a CPCN and in which Kentucky Power Company indicated that Kentucky Transco would also be performing related work that was not the subject of the CPCN but that was related to the Kentucky Power CPCN work?

A. Yes, I'm aware of.

Q. And is one such project the 2018 Enterprise

Park project?

A. Yes. It is.

Q. And has Kentucky Power Company relatively recently Kentucky Transmission Company refiled that project in Case Number 2020-00062?

A. Yes. We have.

Q. Is that project the baseline project or a supplemental project?

A. It has mostly baseline components.

Q. Is it your understanding that the Commission approved the 2018 Enterprise Park project?

A. Yes. That's my understanding.

Q. Thank you. A couple of clarification questions regarding the project selection guidelines.

Do those guidelines cover competitive transmission projects?

A. No, they don't.

Q. Are -- are competitive transmission project transmission projects relatively common or relatively uncommon?

A. They are very unique in PJMs since 2012, only three competitive projects have been awarded.

Q. Do competitive projects include -- or I'll say it differently.

Are asset renewal projects considered to be competitive projects?

A. No, they're not.

Q. Does the project selection guideline document cover asset renewal projects?

A. Yes, it does.

Q. You were asked questions about which entity or entities are ultimately responsible -- responsible for determining the need for transmission investment.

Do you recall those questions?

A. Yes. I do.

Q. Who's responsible for maintaining the transmission system?

A. The AEP transmission and the operating companies.

Q. And within the AEP transmission system, who is the expert regarding the condition, performance, and risk of AEP's transmission assets?

A. It is the AEP transmission and the operating companies.

Q. Does PJM have that expertise?

A. No, PJM does not have engineering field project management expertise. The only expert PJM has is markets, planning, and operation.

Q. Does AEP run its transmission system to failure?
A. Absolutely not.
Q. In your rebuttal testimony on page 6, footnote 1 -- on page 6 and including in footnote 1, you refer to and define the term "good utility practice," correct?
A. Yes. I do.
Q. In your opinion, would it be good utility practice for AEP to run its transmission system to failure?
A. No.
Q. Who is liable ultimately for utilities' or transmission owners' failure to maintain its system?
A. It is the utility itself that is liable, at the end of the day.
Q. Have we seen any recent examples of such liability in other parts of the country?
A. Yes, absolutely, we have. I think a good example is in California. And again, our goal is to never get to that stage. We want to make sure we're proactively replacing our infrastructure and our infrastructure is reliable, safe, and cost effective for our customers.
Q. Changing topics, you were asked about the

level of control that AEP and Kentucky Power have over transmission needs on the system. Do you recall those questions?

A. Yes. I do.

Q. Do you address the system needs that are out of the company's control or any transmission owner's control on pages five and six of your rebuttal testimony?

A. Yes. I do.

Q. You may have touched upon -- I think you touched upon this briefly in response to a question that the Vice Chairman asked you, but Mr. Satterwhite and Mr. Pearce both referred to you as the witness who might be best situated to identify examples of projects that have been performed outside of Kentucky, but that still will benefit -- be helpful or benefit Kentucky Power.

Can you provide some examples of such projects?

A. Yes. There are -- there are various examples of that. I mean, the most recent one that comes to mind is back in 2012, an announcement was made to retire up to 7,500 megawatt of generation in the Ohio Valley, which is a very -- you know, it was a critical generation that was serving the load in

Appalachian and Kentucky and Kingsport areas.

And when we performed analysis we saw significant voltage internal violations, to the point that we were not able to reliably get power back into the region. And the most cost-effective solution was to utilize our 765 kV network and drop down to the lower voltages, 345 and 138 kV systems, so that we can get the power from the market, regardless of where it's at, and get it back to the customer. And that required investments in Ohio, you know.

The one that comes to mind is the Mountaineer 765 to 345 kV substation. I think it was roughly $80 million of investment, the conceptual estimate -- I think the final cost was for a little higher than that. I don't have that on the top of my head.

But those -- there are several examples of that, similarly switchover retirement that resulted in significant load flow changes, and we had to make transmission investment in the West Virginia area to make sure that we were able to reliably get power from the grid to areas like Kentucky.

Q. Thank you.

VICE CHAIRMAN CHANDLER: Can I ask a short question, Ms. Blend? I was confused by the response. Can I ask a short question?

MS. BLEND: By all means.

VICE CHAIRMAN CHANDLER: Thank you.

So the retirement of the generation led to thermal and voltage violations. So those -- were those baseline drivers or supplemental drivers.

THE WITNESS: Your Honor, those were -- those were baseline.

VICE CHAIRMAN CHANDLER: Those were baseline? Okay. And so the baselines have a defined allocation outside of -- let me ask this way -- I didn't want to go this basic: But supplemental projects and baseline projects are allocated differently, correct?

THE WITNESS: Your Honor, it depends. So -- so maybe let me explain that. So for projects that are double circuit 345 kV and above that are baseline, 50 percent of that allocation is across the footprint. Everybody pays based on their load share.

And the remaining 50 percent is based on DFAX. For baseline projects that are less than 345 kV double circuit, 100 percent of that allocation is based on DFAX -- which, by the way, if you go and look at DFAX of baseline projects, 95 percent of those are only assigned to the zone they're in.

Only the projects that are sitting at the boundaries of your zone at low voltages are the ones that are assigned to -- outside your zone. And of course, supplemental projects, 100 percent allocation is to the zone.

You know, one thing, your Honor, that I may want to mention, and I heard this conversation on DFAX mentioned earlier. One thing we've got to remember is the DFAX is not a metric that can compute all of the benefits of a project. And PJM recognizes that limitation.

And for that very reason PJM and its stakeholders identified the projects that are about 345 kV double circuit in our 13-state footprint. They need to be allocated to the entire zone based on their load share because even though we can't calculate and quantify the benefit using DFAX, we know that everybody benefits from that.

I mean, an example of that, your Honor, recently, a project -- in Dominion, and we can make that available if you need, Ladysmith to Chancellor 500 kV line, so Dominion is rebuilding that line.

And when PJM ran DFAX on that, 100 percent of the DFAX was in Dominion, but still 50 percent of that cost got allocated early because we all recognized benefits of an articulated transmission network.

VICE CHAIRMAN CHANDLER: I just want to make sure: There's a significant difference -- this is the question I have for Mr. Pearce.

-- a significant difference between double circuit 345 kV and above, and a 69 kV or a 48 -- or a 46 kV project in Kalamazoo or in Michigan or in northern Ohio, right.

I mean, it's the -- it's the difference between the -- I guess I say that -- I say that as the question: There's a difference between the bulk electric transmission system and the 21 and a half or 22 kV, 46 kV, 69 kV system, right.

THE WITNESS: Your Honor, you're exactly right, that's there's a difference, and that's why I think you've got to look at the layers, right? So when we think about PJM, it's a broader layer, right? It's a very big system.

And in 345 kV network, even sitting in Con Ed, which is in Chicago and New Jersey, it makes a lot of sense. If you get down to the AEP level, even a 69/23 kV system makes sense. You get down to distribution level.

I mean, the same argument is true on the line in Hazard, Kentucky, how is that line benefiting customers in Ashland? It's really not, but it is benefiting customers in Prestonsburg, and the line in Prestonsburg is benefiting customers in Ashland, right?

So it's the same argument that the 69 kV line in Michigan may not be directly benefiting Kentucky, but it's benefiting Ohio, probably. And lines in Ohio are benefiting West Virginia, and West Virginia is benefiting Kentucky

So it's the -- it's the same regional concept that I know PJM is based off basing the 345 kV double circuit on.

VICE CHAIRMAN CHANDLER: That's fair. Apologies, Ms. Blend.

THE WITNESS: Thank you, your Honor.

MS. BLEND: No apologies necessary, Vice Chairman. And I have no further questions on redirect for Mr. Ali. Thank you.

CHAIRMAN SCHMITT: All right. Thank you, Mr. Ali. You may -- you may step down. I'm sure you're glad to get a break.

THE WITNESS: Thank you, your Honor. We really appreciate it.

CHAIRMAN SCHMITT: I guess is Mr. -- we call -- recall Mr. Mattison at this time?

MS. BLEND: Yes, your Honor. We will do that. We will just need a moment to sanitize --

CHAIRMAN SCHMITT: Okay. Thank you.

MS. BLEND: -- the witness table before we resume.

MS. VINSEL: Chairman, could we take about a five-minute break?

CHAIRMAN SCHMITT: Yeah. Staff counsel would like to take a five-minute break. Before we do that, let me ask this: I know Mr. Mattison is being recalled so he remains under oath. I assume -- well, I shouldn't assume anything.

Ms. Vinsel, do you intend to have any questions for Mr. Mattison.

MS. VINSEL: Yes, I do.

CHAIRMAN SCHMITT: Okay. All right. Good. I didn't know if we were just re-cutting direct to Vice Chairman or other counsel -- so we'll begin in with your cross-examination unless, Ms. Blend, you have something on redirect -- or direct that you would like to put on. If not, you'll get to finish up.

MS. BLEND: Not at this time your Honor. I don't at this time, your Honor. Thank you.

CHAIRMAN SCHMITT: All right. We'll take a break until -- we'll be in recess until -- let's go 25 after 2:00.

(A DISCUSSION WAS HELD OFF THE RECORD.)

CHAIRMAN SCHMITT: I think we're back on the record.

Are all the parties and counsel present? Maybe. Okay.

MS. VINSEL: I don't see Kentucky Power yet. There.

MS. BLEND: We are here. Thank you.

CHAIRMAN SCHMITT: All right. I guess we'll proceed, then, with Mr. Mattison -- Mattison's cross-examination. Mr. Mattison, you remain under oath.

THE WITNESS: Yes, sir.

CHAIRMAN SCHMITT: And I guess the cross-examination at this time will begin with Staff Counsel Vinsel.

MS. VINSEL: Thank you, Chairman.

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D. BRETT MATTISON, having been reminded of his oath, testified as follows:

CROSS-EXAMINATION

By Ms. Vinsel:

Q. Good afternoon, Mr. Mattison.

A. Good afternoon.

Q. I believe, but let me double-check: Were you listening and watching to Mr. Satterwhite's testimony yesterday afternoon?

A. Yes, I was.

Q. Okay. And I just want to follow up on a few things that I asked Mr. Satterwhite.

Were you aware that approximately 90 percent of the base rate PJM LSE OATT expenses in the test year in this case are related to transmission investment in other AEP affiliates?

A. Yes, in this case I am.

Q. Did you know that you could challenge the transmission company's updates and projections?

A. When you say the transmission updates and projections here, are you talking about the PJM?

Q. The Kentucky -- the Kentucky Transco, the transmission company's -- yes. The updates and projections that are included in the annual update and annual projections.

A. Just to be clear, are you talking about me