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May 3, 2013

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HAND DELIVERED

Jeff R. Derouen
Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

RE: Case No. 2012-00578

Dear Mr. Derouen:

Enclosed please find and accept for filing the original and ten copies of the rebuttal testimony of the following Kentucky Power Company witnesses:

Gregory G. Pauley
Karl R. Bletzacker
Matthew D. Fransen
Jeffrey D. LaFleur
Karl A. McDermott
Philip J. Nelson
Robert L. Walton
Scott C. Weaver
Ranie K. Wohnhas

A copy of this letter and the accompanying rebuttal testimony is being served by overnight delivery on the individuals indicated below and their associated counsel. Further, in accordance with Mr. Nguyen's request, a copy of the responses also is being served by overnight delivery on Messrs. Drabinski, Boismenu, and Buechel.

STITES & HARBISON PLLC
ATTORNEYS

Very truly yours,

Mark R. Overstreet

MRO
cc: Michael L. Kurtz
Jennifer Black Hans
Shannon Fisk
Joe F. Childers
Robb Kapla
Lane Kollen
Tim Woolf

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For:	)	
(1) A Certificate Of Public Convenience And Necessity	)	
Authorizing The Transfer To The Company Of An	)	
Undivided Fifty Percent Interest In The Mitchell	)	
Generating Station And Associated Assets; (2) Approval	)	
Of The Assumption By Kentucky Power Company Of	)	Case No. 2012-00578
Certain Liabilities In Connection With The Transfer Of	)	
The Mitchell Generating Station; (3) Declaratory Rulings;	)	
(4) Deferral Of Costs Incurred In Connection With The	)	
Company's Efforts To Meet Federal Clean Air Act And	)	
Related Requirements; And (5) For All Other Required	)	
Approvals And Relief	)	

REBUTTAL TESTIMONY OF

GREGORY G. PAULEY

May 3, 2013

VERIFICATION

The undersigned Gregory G. Pauley, being duly sworn, deposes and says he is the President and COO of Kentucky Power Company, that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

Greg G Pauley

GREGORY G. PAULEY

COMMONWEALTH OF KENTUCKY)
) Case No. 2012-00578
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Gregory G. Pauley, this the 1st day of May 2013.

Judy K Rosquist 481393

Notary Public

My Commission Expires: January 23, 2017

REBUTTAL TESTIMONY OF
GREGORY G. PAULEY, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2012-00578

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**REBUTTAL TESTIMONY OF
GREGORY G. PAULEY, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Gregory G. Pauley. My position is President and Chief Operating Officer ("COO"), Kentucky Power Company ("Kentucky Power" or the "Company.") My business address is 101 A Enterprise Drive, Frankfort, Kentucky 40602.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS CASE?

A. Yes.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My rebuttal testimony covers five topics. First, I address the arguments advanced by Mr. Kollen concerning the timing of the Mitchell transfer and his recommendation that the transfer be delayed. Like many of Mr. Kollen's arguments and recommendations, these lack a basis in the real world. Next, I address the allegations raised by Mr. Kollen concerning the relationship between Kentucky Power and its corporate parent, American Electric Power Company, Inc. ("AEP"), as well as my involvement in the decision-making that led to the proposed transfer to Kentucky Power of a 50% interest in the Mitchell generating station. I also address the contention that the Company should have examined a wider universe of units in connection with this topic. Third, I set the record straight concerning claims by the Sierra Club and Kentucky Industrial Utility Customers, Inc. ("KIUC") regarding the effect the transaction will have on the Company's fuel diversity. Fourth, I address KIUC's efforts to interject in this proceeding various red herrings concerning the location of the Mitchell generating station in West Virginia. The final topic I address is the effect KIUC's recommendation (that the Company rely on market purchases) is likely to have on this Commission's jurisdiction. Purchased power agreements, as advocated by both KIUC and the Sierra Club, will undermine, not strengthen, the Commission's ongoing jurisdiction over Kentucky Power's operations and rates. Overarching all of this testimony is the fact that, as described in detail by Company Witness Weaver, the Company's proposal remains the least cost alternative.

III. THE TIMING OF THE MITCHELL TRANSFER

Q. **WHAT DOES KIUC WITNESS KOLLEN PROPOSE REGARDING THE TIMING OF THE TRANSFER OF THE MITCHELL UNITS TO KENTUCKY POWER?**

A. On pages 5 and 8 of his testimony, Mr. Kollen asserts that the transfer of the Mitchell units should be delayed until June 1, 2015, and should not occur prior to the retirement of Big Sandy Unit 2. He also claims that transfer of the units prior to then is "wasteful duplication," and results in increased environmental and merchant generator risk exposure.

Q. IS KIUC'S PROPOSAL REGARDING THE TIMING OF THE TRANSFER REASONABLE?

A. No, it is not. KIUC has failed to consider numerous risks, costs and other issues that will affect Kentucky Power and its customers if the units are not transferred according to the timing proposed by the Company in this filing.

Q. WHAT WAS THE BASIS FOR THE COMPANY'S PROPOSED TIMING OF THE TRANSFER OF THE MITCHELL UNITS?

A. Timing of the transfer is based on the coordination of multiple events including termination of the Pool Agreement and the required transfer of assets from Ohio Power Company ("OPCo") to AEP Generation Resources Inc. ("AEP Generation Resources") in order to address Kentucky Power's long-term needs for base load capacity and energy.

Q. WHAT HAPPENS IF THE MITCHELL UNITS ARE TRANSFERRED TO AEP GENERATION RESOURCES WITHOUT AN IMMEDIATE TRANSFER TO KENTUCKY POWER?

A. First, under the proposed transaction, AEP Generation Resources is a pass-through entity. AEP Generation Resources' current capital structure does not contemplate its acquisition of the Mitchell generating station, even for a period as short as 17 months. If AEP Generation Resources is to acquire the Mitchell units it will be required to obtain additional financing. Thus, as described by Company

Witness Wohnhas in his rebuttal testimony, KIUC's proposals subject the Company to financing risks, additional costs, and market risks.

Second, if AEP Generation Resources has ownership of the assets, regardless of the length of time, it will quite properly work to realize the greatest value from them and to reduce its cost of ownership by committing the units' output in the most economically productive manner available. This could take the form of the sale of the Mitchell units or a long-term contract commitment of the Mitchell units' output to a party other than Kentucky Power. In either event, the Mitchell units may not be available when Big Sandy Unit 2 is scheduled to be retired, or if it is forced to be retired earlier. AEP Generation Resources has no obligation to hold the assets for transfer to Kentucky Power at a later date nor, if they are transferred, to transfer them at net book value at another time. The Company recognizes AEP Generation Resources has no such obligations and therefore Kentucky Power concluded that it is unreasonable to expect that transfer of the units could occur at a later date on the terms that are being offered today.

Q. WILL THE FRR COMMITMENT OF THE MITCHELL UNITS PREVENT AEP GENERATION RESOURCES FROM DISPOSING OF THE MITCHELL UNITS AS KIUC ARGUES?

A. No. Subject to FERC approval, AEP Generation Resources could sell or otherwise dispose of those assets at any time. To meet the existing FRR commitment, AEP Generation Resources could enter into a short-term capacity arrangement whereby it bought capacity back from the purchaser of the Mitchell units. AEP Generation Resources also could make other arrangements to replace the capacity for the 17-month period. In either case, the units would no longer be available for transfer to Kentucky Power at a later date.

Q. **DOES THE RECENT FERC ORDER APPROVING THE TRANSFER OF THE MITCHELL GENERATING STATION TO APPLACHIAN POWER COMPANY AND THE COMPANY HAVE ANY BEARING ON KIUC'S PROPOSAL TO DELAY TRANSFER OF THE MITCHELL GENERATING STATION?**

A. Yes. In its recent order approving the transfer of the Mitchell units, FERC included a requirement that the Company "inform the Commission within 30 days of any material change in circumstances that departs from the facts the Commission relied upon in granting the application." KIUC's proposal to delay the transfer would be one such change in the facts relied upon by FERC in light of the fact that the Company's application stated that immediately following the transfer to AEP Generation Resources, a fifty percent undivided interest in the units would be transferred to Kentucky Power.

Q. **WHAT IS YOUR RECOMMENDATION REGARDING KIUC's PROPOSAL TO DELAY THE TRANSFER OF THE MITCHELL UNITS?**

A. The Commission should reject KIUC's proposal. It fails to consider the long-term view of Kentucky Power's capacity and energy needs, and the fact that this is a one-time opportunity to acquire the Mitchell assets at a price that the rigorous analysis supporting this application demonstrates is the least-cost option. No transfer, construction or acquisition of assets to replace retiring assets is "perfect" in its timing. In other words, you don't just turn one switch off one minute and turn another one on in the next minute. KIUC's position implies it is that simple, when reality says it is not. In addition, the transfer as proposed by the Company provides appropriate mitigation of the risks inherent in financing and reliance on the market, and it allows Kentucky Power to have sufficient resources to meet the needs of its customers.

IV. DECISION-MAKING ON BEHALF OF KENTUCKY POWER

1. The Decision To Transfer The Mitchell Generating Station.

Q. MR. KOLLEN TESTIFIED THAT "THE COMPANY'S INTERESTS AND THOSE OF ITS CUSTOMERS ARE SUBSERVIENT TO THE ECONOMIC AND POLITICAL INTERESTS OF APPALACHIAN POWER COMPANY WHICH OPERATES IN VIRGINIA AND WEST VIRGINIA, AND ITS CUSTOMERS." IS THAT ACCURATE?

A. No. While I report directly to Mr. Patton, who is the President and Chief Operating Officer of Appalachian Power Company ("APCo"), I, and not Mr. Patton, make the decisions upon behalf of Kentucky Power and its ratepayers. The only evidence Mr. Kollen offers in support of his allegation are the lines on the Company's organizational chart. Mr. Kollen is not, and has never been, an employee of Kentucky Power, APCo, or American Electric Power Service Corporation ("AEPSC"), and as such has no real-world experience with how the companies operate, or how decisions are made by me on behalf of Kentucky Power. Although Mr. Kollen's resume indicates he worked as a Planning Supervisor for Toledo Edison Company, which is not a part of AEP, in the mid-

1970s through the early 1980s, such lower-level, non-management experience, which is thirty years out of date in any event, hardly provides him with the experience or expertise to make his unfounded allegations.

Significantly, Mr. Kollen also ignores my direct testimony that "I regularly meet with Robert P. Powers, Executive Vice President and COO of AEP [to whom Mr. Patton reports], and have access to Nicholas K. Akins, President and Chief Executive Officer of AEP, when needed. … [and that] as Mr. Akins has informed the Commission, I am in charge of the Company." My testimony on this point not only stands unrebutted, but directly contradicts Mr. Kollen's allegations.

Q. MR. KOLLEN ALSO POINTS TO THE FACT THAT THE ANALYSES LEADING TO THE DECISION TO TRANSFER THE 50% INTEREST IN THE MITCHELL GENERATING STATION TO KENTUCKY WERE PERFORMED BY AEPSC PERSONNEL, OR CONSULTANTS RETAINED BY AEPSC, AS EVIDENCE THAT THE COMPANY'S INTERESTS WERE SUBORDINATED TO THOSE OF AEP AND APCO. IS HE ON FIRMER GROUND HERE?

A. No. Mr. Kollen again betrays his lack of real-world utility, or even large corporate, experience. Kentucky Power is a relatively small utility. The decision to add or retire an 800 MW generating asset, or how to replace its capacity and energy, may only be made once in a "lifetime." For example, Kentucky Power last added 800 MW of capacity 45 years ago with the construction of Big Sandy Unit 2. Indeed, the last time the Company added any new long-term generation was in 1984 with the execution of the original Rockport Purchased Power Agreement.

Resource planning, is an extremely complex process, requiring sophisticated and expensive tools such as STRATEGIST and AURORA^{XMP}, as well as highly trained professionals. Indeed, I believe that the Commission itself, which regulates four other generation-owning electric utilities in addition to Kentucky Power, and thus would have much greater opportunity to employ the models and personnel, does not license STRATEGIST and AURORA^{XMP}, nor employ personnel to operate them.

Because Kentucky Power is part of AEP, it has access to these and other resources through AEPSC on an as needed-basis for asset disposition and similar analyses in connection with the Company's Integrated Resource Plans. This sort of arrangement is not uncommon, and is one of the many benefits of the utility holding company structure. It would be uneconomic, not to mention bad management, to saddle Kentucky Power's ratepayers with the costs of these tools and personnel for decades so that they would be available for the once in several generation asset disposition analyses, or even every three years in connection with Kentucky Power's Integrated Resource Plan filings.

Q. **MR. KOLLEN ALSO FINDS SIGNIFICANCE IN THE FACT YOU DID NOT PERFORM ANY ANALYSES ON YOUR OWN IN CONNECTION WITH YOUR DECISION ON BEHALF OF THE COMPANY WITH RESPECT TO THE TRANSFER OF A 50% UNDIVIDED INTERST IN MITCHELL TO KENTUCKY POWER. COULD YOU PLEASE ADDRESS HIS CRITICISM?**

A. Certainly; it is no more appropriate to expect that I would have performed the STRATEGIST and AURORA^{XMP} modeling than it would be for Mr. Kollen to perform such modeling before filing his testimony in this case (or the individual Commissioners before deciding this case.) Indeed, I note that it is Mr. Hayet, and not Mr. Kollen, who testifies on behalf of KIUC regarding KIUC's proffered STRATEGIST modeling. As President and COO, I relied upon a cadre of highly experienced, well-trained, and extremely competent personnel to perform for me the sorts of highly complex analyses that undergird the Company's decision with respect to the Mitchell transfer.

Q. **MR. KOLLEN ALSO POINTS TO THE COMPANY'S RESPONSES TO KIUC 1-102 AND KIUC 2-51 IN SUPPORT OF HIS ARGUMENT THAT YOUR DECISION ON BEHALF OF KENTUCKY POWER TO ACQUIRE 50% OF THE MITCHELL PLANT WAS MADE IN SUBSERVIENCE TO AEP AND APCO, AND WITHOUT YOU REVIEWING ANY ANALYSES CONDUCTED BY AEPSC REGARDING THE MITCHELL TRANSFER. IS THAT AN ACCURATE PORTRAYAL OF YOUR TESTIMONY, THE COMPANY'S RESPONSE TO THE DATA REQUESTS, OR YOUR**

DECISION-MAKING WITH RESPECT TO THE MITCHELL TRANSFER?

A. No. First, although I relied upon AEPSC personnel and the work they performed in making the decision, I made the decision in collaboration with AEP executive management. In addition, Mr. Wohnhas and I regularly addressed the Big Sandy disposition issue, and the underlying analyses in conferences and meetings in our respective offices and while traveling on Kentucky Power business. Also, as I indicate early on in my direct testimony (page 4) "I work collaboratively with AEP executive management, the management of the other AEP East operating companies, including ... [Mr. Patton], and AEPSC personnel to address those matters for which I have responsibility." Among those matters was the resolution of the Big Sandy disposition issue. Thus, in addition to Mr. Wohnhas, I met or conferred with Mr. Powers; Mr. Munczinski, Senior Vice President – Regulatory Services, AEPSC; Mr. Weaver, who has provided testimony in this proceeding; Mr. McCullough, Executive Vice President – Generation, AEPSC; Philip J. Nelson, Managing Director of Regulatory Pricing and Analysis, AEPSC; and Mr. Patton, among others, in connection with my decision on behalf of Kentucky Power with respect to the Mitchell transfer. It is through these meetings that I obtained and vetted the information necessary for me to make the decision with respect to the Mitchell transfer.

Q. **YOU INDICATE THAT MR. PATTON WAS PART OF THESE DISCUSSIONS. DOES THAT NOT INDICATE, PARTICULARLY**

BECAUSE YOU REPORT TO MR. PATTON, THAT THIS DECISION WAS DRIVEN BY MR. PATTON AND THE NEEDS OF APCO?

A. No; far from it. Because APCo will own the other 50% of Mitchell, it would have been extraordinary if Mr. Patton, who is the President and COO of APCo, and I had not discussed the transaction that would result in our companies' joint ownership of the Mitchell generating station. If the Mitchell transaction had been decreed by AEP or Mr. Patton, there would have been no need for the multiple meetings and conversations I had with Mr. Patton and AEPSC personnel regarding the transfer. A single phone call or e-mail would presumably have sufficed. But that is not how AEP works, or how I run Kentucky Power.

Q. **DO THE COMPANY'S RESPONSES TO KIUC 1-102 AND KIUC 2-51 INDICATE YOU WERE UNINVOLVED WITH KENTUCKY POWER'S DECISION WITH RESPECT TO THE MITCHELL TRANSFER?**

A. No. I worked closely with, and relied upon, Mr. Wohnhas and AEPSC personnel to provide me with the information I required to evaluate all reasonable options with respect to the disposition of Big Sandy. Indeed, as Mr. Weaver's June 14, 2012 e-mail to me and Mr. Wohnhas makes clear, while the decision-making was a collaborative process, I had substantial input beginning early on in the analysis that led to the recommendation of the Mitchell transfer. My (and Mr. Wohnhas') opinions were sought and we had a full opportunity to raise concerns or offer other options. But like any good executive, I rely upon subject matter experts, such as accountants, auditors, attorneys, engineers, and others, when I am making decisions upon behalf of Kentucky Power.

Q. **MR. WOOLF, WHO TESTIFIED UPON BEHALF OF THE SIERRA CLUB, SUGGESTS THE COMMISSION MAY WANT TO BE SKEPTICAL OF THE COMPANY'S CLAIMS REGARDING THE MITCHELL TRANSFER BECAUSE IT IS BETWEEN AFFILIATED ENTITIES. DO YOU AGREE?**

A. It is not my position, nor I respectfully suggest, is it Mr. Woolf's, to tell the Commission how it should structure its decision-making in this proceeding. What I can say is that as explained in detail by Mr. Weaver and Dr. McDermott in their direct and rebuttal testimonies, the proposed Mitchell transfer represents the least-cost alternative, and that it is "priced at the lesser of market or fully distributed cost."

2. <u>Transfer of Mitchell vs. Other Plants</u>

Q. **THE KIUC AND SIERRA CLUB ASSERT THAT OTHER GENERATION UNITS CURRENTLY OWNED BY OPCO SHOULD HAVE BEEN CONSIDERED BY THE COMPANY. DOES KIUC CONTEND THAT ITS ARGUMENTS REGARDING KENTUCKY POWER'S SELECTION PROCESS REQUIRE THE REJECTION OF A TRANSFER OF THE MITCHELL UNIT?**

A. No. To the contrary, at pages 4, 5, and 8 of his testimony Mr. Kollen recommends on behalf of KIUC that a 20% undivided interest in the Mitchell generating station be transferred to Kentucky Power. Thus, it would seem the disagreement between Kentucky Power and KIUC concerns only the percentage of the Mitchell generating station to be transferred.

Q. TURNING TO THE CRITICISMS OF KENTUCKY POWER'S SELECTION PROCESS RAISED BY MR. KOLLEN AND SIERRA CLUB WITNESS WOOLF, PLEASE EXPLAIN HOW OTHER OPCO UNITS WERE CONSIDERED BY THE COMPANY.

A. As discussed above, the Company was fully engaged in the decision-making process which led to the decision to transfer 50% of the Mitchell units to Kentucky Power. That process included various OPCo units. While not formally documented at the time of the discussion, the Company documented in discovery its thought process concerning the qualitative factors that were considered. In 2011,[1] the OPCo generating assets that historically were used to provide power to Kentucky Power were reviewed to determine the generating units to be analyzed, along with other viable resource options for Kentucky Power. A representation of this qualitative analysis is provided in Exhibit GGP-1R, and as stated above, depicts the thought process behind the screening.

Q. WHAT CRITERIA LED TO THE DECISION REGARDING THE MITCHELL UNITS?

A. First, the list of OPCo's generation assets was narrowed to only those assets which historically provided power to Kentucky Power, will not be retired in the near future, and are not jointly owned with third parties. The remaining units were reviewed to identify base load units that are environmentally controlled. An undivided 50% interest in the Mitchell generating station satisfied each of these criteria. Because the Mitchell units were the appropriate size to meet the

[1] The 2011 analyses pre-dated the merger of Columbus Southern Power Company and OPCo.

combined needs of Kentucky Power and APCo (along with its proposed acquisition of OPCo's share of Amos Unit 3), which both require base load capacity and base load energy, joint ownership of the Mitchell units was the appropriate asset transfer scenario to be evaluated against other options. Through his analyses, Company witness Weaver also has shown that ownership of 50% of the Mitchell units is the least cost of those options.

Q. IN CASE NO. 2011-00401, THE COMPANY INDICATED THAT IN EARLY 2012 IT CONSIDERED THE TRANSFER OF A 20% UNDIVIDED INTEREST IN THE MITCHELL UNITS TO KENTUCKY POWER. WAS THE TRANSFER OF A 20% UNDIVIDED INTEREST IN THE MITCHELL UNITS CONSIDERED BY THE COMPANY IN THIS SUBSEQUENT ANALYSIS?

A. Yes. A 20% interest in the Mitchell generating station is insufficient to replace the approximate 800 MW lost through the retirement of Big Sandy Unit 2. Notwithstanding this fact, Mr. Weaver modeled the transfer of a 20% interest in the Mitchell generating stations in connection with Option 1 (retrofit Big Sandy Unit with a DFGD unit and transfer a 20% interest in the Mitchell generating station), Option 2 (build a nominally rated 762 MW combined cycle and transfer a 20% interest in the Mitchell generating station), and Option 3 (replace Big Sandy Unit 2 with a nominally rated 745 MW combined cycle repowered Big Sandy Unit 2 and transfer a 20% interest in the Mitchell generating station). Each of these options was more expensive than the two options involving the transfer of a 50% interest in the Mitchell generating station.

Q. WHY DIDN'T THE COMPANY CONSIDER OTHER UNITS CURRENTLY OWNED BY THIRD PARTIES?

A. The Mitchell units are well known AEP assets. As discussed in the direct testimony of Company witness LaFleur, the Mitchell units are also good units. The Company has the opportunity to obtain these good units at net book value. While the Company has knowledge of the history, equipment and operations of the Mitchell units, no due diligence of third party assets would provide that same level of detail and third party acquisitions do not come without significant risks. As discussed in the direct testimony of Company witness McManus, the Company has invested in Mitchell and understands the environmental risk associated with the Mitchell units.

Q. KIUC AND THE SIERRA CLUB REFERENCE CERTAIN RECENT TRANSACTIONS FOR GENERATION ASSETS AS REPRESENTATIVE OF AVAILABLE ASSETS AND PRICES. DOES THE COMPANY AGREE WITH THEIR CONCLUSIONS?

A. No. As explained in the rebuttal testimony of Company witnesses Fransen and LaFleur, these assets are not comparable to the Mitchell units. Also, the Mitchell transfer was determined to be the least-cost option based on the analyses of Company witness Weaver.

V. FUEL DIVERSITY

Q. BOTH MESSRS. KOLLEN AND WOOLF ATTACK THE MITCHELL TRANSFER ON THE GROUND IT WILL NOT PROMOTE FUEL DIVERSITY. BEFORE ADDRESSING THE ACCURACY OF THEIR CLAIMS, PLEASE TELL THE COMMISSION WHETHER EITHER WITNESS IDENTIFIES ANY KENTUCKY STATUTE OR REGULATION MANDATING FUEL DIVERSITY.

A. No they do not, and I am unaware of any such explicit requirement in Chapter 278 of the Kentucky Revised Statutes. The Commission's Integrated Resource Planning regulation, 807 KAR 5:058, Section 8(5)(c), includes fuel diversity as an example of a criterion a utility may use in developing its resource assessment and acquisition plan, but the regulation does not require fuel diversity, nor limit by fuel type the generation a utility may plan for or acquire.

Q. IS THE MITCHELL TRANSFER AN EFFORT BY KENTUCKY POWER TO "DOUBLE DOWN" ON COAL GENERATION AS MR. KOLLEN COMPLAINS?

A. No. The transfer of a 50% interest in the Mitchell generation station represents the least cost alternative for meeting the needs of Kentucky Power and its customers. For example, as Company Witness Weaver explains at pages 19-21 of his Rebuttal testimony, and illustrates in Exhibit SCW-1R, the two options incorporating the transfer of a 50% interest in the Mitchell generating station (Options 5A and 6) are, on a cumulative present worth basis, at a minimum $223 million -*less* expensive than any of the other options modeled.

Q. WOULD YOU PLEASE PROVIDE MORE DETAIL ON THESE RESULTS?

A. Certainly. Although Mr. Weaver will be available to address in detail questions concerning his analysis, Exhibit SCW-1R contrasts the results of the Company's modeling under the Base ("Fleet Transition-CSPAR") scenario. The two options modeled that incorporate the transfer of a 50% interest in the Mitchell Generating Station are Option 6 (retire and replace Big Sandy Units 1 and 2 on June 2015 and replace with the transfer of a 50% interest in the Mitchell generating station plus market purchases for ten years), and Option 5A (retire and replace Big Sandy Units 1 and 2 on June 2015 and replace with the transfer of a 50% interest in the Mitchell generating station plus convert Big Sandy Unit 1 to natural gas).

When Option 6 is compared to the remaining options that do not include the transfer of a 50% interest in the Mitchell generating station, Option 6 is more economical, on a cumulative present worth basis, by at least $223 million, when compared to Option 5B, and by as much as $663 million when compared to Option 1B.

Q. YOU INDICATED THAT OPTION 5A LIKEWISE INCORPORATES THE TRANSFER OF 50% OF THE MITCHELL GENERATING STATION. HOW DOES THAT OPTION COMPARE TO THE OTHER OPTIONS MODELED THAT DO NOT INCORPORATE THE TRANSFER OF 50% OF THE MITCHELL GENERATING STATION?

A. The 50% Mitchell transfer option modeled in Option 5A is even more economical than Option 6, on a cumulative present worth basis, vis-à-vis the other options that do not include the transfer of 50% of the Mitchell generating station. Specifically, Option 5A is the more economical option by $379 million ($223 million plus $156 million) when compared to Option 5B, and is more economical by as much as $819 million ($663 million plus $156 million) when compared to Option 1B.

Q. **DID MR. WEAVER'S ANALYSIS COMPARE THE COSTS OF THE 50% MITCHELL TRANSFERS AGAINST NON-COAL FIRED OPTIONS?**

A. Yes. The Company examined a number of non-coal based options with respect to Big Sandy Unit 2. These included the construction of a nominally-rated 762-MW natural gas-fired combined cycle unit to be located at the Big Sandy site, along with the KIUC-endorsed transfer of a 20% interest in the Mitchell generation station (Option 2); and the retirement and replacement of Big Sandy Unit 2 with a nominally-rated 745 MW combined cycle repowered Unit 1, along with the KIUC-endorsed transfer of a 20% interest in the Mitchell generating station (Option 3). In addition, Mr. Weaver's analysis also examined replacing Big Sandy Unit 2 with market purchases, which could include non-coal fired generation. As Mr. Weaver explains at page 19-21 of his rebuttal testimony, the cost of the brownfield combined cycle natural gas unit (Option 2B) would have be reduced by $587 million (nominal), or 47.5%, to a cost of $613 per kW (2011 dollars) to reach an economic breakeven point with the 50% Mitchell transfer combined with a market purchase to replace Big Sandy Unit 1 (Option 6).

Q. WHAT IS THE ECONOMIC BREAK-EVEN POINT BETWEEN THE OTHER 50% MITCHELL TRANSFER OPTION, OPTION 5A, AND OPTION 2B?

A. If the comparison is between a brownfield combined cycle unit (Option 2B) and the transfer of 50% of the Mitchell generating station and the conversion of Big Sandy Unit 1 to natural gas (Option 5A), the cost of the brownfield option would have to be reduced even further to $716 million, or by 62%, to $448 per kW for the Company and its customers to be economically indifferent between the two options. These comparisons only underscore the fact that my recommendation of the transfer to Kentucky Power of a 50% interest in the Mitchell generating stations is soundly grounded in the fact that it is the least-cost alternative, and does not reflect any bias toward coal-fired facilities. I do not understand Mr. Kollen (or Mr. Woolf) to be committing their clients to pay the higher costs associated with the non-coal fired alternatives, or any other alternative that is determined not to be the least cost.

Q. DOES MR. KOLLEN'S CLAIM THAT THE COMPANY IS "DOUBLING DOWN ON COAL" TAKE INTO ACCOUNT THE FACT OF THE COMPANY'S ONGOING INVESTIGATION REGARDING THE LEAST COST ALTERNATIVE FOR THE DISPOSITION OF BIG SANDY UNIT 1?

A. No. The Mitchell Transfer is only a part of the Company's efforts going forward to address the future of the Big Sandy generating station. As the Company has explained from the beginning of this proceeding, a second piece of the

Company's planning is the Big Sandy Unit 1 disposition analysis. As part of that analysis, on March 28, 2013 Kentucky Power issued a request for proposals ("RFP") for up to 250 MW of long-term capacity and energy. The RFP solicitation is open to all forms of proposals, including asset purchase agreements, tolling agreements, and purchased power agreements, without regard to fuel type. In addition, the RFP also solicited demand-side management and cost-effective energy efficiency proposals. Although the responses to the RFP are not due until June 11, 2013, and will have to be evaluated by the Company after the submission date passes, it is possible that some of the proposals will involve non-coal fired generation. Independent of the RFP submission process, AEPSC's Projects, Controls & Construction Group ("PC&C Group) will submit a proposal to convert Big Sandy Unit 1 to a natural gas fired unit. This submission, which must be received before June 11, 2011, will be evaluated and compared to the RFP responses to determine the least-cost alternative to replace Big Sandy Unit 1's coal-fired generation.

In suggesting the Company is "doubling down" on coal-fired generation, and that it missed "a unique opportunity to diversify its base load resources," Mr. Kollen simply ignores the non-coal fired alternatives examined by Mr. Weaver, the non-coal fired alternatives that may be available as a result of the RFP, and the Company's evaluation of the conversion of Big Sandy Unit 1 to a natural gas-fired unit. All of this information was available to Mr. Kollen prior to the filing of his testimony.

Q. WILL THE PROPOSED MITCHELL TRANSFER, COUPLED WITH THE POSSIBLE CONVERSION OF BIG SANDY UNIT 1 TO NATURAL GAS, INCREASE THE COMPANY'S FUEL DIVERSITY?

A. Yes. Currently, the Company's owned generation (Big Sandy Unit 1 and Unit 2), along with its share of the Rockport generation received through the unit power agreement, is 100% coal-fired. With the Mitchell transfer, and the conversion of Big Sandy Unit 1, the Company's fuel sources will be approximately 82% coal and 18% natural gas.

Q. SINCE MR. KOLLEN'S TESTIMONY WAS FILED, HAVE OTHER NON-COAL FIRED GENERATION ALTERNATIVES BECOME AVAILABLE TO KENTUCKY POWER?

A. Yes. On April 10, 2013 Kentucky Power filed for Commission approval of a 20-year renewable energy power agreement ("REPA") to purchase up to 58.5 (net) megawatts of electricity from a biomass power generating facility ecoPower plans to construct in Perry County and expects to be operational in 2017.[2] If approved by the Commission, the REPA will further diversify the Company's fuel sources. KIUC has intervened in Case No. 2013-00144. The Company anticipates KIUC will fully support the application in light of its comments concerning fuel diversity in this case. Similarly, although Sierra Club has yet to intervene in the Commission proceeding, the Company hopes it will support the application in light of Sierra Club's emphasis on renewable resources in Mr. Woolf's testimony.

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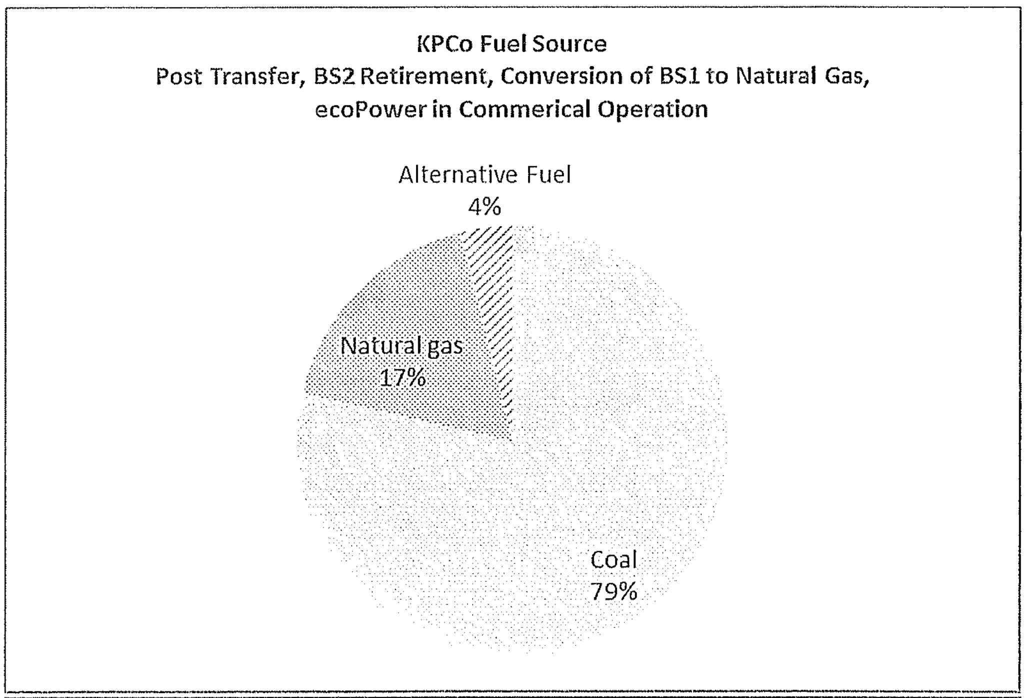
[2] *In The Matter Of: The Application Of Kentucky Power Company For: (1) The Approval Of The Terms And Conditions Of The Renewable Energy Purchase Agreement For Biomass Energy Resources Between The Company And ecoPower Generation-Hazard LLC; (2) Authorization To Enter Into The Agreement; (3) The Grant Of Certain Declaratory Relief; And (4) The Grant Of All Other Required Approvals and Relief,* Case No. 20103-00144.

Q. WHAT WOULD THE COMPANY'S FUEL MIX BE FOLLOWING THE COMMISSION'S APPROVAL OF THE PROPOSED BIOMASS REPA, COMBINED WITH THE MITCHELL TRANSFER AND BIG SANDY UNIT 1 CONVERSION?

A. As shown in Figure 1 below, Kentucky Power's fuel sources would be 79% coal, 17% natural gas, and 4% renewables once the ecoPower unit is approved and becomes commercially operable in 2017, and assuming Big Sandy Unit 1 is converted to natural gas.

<u>**FIGURE 1**</u>



VI. THE LOCATION OF THE MITCHELL GENERATING STATION IN WEST VIRGINIA

Q. MR. KOLLEN RAISES CONCERNS ABOUT THE MITCHELL GENERATING STATION BEING LOCATED IN WEST VIRGINIA. WOULD YOU PLEASE ADDRESS HIS CRITICISMS?

A. Yes. First, I am recommending the Mitchell transfer because it is the least cost alternative and without regard to where the generating station is located. Although Mr. Kollen disagrees with the Kentucky Power's analysis demonstrating that the Mitchell transfer is the least cost alternative, I do not understand him to be testifying that the Mitchell generating station's location in West Virginia is a sufficient reason to deny the Company's application. As such, his arguments concerning the plant's location are make-weight. Second, Mr. Kollen's concerns about the out-of-state location of the Mitchell generating station ring more than a bit hollow in light of his opposition to the Company's earlier proposal to retrofit Big Sandy Unit 2 with a DFGD unit. Kentucky Power's proposal in that case, which the Company withdrew to conduct the further evaluations that led to the Kentucky Power's current application, would have maintained both the jobs and tax base, and more, that Mr. Kollen claims are a benefit of KIUC's recommendation in this case.

Q. WHAT IS YOUR UNDERSTANDING OF THE KIUC RECOMMENDATION SET FORTH IN MR. KOLLEN'S TESTIMONY?

A. Although the proposal is not described in detail, Mr. Kollen appears to recommend that the Commission deny the Company's application, and instead approve the transfer of an undivided 20% interest in the Mitchell generating station effective June 1, 2015 (the approximate anticipated retirement date of Big Sandy Unit 2). In addition, KIUC supports the conversion of Big Sandy Unit 1 to natural gas. Because these two resources, combined with the capacity available through the Rockport Unit Power Agreement, are not sufficient to meet Kentucky Power's customers' requirements, it appears that under the KIUC proposal the balance of the Company's needs will be provided by market purchases.

Q. WHAT LESSONS DO YOU DRAW FROM KIUC'S RECOMMENDATION THAT THE COMMISSION APPROVE THE TRANSFER OF A 20% UNDIVIDED INTEREST IN THE MITCHELL GENERATING STATION?

A. There appear to be two. First, it appears KIUC and the Company agree that the Company requires some amount of base load, coal-fired generation to meet its future capacity and energy needs, and that this requirement is best met by the transfer of an interest in the Mitchell generating station to the Company. Where the parties disagree is the amount of the Mitchell generating station that should be transferred and when that transfer should occur. Second, I note that Mr. Kollen and KIUC recommend the Commission approve the transfer of a 20% interest in the same West Virginia-located Mitchell generation that they attack because it is located in West Virginia. Their willingness to accept 20% of Mitchell only further undercuts Mr. Kollen's arguments about the West Virginia location of the Mitchell facility and West Virginia's Business and Operations tax.

Q. **KIUC ALSO SUPPORTS THE CONVERSION OF BIG SANDY UNIT 1 TO A GAS-FIRED UNIT. DID MR. KOLLEN OR KIUC ORIGINATE THIS PROPOSAL?**

A. Certainly not. As set out in the Company's application and testimony, Kentucky Power is actively exploring this option now. In fact, AEPSC's PC&C Group is developing the costs of such a conversion now. The group's submission is due before June 11, 2013, but the disposition of Big Sandy Unit 1 is not part of this proceeding.

Q. **DOES KENTUCKY POWER OPPOSE THIS PORTION OF KIUC'S RECOMMENDATION?**

A. No. The Company currently is examining the possibility of converting Big Sandy Unit 1 to a natural gas-fired unit and will seek appropriate approvals for the conversion if it proves to be the least cost alternative. In such a case, the jobs and tax base benefits claimed (but not yet quantified) by Mr. Kollen for KIUC's recommendation, will be available even if the Commission were to approve the transfer of a 50% interest in the Mitchell generating station to Kentucky Power.

Q. **IN LIGHT OF MR. KOLLEN'S EMPHASIS ON KENTUCY JOB CREATION AND PRESERVATION, DO THE MITCHELL UNITS BURN KENTUCKY COAL?**

A. Yes. Because the Mitchell units are equipped with WFGD units, they burn a mixture of high sulfur and low sulfur coal. Central Appalachian region coal, which includes much of the coal that is produced in Kentucky in the Company's service territory, meets the specifications for low sulfur coal to be burned at Mitchell.

Q. HOW MUCH KENTUCKY COAL HAS MITCHELL RECEIVED IN THE PAST THREE YEARS?

A. From 2010 through 2012, Mitchell received approximately 5% of its coal from Kentucky mines. As coal supply varies from year to year, this percentage will change. For example, for 2013 year-to-date, 38% of the coal received at Mitchell was supplied from mines located in Kentucky.

Q. HOW MUCH KENTUCKY COAL IS EXPECTED TO BE PURCHASED FOR MITCHELL FOR THREE YEARS BEGINNING IN 2014?

A. The coal requirements for 2014 and beyond have not yet been secured. But when there is a need for low sulfur coal at the Mitchell plant, and pending the results of normal coal procurement practices, there is potential for use of Kentucky coal at Mitchell.

VII. KIUC'S PROPOSED RELIANCE ON PURCHASE POWER AGREEMENTS TO MEET THE COMPANY'S REQUIREMENTS

Q. YOU INDICATED EARLIER IN YOUR REBUTTAL TESTIMONY THAT KIUC'S RECOMMENDATION REQUIRES MARKET POWER PURCHASES. HOW MUCH POWER WOULD HAVE TO BE PURCHASED?

A. As Company Witness Weaver points out at page 6 of his Rebuttal testimony, KIUC's recommendation would leave the Company slightly more than 400 MW short of the capacity required to meet the PJM minimum reserve margin criterion for the 2015/16 capacity planning year. KIUC's recommendation lacks any detail how this shortfall is to be met other than a passing comment that it could be accomplished through market purchases.

Q. HOW DOES THE COMMISSION'S JURISDICTION WITH RESPECT TO MARKET PURCHASES COMPARE WITH ITS CONTINUING AUTHORITY OVER "STEEL IN THE GROUND" ASSETS OWNED BY A JURISDICITIONAL UTILITY?

A. I recognize this Commission has authority under KRS 278.300 to approve certain (generally those longer than two years) power purchase agreements. Once that approval is gained, however, it is my further understanding such agreements are essentially subject to only FERC-regulation. Although the Commission does not appear to have expressly addressed the issue, purchase power agreements for less than two years do not appear to require Commission approval under KRS 278.300. In those instances, the Commission will have even less regulatory authority (both initially and continuing) than over longer agreements.

By contrast, an asset owned by a jurisdictional utility, such the 50% interest in the Mitchell generating stations that is proposed to be transferred to Kentucky Power, is subject to the Commission's full and continuing regulatory authority. Thus, KIUC's recommendation that the Company rely on market power for over 400 MW of its required capacity would have the effect of limiting the Commission's jurisdiction with respect to the Company's operations.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

A. Units Evaluated on Criteria of Staff 2-024

Plant	Amos	Mitchell	Mitchell	Cardinal	Gavin	Gavin
Unit	3	1	2	1	1	2
MW	867	770	790	592	1,319	1,319
Baseload Unit?	✓	✓	✓	✓	✓	✓
Environmental Controlled?	✓	✓	✓	✓	✓	✓
Located in Juris. of APC/WPC or KPC?	✓	✓	✓			
Appropriate Size for Need?*	✓	✓	✓	✓		
Reasonable Cost?	✓	✓	✓	✓	✓	✓
Existing Joint Ownership with APC?	✓					

*Gavin's 1300 MW units were less attractive because forced outage of a single unit exposes APCo and KPCo to larger capacity and energy losses than the Mitchell and Cardinal units and potentially would involve joint ownership issues with the unregulated Genco.

B. Other Ohio Power Owned Units: Slated for Retirement in 2015 or Acquired through Merger with CSP

Plant	Unit	Retired by 6/1/2015	Historically Provided Pool Cap & Energy?	Jointly Owned With 3rd Parties
Beckjord	6	Yes	NA	NA
Conesville	3	Yes	NA	NA
Kammer	1	Yes	NA	NA
Kammer	2	Yes	NA	NA
Kammer	3	Yes	NA	NA
Muskingum	1	Yes	NA	NA
Muskingum	2	Yes	NA	NA
Muskingum	3	Yes	NA	NA
Muskingum	4	Yes	NA	NA
Muskingum	5	Yes	NA	NA
Picway	5	Yes	NA	NA
Sporn	2	Yes	NA	NA
Sporn	4	Yes	NA	NA
Conesville	4	No	No	Yes
Conesville	5	No	No	No
Conesville	6	No	No	No
Darby	1-6	No	No	No
Waterford	1	No	No	No
Zimmer	1	No	No	Yes

Exhibit GPP- 1R

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

The Application Of Kentucky Power Company For:	)
(1) A Certificate Of Public Convenience And Necessity	)
Authorizing The Transfer To The Company Of An	)
Undivided Fifty Percent Interest In The Mitchell	)
Generating Station And Associated Assets; (2) Approval	)
Of The Assumption By Kentucky Power Company Of	) Case No. 2012-00578
Certain Liabilities In Connection With The Transfer Of	)
The Mitchell Generating Station; (3) Declaratory Rulings;	)
(4) Deferral Of Costs Incurred In Connection With The	)
Company's Efforts To Meet Federal Clean Air Act And	)
Related Requirements; And (5) For All Other Required	)
Approvals And Relief	)

REBUTTAL TESTIMONY OF

KARL R. BLETZACKER

May 3, 2013

VERIFICATION

The undersigned, KARL R. BLETZACKER, being duly sworn, deposes and says he is Director, Fundamental Analysis for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing testimony and that the information contained therein is true and correct to the best of his information, knowledge, and belief.

Karl R Bletzacker

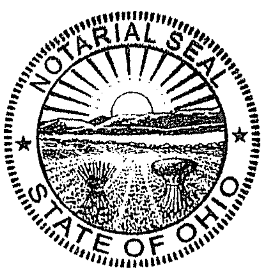
KARL R. BLETZACKER

STATE OF OHIO)
) CASE NO. 2011-00578
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Karl R. Bletzacker, this the 1st day of May 2013.

Josephine Coner

Notary Public



JOSEPHINE CONER
Notary Public, State of Ohio
My Commission Expires 09-20-16

My Commission Expires: 09/20/2016

**REBUTTAL TESTIMONY OF
KARL R. BLETZACKER, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

CASE NO. 2012-00578

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REBUTTAL TESTIMONY OF
KARL R. BLETZACKER, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Karl R. Bletzacker. My position is Director, Fundamental Analysis, American Electric Power Service Corporation ("AEPSC"). AEPSC supplies engineering, financial, accounting, planning and advisory services to the eleven electric operating companies of American Electric Power Company, Inc. ("AEP"), including Kentucky Power Company ("Kentucky Power" or "Company"). My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS CASE?

Yes. I filed direct testimony on behalf of Kentucky Power.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the testimonies of KIUC witness Hayet and Sierra Club witness Woolf. In particular, my testimony addresses the flawed assertions made by Messrs. Hayet and Woolf regarding North American long-term natural gas price and electric energy forecasts, their reliance on the Energy Information Administration's Annual Energy Outlook and NYMEX futures "Forecasts", and the alleged need to prepare an updated long-term North American energy market forecast.

III. THERE WAS NO NEED TO UPDATE THE LONG-TERM NORTH AMERICAN ENERGY MARKET FORECAST

Q. BOTH KIUC WITNESS HAYET AND SIERRA CLUB WITNESS WOOLF ASSERT THAT THE COMPANY SHOULD HAVE REVALUATED THE LONG-TERM NORTH AMERICAN ENERGY MARKET FORECAST USED IN THIS PROCEEDING. DO YOU AGREE?

A. No. The Fundamentals Group routinely evaluates changes in the energy market to determine whether the most recent Long-Term North American Energy Market Forecast needs to be updated. All inputs to that forecast were reviewed for credibility prior to their use in this proceeding. The only notable potential change to the drivers of the Long-Term North American Energy Market Forecast was the August 21, 2012 vacatur of the Cross State Air Pollution Rule ("CSAPR") by the United States Circuit Court in Washington, DC. The DC Circuit's actions reinstated the pre-CSAPR Clean Air Interstate Rule ("CAIR") as the method to address cross-state air pollution. The vacatur of CSAPR only affected the near-term and had no material impact during the period evaluated by Company Witness Weaver for this proceeding. Based upon our comprehensive review of the near- and long-term energy market fundamentals, we concluded that no change to the Long-Term Energy Market Forecast was necessary.

Q. DO CHANGES IN FORECASTED NATURAL GAS PRICES IN THE RECENT ENERGY INFORMATION AGENCY ("EIA") ANNUAL ENERGY OUTLOOK ("AEO") REQUIRE A REVISION OF THE LONG-TERM NORTH AMERICAN ENERGY FORECAST?

A. No. As I described in my Direct Testimony at page 10, even reasonably known and emerging regulations are specifically excluded for such EIA-AEO projection purposes. The use of such a "business as usual" model makes the EIA-AEO projections particularly inappropriate for long-term market forecasts necessary for resource planning activities. Accordingly, changes in the EIA-AEO do not necessarily require that the fundamentals driven Long-Term North American Energy Market Forecast used in this proceeding be updated.

Q. **ARE THERE ANY OTHER ASPECTS OF THE EIA-AEO NATURAL GAS PROJECTIONS THAT MAKE THEM INAPPROPRIATE FOR USE IN LONG-TERM MARKET FORECASTING?**

A. Yes. As clearly stated in my Direct Testimony at page 4, analysis of an entity's long-term natural gas price forecast begins with an analysis of the supply, demand and price relationship. In the EIA AEO 2013 (Early Release) "Total Energy Supply, Disposition, and Price Summary", Table A1, the annual percentage change in consumption (from line 45) divided by the percentage change in Henry Hub price in nominal dollars (from line 67) yields an indicative elasticity. For the period from 2016 to 2026, this ratio averages 0.1, and the period from 2027 to 2040 averages 0.23. Both averages indicate an inelastic view such that a modest increase in demand will yield a significant increase in price. For example, a 3% increase in natural gas consumption (approximately 2-3 bcf per day) as a result of greenhouse gas or CO_2 regulations would imply a corresponding 30% increase in the price of natural gas. Because the EIA AEO projections do not consider "reasonably known or emerging regulations", the EIA AEO projections are at risk of being rendered inaccurate by even a small increase in natural gas consumption.

Q. DO CHANGES IN NATURAL GAS FUTURES PRICES ON THE NYMEX EXCHANGE REQUIRE A REVISION OF THE LONG-TERM NORTH AMERICAN ENERGY FORECAST?

A. No. For reasons clearly stated in my Direct Testimony at page 9, NYMEX prices are not well-suited comparisons to long-term, weather-normalized, price fundamental forecasts used by Company witness Weaver. NYMEX futures represent the price point that willing buyers and sellers can agree to. That price, however, is unique to the individual buyer and seller and are not necessarily representative of the fundamentals of supply, demand and resulting future spot market prices over a long-term (i.e. 25 year) period for the entire market. In addition, near-term natural gas prices are susceptible to considerable volatility arising from weather forecasts. As such, year to year changes in NYMEX future natural gas prices do not require an update to the fundamentals driven Long-Term North American Energy Market Forecast used in this proceeding.

IV. KIUC WITNESS HAYET'S REVISED COMMODITY PRICES

Q. ON PAGE 14 OF HIS TESTIMONY, KIUC WITNESS HAYET ASSERTS THAT THE EIA AEO 2011 NATURAL GAS PRICE PROJECTION "COULD SUBSTITUTE AS A RESONABLE PROXY" FOR THE NATURAL GAS PRICE FORECAST INCLUDED IN THE LONG-TERM NORTH AMERICAN ENERGY MARKET FORECAST IN THIS PROCEEDING. IS MR. HAYET CORRECT?

A. No. Absolutely not. As I have discussed in this Rebuttal Testimony and in my Direct Testimony, the EIA AEO projections do not account for reasonably known and emerging regulations. Further, as discussed in my Direct Testimony on pages 4 through 9, the long-term weather normalized natural gas forecasts used in this proceeding were developed using the AuroraXMP modeling tool. The AuroraXMP Electric Market Model is the most comprehensive and reliable power market forecasting tool available. The EIA AEO projection cannot be used as a proxy for the natural gas forecast used in this proceeding.

Q. HOW HAS MR. HAYET USED HIS ASSERTED, BUT INCORRECT, "PROXY" FOR NATURAL GAS PRICES?

A. It appears that Mr. Hayet is using his asserted proxy relationship between the 2011 EIA AEO natural gas projection and the fundamentals-driven natural gas forecast used in this proceeding to develop a "corrected" natural gas forecast. He then uses this "corrected" natural gas price forecast to prepare a comparison between KIUC's proposed alternative and the Company's Option #6 that would include a 50% Mitchell transfer[1]. Having concluded, incorrectly, that the 2011 EIA EAO projections can serve as a proxy for the natural gas forecast, Mr. Hayet looks to the 2013 EIA AEO projections (which again do not account for reasonably known and emerging regulations) to create a "forecast" of natural gas prices that is 23% lower than the fundamentals-driven forecast used in this proceeding.

Q. DOES MR. HAYET RELY UPON THE USE OF NYMEX FUTURES PRICING AS A BENCHMARK FOR HIS ASSERTION OF A NATURAL GAS PRICE FORECAST?

A. Yes. And, in fact, he refers to the "NYMEX forecast" several times in his testimony starting on page 16 at line 4. The description of NYMEX futures prices as a "forecast" is unique to Mr. Hayet, erroneous, and indicative of a lack of understanding of NYMEX

[1] As explained in the rebuttal testimony of Company witness Weaver, this comparison should have been against the Company's "Option #5A".

futures contracts. As mentioned above, NYMEX futures prices are ill-suited for use in a long-term forecast, and Mr. Hayet's reliance on these prices is inappropriate.

Q. **WHY ARE NATURAL GAS PRICES PRESENTED FOR ANALYSIS IN THIS CASE NOT AS LOW AS THOSE PREFERRED BY MR. HAYET?**

A. I believe Mr. Hayet is prematurely dismissing credible upside threats to US natural gas price. In my Direct Testimony at pg. 7, the prospect of LNG exports and compressed or liquefied natural gas for use as a transportation fuel were identified. As of March 30, 2013, 15.2 bcf per day of natural gas liquefaction for export has been proposed to FERC and sites for an additional 9.4 bcf per day have been identified by project sponsors. Although it is not likely that every project gets approved and built, this potential 24.6 bcf per day incremental demand represents over a third of current natural gas consumption. The use of natural gas for US light-duty vehicles in the form of compressed natural gas and for US long-haul trucking in the form of LNG is not an unreasonable expectation. For US long-haul trucking alone, LNG has the potential to increase natural gas consumption by 9.1 bcf per day. Although manageable, the potential for increased costs associated with groundwater protection due to hydraulic fracturing is also a very likely upside threat to natural gas price.

Q. **IS THE DEVELOPMENT OF MR. HAYET'S ADJUSTMENT TO KENTUCKY POWER'S MARKET ENERGY PRICE FORECAST REASONABLE?**

A. No. Mr. Hayet's statistical approach to the Company's base market energy prices and base natural gas price forecast completely ignore the merit-order dispatch of electric generation in PJM. His proposed 23% reduction to Henry Hub natural gas price was applied ubiquitously to peak and off-peak energy prices implying that natural gas sets the marginal price at all hours – across a 23% spread in prices. This oversimplification does not represent the reality of day-ahead market dispatch within PJM.

Q. DID MR. HAYET REVISE THE COMPANY'S COAL PRICE FORECAST VALUES?

A. Yes. As with natural gas, Mr. Hayet used a revised coal price "forecast" to conduct a comparison between KIUC's proposed alternative and the resource plan proposed by the Company.

Q. HOW DID MR. HAYET PREPARE THIS REVISED COAL PRICE FORECAST?

A. As he did with the natural gas forecast, Mr. Hayet imagined a direct relationship between the fundamentals-driven coal price forecast and the 2011 EIA AEO coal price projection and, therefore, simply used the 2013 EIA AEO coal price projection as part of his analysis.

Q. WAS MR. HAYET'S REVISED COAL PRICE FORECAST APPROPRIATE?

A. No. For all the same reasons that it is inappropriate to simply use the 2013 EIA AEO natural gas price projection, it is also inappropriate to use the 2013 EIA AEO coal price projection as part of his analysis.

Q. DID MR. HAYET REVISE ANY OTHER COMMODITY INPUTS USED IN THE ECONOMIC MODELING BY KENTUCKY POWER?

A. Yes. In addition to revisions to the market energy prices discussed earlier, Mr. Hayet also revised the capacity pricing inputs.

Q. HOW DID MR. HAYET REVISE CAPACITY PRICING INPUTS FOR THE ECONOMIC MODELING?

A. Mr. Hayet used data from a February 2013 Impairment Analysis prepared for Ohio Power Company to develop these revised values.

Q. WAS IT PROPER FOR MR. HAYET TO USE IMPAIRMENT TEST VALUES TO REVISE THE MARKET CAPACITY PRICES?

A. No. As discussed in the rebuttal testimony of Company witness Weaver, impairment analyses are prepared at management's direction as needed for entirely different purposes and, accordingly, may use more conservative values. In contrast, resource planning requires the use of a long-term weather normalized suite of commodity prices for use in economic modeling. The process used to develop the commodity prices for this case relied on rigorous modeling of those commodity prices that produces a market forecast where the components are "fitly-joined" and synchronized. While the values used in the impairment study were appropriate for the purpose of the impairment study, the values resulting from a fitly-joined and synchronized AuroraXMP model output cannot be substituted in "*a la carte*" fashion. The highly correlated commodity price forecast used in the Company's resource alternative modeling for this case were the right values for this purpose.

Q. HAVE YOU CONDUCTED ANY ENERGY MARKET SENSITIVITY MODELING TO ADDRESS MR. HAYET'S INAPPROPRIATE USE OF EIA' S PROJECTIONS?

A. Yes. The Company has conducted an energy market analysis, utilizing the AuroraXMP modeling tool based upon the EIA's 2013 (Early Release) AEO with corrections made for "reasonably known and emerging regulations".

Q. WHAT CORRECTIONS WERE MADE TO THE EIA AEO 2013 (EARLY RELEASE) NATURAL GAS PRICE PROJECTION?

A. By virtue of a multi-run, iterative AuroraXMP modeling process, the EIA AEO 2013 (Early Release) natural gas prices were corrected to quantify the upward movement associated with consumption related to suppressed coal dispatch resulting from a CO_2 "tax", the implementation of the Mercury and Air Toxic Standards, anticipated changes to regulations under Section 316b of the Clean Water Act, anticipated changes in the regulation of Coal Combustion Residuals, and the proposed Greenhouse Gas New Source Performance Standards. Consequently, values for on- and off-peak power prices, capacity prices and others were calculated and processed by the AuroraXMP model. The resulting "fitly-joined" analysis was presented to Company witness Weaver for further application in connection with his rebuttal testimony.

Q. WHAT METHODOLOGY WAS EMPLOYED TO JUSTIFY CORRECTIONS TO EIA NATURAL GAS PRICES DUE TO THEIR EXCLUSION OF "REASONABLY KNOWN AND EMERGING REGULATIONS"?

A. As stated earlier, in the EIA AEO 2013 (Early Release) "Total Energy Supply, Disposition, and Price Summary", Table A1, the annual percentage change in consumption (from line 45) divided by the percentage change in Henry Hub price in nominal dollars (from line 67) yields an indicative elasticity. The inelastic view from the EIA AEO 2013 implies that a modest increase in demand will yield a significant increase in price. Initially, the AuroraXMP model was utilized to determine a North American natural gas fuel burn for electric generation utilizing the EIA's AEO 2013 Early Release natural gas prices. Subsequent model runs were performed with natural gas prices adjusted for the EIA AEO-indicated elasticity to ultimately yield a consumption/price *balanced* outcome. These balanced prices were used to determine the attendant energy, capacity and other values utilized by Company witness Weaver in his rebuttal testimony.

Q. **DO YOU CONSIDER THE "2013 EIA COMPANY-MODIFIED" PRICES PRESENTED ABOVE TO BE SUITABLE REPLACEMENTS FOR THOSE PRESENTED IN THE COMPANY'S LONG-TERM NORTH AMERICAN ENERGY MARKET FORECAST?**

A. No. I do not. The Company has presented a supply/demand/price-balanced long-term energy market forecast with inter-related, "correlative" outputs developed by the industry-accepted AuroraXMP Energy Market Model. Any exogenous, "a la carte" replacement of a value is misrepresentative.

Q. **DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

The Application Of Kentucky Power Company For: (1) A Certificate Of Public Convenience And Necessity Authorizing The Transfer To The Company Of An Undivided Fifty Percent Interest In The Mitchell Generating Station And Associated Assets; (2) Approval Of The Assumption By Kentucky Power Company Of Certain Liabilities In Connection With The Transfer Of The Mitchell Generating Station; (3) Declaratory Rulings; (4) Deferral Of Costs Incurred In Connection With The Company's Efforts To Meet Federal Clean Air Act And Related Requirements; And (5) For All Other Required Approvals And Relief	)	Case No. 2012-00578

REBUTTAL TESTIMONY OF

MATTHEW D. FRANSEN

May 3, 2013

VERIFICATION

The undersigned, MATTHEW D. FRANSEN being duly sworn, deposes and says he is Director, Strategic Initiatives for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing testimony and that the information contained therein is true and correct to the best of his information, knowledge, and belief.

Matthew D. Fransen

MATTHEW D. FRANSEN

STATE OF OHIO	)	
	)	CASE NO. 2011-00578
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Matthew D. Fransen, this the 2nd day of May 2013.

Notary Public

NOTARIAL SEAL STATE OF OHIO

David C. House, Attorney At Law
NOTARY PUBLIC - STATE OF OHIO
My commission has no expiration date
Sec. 147.03 R.C.

My Commission Expires:

REBUTTAL TESTIMONY OF
MATTHEW D. FRANSEN, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2012-00578

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REBUTTAL TESTIMONY OF MATTHEW D. FRANSEN, ON BEHALF OF KENTUCKY POWER COMPANY BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Matthew D. Fransen. I am Director, Strategic Initiatives, American Electric Power Service Corporation ("AEPSC"), a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP"). AEP is the parent company of Kentucky Power Company ("KPCo" or "the Company"). My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING OF BEHALF OF KPCO?

A. No, I did not. I am filing testimony as a rebuttal witness on behalf of KPCo.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I earned a Bachelor of Science in Business Administration as a Finance major from the Fisher College of Business at The Ohio State University in 1999. I earned a Master of Business Administration from the Fisher College of Business at The Ohio State University in 2006.

In 1999, I was employed by Bank One Corporation (now JPMorgan Chase & Co.) in its Finance Professional Development Program. I was hired as a financial analyst by the Private Client Service Finance group upon completion of the program in January 2001.

In January 2002, I was hired by AEPSC as an analyst in its Strategic Analysis group. I transferred to the Corporate Finance group in January 2005 as a financial analyst and progressed to senior financial analyst. In June 2007, I transferred as a principal financial analyst to the Strategic Initiatives group. I transferred back to Corporate Finance in January 2008 assuming the role of manager. I became manager of Strategic Initiatives in January 2010 and was promoted to my current role in April 2013.

Q. WHAT IS YOUR ROLE AS DIRECTOR, STRATEGIC INITIATIVES?

A. My primary responsibilities include the identification and evaluation of potential investments, mergers and acquisitions, divestitures, joint ventures, and strategic opportunities. In addition, our department works on strategic projects, studies, and provides financial expertise to support strategic business development and transaction efforts on a company-wide basis.

Several of the strategic opportunities that I have evaluated include potential electric generating plant acquisitions. Toward that initiative, I routinely track and evaluate comparable plant sales to inform AEP management on relative value and explain the multiple drivers of transaction prices.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. I have testified before the Virginia State Corporation Commission, the Public Service Commission of West Virginia, and the Public Utility Commission of Texas. I have also provided written testimony before the Oklahoma Corporation Commission.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to address issues raised by KIUC witness Kollen and Sierra Club witness Woolf related to price comparisons made between the net book value of an undivided 50% ownership stake in the Mitchell plant and recent third party transactions.

IV. COMPARISON TO THIRD PARTY TRANSACTIONS

Q. MR. KOLLEN (AT PAGES 13-14) AND MR. WOOLF (AT PAGES 45-46) ASSERT THAT, BASED ON RECENT SALES OF POWER PLANTS, THE MARKET VALUE OF THE MITCHELL PLANT IS LESS THAN THE NET BOOK VALUE. DO YOU AGREE THAT THE CITED SALES CAN BE USED TO DRAW MEANINGFUL COMPARISONS WITH THE TRANSFER OF THE MITCHELL PLANT?

A. No. Based on his response to Kentucky Power's data requests[1], Mr. Kollen appears to have based his claim regarding the market value of Mitchell entirely upon the information gathered from a single news article. Similarly, Mr. Woolf primarily relied upon trade press articles and press releases issued by companies involved in the sales to formulate his assertions. In relying on such limited information, both Mr. Kollen and Mr. Woolf have over-simplified the valuation of discrete generating assets and improperly ascribed an erroneous proxy for the valuation of the Mitchell plant.

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[1] Rebuttal Exhibit MDF-1R – KIUC Response to Kentucky Power Data Request 9

Q. **IS IT REASONABLE TO RELY ON NEWS ARTICLES AND PRESS RELEASES?**

A. No. Asset transactions are often too complex and too few of the deal terms are publicly known to accurately communicate such sources. For example, the winning bidder may not have provided the highest price, but may have been successful due to other deal terms. In addition, the technical, operational, and economic dissimilarities between plants make transaction comparisons on a value per kilowatt basis a very 'apples to oranges' issue.

Q. **WHAT INFORMATION SHOULD BE CONSIDERED WHEN ANALYZING THIRD PARTY TRANSACTIONS?**

A. Many variables need to be considered when analyzing third party transactions. While I expand on this list in my rebuttal Exhibit MDF-2R, some considerations include the following:

- Technical/operational characteristics
- Commercial terms
- Selection process
- Seller motivation
- Interested purchasers
- Plant financials

Few of these considerations were detailed in the press releases and news articles announcing the transactions that were referenced by witness Kollen and witness Woolf.

Q. HAVE YOU PERFORMED A MORE DETAILED REVIEW OF THE TRANSACTIONS CITED BY MR. KOLLEN AND MR. WOOLF?

A. Yes. Based on information gathered from the SNL Financial™ database. I have summarized general asset information in Table 1 below.

Table 1. Comparison of Cited Asset Transactions

	Mitchell Units 1&2*	Exelon Sale	Dominion Sale	Ameren Sale
Coal-fueled Baseload Generation				
Owned/Transacted Capacity (MW)	780	2,098	2,258	4,080
Number of Units	2	6	5	14
Average Age (years)	42	42	49	49
Capacity ***with*** Scrubber and SCR Installed (MW (% of total))	780 (100%)	1,273 (61%)	855 (38%)	1,344 (33%)
Capacity ***without*** Scrubber and SCR installed (MW)	-	825	1,403	2,736
5-year Avg. Unit Capacity Factor (%)	68.6%	43.3%	57.9%	76.3%
Gas/Oil-fueled Peaking Generation				
Capacity (MW)	-	550	561	-
Number of Units	-	4	10	-
Average Age (years)	-	48	16	-
5-year Avg. Capacity Factor (%)	-	1.1%	2.5%	-

*Data reflects 50% undivided ownership of Mitchell Units 1&2

As can be seen in the data, the assets cited by Mr. Kollen and Mr. Woolf were transferred as bundles of 10 to 15 generation units. Additionally, the coal-fueled assets are not equipped with the same level of environmental control equipment as the Mitchell Plant, are generally older, and run at lower capacity factors. While I will describe some of these issues in greater detail below, Company witness LaFleur, also elaborates on why these assets are not comparable to the Mitchell Plant from an operational perspective.

Q. YOU MENTIONED ABOVE THAT THE CITED ASSETS WERE TRANSACTED AS BUNDLES OF 10 TO 15 GENERATION UNITS. HOW

DOES THIS MAKE IT DIFFICULT TO COMPARE THEM TO THE COMPANY'S PROPOSED TRANSFER OF THE MITCHELL PLANT?

A. There are several reasons why such large bundled transactions are difficult to compare to the Company's proposed transfer of a 50% share of the Mitchell Plant. In general, one could expect that the market price of 780 MW of generation assets would be greater on a $/kW basis than that for comparable quality assets included in a much larger portfolio, particularly one that has assets that are less desirable.

First, the number of interested buyers of large bundles of generation units is typically extremely limited. The cited transactions range from 10 to 15 units, with the largest transaction being greater than 4,000 MW of capacity. Regulated utilities with relatively predictable future load requirements, such as KPCo, rarely have the need to add that quantity of generation capacity at one time. Geography and timing place further limitations on the already limited number of interested buyers in such large portfolios. Of the buyers involved in the three cited transactions, two are private equity firms and one is a merchant generator. These types of entities do not serve retail customers and tend to have a greater risk profile than most other generation plant owners. A higher financial return target, and thus a lower transaction value, should be expected for taking on the greater amount of risk associated with the types of portfolios cited by Mr. Kollen and Mr. Woolf.

Second, the time for interested parties to perform due diligence on generation portfolios of any size is typically limited to 1 to 2 months. The portfolios cited by Mr. Kollen and Mr. Woolf ranged in size from 10 to 15 individual generation units. To perform thorough due diligence on portfolios of the size cited is even more difficult. It is likely that prospective buyers would have discounted their bid price to account for the limited due diligence that they are able to complete in a short time frame. As Company witness LaFleur further describes, the Company's proposed transfer of the Mitchell Plant does not carry this risk. Even the best due diligence cannot replace the accumulated knowledge gained by AEP through the design, construction, and operation of the Mitchell Plant throughout the entire life of the plant.

Third, large bundles of generation units can be expected to be comprised of a mix of assets of varying quality, and some assets which may even be characterized as liabilities. These lower quality assets drive down the overall price per KW. As a result it is impossible to identify the values of the scrubbed coal units which that were included as part of these transactions. It is not relevant to compare unscrubbed coal units to scrubbed coal units, and these transactions had only 33-61% of their portfolios comprised of scrubbed coal capacity.

V. EXELON TRANSACTION

Q. HAVE YOU IDENTIFIED ANY ISSUES WHICH MAY HAVE IMPACTED THE EXELON SALE THAT MAKES IT NOT COMPARABLE TO THE MITCHELL TRANSFER?

A. Yes. In approving the merger of Exelon and Constellation, the Federal Energy Regulatory Commission ("FERC") required a divestiture of the Brandon Shores, Crane and Wagner plants. The result of Exelon's portfolio divestiture was announced on August 9, 2012. Exelon and the bidders knew Exelon had to divest the assets at whatever price it could get, therefore this was not a transaction involving a voluntary seller. Thus, this transfer is not comparable to the transfer of 50% of the Mitchell Plant.

Further, in response to concerns related to consolidation of market power, the FERC Order precluded eight strategic buyers (all owners of 3% or more of installed capacity in PJM) from participating, including AEP[2]. The only other strategic investor in the region that may have been interested in the asset portfolio would have been NRG Energy, Inc., however NRG announced a merger with GenOn Energy, Inc. on July 22, 2012. As a result of that merger, NRG could not have been a likely purchasing party in the Exelon sale.

Q. **WHAT IMPACT DOES BARRING LARGE UTILITIES HAVE ON THE PRICE OF THE ASSETS?**

A. Barring large utilities greatly reduces demand for the assets, and such reductions in demand certainly could lead to reductions in price.

Q. **WHO REMAINED AS POTENTIAL BUYERS OF EXELON'S PORTFOLIO AFTER ALL REGIONAL UTILITIES WERE ELIMINATED AS BUYERS?**

A. The only interested parties that would have likely remained included financial buyers, which include investment, infrastructure and hedge funds. This buyer set has higher return hurdles than strategic buyers, and would pay a lower value. Riverstone Investment Group LLC was the winning bidder.

[2] FERC Docket Nos. EC11-83-000, EC11-83-001 Order issued March 9, 2012, p. 27. The eight entities precluded from purchasing were American Electric Power Company; First Energy Corp.; GenOn Energy, Inc.; Edison International; Dominion Resources, Inc.; Public Service Enterprise Group Incorporated; Calpine Corp.; and PPL Corporation.

Q. ARE THERE ANY OTHER ISSUES WHICH MAY HAVE IMPACTED THE EXELON SALE PRICE?

A. Yes. Two of the three Exelon plants cited by Mr. Woolf are under pressure through a campaign organized by his client, the Sierra Club, to be retired. These targeted plants, which account for 1,375 MW (39% of the transacted coal-fired capacity), all lack modern environmental controls and are aging (average 51 years old). Even in the absence of the organized campaign by the Sierra Club, bidders would have taken these factors into consideration when developing a bid price for the portfolio. In fact, in response to a discovery request, the Sierra Club acknowledged that such campaigns can affect the market price of a coal plant[3].

VI. DOMINION TRANSACTION

Q. HAVE YOU IDENTIFIED ANY ISSUES WHICH MAY HAVE IMPACTED THE DOMINION SALE THAT MAKES IT NOT COMPARABLE TO THE MITCHELL TRANSFER?

A. Yes. Company motivation, asset quality, and environmental liabilities clearly played a role in the low price seen on this sale.

Dominion had publicly stated an interest in exiting the merchant generation business, and had a stated goal to have 80-90% regulated operating earnings post-2013[4]. As a result of these company decisions, Dominion sold their merchant generation business as a portfolio.

Beyond being a motivated seller, some of the assets in the portfolio had been performing poorly. The Brayton Point Plant was the largest plant involved

[3] Rebuttal Exhibit MDF-3R – SC Response to Kentucky Power Data Request 25

[4] March 4, 2013 Dominion Resources, Inc. Analyst Meeting transcript.

units[6]. This was the largest of the three portfolios cited by Mr. Kollen and Mr. Woolf, consisting of over 4,000 MW of coal fired generation located in Illinois. As I stated earlier, the number of buyers interested in such a large bundle of generation assets is small, and the desire to sell all of the assets at once likely served to drive the price down. The financing structure of the project entity sold by Ameren is complicated and is heavily leveraged with debt which may have further reduced the number of interested buyers.

As with the other cited transactions, the units sold in this transaction were not fully equipped with modern environmental controls. As shown in Table 1 above, of the coal-fired capacity involved, only 33% is equipped with scrubbers and SCR technology. To look at it another way, over 2,700 MW of coal-fired capacity involved in the transaction does not have scrubbers and SCR technology. While Company witness LaFleur will discuss the environmental liabilities associated with the Ameren facilities in greater detail, I can state that the lack of modern environmental controls should have the effect of lowering the price received for generation assets.

In addition, these assets are located in MISO, not PJM. The transaction value of assets sold in MISO may not be directly comparable to the value of assets in PJM.

Q. MUCH OF THE VALUE IN THE AMEREN-DYNEGY TRANSACTION RELATES TO THE TRANSFER OF $825 MILLION IN DEBT. WHAT

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[6] Ameren's December 2012 Form 8-K filing indicated its intention to exit the merchant business.

in the transaction, with a total capacity of 1,546 MW. While Dominion has invested over $1.1 billion in environmental controls at the facility since 2005, the three coal-fired units at the plant had a 2012 average capacity factor of about 21%, with the largest unit having a 17% capacity factor. Company witness LaFleur further discusses this issue from an operational standpoint.

Finally, Dominion recently signed an NSR Consent Decree which involves a civil penalty, costs for environmental mitigation projects, the installation of pollution controls at both of the coal fired plants included in the transaction, and ongoing emissions requirements. The new owner of the generation units, Energy Capital Partners, LLC, will assume responsibility for installing the remaining required pollution controls and for meeting the emissions requirements.[5] Complications such as this, namely capital investments that the buyer knows it has to make after the purchase, have the impact of lowering the market price of the assets. Investments in scrubbers and SCR technology have already been made at the Mitchell plant, which would make it comparably more valuable to an investor.

VII. AMEREN TRANSACTION

Q. HAVE YOU IDENTIFIED ANY ISSUES WHICH MAY HAVE IMPACTED THE AMEREN SALE THAT MAKES IT NOT COMPARABLE TO THE MITCHELL TRANSFER?

A. Yes. As in the Dominion sale cited above, Ameren desired an exit from the merchant generation business and sold their assets as a large bundle of generation

[5] http://www.timesdispatch.com/business/economy/dominion-resources-to-pay-million-to-settle-out-of-state/article_f1bfdfcd-0e97-592e-84c4-fd47e3278ac9.html

CONSIDERATION SHOULD BE GIVEN TO THIS TRANSFER OF FINANCIAL LIABILITIES?

A. The $825 million of debt transferred from Ameren to Dynegy includes bonds with interest rates of 6.3%, 7%, and 7.95%. This debt is much more expensive than current utility market rates and is yet another reason for a low transaction value. This debt represented nearly the entire transaction value. Such a high amount of leverage and the associated future debt service greatly increases the risks to the equity investors. This reduces the cash available for distribution to the equity investors and has a direct result of increasing the investor's required return on the equity capital invested. This in turn drives down the purchase price.

VIII. COMPARABLE TRANSACTIONS

Q. ARE YOU AWARE OF ANY RECENT COAL PLANT TRANSACTIONS WHICH ARE DIRECTLY COMPARABLE TO THE MITCHELL PLANT TRANSFER?

A. No, I am not.

Q. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AUTHORIZING THE TRANSFER TO THE COMPANY OF AN UNDIVIDED FIFTY PERCENT INTEREST IN THE MITCHELL GENERATING STATION AND ASSOCIATED ASSETS; (2) APPROVAL OF THE ASSUMPTION BY KENTUCKY POWER COMPANY OF CERTAIN LIABILITIES IN CONNECTION WITH THE TRANSFER OF THE MITCHELL GENERATING STATION; (3) DECLARATORY RULINGS; (4) DEFERRAL OF COSTS INCURRED IN CONNECTION WITH THE COMPANY'S EFFORTS TO MEET FEDERAL CLEAN AIR ACT AND RELATED REQUIREMENTS; AND (5) ALL OTHER REQUIRED APPROVALS AND RELIEF

Case No. 2012-00578

**KIUC'S RESPONSES TO
KENTUCKY POWER COMPANY'S
FIRST REQUEST FOR INFORMATION**

9. Please refer to page 13, line 16 through page 14, line 8 of Mr. Kollen's testimony. With respect to the Dominion and Ameren transactions referenced there please provide for each transaction the following:

(a) All documents reviewed or used by Mr. Kollen in his analysis of the transactions;

(b) All spreadsheets, work papers, calculations, analyses, and calculations relating to, reviewed by, consulted, that were performed, consulted or relied upon by Mr. Kollen with respect to the identified transactions. The requested information should be provided in an electronic format, with formulas intact and visible, and no pasted values.

RESPONSE:

a,b. Mr. Kollen reviewed the article in the Wall Street Journal cited in his testimony. Please see the attached copy of the article.

Technical/Operational Characteristics	• Age
	• Capacity
	• Physical condition
	• Location
	• Transmission constraints/congestion
	• Dispatch cost
	• Capacity factor
	• Operational performance
	• Environmental retrofits
	  o Operable retrofit (scrubber, SCR, activated carbon injection, baghouse)
	  o Planned/in-progress retrofits
	  o Future environmental requirements
	• Regional emissions rules
	• Environmental liabilities

Commercial Terms	• Representations, warranties, and conditions • Indemnification, escrow, guarantees • Liabilities transferred (financial and environmental) • Contracts assigned (PPA, fuel, vendor, labor) • Date of sale
Selection Process	• Bid evaluation • Counterparty credit quality, financing, ability to close • Time to close and commercial terms
Seller Motivation	• Commission order to divest • Company management strategic decision • Equity pressure • Creditor pressure • Rating agency pressure
Interested Purchasers	• Strategic buyer rationale • Financial buyer rationale • Direct operational experience or specific knowledge of asset • Interest in single asset or portfolio of assets • Requirement for "synergistic" asset portfolio • Ability to mitigate or handle adverse political campaign
Plant Financials	• Market power curves • Market capacity curves • Fuel cost (contracts, sourcing, transportation by rail, truck, barge, coal characteristics) • Operating cost • Hedges or contracts • Labor agreements • Capital expenditures

KPSC Case No. 2012-00578
SC Response to Kentucky Power Data Requests
Item No. 25

25. Is Mr. Woolf aware of the Sierra Club's efforts to force the early retirement of two of the three Maryland Generation Plants sold by Exelon described on page 46, lines 1-9 of his Direct Testimony?

(a) Does Mr. Woolf contend that the Sierra Club's campaign to force the retirement of two of the three Maryland Generation Plants sold by Exelon affects the market price of those plants? If the answer to this data request is anything other than an unqualified "yes," please state each fact upon which Mr. Woolf relies in support of his answer.

Response

In preparing his testimony Mr. Woolf did not make any assumptions or contentions about the factors that lead to the market price of the coal plants cited.

There are many factors that can affect the market price of a coal plant, including but not necessarily limited to: prevailing and expected natural gas prices; prevailing and expected coal prices; the age of the plant; the potential costs of complying with current and future environmental regulations; as well as local, regional and national environmental campaigns such as the Sierra Club's campaign.

Furthermore, as noted on Exelon's August 9, 2012 press release:

> The sale was required by the Federal Energy Regulatory Commission (FERC), U.S. Department of Justice (DOJ) and the Maryland Public Service Commission as part of Exelon's merger agreement. The transaction, which is subject to approval by FERC and DOJ, is expected to close in the fourth quarter of 2012.[2]

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[2] Available at: http://www.exeloncorp.com/newsroom/PR_20120809_EXC_Mdcoalplantsale.aspx

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

The Application Of Kentucky Power Company For: (1) A Certificate Of Public Convenience And Necessity Authorizing The Transfer To The Company Of An Undivided Fifty Percent Interest In The Mitchell Generating Station And Associated Assets; (2) Approval Of The Assumption By Kentucky Power Company Of Certain Liabilities In Connection With The Transfer Of The Mitchell Generating Station; (3) Declaratory Rulings; (4) Deferral Of Costs Incurred In Connection With The Company's Efforts To Meet Federal Clean Air Act And Related Requirements; And (5) For All Other Required Approvals And Relief	))))))))))))	Case No. 2012- 00578

REBUTTAL TESTIMONY OF

JEFFERY D. LAFLEUR

May 3, 2013

VERIFICATION

The undersigned, Jeffery D. LaFleur, being duly sworn, deposes and says he is Vice President Generating Assets APCO/KY, that he has personal knowledge of the matters set forth in the testimony for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge, and belief

Jeffery D. LaFleur

JEFFERY D. LAFLEUR

STATE OF WEST VIRGINIA)
) Case No. 2012-00578
COUNTY OF KANAWHA)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Jeffery D. LaFleur, this the 1st day of May, 2013.

Dorothy E. Philyaw

Notary Public

My Commission Expires: October 2, 2019

OFFICIAL SEAL
STATE OF WEST VIRGINIA
NOTARY PUBLIC
DOROTHY E. PHILYAW
APPALACHIAN POWER
PO BOX 1986
CHARLESTON, WV 25327-1986
My commission expires October 2, 2019

REBUTTAL TESTIMONY OF
JEFFERY D. LAFLEUR, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2012-00578

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REBUTTAL TESTIMONY OF JEFFERY D. LAFLEUR, ON BEHALF OF KENTUCKY POWER COMPANY BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Jeffery D. LaFleur. I am employed by Appalachian Power Company ("APCo") as Vice President of Generating Assets and I will be responsible for the operation of the Mitchell Plant after its transfer to Kentucky Power Company ("Kentucky Power" or "Company"). APCo is a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP"). My business address is 707 Virginia Street East, Suite 1100, Charleston, West Virginia 25301.

Q. ARE YOU THE SAME JEFFERY D. LAFLEUR WHO FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my rebuttal testimony is to address the concerns of Sierra Club Witness Woolf as well as those of Kentucky Industrial Utility Customers, Inc. ("KIUC") Witnesses Kollen and Hayet. Specifically, I will explain why it is advantageous for Kentucky Power to transfer the Mitchell assets to serve as a hedge against significant investments in Big Sandy Unit 2 for the period until its

June 1, 2015 retirement date. I also discuss why the transfer of the Mitchell Plant to Kentucky Power and retirement of Big Sandy Unit 2 reduce, rather than increase, the environmental risk profile for the Company. Finally, along with Company Witness Fransen, I will discuss why several of the plants associated with the unaffiliated third-party acquisitions that are referenced by the intervenor witnesses are not comparable to the Mitchell units.

III. <u>OPERATION OF BIG SANDY UNIT 2 ALONG WITH 50% OF MITCHELL PLANT PROVIDES RISK MITIGATION FOR KENTUCKY POWER</u>

Q. DO YOU AGREE WITH MR. KOLLEN'S STATEMENT (AT PAGE 8) THAT THE ACQUISITION OF THE MITCHELL UNITS PRIOR TO THE RETIREMENT OF BIG SANDY UNIT 2 REPRESENTS "WASTEFUL DUPLICATION"?

A. No, I do not. As discussed by Company Witness Pauley, beginning January 1, 2014, Kentucky Power will not be able to rely on other members of the Interconnection Agreement to meet its capacity and energy needs. Consequently, the Mitchell units will provide Kentucky Power with sufficient owned resources to meet existing Kentucky jurisdictional customer needs and an available generation "hedge" to mitigate potential risks of operational failures at Big Sandy Plant prior to the retirement of its units. With the planned retirement of Big Sandy Units 1 and 2 in June 2015, Kentucky Power has reduced its Plant investments so that expenditures necessary to support plant safety and environmental compliance are incurred, primarily. Should either Big Sandy Unit 1 or Unit 2 encounter a major issue that would take the unit out-of-service before its planned retirement date, additional investment would be more difficult to justify given the need to retire the unit by June 1, 2015. Depending largely on the repair costs and when the issue occurs, Kentucky Power would have the option to consider avoiding the expense to repair the unit and not return it to service. In this instance, Kentucky Power's ownership of Mitchell Units 1 and 2 would mitigate the loss of capacity and energy needs for the Company's customers.

Q. **PLEASE FURTHER EXPLAIN HOW NOT PERFORMING A REPAIR AT BIG SANDY UNITS 1 OR 2 WOULD BENEFIT KENTUCKY CUSTOMERS?**

A. For example, the unforeseen failure of a major component at Big Sandy Units 1 or 2 – such as a turbine – before June 1, 2015, would require a major capital investment or significant O&M expenditure. Under such circumstances, Kentucky Power would carefully consider whether the least cost option would be to undertake the repairs, or to avoid incurring that expense.

IV. ENVIRONMENTAL RISKS

Q. **MR. KOLLEN (AT PAGE 16) AND MR. HAYET (AT PAGE 5) STATE THAT THE COMPANY'S PROPOSAL TO ACQUIRE 50% OF MITCHELL'S ASSETS INCREASES KENTUCKY POWER'S ENVIRONMENTAL RISK EXPOSURE. IS KENTUCKY POWER'S ENVIRONMENTAL RISK ANY GREATER WITH THE ACQUISITION OF MITCHELL PLANT ASSETS?**

A. No. In fact, the proposal to transfer a 50% interest in the Mitchell units to Kentucky Power actually reduces the Company's exposure to environmental risk for the simple reason that the Mitchell units already have been retrofitted with SO_2 emission controls while Big Sandy Unit 2 has not.

Q. WHAT IS THE ENVIRONMENTAL RISK ASSOCIATED WITH THE THIRD PARTY-OWNED UNITS IDENTIFIED BY THE INTERVENORS?

A. The plants involved in the third-party acquisitions that the intervenors allege are comparable have a higher overall environmental risk than Kentucky Power will have with the Mitchell units. As shown in the data gathered by Company Witness Fransen and summarized in Table 1 of his rebuttal testimony, these plants are not fully retrofitted with major environmental controls such as flue-gas desulfurization ("FGD") and selective-catalytic reduction ("SCR") systems. Of the three asset portfolios (Ameren, Dominion Resources, and Exelon) cited by KIUC Witness Mr. Kollen and Sierra Club Witness Mr. Woolf, only 33%, 38%, and 61% of the capacity of the units are equipped with FGD and SCR systems, respectively. Mitchell Plant is already fully equipped with both of these technologies.

In addition, from the cursory information presented by Mr. Kollen and Mr. Woolf, it is unclear whether costs of compliance with future environmental regulations were assessed as part of these transactions. Clearly, the cost to bring such units to environmental compliance comparable to the Mitchell units would lead to significant higher costs beyond the purchase price.

Q. DO YOU FEEL THAT RISKS AT THE MITCHELL PLANT HAVE BEEN IDENTIFIED BY THE COMPANY?

A. Yes. As discussed in my Direct Testimony, the Company is very familiar with the assets that it would receive at the Mitchell Plant. The Plant's current operating company, Ohio Power Company ("OPCo"), completed construction and placed the Mitchell Units in service in 1971, and has been the owner and operator of the Plant since then. OPCo also retrofitted the units with FGD and SCR emission control systems along with associated projects. In addition, AEP initiated planning efforts to identify future environmental project needs and associated costs at the Mitchell Plant due to recently finalized and proposed environmental regulations as discussed by Company Witness McManus.

Based upon the Company's knowledge of Mitchell Plant's history, I am comfortable that the Company understands what it is getting with the transfer of the Mitchell assets. By contrast, it is not possible to have such a detailed understanding with the acquisition of a third-party plant. As part of the AEP system, Kentucky Power knows that the OPCo units at Mitchell Plant have been provided with access to the same engineering, maintenance, and other resources as the 800 MW units at Big Sandy Plant and Amos Plant, which have the same basic design. Through sharing of best practices applicable to all units, a high level of availability and performance has been achieved. However, it is important to recognize that regardless of any company's attempt to assess the impacts of future environmental rules, until a rule is finalized and is not further challenged, any assessment contains an element of uncertainty.

V. UNAFFILIATED THIRD PARTY PLANT ACQUISITIONS

Q. **BASED ON YOUR REVIEW OF PUBLICLY AVAILABLE INFORMATION, DO YOU BELIEVE THE PORTFOLIO OF PLANTS INCLUDED IN THE THIRD PARTY TRANSACTIONS AS DISCUSSED BY KIUC WITNESS KOLLEN (AT PAGES 13-14) AND SIERRA CLUB WITNESS WOOLF (AT PAGES 45-46) ARE COMPARABLE TO THE MITCHELL GENERATING STATION?**

A. No. As further discussed by Company Witness Fransen, the coal-fired units included in the third-party transactions are not comparable to the Mitchell Plant. It is obvious that Mr. Kollen and Mr. Woolf came to general conclusions based upon limited information and understanding. Based upon responses provided by the KIUC and Sierra Club to Kentucky Power's data requests[1], they did not perform analyses of the third party transactions and therefore do not have any knowledge of the condition of the plants included in the third-party transactions.

As stated earlier in my rebuttal testimony, the Company is very familiar with the Mitchell assets and the value of the highly efficient environmental controls that were installed at the units in meeting current and potential future environmental requirements. Although I do not share the same level of personal familiarity with the third-party transactions cited by the intervenors, based on data shown by Company Witness Fransen in Table 1 of his testimony, several of the units included in the third party transactions do not have equivalent environmental control equipment, run at lower capacity factors, and are older.

[1] KIUC's Responses to Kentucky Power Company's First Request for Information, Requests 9 and 10; and Alexander Desha, Tom Vierheller, Beverly May, and the Sierra Club's response to Kentucky Power Company's Data Requests, Request 23-26.

Q. PLEASE EXPLAIN THE MAJOR DIFFERENCES THAT YOU HAVE IDENTIFIED BETWEEN THE COAL-FIRED UNITS IN THE THIRD-PARTY TRANSACTIONS AND THE MITCHELL ASSETS.

A. Both Mr. Kollen and Mr. Woolf cite the sale of certain Dominion Resources assets to Energy Capital Partners. As discussed by Company Witness Fransen, Dominion Resources sold these assets as a portfolio of mixed assets that included poorly performing units. Only 38% of the coal-fired generation capacity in the portfolio have FGD and SCR systems installed, the average age of the coal-fired assets sold is seven years older than the Mitchell units, and the average capacity factors of the units are less than the Mitchell units' average capacity factors. For example, as discussed in Company Witness Fransen's rebuttal testimony, Dominion Resources' three coal-fired units at its Brayton Point facility in Massachusetts ran at an average capacity factor of 21% in 2012.

In addition, the Brayton Point Plant has historically relied on a high amount of import coal from South America, unlike the Mitchell plant that burns domestic coal. The transportation costs of coal imported from South America (and even Appalachian basin coal) to Massachusetts undoubtedly would lend to higher fuel costs, thereby resulting in higher dispatch costs and low capacity factors. Higher operations costs tend to make a unit less attractive to a Regional Transmission Organization ("RTO") when selecting units for dispatch.

Q. WHY DOES CAPACITY FACTOR MATTER WHEN COMPARING THE MITCHELL UNITS WITH THE UNITS IN THE DOMINION RESOURCES, AMEREN AND EXELON TRANSACTIONS?

A. Capacity factors are often overlooked when comparing the pros and cons of various energy sources. Capacity factor is a measure of the performance of a generating station over time as a percentage of its full power potential. As such, capacity factor can be a reflection of production costs, availability of the power plant, and the condition/stability of the power grid. Poor plant availability and high production costs make a unit less likely to be dispatched by the RTO.

Q. ARE THERE SIMILAR ISSUES WITH THE AMEREN UNITS AS FOUND WITH DOMINION RESOURCES' UNITS?

A. Yes, like Dominion Resources, the Ameren transaction represents a portfolio of mixed assets. Only 33% of the coal-fired generation capacity in the portfolio has FGD and SCR systems installed leaving over 2700 MW of generation capacity without FGD and SCR systems. For the same reasons as discussed above, the absence of these environmental control technologies is problematic. For example, there is a half-complete scrubber retrofit on Ameren's Newton Units 1 and 2 where a compliance requirement exists to complete the retrofit sometime in 2019. The new owner, Dynegy, would be responsible for these future costs. Although there was a waiver granted by the Illinois Pollution Control Board ("IPCB") that allowed Ameren to install the scrubber by 2019 due to financial hardships, Dynegy may not qualify for the same waiver since its financial status may allow them to complete the scrubber installation sooner.[2]

In addition, as part of the acquired portfolio, the six units at the Joppa Steam Plant are not retrofitted with FGD or SCR technology and have an average

[2] http://elpc.org/2013/03/22/howard-learner-talks-dynegy-deal-with-bloomberg-bna

age of 59.5 years. The Mitchell units are much newer and already have such equipment installed.

Q. ARE THERE OTHER TRANSACTIONS REFERENCED WITH COAL-FIRED PLANTS THAT ARE NOT COMPARABLE TO THE MITCHELL ASSETS?

A. Yes. Mr. Woolf (at pages 45-46) also discusses the Exelon Power to Constellation Energy Group transaction. Two of the three Exelon plants, the Charles P. Crane and Herbert A. Wagner coal plants in Baltimore and Anne Arundel counties in Maryland, referenced by Mr. Woolf are under pressure by the Sierra Club to retire. These unscrubbed and aging coal-fired units are on average 51 years old. Therefore, they are not assets comparable to the Mitchell units which are scrubbed.

CONCLUSION

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. The transfer of 50% of the Mitchell assets provides a level of risk mitigation in the event Big Sandy Unit 2 experiences a major outage during its path to retirement. This does not represent a wasteful duplication of assets as suggested by KIUC Witness Kollen. In addition, Mr. Kollen and Mr. Hayet fail to recognize that the Company fully understands what it is getting with the 50% transfer of the Mitchell assets. First, the Company will benefit from a continuity of staff expertise given AEP's ownership and operation of 800 MW units at not only the Mitchell Plant, but at Amos Units 1 and 2 and Big Sandy Unit 2 as well. Such an integral knowledge of units external to the AEP system would not exist. Mr.

Kollen and Mr. Hayet simply relied upon newspaper articles and did not thoroughly evaluate the third-party assets. The fact that certain assets are coal-fired assets is not enough, but an analysis should have included many other items such as obtaining a reasonable understanding of environmental risks due to future regulations. Unlike the Mitchell facility, it is not clear whether assessments of environmental risks associated with future regulations were performed for the plants included in the third party transactions. Finally, the assets included in the third-party acquisitions discussed by Mr. Kollen and Mr. Woolf are not comparable to the Mitchell assets given the Mitchell Plant's current installation of state-of-the-art environmental controls including FGDs and SCRs and higher capacity factors, amongst other factors discussed in my testimony.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF:

The Application Of Kentucky Power Company For: (1) A Certificate Of Public Convenience And Necessity Authorizing The Transfer To The Company Of An Undivided Fifty Percent Interest In The Mitchell Generating Station And Associated Assets; (2) Approval Of The Assumption By Kentucky Power Company Of Certain Liabilities In Connection With The Transfer Of The Mitchell Generating Station; (3) Declaratory Rulings; (4) Deferral Of Costs Incurred In Connection With The Company's Efforts To Meet Federal Clean Air Act And Related Requirements; And (5) For All Other Required Approvals And Relief	) Case No. 2012-00578

REBUTTAL TESTIMONY

OF

KARL A. MCDERMOTT

May 3, 12013

VERIFICATION

The undersigned, Karl A. McDermott, being duly sworn, deposes and says he is the Special Consultant with NERA that he has personal knowledge of the matters set forth in the testimony for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge, and belief

Karl A McDermott

Karl A. McDermott

STATE OF ILLINOIS)
) CASE NO. 2012-00578
COUNTY OF CHAMPAIGN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Karl A. McDermott, this the 2 day of May, 2013.

OFFICIAL SEAL
PAMELA R HUFFMAN
NOTARY PUBLIC, STATE OF ILLINOIS
MY COMMISSION EXPIRES: 3/04/2017

Pam Huffman

Notary Public

My Commission Expires: 3-4-17

REBUTTAL TESTIMONY OF
KARL A. MCDERMOTT, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2012-00578

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REBUTTAL TESTIMONY OF KARL A. MCDERMOTT, ON BEHALF OF KENTUCKY POWER COMPANY BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q: PLEASE STATE YOUR NAME, CURRENT POSITION AND BUSINESS ADDRESS.

A. My name is Karl McDermott. I am currently the Acting Director of the Center for Business and Regulation and Ameren Distinguished Professor of Business and Government at the University of Illinois Springfield. I am also a Special Consultant to National Economic Research Associates, Inc. ("NERA"). My business address is 875 N. Michigan Ave. Suite 3650 Chicago Ill. 60611-1907.

Q. ARE YOU THE SAME KARL A. MCDERMOTT THAT FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

II. PURPOSE AND CONCLUSIONS

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of this testimony is to respond to the recommendation by intervenors in this case that Kentucky Power Company ("Kentucky Power" or the "Company") should be required to undertake a Request for Proposal ("RFP") to benchmark the transfer price embedded in the Company's Asset Transfer Proposal (the "Proposal"). In particular, I respond to portions of the direct testimonies from Kentucky Industrial Utility Customers ("KIUC") witness Mr. Kollen and Sierra Club witness Mr. Woolf.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS IN THIS PROCEEDING.

A. After reviewing the regulatory environment in Kentucky and the asset transfer proposal, I conclude that:

1. The Company's benchmarking process was appropriate and demonstrated that the expected market price for similar products is expected to be greater than the transfer price over the planning horizon for the Proposal.

2. The intervenors have failed to show why an RFP process is the <u>only</u> methodology that can be used to analyze the reasonableness of the Proposal, or why the Company erred in relying upon its benchmarking process.

3. It is reasonable to conclude that an RFP process in this case, considering the amount of long-term capacity and energy required, would not yield any additional useful information.

4. The intervenors' portfolio approach has serious limitations that render the alternative proposals infeasible.

<u>III. AN RFP PROCESS IS UNNECESSARY FOR THE COMMISSION TO DETERMINE THAT KENTUCKY POWER SHOULD BE GRANTED A CERTIFICATE OF CONVENIENCE AND NECESSITY AS PROPOSED</u>

Q. WHAT IS YOUR UNDERSTANDING OF THE CONCERN RAISED BY INTERVENORS RELATING TO AN RFP?

A. The intervenors raise a concern that the lack of an RFP process to further benchmark the transfer price of the Mitchell unit makes it difficult or impossible to evaluate the

Proposal's reasonableness. (Kollen, Dir., p. 9, line 19 - p. 10, line 4; Woolf, Dir., p. 4, lines 4-8)

Q. WHAT IS YOUR UNDERSTANDING OF THE INTERVENORS' TESTIMONY?

A. The intervenors seem to think that using an RFP process is the only fair and transparent method to benchmark the proposed transfer price of the Mitchell unit. For example, Mr. Kollen claims that the Company did not attempt to ascertain the market value of the portion of Mitchell proposed to be transferred in this case. (Kollen Dir., p. 9, lines 19-20) Mr. Woolf makes a similar claim. (Woolf Dir., pp.40-41) Both intervenors argue that the Company's failure to determine the market value of the Mitchell units means the proposed transfer cannot go forward.

Q. DO YOU AGREE WITH THESE CONCERNS IN THIS CASE?

A. No. First, the Company did undertake a market test to determine the reasonableness of the Proposal. As I explained in my direct testimony in this proceeding, the Company's methodology models the expected outcome of an RFP for the required capacity and energy in the market. Second, the intervenors have provided no compelling reason why an RFP process is the only appropriate method to use in evaluating the Proposal. Third, the intervenors have failed to show that an RFP process would provide additional relevant information concerning the reasonableness of the analysis used to support the Proposal. Indeed, it may well be that, in this case, an RFP process would provide no additional relevant information, or worse, provide faulty information as I discuss below. Rather, Mr. Woolf claims that an RFP process might "identify options a utility is unaware of," and Mr. Kollen claims that the planning analysis utilities have undertaken for decades is essentially worthless. (Woolf Dir., pp. 40, lines 26-28; Kollen Dir., p. 13, lines 6-15) But there are good reasons to conclude that an RFP process would neither provide a viable market value to which the Commission could attribute any validity nor produce results that would indicate that the transfer price exceeds the RFP price. Company Witness Weaver also addresses this issue.

Q. WHAT APPROACHES COULD BE USED TO EVALUATE THE REASONABLENESS OF RESOURCE ACQUISITIONS SUCH AS THE PROPOSAL?

A. There are only a few accepted methods for benchmarking such a proposal. The first approach is to use a planning model like the one the Company discussed in its Direct Testimony. I have endorsed this method as appropriate for this case. Such models have been relied upon for decades by the utility industry and regulatory commissions alike. The second approach is to utilize a benchmarking process which essentially attempts to ascertain the price that a RFP would return if one were to undertake the process. This can be done by using cost inputs and market forecasts as the Company has also done in this case, or by collecting data on comparable RFP results in the relevant geographic and product markets during a relevant time frame. The third approach is to run a benchmarking RFP process that would invite bidders to provide actual offers for long-term resources.

Q. WHAT ARE THE ADVANTAGES OF USING THE PLANNING MODEL THE COMPANY HAS UTILIZED?

A. While I have discussed this approach in my Direct Testimony in this proceeding, in summary there are two major advantages of this approach. First, utilities and regulators have utilized this approach for decades and it is a well-known and relatively sophisticated method. Second, this approach transparently provides all data and assumptions necessary to develop a benchmark. This allows the Commission and the intervenors to publically evaluate, criticize, and draw conclusions from the analysis. Indeed, there is a great deal of discussion in this case concerning the appropriateness of the technical and data-related issues. This very process provides the Commission with a full opportunity to evaluate the data used to develop the benchmarks and provides a full record on which to draw a conclusion.

Q. IS THERE A DISADVANTAGE OF USING THE PLANNING MODEL THE COMPANY HAS UTILIZED?

A. Some of the intervenors have noted the benchmarks employed in any planning model may not exactly match any given supplier's capital costs, fuel costs, or productivity levels; in the view of some, this suggests that suppliers may bid a different price into an RFP than is found in the benchmarking analysis.

Q. DO YOU CONSIDER THIS DISADVANTAGE SUFFICIENT TO REJECT THE PROPOSAL?

A. No. First, just because a benchmark does not represent any particular suppliers' cost structure does not mean that the benchmark does not provide useful information and, more importantly, it does not mean that that supplier will bid a lower price than the benchmark. As I have noted in my Direct Testimony one would not expect a supplier to bid below their opportunity cost which, in a market place, is the expected market price. That is exactly what the Company's process benchmarks—the expected market price. Further, the purpose of any benchmarking is to assure that the resource planning decisions are appropriate. Benchmarking, by its nature, is for the purpose of determining that the proposed transfer price is reasonable. Any benchmarking process, ***including an RFP process*** in which there is already a known transfer price as would be the case here, is not going to provide an exact number. If the inputs and modeling are found to be appropriate, then the Company's planning model approach is one valid approach, and as discussed below, is the best approach for the Commission to rely on in this case.

Q. WHAT ARE THE ADVANTAGES OF THE SECOND APPROACH YOU IDENTIFY -- BENCHMARKING USING HISTORIC RFP RESULTS?

A. If the benchmarking is done using an appropriate planning model, the advantages of this approach are similar to the approach used by the Company. If the benchmarking utilizes data from competitive solicitations of comparable products (*i.e.* assets or PPAs with similar lives), that has the advantage of providing a snap shot of the market for these products.

Q. WHAT ARE THE DISADVANTAGES OF BENCHMARKING VIA HISTORIC RFP RESULTS?

A. In order to benchmark using other RFPs one would have to collect data on results of RFPs for a comparable asset/PPA of a comparable time frame, similar geographical market (PJM), and comparable non-price terms and conditions. Such an approach has been used in the past but this approach is not without complexity and demerits. For example, as Company Rebuttal Witness Fransen indicates, determining comparability may be difficult if not impossible. In addition, in many cases the number of truly comparable sales and RFP responses will not be sufficient to provide enough information such that a reasonable and reliable comparable benchmark can be constructed. In this regard, I am aware that a number of entities, including AEP, have been precluded from bidding on certain assets because of market power concerns as discussed in the Rebuttal Testimony of Company witness Fransen. Further, non-price terms and conditions are often not publically available, but can be significant variables in the valuing of the asset. Properly incorporating these terms and conditions of the sales requires additional evaluation and presents significant difficulties in the analysis. It is also unclear that a single cost would result from this analysis. Indeed, it is quite likely that a range of costs would result that would reflect differing time frames, non-price terms and conditions, and a variety of other factors that would be difficult to evaluate. For example, prices may vary over the term based on various indices or cost components which may not be predictable.

Q. ARE THE DISADVANTAGES ASSOCIATED WITH BENCHMARKING COMPETITIVE OUTCOMES SIGNIFICANT?

A. Yes. In some sense the disadvantages to this approach are more problematic than evaluating the inputs to the Company's modeling that has been presented. The modeling approach used by the Company allows the Commission to look closely at all of the factors that affect the likely market price from fuel costs to demand conditions. An RFP analysis provides only a general look at a limited set of assets or

PPAs. In my opinion this process is not a "better" process, merely a different process. It is not clear that by simply using a different process it would result in any additional useful information for the Commission.

Q. WHAT ARE THE ADVANTAGES OF UTILIZING A COMPETITIVE SOLICITATION?

A. The main advantage of this approach is that it provides a method of evaluating the reasonableness of an affiliate relationship from a competitive perspective. Regulators (namely the Federal Energy Regulatory Commission) have identified a problem with evaluation of an affiliate transaction in that competitors may be unfairly excluded from the market if an affiliate obtains an unfair or otherwise out of market deal with an affiliated company. (*See e.g.,* FERC Opinion No. 473, July 29, 2004.) Utilizing a transparent method of solicitation and requiring the utility to compete against non-affiliated providers is used as a policy to support and promote competition in the electric industry.

Q. WHAT ARE THE DISADVANTAGES OF COMPETITIVE SOLICITATION IN THIS CASE?

A There are several disadvantages. First, Kentucky Power Company has already publically announced the price at which it would be willing to transfer the asset. In fact, this price was publically available as early as February 2012 when filings were first made at the Federal Energy Regulatory Commission. This creates a ceiling price that potential bidders would have to beat in order to win the RFP. Bidders are in some sense not free to bid their costs since they are constrained by the transfer price.

Second, both Mr. Kollen and Mr. Woolf suggest that the transfer price should be set at the lower of cost or market. (Koolen Dir. p. 9, lines 14-15; Woolf Dir., p. 4: lines 19-20) Of course, this is exactly the analysis that the Company has undertaken. If the market were less costly, the Company's analysis of Options #4A or #4B would indicate such. Moreover, the approach proposed by the intervenors is to utilize an indicative RFP to set the market price. But such an RFP would not be independent of the Proposal as the "bid" price for the Company's Proposal is already known. A bidder might be unwilling to reveal its actual costs when it is bidding into a process that is used solely for the purposes of benchmarking. This might occur because the bidder may perceive that it would never actually have to perform on its bid proposal as the bid is used solely to set the transfer price. Such a process hardly provides the Commission with objective data concerning the market price (and more likely sets up a long and protracted argument as to whether the bid prices were "real" bid prices). Alternatively, if the bidders know that the process is solely for the purposes of setting a transfer price, they may either chose to not bid or to not spend the necessary resources to provide an accurate bid. Again, the data recovered from such a process would be suspect at best.

The alternative is to allow the Company to bid into the RFP process with other bidders. Suppose the Company's bid is lowest, though above the current Proposal's all-in net book value cost. Would the Company be allowed to transfer the units at the higher market price? If not, then what is the purpose of allowing the Company to bid into the RFP? Finally, suppose that the RFP price for a PPA comes in below the Proposal's all-in price. Would the Commission accept the RFP and force Kentucky

Power to purchase long-term base load power from a non-affiliated supplier assuming it remained available? This brings up issues of regulatory control that I addressed in my direct testimony.

Third, buying long-term power from an RFP process is not like buying hammers from the local hardware store. In most cases, markets are unwilling to provide long-term power contracts due to the extreme risk associated with unknowns. (For example, in truly competitive electric markets, forward sales of electricity generally go out three years at most.) In general, a long-term RFP will cause bidders to demand relatively high prices (at least above the net book value of Mitchell). Indeed, that is what Kentucky Power's analysis has determined. (*See* Weaver Dir.)

Fourth, the RFP process for long-term products is generally a protracted negotiation. For example, while a large number of players may bid into the RFP, generally there is a second (and sometimes third) round of bidding to discover the final price and set of terms and conditions. (A description of this process is found in the Louisville Gas and Electric 2011 Resource Assessment filed in KPSC Case No. 2011-00375, pp. 13-23.) This subsequent round of bidding will generally be a smaller group of bidders (perhaps even one) which limits the competitive effects. Also, if the intervenors' proposal of using an indicative RFP to set the market price is adopted, at what point does the Commission accept the final RFP price as indicative of the market price? In the first round of bidding? The second round? Only after a contract has been signed? (Though if the RFP process is solely used for benchmarking purposes there would be no contract signed and the question is raised as to whether the bids were true final cost bids.)

Finally, undertaking the RFP process is not costless in terms of resources to run the RFP and in terms of the timing of the Proposal. Staff and Commission resources would be required as well, not to mention those resources of the potential bidders and others involved in the activity

Q. FROM THIS DISCUSSION DO YOU AGREE THAT THE RFP IS THE BEST METHOD FOR EVALUATING THE PROPOSAL?

A. No. By claiming that the RFP is the "best" method, that presumes there are no disadvantages that could cause the RFP process to be essentially valueless or, at a minimum, controversial. As I have noted there are serious drawbacks to the RFP process in this case that could lead a reasonable person to doubt its value as a benchmark.

Q. MR. KOLLEN STATES THAT THE COMPANY DID NOT ATTEMPT TO SELL THE MITCHELL CAPACITY TO AN UNAFFILIATED THIRD PARTY. (KOLLEN, DIR., P. 10, LINES 6-11). DOES THIS SUGGEST THAT THE COMPANY'S APPROACH IS INAPPROPRIATE?

A. No. Selling capacity from the units, or selling the units themselves, to a third-party may not provide a good market benchmark either. For example, there are likely few bidders that have the capabilities or business model to purchase coal resources and the ones that do may face problems of market concentration. Indeed, as Mr. Fransen testifies, often likely bidders are precluded from bidding due to market concentration concerns. The pool of bidders then shrinks to those entities with portfolios outside the region (such as the case of Edison Mission purchasing the fossil fuel units from

Commonwealth Edison Company in Illinois) or financial players (such as those described by Mr. Fransen in his rebuttal testimony). Here, as with the issue of using an RFP process, the intervenors seem to be grasping for any issue that might cast doubt on the market analysis completed by the Company. At this point, only the Company has come forward with a realistic proposal to address the needs of its customers over the long term.

Q. WHAT DO YOU CONCLUDE ABOUT THE PROPOSALS MADE BY MR. KOLLEN AND MR. WOOLF CONCERNING THE COMPANY'S APPROACH TO ADDRESSING ITS RESOURCE NEEDS THAT INDICATE THE PROPOSALS ARE NOT CONSISTENT WITH A PORTFOLIO APPROACH TO RESOURCE ACQUISITION?

A. While I commend both of these witnesses for recommending a portfolio approach to resource acquisition, both of the witnesses have proposed alternatives that are not fully operational or have various conceptual or practical barriers to implementation, such as relying on an yet to be developed RFP process. (Mr. Weaver addresses the more practical problems with the recommendations.) Given these concerns with the intervenors' proposals I continue to support the methodology used by the Company to evaluate the Proposal as the most practical and reasonable approach proposed in this case.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY IN THIS DOCKET?

A. Yes it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

The Application Of Kentucky Power Company For:	)
(1) A Certificate Of Public Convenience And Necessity	)
Authorizing The Transfer To The Company Of An	)
Undivided Fifty Percent Interest In The Mitchell	)
Generating Station And Associated Assets; (2) Approval	)
Of The Assumption By Kentucky Power Company Of	) Case No. 2012-00578
Certain Liabilities In Connection With The Transfer Of	)
The Mitchell Generating Station; (3) Declaratory Rulings;	)
(4) Deferral Of Costs Incurred In Connection With The	)
Company's Efforts To Meet Federal Clean Air Act And	)
Related Requirements; And (5) For All Other Required	)
Approvals And Relief	)

REBUTTAL TESTIMONY
OF
PHILIP J. NELSON

May 3, 2013

VERIFICATION

The undersigned, PHILIP J. NELSON being duly sworn, deposes and says he is Managing Director, Regulatory Pricing and Analysis for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing testimony and that the information contained therein is true and correct to the best of his information, knowledge, and belief.

PHILIP J. NELSON

STATE OF OHIO)
) CASE NO. 2011-00578
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Philip J. Nelson, this the 1st day of May 2013.

Ann Dawn Clark
Notary Public

NOTARY PUBLIC STATE OF OHIO

Ann Dawn Clark
Notary Public-State of Ohio
My Commission Expires
November 16, 2015

My Commission Expires: November 16, 2015

REBUTTAL TESTIMONY OF
PHILIP J. NELSON, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2012-00578

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REBUTTAL TESTIMONY OF PHILIP J. NELSON ON BEHALF OF KENTUCKY POWER COMPANY BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Philip J. Nelson. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. PLEASE INDICATE BY WHOM YOU ARE EMPLOYED AND IN WHAT CAPACITY.

A. I am employed as Managing Director of Regulatory Pricing and Analysis in the Regulatory Services Department of American Electric Power Service Corporation ("AEPSC"), a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP"). AEP is the parent company of Kentucky Power Company ("Kentucky Power").

II. BACKGROUND

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I graduated from West Liberty University in 1979 receiving a Bachelor of Science Degree in Business Administration, majoring in accounting. In 1979, I was employed by Wheeling Power Company, an affiliate of AEP, in the Managerial Department. At Wheeling Power, I was responsible for rate filings with the Public Service Commission of West Virginia ("PSC"), for resolving customer complaints made to the PSC, as well as for preparation of the Company's operating budgets and capital forecasts. In 1996, I transferred to the AEP-West Virginia State Office in Charleston, West Virginia as a senior rate analyst. In 1997, I transferred to AEPSC as a senior rate consultant in the Energy Pricing and Regulatory Services Department, with my primary responsibility being the oversight of Ohio Power Company's ("OPCo") and Columbus Southern Power's ("CSP") Electric Fuel Component ("EFC") filings. In 1999, I transferred to the Financial Planning Section of the Corporate Planning and Budgeting Department where I helped prepare AEP financial forecasts. I held various positions in the Corporate Planning and Budgeting Department until my transfer to Regulatory Services in February, 2010.

Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR OF REGULATORY PRICING AND ANALYSIS?

A. My department supports regulatory filings across the AEP system in the areas of cost of service, rate design, cost recovery trackers and tariff administration. It also provides expert witness testimony on AEP's east and west power pools as well as technical advice and support for power settlements and performs financial analysis of changes to AEP's generation fleet. In addition, my department provides support and filing of generation and transmission formula rate contracts.

Q. HAVE YOU EVER SUBMITTED TESTIMONY AS A WITNESS BEFORE A REGULATORY COMMISSION?

A. Yes. I have testified before the Virginia State Corporation Commission and the Public Service Commission of West Virginia on behalf of Appalachian Power

Company ("APCo"), before the Public Service Commission of West Virginia on behalf of Wheeling Power Company, before the Indiana Utility Regulatory Commission on behalf of Indiana Michigan Power Company and before the Public Utilities Commission of Ohio ("PUCO") on behalf of CSP and OPCo.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to address KIUC witness Kollen's incorrect contention that during the period from January 1, 2014 through May 31, 2015, AEP would double recover certain costs if the proposal to transfer a 50% ownership interest in Mitchell plant to Kentucky Power is approved.

Q. WHAT EXHIBITS ARE YOU SPONSORING IN THIS PROCEEDING?

A. I am sponsoring Exhibit PJN-1R which provides the KIUC response in this proceeding to Staff's First Request for Information No. 6 referred to in this testimony.

IV. OHIO ESP AND CAPACITY CASES

Q. DID YOU PARTICIPATE IN THE OHIO PROCEEDINGS WHICH ESTABLISHED A COST-BASED CAPACITY CHARGE FOR OPCO[1] RETAIL CUSTOMERS WHO CHOOSE AN ALTERNATIVE SUPPLIER?

A. Yes. In response to an information request from the KYPSC Staff to KIUC, the KIUC references my testimony in Cases Nos. 11-346-EL-SSO et. al. ("ESP Case") and 10-

[1] On December 31, 2011, CSP merged into OPCo. All references to OPCo in this testimony refer to CSP and OPCo collectively.

2929-EL-UNC ("Capacity Case") and suggests that the Ohio testimony somehow supports KIUC's position that there is a double recovery of the Mitchell costs. My testimony and the testimony of Dr. Pearce in the Ohio cases do not in any manner support this contention. I have attached the KIUC's data response to this testimony for reference as Exhibit PJN-1R.

Q. PLEASE PROVIDE THIS COMMISSION WITH THE NECESSARY BACKGROUND ON THE OHIO PROCEEDINGS SO THAT IT CAN PUT THE PROPER CONTEXT TO THE ISSUE RAISED BY KIUC WITNESS KOLLEN IN HIS TESTIMONY ON PAGES 22 AND 23.

A. Ohio has been moving, in fits and starts, for a number of years to a competitive structure for electric generation service. More recently, the PUCO has clearly directed OPCo and other utilities in the state to move more quickly to a competitive market structure. This has involved complicated and lengthy regulatory proceedings and has resulted in a short transition period for OPCo to completely separate its transmission and distribution business from the competitive generation business. As part of this transition, the issue of an appropriate capacity charge to Competitive Electric Retail Service ("CRES") providers was hotly contested. CRES providers serve retail customers that choose to receive their generation service from a supplier other than the incumbent utility. Because of capacity commitments made during the period of more regulated structure in Ohio, OPCo charges CRES providers for the capacity OPCo makes available for customers who choose a CRES provider during a transition period ending May 31, 2015.

Also, and most important to this Commission, the changes in Ohio were a contributor to the termination of the current Interconnection Agreement ("Pool Agreement") and are the reason that a 50% interest in the Mitchell units is available to transfer to Kentucky Power.

Q. PLEASE BRIEFLY DESCRIBE THE DEVELOPMENT OF THE OHIO CAPACITY CHARGE?

A. The Ohio capacity charge to CRES providers was created to reimburse OPCo for the use of its capacity in serving retail customers that are no longer receiving generation service directly from OPCo. The CRES providers are using OPCo's capacity since OPCo has already committed to providing that capacity in PJM for all its retail customers including those that are now served by a CRES provider. Therefore, a CRES provider has no obligation to supply its own capacity in PJM, but can rely on and purchase that capacity from OPCo through May 31, 2015. The capacity charge was developed based on a cost of service "formula rate" approach that has been used in the development of firm wholesale rates charged to co-ops and municipalities that purchase generation service. The costs and revenues (credits) used in the formula rate are taken from FERC Form 1 data and is typically updated annually. This formula rate concept was proposed by OPCo to the PUCO and FERC to develop the proper capacity charge to CRES providers for their use of OPCo's capacity to serve OPCo retail customers that choose another generation supplier. The PUCO generally used this method to develop the capacity charge stated in its Capacity Case and ESP Case orders.

Q. IS THERE A DOUBLE RECOVERY OF MITCHELL COSTS THAT OCCURS THROUGH THE CAPACITY RATE APPROVED BY THE PUCO AND THE TRANSFER OF THE MITCHELL UNITS TO KENTUCKY POWER AND APCO FROM OPCO EFFECTIVE JANUARY 1, 2014?

A. No. As I explain below, the capacity charge developed in Ohio provides compensation to OPCo for the cost of capacity used to serve retail customers in Ohio. The recovery of capacity costs from Ohio retail customers does not provide any revenues for replacement of the wholesale sales that will be lost from termination of the Pool Agreement and, importantly, does not overlap at all with the costs that Kentucky Power's customers will pay as a result of the transfer of the Mitchell units effective January 1, 2014.

V. EVIDENCE SHOWING MR. KOLLEN'S TESTIMONY IS INACCURATE

Q. KIUC'S RESPONSE STATES THAT OPCO'S FORMULA CAPACITY CHARGE CALCULATION STARTS WITH ITS PLANT IN SERVICE, INCLUDING THE MITCHELL UNITS. IS THIS PART OF ITS RESPONSE ACCURATE?

A. Yes, but the key word is "starts". They have ignored the fact that included in the development of the PUCO determined capacity charge was a credit to the cost of service ("Pool Credit") for capacity sold by OPCo to the other members of the Pool Agreement. As I explain in more detail later, there is no double recovery as claimed by Mr. Kollen because the PUCO-determined Ohio capacity charge was not designed nor approved as a means to recover all of the generation capacity costs of OPCo;

rather it recovers only the capacity cost associated with the capacity necessary to serve retail customers. The Pool Credit reduces the retail capacity charge determined by the PUCO and reflects the fact that a portion of OPCo's capacity costs are being recovered from the other parties to the Pool Agreement.

Q. WHY DOES THE DEVELOPMENT OF THE RETAIL CAPACITY CHARGE USING THE POOL CREDIT ELIMINATE ANY DOUBLE RECOVERY?

A. As this Commission is aware, the Pool Agreement terminates effective January 1, 2014. Therefore, the Pool Agreement capacity revenue provided to OPCo does not continue past December 31, 2013. The Pool Agreement payments received by OPCo are not specifically for the Mitchell units, they are compensation to OPCo for the significant portion of its generation capacity that it sells to its affiliates, including Kentucky Power. OPCo's Pool Credit was incorporated in the PUCO-determined capacity rate charged to CRES providers, reducing the Ohio capacity charge. Therefore, the retail capacity rates represent the netting of the credit and charge, and thus do not provide full compensation for all of OPCo's capacity. Instead the retail capacity rates provide only the amount needed to serve Ohio retail customers and do not replace lost wholesale revenue.

Q. CAN YOU DEMONSTRATE THAT THE POOL AGREEMENT CAPACITY CREDIT WAS IN FACT USED BY THE PUCO TO REDUCE THE CAPACITY CHARGE IT APPROVED IN THE CASES CITED BY MR. KOLLEN?

A. Yes, the $401 million in Pool Credit is clearly evident in the record in these cases and it was not disputed by any party to the cases, including the Ohio Energy Group

("OEG"), since it reduced the capacity charge for retail customers served by CRES providers. One specific reference I can point to is on page 4 of my rebuttal testimony filed May 11, 2012 in the Capacity Case where I provided the value of the Pool Credit and the amount by which it lowers the Ohio retail capacity charge.

In addition to the Pool Credit, an energy credit also reduced the capacity charge approved by the PUCO. This energy credit included the energy sales made from the Mitchell units. When the Mitchell units are transferred and the Pool Agreement ends, the energy credit would be reduced and the Pool Credit will be zero. This would result in a higher Ohio retail capacity charge all else being equal. The off-set to the end of the Pool Credit and energy credit, is the elimination of the Mitchell (and Amos 3) expenses that would no longer be on OPCo's books after the transfer of the units. These increases and reductions in the PUCO-determined capacity charge, if re-calculated on January 1, 2014, would in all likelihood result in a higher capacity charge, but there is no double recovery as suggested by KIUC witness Kollen.

Q. **WILL THE PUCO-DETERMINED CAPACITY CHARGE BE UPDATED AFTER THE POOL AGREEMENT TERMINATES AS PROPOSED BY OPCO IN ITS FILING?**

A. No. The PUCO did not accept the proposal for a formula rate to be updated annually, so the capacity charge is fixed for the entire transition period and, therefore, even though the Pool Credit and energy credits for the transferred units end effective January 1, 2014, they remain as a permanent reduction to the capacity charge to be charged in Ohio for the January 1, 2014 through May 31, 2015 transition period, thus eliminating any potential for double recovery because, as I discuss below, the Pool Credit is a good proxy for the assets being transferred.

Q. DID OPCO PREPARE A CALCULATION OF THE CAPACITY CHARGE WITHOUT THE MITCHELL UNITS?

A. No. However, I am confident that if the PUCO-determined capacity charge was updated after the transfer of the Mitchell units and the termination of the Pool Agreement, the updated capacity charge would in fact be higher than the capacity charge approved by the PUCO. In support of this conclusion I can point to Exhibit PJN-3 attached to my direct testimony filed March 30, 2012 in the ESP Case. This exhibit shows that OPCo sold about 2500 MW to other Pool Agreement members, which is comparable to the capacity of the Mitchell and Amos units being transferred to Kentucky Power and APCo. The Pool Credit of $401 million associated with the 2500 MW sold to other Pool Agreement members, which reduced the PUCO-determined capacity charge, exceeds the carrying cost of 100% of the Mitchell units and OPCo's share of Amos Unit 3.

VI. PUCO APPROVED POOL MODIFICATION RIDER

Q. GRANTED THAT THE PUCO APPROVED CAPACITY CHARGE DOES NOT COMPENSATE OPCO FOR ITS LOST POOL AGREEMENT REVENUE, THE PUCO APPROVED A SEPARATE RIDER PROVIDING OPCO THE POTENTIAL FOR SUCH RECOVERY, DID IT NOT?

A. Yes. However, the rider would only apply if the Mitchell and Amos unit transfers were not approved. This was in recognition of the fact that if all OPCo generating units were to be retained for OPCo's retail customers' benefit, then the rider should compensate OPCo for its lost wholesale (Pool Agreement) revenue, since the PUCO's approved capacity charge and other retail rates did not. If OPCo were permitted to transfer the units, then it would no longer have the need to recover the costs of the transferred units thus reducing or eliminating the need for the rider charge. Approval of a separate rider charge only in the event that the assets are not transferred is further evidence, again ignored by Mr. Kollen, that the current capacity charge mechanism does not allow for double recovery.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY?

A. The evidence presented in the PUCO cases cited by KIUC in its response to Commission Staff's First Request for Information No. 6, does not support its contention that there would be a double recovery of Mitchell costs during the 17-month period from January 1, 2014 through May 31, 2015. In fact an examination of the record in the cases cited by KIUC refutes this contention. Clearly with the termination of the Pool Agreement, OPCo is losing substantial capacity revenue that is not being recovered by retail customers in Ohio, so there is no double recovery. The KIUC's accusation is not supported by any evidence they have offered.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes it does.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AUTHORIZING THE TRANSFER TO THE COMPANY OF AN UNDIVIDED FIFTY PERCENT INTEREST IN THE MITCHELL GENERATING STATION AND ASSOCIATED ASSETS; (2) APPROVAL OF THE ASSUMPTION BY KENTUCKY POWER COMPANY OF CERTAIN LIABILITIES IN CONNECTION WITH THE TRANSFER OF THE MITCHELL GENERATING STATION; (3) DECLARATORY RULINGS; (4) DEFERRAL OF COSTS INCURRED IN CONNECTION WITH THE COMPANY'S EFFORTS TO MEET FEDERAL CLEAN AIR ACT AND RELATED REQUIREMENTS; AND (5) ALL OTHER REQUIRED APPROVALS AND RELIEF

Case No. 2012-00578

**KIUC'S RESPONSES TO
COMMISSION STAFF'S
FIRST REQUEST FOR INFORMATION**

6. Refer to page 22, lines 6 through 8 of the Kollen Testimony. Provide support for the statement, "Ohio Power Company will continue to receive a form of cost- based recovery for the Mitchell units through May 31, 2015.

RESPONSE:

Please refer to the PUCO Orders in Case Nos. 10-2929 and 11-346, which are available on the PUCO website. In addition, please refer to the testimony of AEP Ohio Power Company witnesses Kelly D. Pierce in Case No. 10-2929 and Phillip J. Nelson in Case No. 11-346 wherein they start with that company's steam plant in service from the FERC Form 1. These testimonies are also available on the PUCO website. The steam plant in service amounts include the Mitchell units. In Case No. 10-2929, the PUCO determined an appropriate cost-based capacity

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AUTHORIZING THE TRANSFER TO THE COMPANY OF AN UNDIVIDED FIFTY PERCENT INTEREST IN THE MITCHELL GENERATING STATION AND ASSOCIATED ASSETS; (2) APPROVAL OF THE ASSUMPTION BY KENTUCKY POWER COMPANY OF CERTAIN LIABILITIES IN CONNECTION WITH THE TRANSFER OF THE MITCHELL GENERATING STATION; (3) DECLARATORY RULINGS; (4) DEFERRAL OF COSTS INCURRED IN CONNECTION WITH THE COMPANY'S EFFORTS TO MEET FEDERAL CLEAN AIR ACT AND RELATED REQUIREMENTS; AND (5) ALL OTHER REQUIRED APPROVALS AND RELIEF	Case No. 2012-00578

KIUC'S RESPONSES TO COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION

charge and allowed the Company to defer the difference between the revenues based on that capacity charge and RPM. In Case No. 11-346, the PUCO established a cost-based "state compensation mechanism" that provided for further recoveries of the same costs, subject to an earnings cap under the Significantly Excessive Earnings Test, and recovery of the capacity charges deferrals and the state compensation mechanism deferrals.

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF:

The Application Of Kentucky Power Company For:	)	
(1) A Certificate Of Public Convenience And Necessity	)	
Authorizing The Transfer To The Company Of An	)	
Undivided Fifty Percent Interest In The Mitchell	)	
Generating Station And Associated Assets; (2) Approval	)	
Of The Assumption By Kentucky Power Company Of	)	Case No. 2012-00578
Certain Liabilities In Connection With The Transfer Of	)	
The Mitchell Generating Station; (3) Declaratory Rulings;	)	
(4) Deferral Of Costs Incurred In Connection With The	)	
Company's Efforts To Meet Federal Clean Air Act And	)	
Related Requirements; And (5) For All Other Required	)	
Approvals And Relief	)	

REBUTTAL TESTIMONY

OF

ROBERT L. WALTON

May 3, 2012

VERIFICATION

The undersigned, Robert L. Walton being duly sworn, deposes and says he is the Managing Director of Projects for American Electric Power that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

ROBERT L. WALTON

STATE OF OHIO)
) CASE NO. 2011-00578
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Robert L. Walton, this the 1 day of May 2013.

NOTARIAL SEAL
STATE OF OHIO

PETRA G. MYERS
NOTARY PUBLIC
STATE OF OHIO
Comm. Expires
May 29, 2017
Recorded in
Fairfield County

Notary Public

My Commission Expires: 5-29-2017

REBUTTAL TESTIMONY OF
ROBERT L. WALTON, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2012-00578

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ROBERT L. WALTON, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q: PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Robert L. Walton, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by the American Electric Power Service Corporation ("AEPSC") as Managing Director of Projects. AEPSC supplies engineering, financing, accounting, project management and planning and advisory services to the ten electric operating companies of the American Electric Power System, one of which is Kentucky Power Company ("Kentucky Power").

Q: DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING ON BEHALF OF KENTUCKY POWER?

A. No, I did not. I am filing testimony as a rebuttal witness on behalf of Kentucky Power.

II. BACKGROUND

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I graduated from The Ohio State University in Columbus, Ohio in 1974 with a Bachelor of Science Degree in Mechanical Engineering. From 1975 to 1978 I was employed by the Babcock and Wilcox Company ("B&W") as a Field Service Engineer. From 1978 to 1985, I was employed by the B&W Construction Company in various positions of increasing responsibility including Site Project

Engineer, Site Construction Manager, and ultimately Regional representative, responsible for all aspects of Company business in a five-state area.

I joined American Electric Power ("AEP") in 1985 as a Senior Engineer progressing to Assistant Manager in 1987 and then to Manager of Maintenance Planning in 1988. In 1993, I was named Manager of Steam Generation Engineering and became Manager, Selective Catalytic Reduction ("SCR") Engineering in 1999. In 2000, I became the Director, Engineering & Consulting Services West. In 2003, I was named Director, Environmental Projects and subsequently named Managing Director, Plant and Environmental Retrofit Projects in April 2006. During this tenure, I was involved in or responsible for the installation of 13 individual Flue Gas Desulfurization ("FGD") systems and 10 individual SCR systems on AEP and AEP affiliate facilities, including Kentucky Power's Big Sandy Unit 2. In November 2010 I became the Managing Director of Projects and Controls with expanded additional responsibility for project scheduling and monitoring services as well as cost analysis and control services. I was named to my current position of Managing Director of Projects in January 2013.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. I offered testimony on behalf of Kentucky Power before the Kentucky Public Service Commission ("KPSC") in Case No. 2011-00401. I have also submitted written testimony on behalf of Indiana Michigan Power Company before the Indiana Utility Regulatory Commission in Cause Nos. 43636, 43636

ECR 1, 44033, and Cause No. 44331 as well as written testimony before the Michigan Public Service Commission in Case No. U-16801. In addition, I have submitted written testimony on behalf of Appalachian Power Company in Case No. PUE-2008-00045 before the Virginia State Corporation Commission.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my rebuttal testimony is to respond to KIUC Witness Kollen's opposition to the deferral of certain Big Sandy Unit 2 study costs and to support Company Witness Wohnhas' rebuttal testimony. Specifically, I discuss the prudency of the Company's decision to perform a feasibility study to investigate the need to retrofit Big Sandy Unit 2 with FGD technology.

Q. ARE YOU SPONSORING AN EXHIBIT WITH YOUR REBUTTAL TESTIMONY?

A. Yes; I am sponsoring Rebuttal Exhibit RLW-1R.

Q. WAS THE REBUTTAL EXHIBIT PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, it was.

IV. PRUDENCY OF THE BIG SANDY UNIT 2 FEASIBILITY STUDY

Q. KIUC WITNESS KOLLEN RECOMMENDS THAT THE KPSC NOT APPROVE THE ESTABLISHMENT OF A REGULATORY ASSET RELATED TO COSTS INCURRED BY THE COMPANY DURING 2004 THROUGH 2012 FOR THE INVESTIGATION OF A FGD RETROFIT

TECHNOLOGY AT BIG SANDY UNIT 2. DO YOU AGREE WITH HIS RECOMMENDATION?

A. No, I do not. The cost of the work performed on the Big Sandy Unit 2 retrofit technology feasibility investigation from 2004 through 2012 was prudently incurred. The investigation was undertaken in response to known and/or emerging environmental regulations, and ensured that Kentucky Power was prepared to address these regulations with a least cost compliance plan. In the absence of such an investigation, Kentucky Power would not have been in a position to make an informed planning decision regarding Big Sandy Unit 2.

Q. KIUC WITNESS KOLLEN STATES THAT THERE WERE TWO SEPARATE AND DISTINCT INVESTIGATIONS OF SCRUBBER RETROFIT ALTERNATIVES FOR BIG SANDY UNIT 2. IS THAT CORRECT?

A. No. The engineering work performed during 2004-2012 to determine the most cost effective technology to reduce the emission of sulfur dioxide ("SO_2") from Big Sandy Unit 2 was a single investigation as shown in Rebuttal Exhibit RLW-1R. This investigation was suspended for a period of time (2006-2010), and the technology selected was changed from wet FGD to dry FGD. However, the work was part of a single investigation, with all costs associated with it recorded to a single project.

Q. PLEASE PROVIDE A MORE DETAILED DESCRIPTION OF THE INVESTIGATION.

A. The work began in 2004 in response to the Clean Air Interstate Rule ("CAIR") requirements. In 2006, during the course of the investigation, the Company determined that suspending work on the project would be the most prudent path forward and would provide the most benefit to Kentucky Power and its customers.

The project to retrofit Big Sandy Unit 2 was continued in 2010 to meet the requirements of AEP's New Source Review ("NSR") Consent Decree, of which Kentucky Power was a party. Kentucky Power was bound by this decree to retrofit a FGD system on Big Sandy Unit 2 by December 31, 2015. Based upon our experience and knowledge, it was known that the FGD retrofit would require 54 to 60 months from the continuation of the investigation to the start-up of the FGD system. To meet the required in-service date, AEPSC continued the project in the first quarter of 2010 in support of a Certificate of Public Convenience and Necessity application filing[1]. The suspension of the project in 2006 also allowed time for new co-beneficial technology to develop in the marketplace that would be more suitable to comply with final and proposed EPA regulations, which created even more potential benefit for Kentucky Power's customers.

Q. WHEN THE PROJECT WAS CONTINUED IN 2010, DID THE COMPANY SIMPLY PICK UP FROM WHERE IT LEFT OFF?

A. No. The prudent path forward was to first reexamine our previous 2004-2006 efforts which had resulted in our selection of a wet FGD technology for Big Sandy Unit 2. Several developments had occurred that affected the power industry and our ongoing analyses, also playing an integral part in the decision-making process for retrofitting a FGD on Big Sandy Unit 2. These changes

[1] KPSC Case No. 2011-00401

included lower natural gas prices, the development of a new cost-effective dry FGD ("DFGD") technology, and the issuance of final and proposed environmental regulations as discussed by Company witness McManus in his direct testimony. The Company's evaluation during 2010-2012 resulted in its determination that if Big Sandy Unit 2 were to remain a cost-effective source of generation for Kentucky Power's customers, then the installation of a DFGD system was necessary for compliance with the final and proposed environmental regulations as well as compliance with the NSR consent decree.

Q. DID THE COMPANY USE ANY INFORMATION FROM THE INVESTIGATION DURING 2004-2006 WHEN IT CONTINUED ITS EVALUATION IN 2010?

A. Yes. Not only was the 2004-2006 cost estimation work for the wet FGD system utilized in the continuing analyses performed in 2010-2012, but the work performed to establish the site layout, the balance of plant ancillary services requirements, the coal handling modification requirements, the byproduct handling and disposal requirements, the reagent handling requirements and the associated cost estimates of these items were all used in the continuation of the evaluations in 2010-2012.

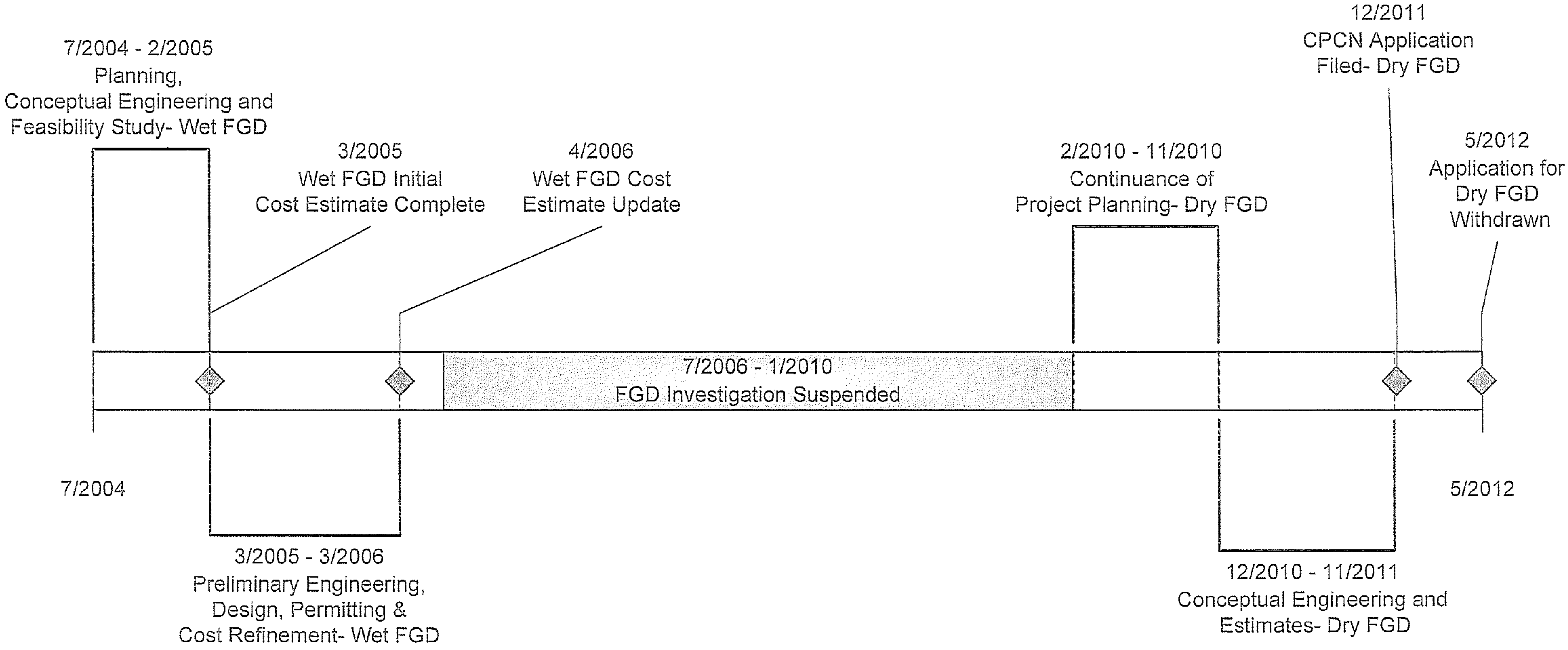
Q. IN RETROSPECT, DID THE COMPANY PERFORM ITS INVESTIGATION TO RETROFIT A FGD TECHNOLOGY ON BIG SANDY UNIT 2 IN A REASONABLE AND PRUDENT MANNER, GIVEN THE INFORMATION AVAILABLE AT THE TIME?

A. Yes. Given the information available at the time, the Company performed its investigation to retrofit a FGD technology on Big Sandy 2 in a reasonable and prudent manner. The methodology used minimized the cost incurred and ultimately resulted in an informed decision not to retrofit SO_2 reduction technology at Big Sandy Unit 2, to the benefit of Kentucky Power and its customers.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Big Sandy Unit 2 FGD Project
Timeline



COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

The Application Of Kentucky Power Company For: (1) A Certificate Of Public Convenience And Necessity Authorizing The Transfer To The Company Of An Undivided Fifty Percent Interest In The Mitchell Generating Station And Associated Assets; (2) Approval Of The Assumption By Kentucky Power Company Of Certain Liabilities In Connection With The Transfer Of The Mitchell Generating Station; (3) Declaratory Rulings; (4) Deferral Of Costs Incurred In Connection With The Company's Efforts To Meet Federal Clean Air Act And Related Requirements; And (5) For All Other Required Approvals And Relief	) Case No. 2012-00578

REBUTTAL TESTIMONY

OF

SCOTT C. WEAVER

May 3, 2013

REBUTTAL TESTIMONY OF
SCOTT C. WEAVER, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2012-00578

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SCOTT C. WEAVER, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION?

A. My name is Scott C. Weaver, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by the American Electric Power Service Corporation (AEPSC) as Managing Director-Resource Planning and Operational Analysis.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS CASE?

A. Yes. I filed direct testimony on behalf of Kentucky Power Company (Kentucky Power or, the Company).

II. PURPOSE

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to certain arguments made by Kentucky Industrial Utility Customers, Inc. (KIUC) witnesses Lane Kollen and Phillip Hayet in their respective testimonies; as well as the testimony of Sierra Club, et al, (SC) witness Tim Woolf.

For Mr. Kollen, I will first challenge the recommended resource plan offered by KIUC. KIUC's recommendation includes only a 20% Mitchell transfer which is insufficient to meet the long-term needs of Kentucky Power's customers. I will, along with other Company witnesses, address the issue of a need for a "market test" to support the proposed (net book value) price of the proposed 50% Mitchell transfer. I will also challenge the changes proposed by Mr. Kollen (as well as Mr. Hayet) as it relates to the long-term commodity pricing assumptions utilized in the Company's Strategist®-based least-cost resource modeling; with a particular focus on PJM capacity pricing assumed in that modeling. Lastly, I will address assertions by Mr. Kollen that Kentucky Power has understated the levels of future annual operation and maintenance (O&M) expenditures captured in that modeling for Mitchell.

For Mr. Hayet, I will rebut his support of the KIUC recommended resource plan and its reliance on only a 20% Mitchell transfer which he based on his high-level takeaways from the Company's separate (AURORAxmp) risk modeling that was offered in my direct testimony. I will also address certain modeling that Mr. Hayet performed—using the Strategist® tool—that would seek to "re-cast" the Company's modeled results using his own improper input parameters. In response to that KIUC modeling, Company witness Bletzacker will also address, at greater depth, the impropriety of utilizing other long-term commodity pricing data as suggested by Mr. Hayet that are sourced from the U.S. Energy Information Administration (EIA), as compared to the Company's forecast of fundamental pricing used in the unit disposition modeling that was performed. I will discuss that a re-analysis performed by the Company of a modified set of "EIA-based" long-term pricing estimates will refute KIUC's attempt to establish through its modeling that Kentucky Power's alternative inclusive of a 50% transfer of Mitchell generating station is somehow more costly than KIUC's recommended 20% transfer.

Finally, for Mr. Woolf I will refute his argument that the Company's unit disposition analysis addressing Big Sandy 1 and 2 was deficient because, according to Mr. Woolf, it lacked consideration of incremental levels of demand-side management (DSM) as well as renewable resources. In particular, I will address the significant discussion he offers in his direct testimony on the levels of DSM that could reasonably be expected to be achieved by Kentucky Power. Note also that while Mr. Woolf offers other rebuttable issues in his testimony, to the extent they are similar to issues raised by KIUC witnesses, I will address those rebuttable points in the designated sections of Messrs. Kollen and Hayet.

III. <u>COMPANY CORRECTION OF THE STRATEGIST®-MODELED RESULTS PROVIDED IN DIRECT TESTIMONY</u>

Q. **PLEASE DESCRIBE THE MODELING CORRECTION.**

A. It was brought to the attention of the Company by KIUC that, in their modeling emulation of the resource options analyzed by the Company, an understatement of costs was uncovered with respect to those options that incorporated some level of Mitchell asset transfer. Specifically, the Company's Strategist® modeling—as did KIUC's—incorrectly reflected capacity revenue associated with the Mitchell transfer that would be attributable to Kentucky Power for the period January 2014 through May 2015.

Q. **HOW DID THE STRATEGIST® RESULTS CHANGE AND WERE THOSE CHANGES SIGNIFICANT?**

A. First, the modification just described was <u>not</u> significant in that there is no material impact on the relative economic results originally offered by the Company. Only a brief, 17-month period would be impacted within the full (30-year) study period. Exhibit SCW-1R offers a "modified" summarization of the relative cumulative present worth (CPW) of costs across the eleven (11) Big Sandy disposition options examined by the Company (previously summarized on Exhibit SCW-5 of my direct testimony). **TABLE 1R** that follows further capsulized those 'Original' and 'Modified' relative cost determinations.

TABLE 1R
KPCo
Relative Economic (CPW) Comparisons
Big Sandy Disposition Alternatives
Modfication to Reflect No Capacity Value for Mitchell Transfer (1/2014 thru 5/2015 only)
Base Pricing
2011-2040 Study Period, 2011$

($Millions)	(A) Based on **Company's Original Analysis** *(From: Weaver Direct, Exhibit SCW-5)*		(B) Based on **Company's MODIFIED Analysis** *(From: Weaver Rebuttal, Ex. SCW-1R)*		(B) - (A) *RELATIVE CPW IMPACT of Capacity Value 'Basis'*	
CASE 'X'...	Case # 'X' *vs.* **Case #6**	Case # 'X' *vs.* **Case #5A**	Case # 'X' vs. **Case #6**	Case # 'X' vs. **Case #5A**	*Case # 'X' vs. **Case #6***	*Case # 'X' vs. **Case #5A***
#1A *(BS2 DFGD w/ 20% ML)*	490	646	469	626	*(21)*	*(21)*
#1B *(BS2 DFGD w/ PJM Market)*	697	854	663	819	*(34)*	*(34)*
#2A *(New CC w/ 20% ML)*	347	504	327	483	*(21)*	*(21)*
#2B *(New CC w/ PJM Market)*	560	717	526	682	*(34)*	*(34)*
#3A *(BS1 CC Repwr w/ 20% ML)*	423	580	402	559	*(21)*	*(21)*
#3B *(BS1 CC Repwr w/ PJM Market)*	633	789	598	755	*(34)*	*(34)*
#4A *('Full' Market 5 Yrs, then CC)*	411	567	376	533	*(34)*	*(34)*
#4B *('Full' Market 10 Yrs, then CC)*	435	591	401	557	*(34)*	*(34)*
#5A *(50% ML w/ BS1 gas conversion)*	(156)	-	(156)	-	-	-
#5B *('Full' Market 5 Yrs, then CC w/ BS1 conv)*	258	414	223	380	*(34)*	*(34)*
#6 *(50% ML w/ PJM Market)*	-	156	-	156	-	-

As demonstrated in the table, the relative impact of this recognized capacity value adjustment was to slightly reduce the study period cost advantage of either of the two analyzed options incorporating a 50% Mitchell Transfer (Option #5A, or Option #6) by amounts ranging from $21 to $34 million; or amounts representing approximately only a 0.36% to 0.59% change in CPW from results offered in the original analysis filed in this case.

Q. DOES KIUC CONCUR WITH THIS IMPACT?

A. Yes. In reviewing the Amended Direct Testimony and Exhibits of KIUC witness Hayet, his adjustments appear to be very similar, with the modeled CPW of costs for a "50%" Mitchell transfer option being increased by $34.27 million (versus my calculation of $34.42 million); and for a "20%" Mitchell transfer option being increased by $13.71 million (versus my calculation of $13.77 million).

KOLLEN REBUTTAL

IV. KIUC's RECOMMENDED RESOURCE PLAN LEAVES KENTUCKY POWER SIGNIFICANTLY CAPACITY DEFICIENT RELATIVE TO PJM REQUIREMENTS

Q. WHAT IS MR. KOLLEN'S RECOMMENDATION FOR KENTUCKY POWER'S FUTURE RESOURCES IN GENERAL, AND, SPECIFICALLY, AS IT PERTAINS TO THE TRANSFER OF THE MITCHELL ASSETS?

A. On page 4 of his direct testimony, Mr. Kollen recommends that the Commission authorize the Company to transfer only 20% of the Mitchell generating units. In addition, he recommends that this acquisition be combined with a Big Sandy Unit 1 conversion from a coal-fired to a gas-fired unit as well as market purchases to satisfy, presumably, PJM-required minimum reserve margin criterion on a short-term basis. Mr. Kollen's recommendation actually combines two Mitchell-related components: 1) that the Company transfer only 20% of the Mitchell facility; and 2) that the transfer of that 20% interest be delayed until June 1, 2015. Both recommendations are problematic and Company witnesses Pauley and LaFleur also address the timing of the transfer.

Q. DO YOU CONCUR WITH THR FIRST COMPONENT OF KIUC'S RECOMMENDATION?

A. No. As I will describe, this myopic consideration of Kentucky Power's resource planning needs ignores the long-term and should be dismissed as lacking in thought and detail. Mr. Kollen—and Mr. Hayet—are effectively suggesting that the Company should ignore established PJM criterion for minimum reserve margins, which it is required to maintain.

Q. WHAT ARE THOSE PJM REQUIREMENTS AND TO WHAT EXTENT DO KIUC'S RECOMMENDATIONS FAIL TO ACHIEVE THEM?

A. As described in my direct testimony, Kentucky Power—along with affiliates Appalachian Power Company (APCo) and Indiana Michigan Power Company (I&M)—have an obligation to achieve a combined (or, "3-company") minimum PJM Installed Reserve Margin (IRM) requirement through and including the most recently-established 2016/17 PJM 3-year forward capacity planning year as part of the elected Fixed Resource Requirement (FRR) planning option. As also described in that testimony, under the proposed Power Coordination Agreement, Kentucky Power, APCo and I&M need to be self-sufficient for both capacity and energy requirements.

Exhibit SCW-2R offers a summary of the Kentucky Power shortfall, on a "stand-alone" basis, resulting from KIUC's recommended resource plan vis-à-vis the PJM minimum reserve margin criterion. The summary clearly indicates that beginning with the 2015/16 capacity planning year, the KIUC-recommended resource plan for Kentucky Power would fall 406 MW below the PJM minimum threshold; and, in fact, would result in an unacceptable *negative* 35.4% reserve margin (-35.4%).

Q. DID MR. KOLLEN RECOGNIZE THIS OBLIGATION?

A. No. Nowhere in his direct testimony, did Mr. Kollen address this *longer-term* resource requirement. Rather, the primary thrust of his testimony is his allegation of "wasteful duplication" as it relates to the timing of the transfer of the Mitchell units.

Q. DO YOU AGREE THAT THE MITCHELL TRANSFER WILL RESULT IN WASTEFUL DUPLICATION?

A. No. Company witnesses Pauley and LaFleur provide rebuttal testimony regarding the timing of the transfer of the assets and address Mr. Kollen's claims of "wasteful duplication" for a 17-month period (*i.e.*, the proposed Mitchell asset transfer date of January 1, 2014 -to- the expected June 1, 2015 Big Sandy Unit 2 retirement date).

I will focus on certain reserve margin calculation inaccuracies contained in Mr. Kollen's testimony that encompass that period. First, on pages 8 and 9 of his testimony, Mr. Kollen suggests that the 2014 (*i.e.*, 2014/15 PJM Reliability Pricing Model [RPM] planning year[1]) Kentucky Power reserve margin assuming a 50% Mitchell transfer would be 108%. This was determined by taking the difference between Kentucky Power's projected capacity (2,250 MW) and retail summer peak demand (July 2014 of 1,082 MW), or a difference of 1,168 MW; divided by the peak demand (1,168 / 1,082 = 1.08). This does not, however, represent an accurate portrayal of a Kentucky Power stand-alone reserve margin obligation in PJM. An

[1] The PJM-RPM capacity market construct operates on a fiscal planning year beginning June 1 through the following May 31.

important factor in this calculation is that the determination of the Company's peak demand for the established planning years should be based on *PJM's* projection of such load levels, not the Company's. This was clearly noted in the Company's response to KIUC 2-26 (including the first footnote on the attachment to that response) which Mr. Kollen relies on in making his determination. The Company was simply attempting to be responsive to that KIUC request for "monthly" information for the 2014-2015 period but, given that PJM projects only the single summer season coincident peak, providing such PJM information would not have been responsive to the request.

As noted on "Table 1-3" of my direct testimony Exhibit SCW-1, the Kentucky Power portion of the PJM-determined zonal peak demand for the 2014/15 planning year was estimated to be 1,196 MW, net of DSM. Therefore, the correct 2014/15 Kentucky Power stand-alone PJM reserve margin estimate would be approximately 83%, again, not 108% as asserted by Mr. Kollen.[2]

Q. **FURTHER, ON PAGE 5 OF HIS TESTIMONY, MR. KOLLEN ALSO ALLUDES TO A KENTUCKY POWER 2014 RESERVE MARGIN OF "...MORE THAN 140% IN OTHER NON-PEAK MONTHS BEFORE BIG SANDY 2 IS RETIRED." ARE SUCH AMOUNTS AT ALL RELEVANT?**

A. No they are not. It is well established that utilities plan for and ultimately build/buy capacity resources to meet "peak" load events. Therefore a proper reserve margin is primarily focused on ensuring reliability during more extreme weather months. In the

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[2] 2014/15: [2,250 MW (Existing Installed Capacity [ICAP]) - 69 MW (Incremental EFORd) + 11 MW (Interruptible Demand Response)] / 1,196 (Net Internal Demand) = 1.83 – 1 = 83%

case of PJM, that criterion focus is on extreme summer months only—typically June through August—when an overall PJM coincident peak would be anticipated to occur.[3] All other months represent periods with lower peak demands that would naturally result in higher reserve margins; hence any calculation of reserve margins in non-peak months is meaningless. Mr. Kollen not only incorrectly identified Kentucky Power's (PJM-based) reserve margin for that period, but offers these figures to incorrectly support his "wasteful duplication" contention.

Q. **DOES MR. KOLLEN SUGGEST THAT KENTUCKY POWER RELY ON A LIMITED 20% TRANSFER OF THE MITCHELL FACILITY FOR "ONLY" THE 2014/15 PJM PLANNING YEAR, THEN MIGRATE TO A 50% TRANSFER AS RECOMMENDED BY THE COMPANY?**

A. No. Mr. Kollen does not propose any particular plan to fully offset his recommended reduction in Mitchell capacity. Rather, Mr. Kollen alludes to other "diversity" benefits of a lower percentage transfer from the Mitchell facility when combined with a Big Sandy Unit 1 gas conversion. However, as previously discussed, he never offers a specific recommendation or plan to remedy the approximate 400 MW of capacity deficiency beginning in the 2015/16 planning year; suggesting only on page 4 of his testimony that the Company also consider "…market purchases to satisfy on a short term basis any remaining native load."

[3] This is in spite of the fact that Kentucky Power's load shape is "winter-peaking". PJM does not establish reserve margin planning criterion for PJM coincident winter peak demand.

Q. WOULD YOU CONSIDER THAT PRUDENT PLANNING FOR THE BENEFIT OF KENTUCKY POWER'S CUSTOMERS, INCLUDING KIUC'S MEMBERS?

A. Absolutely not.

Q. IN RESPONSE TO MR. KOLLEN'S ASSERTIONS ON PAGE 18 OF HIS TESTMONY THAT THE ACQUISITION OF MITCHELL PRIOR TO JUNE 2015 WOULD RESULT IN KENTUCKY POWER BECOMING "MORE ENERGY LONG" AND SUGGESTING IT "DOES NOT NEED THE ENERGY", COMPANY WITNESS WOHNHAS' REBUTTAL TESTIMONY INDICATES THAT THE POSSIBILITY EXISTS THAT KIUC's RECOMMENDED APPROACH OF DELAYING ANY MITCHELL TRANFER UNTIL JUNE 2015 WILL RESULT IN THE COMPANY HAVING *INSUFFICENT* ENERGY TO MEET ITS NEEDS. COULD YOU PLEASE ADDRESS THIS ISSUE?

A. Yes. As indicated on the following TABLE 2R, based on an assessment of the Strategist® modeled results for the specific period January 2014 through May 2015 that are applicable to Option #5B (*i.e.*, <u>No</u> Mitchell transfer, with Big Sandy 1 and 2 operating as coal units through that period), it indicates that Kentucky Power's typical monthly energy position could be "short", or below its internal requirements, by a range of 86 Gwh -to- 473 Gwh. These modeled results are of course dependent on the ultimate monthly energy requirements, assumed planned maintenance schedules, projected forced outage rates, and the unit's 'economic dispatch' (vis-à-vis concurrent projected energy pricing). Additionally, I offer in this table a summary of Kentucky

Power's energy position for these months based on a "MAX (Availability) Threshold". This simply assumes that Kentucky Power's generation sources would *fully*-dispatch during all hours—excluding planned and forced outages—regardless of the relative dispatch economics. Even under that scenario, the Company would be expected to be deficient in meeting its internal energy requirements in 9 of the 17 months in that period.

TABLE 2R

KPCo

Surplus/**(Deficit)** Energy Position <u>Excluding</u> Mitchell Transfer [(A)]

January 2014 thru May 2015

(Gwh)	As Function of KPCo ECONOMIC DISPATCH [(C)]	As Function of KPCo UNIT AVAILABILITY [(B)] *(i.e., MAX Threshold)*
Jan-14	(268)	266
Feb-14	(352)	(55)
Mar-14	(462)	(346)
Apr-14	(415)	(309)
May-14	(457)	(403)
Jun-14	(195)	226
Jul-14	(86)	272
Aug-14	(127)	253
Sep-14	(244)	92
Oct-14	(389)	(293)
Nov-14	(473)	(357)
Dec-14	(321)	131
Jan-15	(135)	268
Feb-15	(250)	27
Mar-15	(411)	(233)
Apr-15	(428)	(342)
May-15	(402)	(265)
Sum	(5,415)	(1,069)

(A) Determined as KPCo's generation sources (including Rockport) *less KPCo* internal energy requirements (internal sales + line losses)

(B) Total Hours *less* Planned Maintenance Hours and Forced Outage rates

(C) Strategist-modeled dispatch (per Company Option #5B)

Q. DO YOU TAKE ISSUE WITH MR. KOLLEN'S RECOMMONDATION TO CONVERT BIG SANDY UNIT 1 TO NATURAL GAS?

A. While I don't have an issue with the potential economic merits of converting Big Sandy Unit 1 to burn natural gas, I do take issue with how Mr. Kollen is presenting that option/capacity. To begin, the Company does not dispute that the conversion of Big Sandy Unit 1 to a gas-fired unit may be the best alternative relative to the disposition of that unit. In fact, the unit disposition evaluation supported in my direct testimony demonstrated that it could be the "least-cost" option.[4] However, recognizing, among other things, the probable lower generation (*i.e.*, capacity factor) of a "gas-steam" unit, the Company also concluded that it would like to consider other alternatives. As a result, the Company opted to seek a competitive long-term (15 year) solicitation of 250 MW of capacity and energy. As clearly and transparently indicated in that Request for Proposals (RFP), the Company,

> "… will use the proposals (Proposals) received as a result of the 250 MW RFP along with the BS1 Conversion cost estimate to determine the least, reasonable cost solution to replacing the Big Sandy Unit 1 capacity as a coal fired generating unit." [5]

Therefore, it is quite possible that the Company could proceed with this conversion option.

However, Mr. Kollen is using the conversion and continued operation of this (Big Sandy U1) capacity to effectively "bolster" the overall longer-term capacity

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[4] "Option #5A" which included a BS1 gas conversion coupled with a 50% Mitchell facility transfer, was the lowest-cost option evaluated as summarized in my direct testimony, Exhibit SCW-5 (as well as Exhibit SCW-1R of this rebuttal testimony) .
[5] Kentucky Power Company 250 MW RFP issued March 28, 2013; pg. 3.

position of the Company. Obviously, *without* that 260 MW of (BS1) capacity, the approximate 380 -to- 400 MW of Kentucky Power capacity "gap" in PJM—as outlined in my Exhibit SCW-2R—would approach 650 MW, or more. Given the arguments he offers regarding the need for full market-based price discovery as it pertains to the transfer cost/price of the 50% share of Mitchell 1 and 2, I find it disingenuous that he would not embrace the fact that the Company is examining potential market solutions in lieu of a Big Sandy Unit 1 gas conversion, but rather "assume" up-front this gas conversion option.

Q. FOCUSING ON MR. KOLLEN'S CONTENTION ON PAGE 5 OF HIS TESTMONY THAT HIS RECOMMENDATION WOULD OFFER "GREATER RESOURCE DIVERSITY", HOW DO YOU RESPOND?

A. The Company's ultimate resource plan will lead to greater resource/fuel diversity. The Company is proposing to retire 1,078 MW of coal-fired capacity in the form of the Big Sandy units, but also proposes to replace it with <u>only</u> 780 MW of coal-fired capacity associated with proposed Mitchell facility transfer. The difference will either be a gas-converted Big Sandy Unit 1 *or* a market-purchased resource. That is far removed from a one-for-one replacement of coal. Rather the Company would expect to see its overall gas-fuel diversity factor to increase from *zero* to approximately 18 percent of total resources.[6]

V. <u>SUFFICIENT ANALYSIS WAS PERFORMED TO DEMONSTRATE THE (NET BOOK) VALUE OF THE MITCHELL ASSETS WOULD BE EXPECTED TO BE BELOW A "MARKET" VALUE</u>

[6] Either: 250 MW (market) or 260 MW (converted BS1) of potential "gas-sourced" supply / [Rockport purchase power (393 MW) + 50% Mitchell transfer (780 MW) + (either: 250 MW or 260 MW)] = 18%.

Q. ON PAGES 9-16 OF HIS DIRECT TESTIMONY, MR. KOLLEN STATES THAT THE COMPANY HAS FAILED TO ADEQUATELY ESTABLISH THAT THE MARKET VALUE OF THE MITCHELL ASSETS WAS EQUAL TO OR ABOVE THE PROPOSED (NET BOOK VALUE) TRANSFER PRICE. DO YOU AGREE WITH HIS ASSERTION?

A. No I do not, for the reasons I will describe along with those of Company witnesses Pauley and McDermott. For instance, as discussed in Dr. McDermott's rebuttal testimony at page 4, there are sufficient market proxies or "benchmarks" reflected in the Company's analysis to mitigate the need to solicit a formal RFP process for purposes of establishing a market value for 50% of the Mitchell facility.

Q. DID MR. KOLLEN RECOMMEND A WAY TO OBTAIN A MARKET VALUE FOR THE MITCHELL UNITS?

A. Yes. On page 9 of his testimony, Mr. Kollen suggests that "(t)he best way to obtain an actual market value is through an RFP either to sell (the Mitchell units) or acquire (replacement for Big Sandy 2). Another approach, also suggested by SC witness Woolf, is to develop a proxy for market value by reviewing sales or purchases of similar units."[7]

Q. DO YOU AGREE WITH HIS RECOMMENDATION?

A. No. Regarding an RFP to sell the Mitchell units, such an approach would have been artificial and less than genuine for the bidding community. Such "price fishing" would have been viewed as an attempt to gain market intelligence for capacity

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[7] SC witness Woolf suggests on page 40 of his testimony that "…it is standard industry practice to use competitive bidding processes as a way to provide a check on utility analyses, *i.e.*, a 'market test'."

understood to be already obligated. Further, if this capacity would have been offered for sale effective subsequent to the 2014/15 planning year (*i.e.*, effective beginning June 1, 2015), then Kentucky Power (as well as APCo which is seeking to receive the remaining 50% of Mitchell), would have to concurrently replace most or all of the full 1,560 MW of Mitchell ICAP in order to meet the "3-Company" (Kentucky Power, APCo and I&M) FRR commitments for the 2015/16, and now 2016/17 forward FRR planning periods in which the Mitchell capacity has continued to be committed.

Regarding options for the replacement of Big Sandy Unit 2 capacity and energy, my direct testimony provided extensive evidence on the subject. I will highlight pertinent sections that address KIUC's proposal. Specifically, on page 37 of my direct testimony I respond to a question as to why an RFP was not considered by the Company to replace the (full) approximately 1,100 MW of Big Sandy plant capacity:

> "Such a market/option view *was* effectively considered. Option #2 (Retire and Replace Big Sandy 2 with a New Build CC option) offers such a market proxy. Based on the discussion with AEP commercial experts, it is very reasonable to assume that a long-term (minimum, 10-20 year term) competitive purchase power agreement ("PPA") solicitation—for not only up to as much as 1,100 MW of replacement capacity, but for the largely baseload energy also being replaced—would likely be offered/priced at the cost of a new-build combined cycle in response to such an RFP. Based then on indicative cost-of-electricity evaluations that would assess the cost of a new-build CC, for instance, it

> was determined that such options would likely exceed the cost of the Mitchell generating asset transfer."

Beyond such a screening exercise indicated above, the Company has demonstrated that a new-build CC-based market value proxy would result in a significantly greater cost for Kentucky Power and its customers when compared to the costs of the 50% Mitchell transfer options (*i.e.*, either Company-evaluated Option #5A or Option #6). Because the Company's analysis a) examined *all* performance and cost attributes of an efficient replacement gas-fired CC generating facility and, b) utilized the units' estimated December 31, 2013 Net Book Value (NBV) as the price for the Mitchell transfer; it can be concluded that the equivalent market replacement value/cost would have exceeded Mitchell's (50%) NBV. Rather, Mr. Kollen's accusations that the Company's conclusions were based on "self-serving, circular and conclusory reasoning"[8] is *itself* short-sighted in that it fails to fairly recognize the rigor that went into the comparative modeling. The Company employed proper analytics and transparently set forth its modeling approach and all underlying assumptions. For example, the modeling for future costs associated with the Mitchell facility included known and emerging U.S. Environmental Protection Agency (EPA) initiatives around effluent guideline, coal combustion residuals (CCR) and Clean Water Act "316(b)" rulemaking, *as well as the potential for a carbon tax in the future;* a prospect clearly more deleterious to a coal solution versus a natural gas solution. Further, the Company employed an extensive stochastic (Monte Carlo) analysis that clearly indicated a "market dependent" option based on a larger exposure to (PJM) capacity

[8] Kollen at pg. 11.

and energy market volatility would result in a solution with greater long-term "revenue requirement at risk (RRaR)" than either of the solutions which included a 50% Mitchell transfer (Options #5A and #6).[9] In fact, Mr. Kollen's—nor Mr. Woolf's—testimony offer no mention of that RRaR analysis performed by Kentucky Power. Despite the fact that the Company has provided more than ample "empirical evidence", Mr. Kollen simply broad-brushes the Company's analysis as being lacking without any support for his position.

Q. **DO YOU STAND BY YOUR PRIOR CONCLUSION THAT THERE IS NO NEED FOR AN RFP FOR THE REPLACEMENT OF <u>ALL</u> OF BIG SANDY?**

A. Yes. I conclude that the Company's analysis, and its costs of various resource options, fully supports that a market valuation would exceed the NBV of the Mitchell units. I also conclude that the comparative examination and analysis of a new-build CC option provides the reasonable benchmarks that were required by the Company. This conclusion is also supported by Company witness McDermott at pages 3 and 4 of his rebuttal testimony, as well as on page 10 of his direct testimony.

Q. **DOES MR. KOLLEN (OR MR. WOOLF) OFFER SPECIFIC EVIDENCE THAT EXISTING GAS-FIRED GENERATING ASSETS ARE AVAIABLE TO REPLACE BIG SANDY?**

A. No.

Q. **DO YOU BELIEVE THERE IS AN EFFICIENT, LOW-COST COMBINED CYCLE FACILITY THAT WOULD OFFER A LOWER ECONOMIC COST THAN THE MITCHELL UNITS?**

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[9] Weaver direct at pgs. 42-44; Exhibit SCW-1, pgs. 14-15.

A. I believe it is very doubtful. On page 41 of my direct testimony I provided an analysis of the "break-even" price for a CC that would result in the long-term study period CPW cost profile being on par with the costs of the 50% Mitchell transfer option. That is, what reduction in the cost to install a new-build CC would it take for the relative study period cost differentials between that option and the 50% Mitchell transfer option to be zero dollars (*i.e.*, an economic "point of indifference"). Based on the slight modifications to the study period CPW costs now summarized on TABLE 1R (and Exhibit SCW-1R) of this rebuttal testimony, when comparing the results between Option #2B (New-Build CC, with no Mitchell transfer) and Option #6 (50% Mitchell transfer, with no BS1 gas conversion), the cost of a new-build CC would have to decline by $587 million (nominal dollars), or by 47.5%, to a cost of $613 per kW (2011 dollars) to achieve that economic point of indifference with the 50% Mitchell transfer option. That "break-even" CC cost figure would have to be reduced *even further*, perhaps as low as $430/kW, or less, if one speculated that the replacement CC could be an existing facility. This would be due to the fact that an existing facility would naturally be an older vintage asset (in all likelihood, built in the late-1990's/early-2000's), with poorer thermal efficiency (heat rate), and costlier to operate—including being prone to higher and earlier major capital maintenance—vis-a-vis the modeled new-build CC.

Expanding this break-even analysis exercise to compare results versus the lowest cost alternative the Company evaluated—*Option #5A*—which called for a 50% Mitchell replacement *with* Big Sandy 1 converted to gas—the latter prospect essentially being endorsed by Mr. Kollen (as well as Mr. Hayet)—that economic point of indifference required the cost of the replacement new-build CC to fall even lower, to $448/kW (2011 dollars), or a reduction of ***nearly 62%***. This revised break-even purchase price would perhaps fall even further to a discounted value as low as $310/kW, or less, based again on the relative poorer attributes of an existing (versus new) CC facility. Such a price for an existing CC will likely not be found in today's asset marketplace.

In my estimation, this break-even analysis, together with the body of evidence the Company has offered regarding the cost of various options, demonstrates the merits of not pursuing an RFP for replacement capacity for the whole of Big Sandy.

VI. THE LONG-TERM COMMODITY PRICING ASSUMPTIONS USED IN THE COMPANY'S STRATEGIST® MODELING ARE REASONABLE

Q. **BEGINNING ON PAGE 23 OF HIS TESTIMONY, MR. KOLLEN DESCRIBES THE IMPAIRMENT ANALYSIS TESTS PERFORMED BY AEP FOR EACH OF THE OPCO (aka AEP-OHIO) GENERATING UNITS, INCLUDING THE MITCHELL UNITS. DOES MR. KOLLEN SUGGEST THAT THESE ANALYSES WERE PERFORMED INCORRECTLY, OR IN A MANNER NOT IN ACCORDANCE WITH GENERALLY ACCEPTED ACCOUNTING PRINCIPLES?**

A. No. Mr. Kollen's testimony does not indicate that these impairment analyses, including the results of the recoverability test analysis offered for Mitchell Units 1 and 2 within the response to (Confidential) KIUC 2-55, were performed inappropriately.

Q. DID MR. KOLLEN SUMMARIZE THE RESULTS OF THAT TEST AS IT PERTAINED TO THOSE MITCHELL UNITS?

A. No he did not.

Q. WHAT WERE THE RESULTS OF THAT IMPAIRMENT ANALYSIS RECOVERABILITY TEST FOR THE MITCHELL UNITS?

A. Based on my review of the analysis results summarized on (Confidential) Attachment 1, Page 7 of 8, of the Company's response to KIUC 2-55, and reproduced here as (Confidential) Exhibit SCW-3R, on a combined 'total plant' (100%) basis, Mitchell's projected "Excess Cash Flow over NBV" was estimated at [redacted][10] Accordingly, the analysis indicated that the Mitchell units [redacted]

Q. WHAT IS MR. KOLLEN'S ARGUMENT REGARDING THIS IMPAIRMENT TEST ANALYSIS?

A. Based on a review of the KIUC responses to Company data requests as well as the analysis discussed by Mr. Hayet, Mr, Kollen's primary point is that the analysis performed to support these impairment tests and the Strategist® analysis utilized in this Kentucky Power filing offer different estimated levels of the projected future value for PJM RPM-based capacity. He infers on page 30 of his testimony that the Fundamental Analysis-based capacity value estimates used in Kentucky Power's

[10] [redacted] Mitchell Unit 1; [redacted] Mitchell Unit 2.

Strategist® modeling would create results that would favor the 50% Mitchell transfer alternative (either Options #5A or #6).

Q. **IF YOU USED THE LOWER (IMPAIRMENT ANALYSIS) PROJECTION OF PJM-RPM CAPACITY VALUES, INSTEAD OF THE VALUES DEVELOPED BY THE AEP FUNDAMENTAL ANALYSIS GROUP, WOULD IT CHANGE THE CONCLUSION OF YOUR STRATEGIST®-BASED STUDY THAT THE TRANSFER OF 50% IF MITCHELL IS THE LEAST-COST OPTION?**

A. No. As shown in TABLE 3R below, as well as the supporting Exhibit SCW-4R, *even if* the Company would have utilized the specific "$ per kW-year" capacity value set forth in the impairment test analysis (and included in the response to [Confidential] KIUC 2-55) the results would be largely consistent with my original analysis offered in direct testimony. In other words, this sensitivity analysis demonstrated that whether the capacity values developed by the AEP Fundamental Analysis group are used, or Mr. Kollen's preferred values from the AEP-Ohio generation impairment test analysis, the fact remains that the transfer of a 50% interest in the Mitchell generating station, coupled with the conversion of Big Sandy Unit 1 to natural gas (or, a potentially lower cost RFP result), is the least-cost alternative. In fact, some relative study period CPW cost comparisons of alternatives versus either Option #6, or Option #5A, would become more costly.

TABLE 3R

KPCo

Sensitivity: Relative Economic (CPW) Comparisons

Big Sandy Disposition Alternatives

"Alternative" PJM Capacity Valuation Approaches (2015-2040)

Base Pricing

2011-2040 Study Period, 2011$

($Millions)		(A) Based on **AEP-Fundamental Analysis** Projection of (PJM) Capacity Value (MODIFIED Analysis)		(B) Based on KIUC-recommended PJM Capacity Value/Rate Projection from **AEP-Ohio Impairment Analysis**		*(B) - (A) RELATIVE CPW IMPACT of Modification*	
CASE 'X'...		Case # 'X' *vs.* **Case #6** ***(Per Rebuttal, TABLE 1R)***	Case # 'X' *vs.* **Case #5A** ***(Per Rebuttal, TABLE 1R)***	Case # 'X' vs. **Case #6**	Case # 'X' vs. **Case #5A**	*Case # 'X' vs.* ***Case #6***	*Case # 'X' vs.* ***Case #5A***
#1A	*(BS2 DFGD w/ 20% ML)*	469	626	483	599	*14*	*(27)*
#1B	*(BS2 DFGD w/ PJM Market)*	663	819	585	701	*(78)*	*(118)*
#2A	*(New CC w/ 20% ML)*	327	483	382	498	*55*	*15*
#2B	*(New CC w/ PJM Market)*	526	682	503	619	*(22)*	*(63)*
#3A	*(BS1 CC Repwr w/ 20% ML)*	402	559	414	530	*11*	*(29)*
#3B	*(BS1 CC Repwr w/ PJM Market)*	598	755	532	648	*(66)*	*(107)*
#4A	*('Full' Market 5 Yrs, then CC)*	376	533	270	386	*(106)*	*(146)*
#4B	*('Full' Market 10 Yrs, then CC)*	401	557	195	311	*(206)*	*(246)*
#5A	*(50% ML w/ BS1 gas conversion)*	(156)	-	(116)	-	*40*	*-*
#5B	*('Full' Market 5 Yrs, then CC w/ BS1 conv)*	223	380	131	247	*(93)*	*(133)*
#6	*(50% ML w/ PJM Market)*	-	156	-	116	*-*	*(40)*

Q. UNDERSTANDING THAT EVEN IF MR. KOLLEN IS CORRECT IN ASSERTING THE COMPANY SHOULD HAVE USED THE CAPACITY VALUES FROM THE AEP-OHIO IMPAIRMENT TEST ANALYSIS, BUT RECOGNIZING THE TRANSFER OF A 50% INTEREST IN THE MITCHELL GENERATING STATION WOULD REMAIN THE LEAST-COST ALTERNATIVE, DO YOU AGREE WITH HIS CONTENTION ON PAGE 30 OF HIS TESTIMONY THAT THE ASSUMPTIONS USED IN THE IMPAIRMENT TEST ANALYSIS SHOULD BE GIVEN "...GREATER WEIGHT BECAUSE THEY ARE REVIEWED BY THE COMPANY'S

INDEPENDENT OUTSIDE AUDITOR AND BECAUSE THE COMPANY'S OFFICERS MUST ATTEST TO THE ACCURACY OF THE COMPANY'S FINANCIAL STATEMENTS FOR SEC AND FERC REPORTING PURPOSES."

A. I strongly disagree with this assertion. First, at issue here is the applicability of <u>forecasted</u> data points. Specifically, what is being attested to is the reasonableness of results based on the underlying capacity value data points assumed for the unique modeling undertaken for the AEP-Ohio generation asset impairment test analysis, *versus* the fundamentals-based capacity value data points used in the Company's modeling performed as part of this filing.

To the point, the respective fundamentals-based projection of the value of (PJM-RPM market) capacity used for, specifically, the Company's Big Sandy unit disposition evaluation was the more appropriate value after consideration of the differing requirements and purposes of the two analyses. By way of analogy, it was as reasonable for different capacity values to be used for the respective Strategist®-based unit disposition analysis and the AEP-Ohio impairment study, as it is for a first baseman and a catcher to use different mitts. Although *catching* the ball remains the ultimate objective for both the first baseman and the catcher, the *effective* accomplishment of the common objective is better served by using the glove that is designed for the requirements of a particular position. Such is the case here. By contrast, Mr. Kollen would require for the sake of uniformity that the catcher and first baseman use the same mitt even if doing so resulted in more dropped balls.

As identified on (Confidential) Exhibit SCW-5R, the basis for the capacity value/price used in the AEP-Ohio impairment test analysis—the catcher's mitt—was set [redacted] for the 2016/17 PJM planning year; representing a [redacted] from the levels projected by the Fundamental Analysis group. This was determined to be a reasonable approach for purpose of the AEP-Ohio impairment test analysis exercise. Considering the context of an "impairment test", to the extent that such (market) capacity values/prices were lower, it would comport with a more conservative outcome. In other words, the lower the projected capacity pricing estimate for PJM-RPM, the greater the likelihood that an asset may fail the impairment test. Thus, it was perfectly reasonable for AEP management to conservatively assume a relative greater market exposure (*i.e.*, lower value attribution) by way of introducing such a discounted market price for capacity so as to effectively "stress" or challenge that uniquely-required accounting examination.

Contrastingly, as part of the Company's Big Sandy unit disposition evaluation process, the intent has been to utilize sets of long-term commodity pricing parameters—the first baseman's mitt—that were established through a rigorous modeling-derived process. As discussed in the rebuttal testimony of Company witness Bletzacker, the result of that iterative AURORAxmp-based modeling process was to craft a suite of commodity prices—inclusive of natural gas, various coals, regional energy, emission allowances, *as well as* regional (PJM-RPM) capacity pricing—that is "fitly-joined" and effectively synchronized.

Q. **WOULD YOU PLEASE SUMMARIZE THIS POINT AS TO WHY THE COMMISSION SHOULD NOT BE MISLED BY MR. KOLLEN'S**

ASSERTIONS CONCERNING THE DIFFERENCES IN THE CAPACITY VALUES USED IN THE MITCHELL IMPAIRMENT TEST ANALYSIS AND THOSE USED IN YOUR STRATEGIST®-BASED UNIT DISPOSITION ANALYSIS?

A. Yes. The capacity values used in the Company's Strategist® analysis were reasonable and appropriate for such respective unit disposition analysis purposes. Equally important, even if Mr. Kollen's preferred capacity values are used, the transfer of a 50% interest in the Mitchell facility remains the least-cost alternative.

VII. LEVELS OF PROJECTED MITCHELL O&M UTILIZED IN THE COMPANY'S STRATEGIST® ANALYSIS ARE IN-LINE WITH (AND EXCEED) LEVELS UTILIZED IN THE KENTUCKY POWER RATE IMPACT ANALYSIS

Q. ON PAGES 30 AND 31 OF HIS TESTIMONY, MR. KOLLEN ASSERTS THAT THE COMPANY'S UNIT DISPOSITION ANALYSIS PERFORMED IN STRATEGIST® HAS SIGNIFICANTLY UNDERSTATED THE ANNUAL O&M COSTS FOR THE MITCHELL FACILITY, THEREBY BIASING THE RESULTS IN FAVOR OF THE ASSET TRANSFER OPTION. DO YOU AGREE WITH THAT ASSERTION?

A. No I do not. First, Mr. Kollen failed to consider a variable O&M rate that the Company applied to each Mwh of Mitchell unit generation. Such amounts were clearly identified and offered in Strategist® input documentation provided to KIUC.[11] For 2014 and 2015, the additional variable O&M amounts for the full (100%)

[11] Note that such amounts <u>exclude</u> other variable O&M costs associated with "consumable" costs tied to retrofit-related chemicals (limestone, trona, and urea). Given that Mr. Kollen excluded such consumable costs in his 2011 and 2012 totals offered on page 31 of his testimony, they were also not captured in the Exhibit SCW-5R summary of Strategist®-modeled O&M.

Mitchell facility equaled \$13.8 million and \$12.7 million, respectively. Additionally, Mr. Kollen argues that the Strategist®-based evaluations for the most part lacked administration and general (A&G) expenses that are considered part of O&M. But he failed to recognize that one component of the levelized carrying charge rates applied to the Mitchell investment was applicable to anticipated A&G expense. For instance the 25-year Kentucky Power levelized carrying charge rate applied to the Mitchell transfer was 13.98%; comprised of the following components: Return (8.62%), Depreciation (2.17%), Federal Income Tax (1.58%), and Property Tax, General & Admin (1.60%). The specific "A&G" sub-component of the last category being 1.08%. Thus, administrative and general expenses were included. This "A&G component" of the levelized carrying charge calculations produces another \$13.3 million and \$14.6 million of O&M costs for the respective 2014 and 2015 forecast years.

Exhibit SCW-6R provides both a summary of the total annual Mitchell O&M costs included in the Strategist® modeling, as well as a reconciliation with the (100%) Mitchell O&M figures Mr. Kollen cites in his testimony. **TABLE 4R** provides the corrected representation of Mr. Kollen's Mitchell O&M (100%) values for 2014 and 2015. It demonstrates the Company's modeling has not understated Mitchell O&M costs but, in fact, it may have *overstated* such costs when compared to recent (2011 and 2012) history that Mr. Kollen determined to be included in the Company's rate impact study.

TABLE 4R

Mitchell Plant (100%)
Total O&M
(Excl. Consumables)
(Millions)

	2014	2015
Per Kollen (Pg. 30)	$48.990	$55.965
+ Adj. for Variable O&M	$13.782	$12.678
+ Adj. for A&G	$13.323	$14.593
Adjusted Total (in Company Modeling)	**$76.095**	**$83.236**
Amounts Cited by Kollen from Rate Impact Study:	*2011*	*2012*
(Direct, pg. 31)	*$67.741*	*$68.108*

Q. DID KIUC WITNESS HAYET INCORPORATE ANY ADJUSTMENTS (INCREASES) TO PROJECTED MITCHELL UNIT O&M COSTS AS SUGGESTED BY MR. KOLLEN IN HIS MODELING?

A. Based on a review of the input parameters for Mr. Hayet's version of Strategist®-based modeling that were provided by KIUC in response to data discovery, it would appear that he—correctly—made neither adjustments to the Company's O&M levels in that modeling, nor did he even anecdotally mention that prospect in his testimony.

HAYET REBUTTAL

VIII. KIUC'S RECOMMENDED RESOURCE PROFILE CANNOT BE SUPPORTED BY THE RESULTS FROM THE COMPANY'S RISK MODELING

Q. DOES MR. HAYET MAKE THE SAME RECOMMENDATIONS AS KIUC WITNESS KOLLEN WITH RESPECT TO KENTUCKY POWER'S FUTURE RESOURCE NEEDS?

A. Yes. Mr. Hayet recommends the same, limited, 20% Mitchell transfer, along with the Big Sandy Unit 1 coal-to-gas conversion and a long-term reliance on market purchases of capacity and energy, to achieve the Company's resource needs in lieu of Big Sandy Unit 2.

Q. **DOES MR. HAYET ATTEMPT TO OFFER ANY ADDITIONAL VALIDATION OF THIS RECOMMENDATION?**

A. His validations appear to be based on the same arguments set forth by Mr. Kollen. He did, however, introduce an additional notional concept based on the results of the Company's risk analysis performed using the proprietary AURORAxmp tool that was described in my direct testimony.

Q. **PLEASE DESCRIBE HIS ASSESSMENT OF THAT RISK ANALYSIS AS IT PERTAINS TO HIS RECOMMENDATION.**

A. Mr. Hayet suggests on page 12 of his testimony that the Company's "recommended" option (Option #6 50% Mitchell transfer coupled with [PJM] market purchase of capacity and energy), was the "5th highest ranked (*i.e.*, best) plan", based on the Company's risk-modeling exercise using AURORAxmp. He further suggests that the four options that ranked higher than Option #6 (options which included only 20% Mitchell transfer [Options #1A, #2A and #3A], or included a Big Sandy 1 gas conversion [Option #5A]), somehow validate the notion that a plan with "some portion" of a Mitchell transfer (lower than 50%), coupled with a BS1 gas conversion, would be a plan of lower cost and risk to the Company.

Q. **DO YOU AGREE WITH THIS CONCLUSION?**

A. Absolutely not. Mr. Hayet's logic contains numerous flaws on which I will elaborate.

First, contrary to Mr. Hayet's view, the results of the Company's AURORAxmp risk modeling should not be used to establish the chief underlying *basis* for any resource conclusions or recommendations. The empirical basis for the Company's recommended resource profile was the result of long-term resource optimization modeling that was performed utilizing the Strategist® tool. (I will later address modeling that Mr. Hayet performed, also using Strategist® tool, in his attempt to validate KIUC's recommendation.) Rather—as I explained on Exhibit SCW-1, page 11 of my direct testimony—the Monte Carlo modeling performed in AURORAxmp was offered to subject the *Strategist®-determined* outcomes to risk "stress-testing." This was done to <u>support</u> how the Company's Strategist®-determined recommended resource plan would hold up, when compared to other plans examined, under an array of input variables and multiple forecast simulations.[12] Mr. Hayet mistakenly draws certain conclusions as to the results of those Company-performed analyses that he uses to attempt to justify his resource recommendations.

Second, the clear Strategist®-determined least-cost alternative offered by the Company was Option #5A, which called for a 50% Mitchell transfer coupled with a Big Sandy 1 gas conversion. That fact has not been addressed by the KIUC, but was clearly supported in my direct testimony.[13] However, the Company has initially proceeded down the path of Option #6 (50% Mitchell transfer with a reliance upon approximately 250 MW of market-based resources) fully recognizing that subsequent

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[12] This risk modeling sought to establish a Revenue Requirement at Risk ("RRaR") which represents the difference between the calculated generation-cost CPW result at the 50^{th} (median) and 95^{th} percent outcome across 100 simulations modeled. The 95^{th} percentile representing a level of required revenues sufficiency high that it will be exceeded, assuming the given plan was adopted, with an estimated probability of just 5%. Therefore, RRaR represents a measure of customer risk or uncertainty inherent in each option portfolio.
[13] See results summary, Exhibit SCW-5.

to any commercial RFP evaluation process for that 250 MW, "…if this conversion alternative were to prove out as being the least-cost approach, then the Company could then exercise such a Big Sandy 1, gas conversion option."[14] Hence, Kentucky Power was hedging any such "unknowns" surrounding a long-term market solicitation with an option that its indicative modeling had *already* determined would be least-cost.

Third, based on the Strategist® results, Mr. Hayet fails to recognize that any such relative comparisons of the Company's risk-modeling results should also be reflective of whether or not that particular option contained "market dependencies". In other words, when comparing the results of options with higher market exposures (*i.e.*, options evaluated that offered outcomes that did not fully-meet Kentucky Power resource needs with a metal-in-the-ground solution; such as Options #1B, #2B, #3B, #4A, #4B, #5B and #6), such options should be uniquely compared. When doing so, it clearly indicated that the option containing the 50% Mitchell transfer solution (Option #6) possessed the lowest Revenue Requirement at Risk (RRaR).[15] *Conversely*, the remaining options that did assume adequate resources without necessitating such market solicitations (Options #1A, #2A, #3A and #5A) should, likewise, be viewed in concert with each other. Based on that, Option #5A, which was the Company's recognized lowest-cost alternative—that was also inclusive of a 50% Mitchell transfer—was nearly the option with the lowest RRaR. Only Option

[14] Weaver direct at 39, li. 21-23.
[15] See discussion of this point in Exhibit SCW-1, pg. 14; and Exhibit SCW-6 (pg. 2).

#3A had a very slight ($5 million) RRaR advantage over the full long-term study period. However, as I will describe, even that fact should be considered moot.

Fourth, Mr. Hayet misses the fact that these Monte Carlo analyses were designed to effectively *validate* the underlying robust portfolio analyses performed in Strategist®. If one were to closely examine only the specific "50th percentile" or median result from the AURORAxmp modeling, relative results would emerge that were similar to those from the Strategist® modeling. This means that the two options possessing a 50% Mitchell transfer (Option #5A that included a BS1 gas conversion; and Option #6 which did not) had the lowest CPW result at that *50th percentile* outcome of the 100 simulations performed in that tool by amounts comparable to the Strategist® results summarized in Exhibit SCW-5A of my direct testimony.[16] Mr. Hayet instead ignores the intended scope and purpose of this risk modeling. In assembling his recommended Kentucky Power unit disposition plan, Mr. Hayet haphazardly mixed-and-matched option profile results from these risk analyses. For instance, he conveniently, forgets the fact that three of the "higher ranked" alternatives, versus Option #6 (*i.e.*, Options #1A, which assumed the scrubber retrofit of Big Sandy 2; Option #2A, which assumed a CC-build in lieu of BS2; and Option #3A which assumed the CC-repowering of BS1 in lieu of BS2) were all determined to be far more costly based on the Strategist® profiling. The fact that the Company

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[16] For instance, from the risk modeling, Option #5A has the lowest study period CPW outcome at the "50th percentile" result (@ $5,458 million) by a range of <$154 million> versus Option #6, to <$867 million> versus Option #3B. In Strategist®, those same relative 'option versus option' results were similar at <$156 million> and <$754 million>, respectively, favoring Option #5A... Likewise, Option #6 has the lowest study period CPW outcome at the 50th percentile result (@ $5,612 million) by a range of <$244 million> versus Option #5B, to <$713 million> versus Option #3B (excluding Option #5A). In Strategist®, those same relative option versus option results—identified on rebuttal Exhibit SCW-1R—were similar at <$223 million> and <$598 million>, respectively.

reviewed those three options which assumed 'only' a 20% Mitchell transfer has no bearing on KIUC's recommendation for suggesting that a smaller take from Mitchell was somehow economically-justified. In fact, the only other (Strategist®-based) economically-merited option with a lower RRaR risk profile than Option #6 was Option #5A which also assumed a 50% Mitchell transfer.

In summary, Mr. Hayet's attempted "validation", using the Company's risk modeling, for recommending that only 20% of Mitchell should be transferred was over-reaching and not supported by the facts.

IX. <u>THE COMPANY'S STRATEGIST®-BASED ANALYSES WERE APPROPRIATELY PERFORMED WHILE THE COMPARATIVE COUNTER-MODELING PERFORMED BY MR. HAYET IS FLAWED.</u>

Q. **DOES MR. HAYET PERFORM HIS OWN MODELING OF OPTION-SPECIFIC RESULTS USING THE STRATEGIST® TOOL?**

A. Yes. Mr. Hayet offers his (Revised) Tables 1, 2 and 3 (pages 23, 26 and 28, respectively, from his Amended Testimony) containing summary results of modeling he independently performed in Strategist®. He did so by first replicating the resource option associated with the Company's Option #6 (50% Mitchell transfer to replace BS2, with needed PJM market purchases to replace BS1) but layering-in his revised input parameters associated with long-term energy, natural gas, coal and capacity pricing. Then he established an additional set of results based on utilizing KIUC's recommended resource plan for Kentucky Power which included only a 20% Mitchell transfer, an assumed Big Sandy 1 gas conversion, as well as (PJM) capacity and energy purchases.

Q. ASIDE FROM THE INPUTS UTILIZED BY THE COMPANY, DOES MR. HAYET TAKE ANY SPECIFIC ISSUE WITH HOW THE COMPANY UTILIZATED THE STRATEGIST® TOOL?

A. No he does not. He makes no criticism of the Company's use of the Strategist® tool regarding its set-up, introduction of data, or ultimate execution.

Q. FROM YOUR PERSPECTIVE, IS THAT AN IMPORTANT FACTOR?

A. Yes it is. Given Mr. Hayet's prior experience, he clearly is knowledgeable of the Strategist® tool and its application. Because he challenged only the input parameters that would seem to represent an important validation of the reasonableness of the Company's modeling approach and utilization of the tool itself.

Q. WHAT ISSUES DOES MR. HAYET MENTION REGARDING CERTAIN OF THE INPUT PARAMETERS USED IN THE COMPANY'S MODELING?

A. As highlighted previously, Mr. Hayet suggests modification to certain long-term commodity pricing parameters. Based on that presumption, he then revised those pricing parameters for use in his version of Strategist® modeling.

Q. PLEASE SUMMARIZE THE COMPANY'S CONCERNS WITH MR. HAYET'S REVISED INPUT PARAMETERS.

A. I previously addressed my disagreement with the use of an alternative capacity pricing profile, in lieu of the pricing profile established by the AEP Fundamental Analysis group, in my rebuttal of the testimony of Mr. Kollen. I also demonstrated that such capacity pricing changes, even if they were assumed to be valid, would neither materially change the resultant modeling outcomes (see TABLE 3R), nor change the conclusions of the Company concerning the proposed 50% Mitchell transfer being the least-cost alternative. From a qualitative perspective, Company witness Bletzacker also addresses in his rebuttal testimony the appropriateness of Kentucky Power's use of such fundamentally-determined capacity prices for purpose of this long-term resource optimization exercise.

Likewise, Mr. Bletzacker addresses certain criticisms made by the intervenors regarding the appropriate long-term natural gas, coal and energy pricing. He refutes any identified alternative pricing that Mr. Hayet has used—based purely on 2013 EIA projections—in his modeling, and why any attendant modeling using those commodity pricing levels should be ignored. Further, Mr. Bletzacker *restated* Mr. Hayet's assumed pricing to reflect more reasonable apples-to-apples representations of those 2013 EIA projected commodity prices.

In sum, any attempt to "re-up" any of the Company's Strategist® portfolio analyses with the isolated, "a la carte" revised modeling parameter assumptions suggested by KIUC is wrong for the reasons Company witness Bletzacker has described in his rebuttal testimony. Rather, the input assumptions utilized by the Company in its original modeling—and as slightly modified in the Exhibit SCW-1R results summary—remain appropriate, and Kentucky Power stands behind each of them.

Q. WHAT OTHER CONCERNS DO YOU HAVE WITH MR. HAYET'S SUMMARY OF THE ALTERNATIVE ECONOMICS AS SUGGESTED BY HIS TABLES 1 THROUGH 3?

A. Mr. Hayet's tables contrast KIUC's recommendation with an option (Option #6) *not being advocated by the Company is this proceeding*. As such, they are both disingenuous and constitute the most transparently obvious of straw-man arguments.

Q. CAN YOU ELABORATE?

A. Certainly. Mr. Hayet's (Revised) Tables 1-3 compare the KIUC recommendation with Kentucky Power's "Option 6" view which, while it incorporates a 50% Mitchell transfer, *excludes* the Big Sandy 1 gas conversion. At no time have I, or any other Kentucky Power witness recommended Option #6 as the final, least-cost alternative. Instead, Option #6 was simply the "base" option against which all other options were compared for presentation purposes. Any of the other options could have been used as the base option against which all other options were compared because the purpose of my analysis was to identify the relative least-cost options.

Q. WHAT DOES YOUR ANALYSIS INDICATE IS THE RELATIVE LEAST-COST OPTION?

A. As stated throughout my direct and this rebuttal testimony, the lowest-cost disposition alternative for Kentucky Power was Option #5A which, in addition to a 50% Mitchell transfer, did incorporate a Big Sandy 1 gas conversion.

Q. IS THE COMPANY ADVOCATING OPTION #5A IN THIS PROCEEDING?

A. Kentucky Power has neither embraced nor excluded the BS1 gas conversions option because it is too early to do so. That decision must await the results of the March 28, 2013, RFP issued by the Company. If the conversion has a lower cost than any of the options available through the RFP, Kentucky Power is poised to proceed down that path. If not, the Company would enter into negotiations in accordance with the RFP.

But in *__either__* event, the transfer to Kentucky Power of a 50% interest in the Mitchell facility is a necessary predicate to that least-cost alternative.

Q. YOU INDICATED EARLIER YOU BELIEVE MR. HAYET'S TABLES WERE DISINGENUOUS. PLEASE EXPLAIN.

A. Mr. Hayet compares the KIUC-recommended disposition path that calls for Big Sandy 1 to be converted, versus a Company-modeled result that is not the Company's recommendation with respect to BS1 and does *not* assume such a conversion. Indeed, his tables are particularly disingenuous when he knew or should have known that a) that same BS1 gas conversion scenario *was* modeled by the company as part of Option #5A; and b) that Option #5A, which, again, *also included* the transfer of a 50% interest in the Mitchell generating station, was the least-cost alternative.

Q. WHAT MUST BE DONE TO "RE-STATE" MR. HAYET'S SUMMARY TABLES TO REFLECT THE FACT THAT OPTION #5A IS THE LEAST-COST ALTERNATIVE?

A. The following changes must be made. First, the table must compare the "KIUC" recommendations to Option #5A, which did incorporate a BS1 gas conversion, and not Option #6. Second, as previously discussed, any restatement by Mr. Hayet of PJM-RPM projected capacity values should be ignored. Third, any further restatement of Mr. Hayet's Revised Tables 1 and 2 of the 2013 EIA projected pricing for natural gas that he relied upon should also be rejected and, minimally, should be "restated"—along with the attendant projected PJM energy prices that correlate with natural gas pricing—for the reasons set forth by Company witness Bletzacker in his rebuttal testimony. Any such restatements do __not__, however, suggest that these "2013

EIA Company-Modified" prices would now be offered *in lieu of* the Company's projected Fundamental Analysis pricing. As represented in the rebuttal testimony of Mr. Bletzacker, the fundamentals-based forecast continues to represent the appropriate long-term commodity price profile to be utilized in the Company's analysis. Rather, this (EIA pricing) restatement exercise represents a transparent modeling sensitivity effort on the part of the Company to address the significant shortcomings observed by Mr. Bletzacker, as part of both his rebuttal <u>and</u> direct testimonies, in relying fully—and myopically—upon such reported EIA long-term estimates of commodity pricing, including natural gas.

Finally, the Company performed additional Strategist®-based sensitivity analyses to incorporate the suite of 2013 EIA Company-Modified pricing established by Company witness Bletzacker. A summary of which is provided as Exhibit SCW-7R. **TABLE 5R** below serves to replicate and correct Mr. Hayet's "(Revised) Table 1" (as well as his "(Revised) Table 2" which was further adjusted to reflect purported equivalent EIA-based projected coal pricing that Company witness Bletzacker also addresses):

TABLE 5R

Company Restatement of Hayet "REVISED-Table 1" (and "REVISED-Table 2")
Natural Gas, Energy Market Forecast, and Impairment Capacity Market Adjustments

Case	Mitchell	BS1 Gas Conv	Gas		Coal	Market $/MWH		ICAP $/MW-Day	NPV (k$)		Diff (k$)
		(A)									
KPCo	50%	Y	2011 AEP		2011 AEP	2011 AEP			$5,665,051	(A)	
KPCo	50%	Y	2013 EIA-"Co. Modified"	(B)	2011 AEP	2013 EIA-"Co. Modified"	(B)		$5,690,937	(C)	
KPCo	50%	Y	2013 EIA-"Co. Modified"	(B)	2011 AEP	2013 EIA-"Co. Modified"	(B)	~~Impair~~ *(Not Applicable)*	*N/Ap*		
KIUC	20%	Y	2011 AEP		2011 AEP	2011 AEP			$5,895,211	(D)	$230,160
KIUC	20%	Y	2013 EIA-"Co. Modified"	(B)	2011 AEP	2013 EIA-"Co. Modified"	(B)		$5,765,358	(C)	$74,421
KIUC	20%	Y	2013 EIA-"Co. Modified"	(B)	2011 AEP	2013 EIA-"Co. Modified"	(B)	~~Impair~~ *(Not Applicable)*	*N/Ap*		

(A) Represents Company "**Option #5A**" results *instead of* "Option #6 utilized by Mr. Hayet (results extracted from Weaver Rebuttal Exhibit SCW-1R)
(B) Reflects KPCo's development of a suite of adjusted natural gas and energy pricing utilizing 2013-EIA data as an underpinning (see Bletzacker rebuttal testimony)
(C) Results from Weaver Rebuttal Exhibit SCW-7R
(D) per Hayet 'REVISED-Table 1' & 'REVISED-Table 2' from his Amended Direct Testimony

Rather than suggesting an approximate \$218 million cost advantage for the KIUC-recommended Kentucky Power resource plan as Mr. Hayet indicates in his Revised-Table 1 (or \$343 million in his Revised-Table 2) of his Amended Testimony, this TABLE 5R "restatement" demonstrates KIUC's recommended 20% Mitchell + BS1 gas conversion + market purchase approach is \$74 -to- \$230 million ***more expensive*** than the Company's proposed transfer of 50% of the Mitchell facility combined with, subject to the results of the RFP, a comparable view reflective of the conversion of Big Sandy Unit 1 (*i.e.*, Option #5A).

Q. **WHAT WAS THE APPROACH TAKEN BY MR. HAYET TO CREATE HIS "(REVISED) TABLE 3", AND DO YOU HAVE ISSUES WITH THE RESULTS OFFERED IN THAT TABLE AS WELL?**

A. Yes. In this "Table 3" view, as with the other modeling summary tables he offers, Mr. Hayet incorrectly attempted to model and restate the Company's 50% Mitchell transfer with no BS1 conversion alternative (Option #6), instead of the Company's lowest-cost alternative that included the BS1 conversion (Option #5A). Under the prior (Revised) Table 1 and 2 summaries, that "basis" Kentucky Power alternative CPW cost would be over \$156 million lower than what Mr. Hayet represented on those tables.[17] Therefore assuming that this cost relationship would be approximately the same under his "Table 3" modeling, right out of the gate, his perceived \$149.6 million ("NBV") cost advantage for the KIUC (20% Mitchell) recommendation, would turn into a \$16 million *disadvantage*.

[17] \$5,821,342 on his (Revised) Tables 1 and 2, versus \$5,665,051 on my rebuttal TABLE 5R. This \$156 million amount is also reflected as the savings of Option #5A versus Option #6 on rebuttal Exhibit SCW-1R.

Concerning the specific modeling undertaken to support his Revised-Table 3, this exercise, instead of introducing "2013 EIA" sourced pricing inputs into that modeling as he did in his Revised-Tables 1 and 2, Mr. Hayet utilized parameters he purported to extract from the AEP-Ohio generation impairment analysis previously discussed. Upon review of his input data sets for that process, however, a serious modeling flaw was discovered.

Q. **PLEASE DESCRIBE THIS MODELING FLAW.**

A. Based on workbook file information provided by KIUC in response to the Company's data request Kentucky Power 1-20, it was determined that Mr. Hayet used the "Fuel + VOM" dollar per Mwh outputs from the AEP impairment analysis modeling for Mitchell that were provided in response to (Confidential) KIUC 2-55.[18] In an attempt to establish the Mitchell fuel (*i.e.*, consumed coal) prices for his analysis, while he properly 'backed-out' projected variable O&M (VOM) costs, Mr. Hayet apparently failed to realize that also contained in these "Fuel + VOM" outputs were the costs of consumables (lime, urea, etc.) for the Mitchell units, as well as a carbon tax beginning in the year 2022. Those costs were not excluded by Mr. Hayet which resulted in a double-counting, because such costs were already uniquely accounted for as part of other Strategist® input files he utilized for this Revised-Table 3 exercise. As an example, from 2016 to 2021 Mr. Hayet's assumed Mitchell fuel prices were approximately $0.50 -to- $0.90 per MMBtu higher than those used in the spread option (impairment analysis) model due to double-counting the cost of consumables. Beginning in 2022, this error was compounded. His Mitchell fuel prices shifted to

[18] Hayet file: KPCO 1-20 attachment a – Mitchell-ImpairmentAnalysis.xlsx

approximately \$1.80 -to- (over) \$2 per MMBtu higher than those used in the impairment analysis due to the *additional* double-counting associated with the advent of an assumed carbon tax at that point.

Q. **WHAT WAS THE IMPACT OF THAT "FUEL PRICE" ERROR ON HIS RESULTS?**

A. As detailed on Exhibit SCW-8R, based on relative Mitchell heat input between the two views of Mitchell transfer he analyzed, I have determined that this fuel pricing error caused the "50% Mitchell" comparative view in his Revised-Table 3 to be overstated by \$167 million dollars on a CPW-basis. That correction would now cause his purported \$149.6 million NBV benefit of a 20% Mitchell transfer to now be more costly—considering also the assumed \$156 million change in Company modeling basis via applying Option #5A—by nearly \$174 million.[19]

Moreover, by virtue of Mr. Hayet's Strategist® modeling having severely overstated the Mitchell units' fuel cost, it had a destructive impact on the units' ability to dispatch as part of that modeling. As a result, the modeled view resulted in Mitchell unit capacity factors being only in the very low 17% -to- 39% range beginning in that 2022 and beyond timeframe.[20] With that, the modeling would have then necessarily increased its net imports of (market) energy to make up for that generation shortfall, further exacerbating the bias against the larger, "50%" Mitchell option examined. Such relative energy shortfalls offset with expensive market purchases would easily cause the relative "net energy" costs of the 50% Mitchell

[19] (\$149.6) million (benefit) on Hayet Revised-Table 3 + 156.3 million (assumed Option #6 vs. Option #5A differential) + \$167.1 million Mitchell fuel cost correction = \$173.8 million.
[20] KIUC Strategist Run11R20.SAV for AEP Option #6 data and Run11R20a.SAV for KIUC Option data.

transfer (versus 20% Mitchell transfer) view to appear to be more expensive. Although the Company did not attempt to re-calculate the modeling for Mr. Hayet's error using appropriate fuel data points, it is reasonable to assume that the previously "corrected" variance of a $174 million relative *cost* of the 20% transfer option would be increased even more after consideration of a further correction for this attendant market purchase impact.

In sum, for these reasons alone, Mr. Hayet's Revised-Table 3 should be ignored in its entirety.

Q. **ALTHOUGH HE INDICATES IT "...MAY NOT BE A "SIGNIFICANT CONCERN", ON PAGE 30 OF HIS TESTIMONY, MR. HAYET CONCLUDES THAT THE INSTALLED COST OF THE COMPANY'S CC-BUILD OPTION (OPTION #2) WAS OVERSTATED WHEN COMPARED WITH DATA AVAILABLE FROM LG&E AS WELL AS FROM EIA DATA SOURCES. COULD YOU PLEASE COMMENT ON THAT?**

A. The new-build CC cost assumed for Option #2 is not overstated. The value used by the Company takes into consideration, as any reasonable analysis must, the design basis including plant functionality, location, reliability and risk. The Company's estimate was prepared in accordance to the Association for the Advancement of Cost Engineering (AACE) "Class 3 level" in which the scope of a (brownfield) CC estimate is fully defined with a project maturity level that would result in an ultimate installed cost variance range of -10% to -20% / +10% to +30%.[21] The estimate was

[21] AACE International Recommended Practice No. 18R-97; *Cost Estimate Classification System—As Applied in Engineering, Procurement, and Construction for the Process Industries* (Dated: November 29, 2011)

prepared in collaboration with Sargent & Lundy (S&L), a leading architectural engineering firm with extensive experience in designing CC plants. Additionally, S&L worked with Kiewet, a leading power plant construction firm and with internal AEP operations and engineering expertise to ensure all issues associated with this project were understood. To compare the Company's estimate to the LG&E estimate, or a more generic estimate from EIA, is neither proper nor reasonable, particularly in light of the unknown scope for each.

WOOLF REBUTTAL

X. FOR PURPOSES OF THIS COMPARATIVE UNIT DISPOSITION ANALYSIS, THE COMPANY'S ASSUMED LEVELS OF DEMAND SIDE MANAGEMENT ARE APPROPRIATE

Q. PLEASE SUMMARIZE THE TESTIMONY OF MR. WOOLF IN REGARD TO DEMAND-SIDE MANAGEMENT OPTIONS.

A. Mr. Woolf contends that DSM was given short shrift in the analyses performed by the Company, that energy efficiency is a nearly limitless resource that, if utilized in conjunction with market purchases of capacity and energy, would eliminate the need for the Mitchell transfer. He artfully cites the results from selected utilities and states and the plans from others to support his contention.

Q. ON PAGE 27 OF HIS TESTIMONY, MR. WOOLF SUGGESTS THAT TO NOT OFFER DSM PROGRAMS TO INDUSTRIAL CUSTOMERS AT ALL "IS INCONSISTENT WITH DSM PROVISIONS OF THE KENTUCKY LAW." DOES THE COMPANY VIOLATE KENTUCKY LAW BY NOT

OFFERING ENERGY EFFICIENCY PROGRAMS TO ITS INDUSTRIAL CUSTOMERS?

A. Although I am not an attorney, I understand the answer is no. In fact, Kentucky Power was ordered by the Commission to discontinue its DSM surcharge factor for industrial customers in Case No. 95-427. Further, the DSM Collaborative, which included KIUC at the time, requested the discontinuation of programs due to lack of participation.

Q. **BECAUSE THE COMPANY DOES NOT OFFER PROGRAMS TO ITS INDUSTRIAL CUSTOMERS, DOES THIS MEAN THOSE CUSTOMERS ARE NOT MAKING ECONOMICAL DECISIONS ABOUT THEIR ENERGY USAGE?**

A. No, quite the contrary. The reason industrial customers often petition for, and receive, exemptions or "opt-outs" from utility-sponsored energy efficiency programs is that they are already well-aware of the cost-effectiveness of efficiency investments, and can be counted on to make them. In fact, as summarized on **TABLE 6R,** an analysis of manufacturing efficiency in the south census region, which includes Kentucky, shows that considerable efficiency improvements have been made outside of a utility-sponsored program.

TABLE 6R

	1998	2010	Change	% Change
Manufacturing Fuel Use (trillion Btu)	13,553	10,872	(2,681)	-20%
Manufacturing GDP (millons 2005$)	439,842	563,560	123,718	28%
MMBtu/$GDP	0.031	0.019	(0.012)	-37%

This table was constructed from readily-available data[22] and shows the significant decrease in energy used per unit of real gross domestic product (GDP) that has occurred in the south. It is reasonable to expect that manufacturers in Kentucky have contributed to this trend.

Q. **ON PAGES 15 AND 16 OF HIS TESTIMONY MR. WOOLF DESCRIBED A GOAL OF REDUCING ENERGY DEMAND BY 18% PROPOSED BY GOVERNOR BESHEAR IN 2008. PROVIDE THE FULL CONTEXT AROUND THE GOAL AS DESCRIBED.**

A. First, the energy efficiency discussion in the plan (Intelligent Energy Choices for Kentucky's Future) is a step back in time, with multiple references to "dramatic increases" in the cost of non-renewable fuels such as natural gas (@ $12/MMBtu) and, as a result, also advocates development of nuclear energy, coal-to-gas conversion, and coal-to-liquids transformation, among other strategies. It was authored before the recession and before the current proliferation of shale gas. This long-term plan envisioned an approximate 16% energy reduction coming from a combination of utility and non-utility programs, with the balance of savings coming from the transportation sector. Examining the source document[23] for the projections of residential and commercial sector savings, one can see that the residential savings projection is simply based on an assumption that, "…between 2008 and 2025, one-half of the existing housing stock will implement energy efficiency measures

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[22] Manufacturing energy use from "Manufacturing Energy Survey (MECS)", Energy Infomration Administration (eia.gov); manufacturing GDP, by state, from Bureau of Economic Analysis, U.S. Department of Commerce (bea,gov).
[23] *Kentucky Resources to Meet the Energy Needs of the 25 x '25 Initiative*, University of Kentucky – College of Agriculture, Cooperative Extension Service

sufficient to reduce their Base case energy consumption 20%"[24] and that a growing portion of new housing stock will be 15% more efficient than homes built at the same time. The commercial savings is based on the assumption that new building energy-use intensity (EUI) is reduced 30% every five years. This is a not a comprehensive plan to reduce consumption through the implementation of utility-sponsored energy efficiency programs, it is simply a "what if" exercise. Mr. Woolf's superficial reliance on headlines or "sound bites" and omission of the relevant context is troubling.

Q. DOES MR. WOOLF MISCHARACTERIZE OTHER RESULTS OR STUDIES?

A. Yes. On pages 20-22 of his testimony, Mr. Woolf seeks to compare (and marginalize) the Electric Power Research Institute (EPRI) study[25], which the Company used as the basis for its projections of achievable energy efficiency versus, particularly, a study performed by McKinsey & Co.[26] However, the studies are not entirely comparable, although there is a comparison of the two reports available that was prepared by McKinsey.[27] The McKinsey study developed an estimate of "economic potential" for energy efficiency. That is, the total energy in the economy that could be saved if every single cost-effective energy efficiency measure was implemented. Nowhere in the study does it suggest that all cost-effective measures would or could be implemented; nor does it suggest which part of that percentage

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[24] *Ibid*, page 6.
[25] *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. (2010-2030)*, Electric Power Research Institute.
[26] *Unlocking Energy Efficiency in the U.S. Economy*, McKinsey & Co.
[27] *EPRI and McKinsey Reports on Energy Efficiency: A Comparison*, McKinsey & Co.

could best be addressed through utility-sponsored energy efficiency programs. In fact, the McKinsey study states, very unambiguously, "Nowhere in this report do we calculate an 'achievable' potential as is typically done using top-down estimates from an 'economic' potential"[28] and that "(t)he intention of this report is not to recommend particular policy solutions".[29]

That the two studies have different values for economic potential is primarily a function of two purposefully different assumptions by the studies' authors. First, the McKinsey study is more ranging in its inclusion of measures because it was not preparing the report with the purpose of determining what energy efficiency measures would logically be implemented by a utility. Second, it assumed the replacement of measures prior to the end of their useful life. In the comparison of the two reports, McKinsey explains the distinction this way, "McKinsey allows an incandescent bulb to be replaced with a CFL or LED without waiting for the incandescent bulb to reach its natural end-of-life replacement cycle if cost-effectiveness is met".[30] That is not a practical assumption for the purposes of examining either the economic or achievable potential for a utility-sponsored energy efficiency program, but works fine for a policy-neutral report such as the McKinsey study.

Q. **REGARDING THE BRATTLE REPORT ON DEMAND RESPONSE OPPORTUNITY CITED BY MR. WOOLF ON PAGE 22 OF HIS TESTIMONY, ARE THE FINDINGS IN THAT REPORT TAKEN OUT OF CONTEXT AS WELL?**

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[28] *Unlocking Energy Efficiency in the U.S. Economy*, McKinsey & Co., Introduction, page 4
[29] *Ibid*, Introduction, page 6
[30] *EPRI and McKinsey Reports on Energy Efficiency: A Comparison*, McKinsey & Co,, page 1.

A. Unfortunately so. In the cited report, in bold letters no less, it is emphasized that the results "are in fact estimates of **potential**, rather than **projections of what is likely to occur**".[31] The "Full Participation" scenarios identified in the report can be thought of as what is technically possible employing all technologies including direct load control, dynamic pricing with smart meters, and interruptible contracts. In this regard, the Brattle Report estimate of 18% for demand response lines up fairly well with the EPRI "technically achievable" estimate of 16.9% (in 2020). However, the EPRI report also defines what is "*realistically* achievable", given customers' willingness to participate and the prospects of a complete roll-out of smart meter infrastructure. That estimate is 4.6% and is the useful number. Additionally, the Brattle Report estimates were made with publically available information, and thus, any inferences about a state's potential versus a utility's potential, such as the one made by Mr. Woolf, is uninformed speculation.

Q. ON PAGES 23-24 OF HIS TESTIMONY SIERRA CLUB WITNESS WOOLF COMPARES THE ESTIMATES OF DEMAND RESPONSE POTENTIAL IN THE COMPANY'S SERVICE TERRITORY VERSUS THAT OF AEP'S OTHER EASTERN OPERATING COMPANIES. DO YOU TAKE ISSUE WITH THAT COMPARISON?

A. Yes. In SC 01-39 (part k), Sierra Club inquired,

> "Explain why the AEP-East system is projected to achieve more than twice as much peak demand reduction, as a percent of total demand, from demand response than Kentucky Power is projected to achieve in each of 2013 through 2031".

[31] *A National Assessment of Demand Response Potential*, Executive Summary, pg. x., The Brattle Group, 2009.

The Company responded that,

> "KPCo demand response potential is limited due to the high prevalence of mining operations, which does not lend itself to demand reduction".

This was subsequently mischaracterized by Mr. Woolf when he conflates that response with a study showing potential for energy efficiency in mining operations. They are not the same thing.

Q. DOES AEP HAVE MINING CUSTOMERS IN OTHER STATES?

A. Yes, AEP serves mining operations in 6 of its 11 states. In fact, refining operations, another significant Kentucky industrial classification, resides in all of the states AEP serves. However, as in Kentucky, these customers typically do not participate in demand response programs offered by their respective utilities. Some industrial processes—such as mining and refining—do not lend themselves to demand response; and if those industries constitute a large percentage of the industrial load, as they do in Kentucky Power's service territory when compared to AEP's other operating companies, the (overall retail) demand response potential may be relatively very low.

Q. IN EXHIBIT TW-3 OF HIS TESTIMONY, SIERRA CLUB WITNESS WOOLF USES THE RESULTS FROM SEVERAL UTILITIES OR STATES FROM THE PREVIOUS DECADE TO ARGUE THAT THE AMOUNTS OF ENERGY EFFICIENCY IN KENTUCKY POWER'S LOAD FORECAST ARE UNREASONABLY LOW. WHAT ARE THE FLAWS WITH THIS ARGUMENT?

A. The argument relies on a simplistic extrapolation of uncorrected data, from an inappropriate time period, to a service territory that is fundamentally different in a material way.

Q. **SPECIFICALLY, ON PAGE 25 OF HIS TESTIMONY MR. WOOLF SUGGESTS THAT, DUE TO SOME STATES HAVING ACHIEVED ANNUAL ENERGY EFFICIENCY SAVINGS OF "TWO PERCENT OF RETAIL SALES PER YEAR", KENTUCKY POWER'S FORECASTED DSM SAVINGS ARE "OVERLY LIMITED". ARE THERE FUNDAMENTAL PROBLEMS WITH USING THE ACCOMPLISHMENTS OF OTHER STATES TO DRAW SUCH CONCLUSIONS?**

A. There are numerous problems with taking the unverified results from different states from a different time period and overlaying them on Kentucky. To begin, Department of Energy regulations and EISA 2007 require that commercial T-12 lighting no longer be manufactured or imported after July 2012 and that standard screw-in lights be 25% more efficient beginning with a phase-in in 2012. Energy efficiency "accomplishments" in the years prior to 2012 are relative to the old bulbs, while *prospective* savings must be measured against the new standard. Since lighting has constituted the vast majority of program savings from the states and programs listed by Mr. Woolf, the same lighting programs would have at least 25% less impact in the years after 2012 and are therefore not indicative of prospective program accomplishments. However, the picture is actually worse than that. Since the alternatives to compact fluorescent lighting (CFLs) that meet the new standard are more expensive than CFLs, it becomes a question as to the necessity of some utility-sponsored lighting programs at all. The same is true for commercial lighting programs which have largely been converting T-12 to T-8 lighting retrofits. While there are other lighting alternatives, such as T-5 and light-emitting diodes (LEDs), the gains from these are small relative to an incandescent-to-CFL, or T-12-to-T-8 transition. There are no instances of utilities achieving large (verified) energy efficiency savings when CFL and T-8 programs are *excluded.* As such, it would be imprudent to continue to plan for that to happen.

Q. **IN WHAT OTHER WAYS DOES MR. WOOLF INCORRECTLY EXTRAPOLATE DATA FROM OTHER STATES?**

A. As with demand response, Sierra Club witness Woolf gives little thought to the differences between Kentucky Power and utilities on the east and west coasts of the U.S. However inconvenient to Sierra Club's argument, there are basic immutable differences that, when ignored, introduce vast errors in the results of the simplistic extrapolation techniques employed by Mr. Woolf. The same lighting programs that purport to save 2% of residential load in California, will not save that much in Kentucky. If lighting constitutes approximately 20% of residential load in California and 10% of residential load in Kentucky, a 10% reduction in lighting load naturally results in a 2% reduction in California and a little over 1% reduction in Kentucky; simple math.[32] Yet, results from these states which, again, are comprised largely of lighting measures, are casually used to imply what is possible in Kentucky.

[32] Lighting as a share of residential consumption is available by census region. Census regions are population-weighted. California belongs to the Pacific region where lighting is 21.5% of residential consumption, Kentucky is in the East South Central region where lighting is 10.5% of consumption.

Q. IS THAT THE ONLY PROBLEM WITH USING RESULTS FROM CALIFORNIA PROVIDED BY MR WOOLF ON HIS EXHIBIT TW-3, PAGE 4?

A. No. California has been, in many ways, a model program and they have been diligent in providing critical and objective data on cost and results that the entire energy efficiency industry uses. Unfortunately, Mr. Woolf chose to characterize initial "reported" results from 2007 as "accomplished" in his Exhibit TW-3, instead of the "actual" results that were made available in 2010.[33] The difference in the initial results and the claimed results was a very significant 59%. That is, the initial results from the state's three major utility-sponsored energy efficiency programs[34] for the 2006-2008 period were 9,999 GWh and subsequent net verified savings was 4,093 GWh (or, approximately 0.6% annually).[35] It is puzzling why Mr. Woolf would use the initial number when the net verified number is more relevant and widely known in the industry.

Q. WHAT IS CALIFORNIA'S OUTLOOK FOR ENERGY EFFICIENCY PROSPECTIVELY?

A. Considering the evaluated outcomes from utility-sponsored energy efficiency programs, and in light of the practical implications of 2007 EISA lighting standards, California commissioned a state-wide energy efficiency potential study which was

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[33] Results for the three investor-owned utilities are reported for the three-year period 2006-2008. Verified net results for 2010 are not yet available.
[34] Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric
[35] *2006-2008 Energy Efficiency Evaluation Report*, July 2010, California Public Utilities Commission. (aggregation of Tables 5, 7 and 9 [pgs. xxi, xxiii, and xxvi]).

published in 2012.[36] It covers the years 2013-2024. The study estimates a "maximum achievable" level of energy efficiency of approximately 1,400 (2013) -to- 1,000 (2024) Gwh a year from utility-sponsored programs[37] on annual consumption over that timeframe of 234,000 -to- 250,000 Gwh,[38] or about 0.60% (in 2013), declining to 0.40% (in 2024). The study further indicates that if credit is given to utilities from the impact of codes and standards, and further consideration is given to potential emerging technologies, the maximum possible achievement is 0.9%, declining to 0.7%. Again, these are "maximum" numbers, not necessarily what is likely and are a far cry from the 2% of annual savings Mr. Woolf would suggest are not only possible, but are *perpetually* possible.

Q. WHY WAS USING THE SAME QUANTITY OF FORECASTED DSM IN EACH OF THE COMPANY'S MODELED BIG SANDY UNIT DISPOSITION OPTIONS A VALID PREMISE?

A. The EPRI study, which served as the basis for the assumed levels of projected Kentucky Power DSM, takes into account the realities of the marketplace to calculate its "realistically achievable" level of such energy efficiency. Some energy efficiency products will not be done due to "market barriers". Further, not all consumers will make economically-rational decisions. While Mr. Woolf was quick to point out the low (relative to a plan) participation levels of several Kentucky Power DSM programs, the significance of that reality went unrealized. The reality is, Kentucky Power, or any other utility that is counting their energy savings critically, will be

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[36] *Analysis to Update Energy Efficiency Potential, Goals, and Targets for 2013 and Beyond*, Navigant Consulting.
[37] *Ibid*, Figure 6, Executive Summary, pg. 10.
[38] *Ibid*, Figure 8, Executive Summary, pg. 12.

doing well to achieve the EPRI study thresholds. Hence, the notion of incorporating yet additional levels of Kentucky-projected DSM as part of a unique modeled "alternative" was simply not reasonable.

Q. **IN FACT, WAS DSM GIVEN PRIORITY STATUS BY THE COMPANY IN ITS RESOURCE EVALUATION?**

A. Yes. By assuming that Kentucky Power will continue to fund energy efficiency programs at a level necessary to achieve a "realistic" reduction in energy consumption under *all* Big Sandy unit disposition alternatives considered, the Company is demonstrating its commitment to give demand-side resources such priority.

XI. RENEWABLE RESOURCES WOULD NOT SIGNIFICANTLY CONTRIBUTE TO ANY RESOURCE PORTFOLIO DESIGNED TO REPLACE KENTUCKY POWER'S SIGNIFICANT RESOURCE NEEDS IN LIEU OF BIG SANDY

Q. **WHAT IS MR. WOOLF'S ARGUMENT AROUND THE CONSIDERATION OF RENEWABLE RESOURCES FOR PURPOSE OF THIS APPLICATION?**

A. He simply suggests on page 30 of his testimony that a least-cost approach will generally rely on a mix of resources including DSM, renewables purchases, CC and CT plants, and more.

Q. **DO YOU AGREE WITH THAT GENERALIZATION?**

A. While I certainly appreciate the premise, as I had indicated on page 27 of my direct testimony, when considering any prospects associated with incremental levels of DSM *over-and-above* what has already been reflected in the underlying load and demand forecast, the amount required to offset even a small fraction of the nearly 1,100 MW associated with the Big Sandy plant that will be replaced in the year 2015, is simply not tenable. The same premise holds true for incremental contributions of renewable resources, including wind capacity and its attendant energy. Wind resources are naturally intermittent and, with that, PJM criterion dictates that a planning entity can only initially "count" 13 percent of a wind resources' nameplate capability for purposes of establishing capacity (ICAP) contributions. So, for example, even if Kentucky Power were interested in meeting only *10 percent* of the needed 1,100 MW of Big Sandy replacement capacity via wind resources, it would require the installation of *846 MW* of wind (1,100 * 10% / 13%). In truth, wind resources represent an energy play, not a (replacement) capacity play.

Rather, the purpose of the Company's exercise that is before this Commission is to assess alternative approaches that would determine the relative least-cost unit disposition strategy for Big Sandy plant. The Company will continue to seek out "alternative" resource approaches—be it DSM or renewables—when and where it is economically justified, or where there are specific federal and/or state mandates to do so. In any event, the primary reasons for not expressly including (incremental) DSM and/or renewable resources in this filing is purely a function of a) the relative capacity and energy "needs" of Kentucky Power's customers going-forward; and b) the fact that, in all likelihood, such small relative contributions, if warranted, would ultimately be considered in <u>all</u> of the alternatives analyzed. Hence, the omission of such levels in these "comparative" analyses does *not* suggest that any future "bottom up" IRP planning process would also not incorporate some levels of incremental

DSM or renewables. They are two unique proceedings. The Company contends, however, that, due to the tranche of capacity and energy required, the omission of any such levels of incremental DSM or renewables for purposes of this unit disposition exercise would have <u>no bearing</u> on the relative (slightly modified) results set forth in Exhibit SCW-1R of this rebuttal testimony.

Q. **DOES MR. WOOLF ADDRESS REGULATORY RISKS REGARDING THE INTRODUCTION OF, SPECIFICALLY, WIND RESOURCES?**

A. No. Mr. Woolf's testimony makes no mention of that fact that the Company could be denied approval of proposed wind resources. This was the case in 2009 when this Commission denied approval of the 100 MW Lee-DeKalb wind farm.

Q. **DID EITHER KIUC WITNESSES KOLLEN OR HAYET RECOMMEND THAT THE COMPANY INCORPORATE RENEWABLE RESOURCES OR ADDITIONAL LEVELS OF DSM OVER-AND-ABOVE AUTHORIZED LEVELS FOR PURPOSE OF THIS UNIT DISPOSITION EVALUATION?**

A. No. Neither KIUC witness made such recommendations.

Q. **DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

A. Yes.

MODIFIED TO REFLECT REDUCED CAPACITY VALUE ATTRIBUTABLE TO "MITCHELL TRANSFER" OPTIONS (for 1/2014 thru 5/2015 only)

<u>*COMPARATIVE*</u> Cumulative Present Worth (CPW) of Relative KPCo "G" Revenue Requirements (2011 $)

(COST / <SAVINGS>)

	Option #1		Option #2		Option #3		Option #4		Option #5	
	RETROFIT Big Sandy Unit 2; RETIRE & REPLACE Big Sandy Unit 1 (6/2015) Retrofit BS2 with Dry (NID) FGD Technology (6/2017)		RETIRE & REPLACE Big Sandy Units 1 and 2 (6/2015 & 1/2016, respectively) Replace BS2 with "Brownfield New-Build" NG-Combined Cycle (@ Big Sandy site) (7/2017)		RETIRE & REPLACE Big Sandy Unit 2 (1/2016) "CC-Repowered" Big Sandy Unit 1 (7/2017)		RETIRE & REPLACE Big Sandy Units 1 and 2 (6/2015) Replace with Purchased Capacity & Energy		RETIRE & REPLACE Big Sandy Unit 2 (1/2016) "Gas-Converted" Big Sandy Unit 1 (7/2015)	
	Option #1A	Option #1B	Option #2A	Option #2B	Option #3A	Option #3B	Option #4A	Option #4B	Option #5A	Option #5B
	Remaining Capacity from 20% (312-MW) Mitchell Asset Transfer (1/2014)	Remaining Capacity from (PJM) Market Purchases for 10-yrs, then new-build CC or CT(s)	Remaining Capacity from 20% (312-MW) Mitchell Asset Transfer (1/2014)	Remaining Capacity from (PJM) Market Purchases for 10-yrs, then new-build CC or CT(s)	Remaining Capacity from 20% (312-MW) Mitchell Asset Transfer (1/2014)	Remaining Capacity from (PJM) Market Purchases for 10-yrs, then new-build CC or CT(s)	Capacity from (PJM) Market Purchases for <u>5-yrs</u>, then ~700-800 MW CC and/or CT-build	Capacity from (PJM) Market Purchases for <u>10-yrs</u>, then ~700-800 MW CC and/or CT-build	Capacity from 50% (780-MW) Mitchell Asset Transfer (1/2014)	Capacity from (PJM) Market Purchases for <u>5-yrs</u>, then ~700-800 MW CC and/or CT-build

all versus...

$ Millions

("BASE") Option #6: RETIRE & REPLACE Big Sandy 1 and 2 (6/2015) with <u>50% (780-MW) Mitchell Units Ownership Transfer</u> (1/2014) plus (PJM) Market Purchases (for 10-yrs)

	1A	1B	2A	2B	3A	3B	4A	4B	5A	5B
BASE: "Fleet Transition-CSAPR"	469	663	327	526	402	598	376	401	**(156)**	223
% Relative Variance	*8.1%*	*11.4%*	*5.6%*	*9.0%*	*6.9%*	*10.3%*	*6.5%*	*6.9%*	*-2.7%*	*3.8%*
'Commodity Price Banding' Scenarios...										
2. "Fleet Transition-CSAPR: HIGHER Band"	442	810	533	899	615	982	781	869	**(149)**	639
3. "Fleet Transition-CSAPR: LOWER Band"	486	583	232	338	303	406	186	183	**(154)**	27
'Carbon/CO_2 Pricing' Scenarios...										
4. "Fleet Transition-CSAPR: No Carbon"	462	692	382	617	457	688	464	502	**(168)**	307
5. "Fleet Transition-CSAPR: Early Carbon (2017)"	472	626	276	438	350	509	299	311	**(144)**	149

Note:

-- A "POSITIVE" value above would favor the 50% Mitchell Transfer (Option #6)... a "<NEGATIVE>" value would favor the alternative option

-- Every $100 Million change in CPW is equivalent to a <u>$ 2.00 per Mwh</u> (0.200 cents/kWh) impact on <u>levelized annual</u> KPCo G-revenue requirements (2011$) over the entire affected (2016-2040) period

Additional Notes:

- 'BASE' ("Fleet Transition-CSAPR") pricing scenario --as well as '"HIGHER Band" and "LOWER Band" pricing scenarios-- assumes carbon/CO2 pricing is effective in 2022
- Any (short-term) "interim" requirements post-Big Sandy unit retirement dates that would *precede* the in-service date of the DFGD, or replacement CC-builds (Options #1, #2, #3) would be met w/ PJM market purchases
- Option #1 (RETROFIT Big Sandy 2) assumes the unit would operate and recovery costs through the full study period
- Option #2 (RETIRE & REPLACE BS2 w/ "New-Build CC") assumes a 30-year operation and capital cost recovery period for the CC in all analyses
- Option #3 (RETIRE & REPLACE BS2 w/ "CC-Repowered BS1") assumes a 20-year operation and capital cost recovery period for the CC in all analyses (i.e., thru 2035)
- Option #4 (Gas Convert Big Sandy 1) assumes the unit would operate and recovery capital costs for the subseqent 15 period (i.e., thru 2030)
- Options #1, #2, #4 and #6 assume Big Sandy Unit 1 is retired 6/2015 (Option #3 assumes that unit is repowered as a CC unit; Option #5 assumes the unit is 'converted' to burn natural gas in the existing boiler)
- <u>All</u> options analyses include KPCo's 30% purchase entitlement share of AEG's 50% portion of Rockport Units 1 and 2 (or, collectively, ~393-MW of capacity and energy)
  (i.e. resulting in effectively no relative impact on any of these Big Sandy 2 disposition analyses)
- Big Sandy 2 "Retirement" Options #2, #3, #4, #5 and #6 also conservatively <u>exclude</u> costs associated w/ socio-economic impacts to the region
  (i.e. resulting in effectively no relative impact on any of these BS2 disposition analyses)
- "G" Revenue Requirements established on a KPCo "stand-alone" basis and is reflective of a 'cost-optimized' resource plan necessary to achieve PJM minimum reserve margin criterion (summer peak)... Such costs being inclusive of:
  1) <u>All</u> KPCo (company-dispatched) Fuel, VOM and Emission Costs (incl. CO2); 2) on-going plant FOM; and
  3) FOM and Capital (carrying charges) on *incremental* investments (e.g. environmental retrofits on coal unit and/or new-build/repowered NG-CC capacity)

Exhibit SCW-1R

SUMMARY

Kentucky Power Company
(PJM) 'Stand-Alone' Reserve Margins Based on KIUC Recommendations

o 20% Mitchell 1&2 Transfer (2014)
o Big Sandy U1 Gas Conversion (2015)
o Big Sandy U2 Retirement (2015)

PJM Planning Year	(A) KPCo UCAP Obligation MW	(B) KPCo Available UCAP MW	(C)=(B)-(A) KPCo PJM Capacity Position Long / <Short> MW	KPCo PJM Reserve Margin Above / <Below> Required "Installed Reserve Margin (%)"
2014/15	1,288	1,627	339	30.1%
2015/16 *	1,306	900	(406)	-35.4%
2016/17 *	1,292	906	(386)	-34.3%
2017/18	1,290	906	(384)	-34.1%
2018/19	1,300	914	(386)	-34.1%
2019/20	1,302	914	(388)	-34.2%
2020/21	1,298	917	(381)	-33.5%
2021/22	1,302	915	(387)	-33.8%
2022/23	1,305	914	(391)	-34.0%
2023/24	1,301	918	(383)	-33.3%
2024/25	1,302	916	(386)	-33.4%
2025/26	1,309	916	(393)	-33.7%
2026/27	1,316	917	(399)	-34.0%
2027/28	1,324	917	(407)	-34.4%
2028/29	1,329	917	(412)	-34.6%
2029/30	1,335	917	(418)	-35.0%
2030/31	1,345	662	(683)	-56.8%

* KPCo is currently obligated --along with affiliates Appalachian Power Co. and Indiana Michigan Power Co.-- as part of a "3-Company" Fixed Resource Requirement (FRR) commitment for the most recently-established 2015/16 PJM planning year, as well as the upcoming 2016/17 planning year.

GENERATING PLANT	Unit	NBV November 2012	NBV Adjustment	Estimated ARO Dec Adj	CWIP November 2012	Adjusted NBV November 2012	Gross Cash Flows	Excess Cash Flow over NBV	Impairment
					($ millions)				
Fully Exposed Units							[redacted]		
Beckjord	6	8.4			0.1	8.5	[redacted]		8.5
Conesville	3	1.1				1.1	[redacted]		1.1
Kammer	1	32.4	(0.8)		0.4	32.0	[redacted]		32.0
Kammer	2	32.4	(0.8)		0.3	31.9	[redacted]		31.9
Kammer	3	32.5	(0.7)		0.3	32.1	[redacted]		32.1
Muskingum	1	23.8	(0.5)		0.3	23.6	[redacted]		23.6
Muskingum	2	23.8	(0.4)		0.2	23.6	[redacted]		23.6
Muskingum	3	23.8	(0.4)		0.2	23.6	[redacted]		23.6
Muskingum	4	23.8	(0.5)		0.3	23.6	[redacted]		23.6
Philip Sporn	2	32.3		(0.6)	0.3	32.0	[redacted]		32.0
Philip Sporn	4	32.3		(0.6)	0.3	32.0	[redacted]		32.0
Picway	5	10.3				10.3	[redacted]		10.3
		276.9	(4.1)	(1.2)	2.7	274.3	[redacted]		274.3
Other Units							[redacted]		
Amos	3	786.3			11.8	798.1	[redacted]		
Cardinal	1	521.7			7.5	529.2	[redacted]		
Darby	1	15.2			-	15.2	[redacted]		
Darby	2	15.2			-	15.2	[redacted]		
Darby	3	15.2			-	15.2	[redacted]		
Darby	4	15.2			-	15.2	[redacted]		
Darby	5	15.2			-	15.2	[redacted]		
Darby	6	15.2			-	15.2	[redacted]		
Gavin	1	475.7			22.0	497.7	[redacted]		
Gavin	2	475.7			22.0	497.7	[redacted]		
Mitchell	1	604.9	1.1		37.6	643.6	[redacted]		
Mitchell	2	604.9	1.2		35.1	641.2	[redacted]		
Muskingum	5	173.6	1.8		-	175.4	[redacted]		
Waterford	1	177.3			3.0	180.3	[redacted]		
Stuart	1	90.2			0.9	91.1	[redacted]		
Stuart	2	90.2			0.9	91.1	[redacted]		
Stuart	3	90.2			0.9	91.1	[redacted]		
Stuart	4	90.2			0.9	91.1	[redacted]		
Zimmer	1	415.3			1.9	417.2	[redacted]		
Conesville	4	257.2			24.9	282.1	[redacted]		
Conesville	5	217.5			8.8	226.3	[redacted]		
Conesville	6	217.5			8.8	226.3	[redacted]		
Racine		36.6			-	36.6	[redacted]		
		5,416.0	4.1	-	186.9	5,607.0	[redacted]		
		5,692.9	-	(1.2)	189.6	5,881.3	18,025.2	12,143.9	274.3

KPCO Big Sandy Unit Disposition Options

"BASE" ('Fleet Transition-CSAPR') Commodity Pricing

Expansion Plan Summary and Costs

SENSITIVITY: **MODIFIED TO REFLECT CAPACITY VALUES UTILIZED IN MITCHELL IMPAIRMENT ANALYSIS [Response to KIUC 2-55, CONFIDENTIAL])**

Option	#1A	#1B	#2A	#2B	#3A	#3B	#4A	#4B	#5A	#5B	#6
Big Sandy 1 Disposition	Retire 6/2015		Retire 6/2015		(CC) Repower 6/2017		Retire 6/2015		Gas Conversion 7/2015		Retire 6/2015
Big Sandy 2 Disposition	Retrofit 6/2017 (Idling 1/2016)		Retire 1/2016		Retire 1/2016		Retire 6/2015		Retire 6/2015		Retire 6/2015
Mitchell 1&2 Transfer (1/2014)	20%	0%	20%	0%	20%	0%	0%	0%	50%	0%	50%
BS Repl-Build Capacity at Big Sandy Site	None		Combined-Cycle (6/2017)		(Repowered) Combined-Cycle (6/17)		None (thru 2025)	None (thru 2025)	None (thru 2030)	None (thru 2020)	None (thru 2025)
BS Repl-Build Capacity at Generic Site	None	None (thru 2025)	None	None (thru 2025)	None	None (thru 2025)	None (thru 2020)	None (thru 2025)	None	None (thru 2025)	None
Market Puchase Duration	None	To '26 (~250 MW)	None	To '26 (~250 MW)	None	To '26 (~250 MW)	To '21(~1050 MW)	To '26(~1050 MW)	None	To '21(~800 MW)	To '26 (~250 MW)
2011-2013											
2014	2- 20% ML,		2- 20% ML,		2- 20% ML,				2- 50% ML,		2- 50% ML,
2015									- 260 MW BSGAS	- 260 MW BSGAS	
2016											
2017	1 -788 MW Retrofit	1 -788 MW Retrofit	1- 762 MW BFCC,	1- 762 MW BFCC,	1- 745 MW RPWR	1- 745 MW RPWR					
2018-2020											
2021							4 -85 MW CTs, 1- 352 MW CC1,			1- 381 MW BFCC,	
2022-2025											
2026		4 -85 MW CTs,		4 -85 MW CTs,		4 -85 MW CTs,	1- 381 MW BFCC,	4 -85 MW CTs, 1- 762 MW BFCC,		4 -85 MW CTs,	1- 381 MW BFCC,
2027-2030											
2031									1- 381 MW BFCC,	1- 352 MW CC1,	
2032-2040											
2011- 2040 CPW ($000)											
NOTE: (ABSOLUTE) CPW RESULTS BELOW DO NOT INCORPORATE POST-MODELING ADJUSTMENT FOR "2014 & 2015" PJM-FRR CAPACITY VALUE ADJUSTMENT RE: MITCHELL											
REVISED w/ Modified 'Capacity Value' (per Impairment Analysis)											
KPCO Production and Capital Cost	*6,269,937*	*6,322,529*	*6,214,342*	*6,286,130*	*6,209,935*	*6,276,564*	*5,972,503*	*5,815,008*	*5,680,947*	*5,855,373*	*5,752,470*
Less: Value of ICAP Revenue <Charge>	(13,861)	(77,196)	31,493	(31,842)	(4,715)	(68,050)	(112,301)	(194,129)	16,813	(90,052)	(27,707)
Total KPCO Revenue Requirement, Net	6,283,797	6,399,725	6,182,848	6,317,972	6,214,650	6,346,614	6,084,803	6,009,136	5,664,134	5,945,425	5,780,177
Cost / <Savings> vs. "Option #6"	503,620 8.7%	619,548 10.7%	402,671 7.0%	537,794 9.3%	434,473 7.5%	566,437 9.8%	304,626 5.3%	228,959 4.0%	(116,043) -2.0%	165,248 2.9%	-
"As-Filed" (w/ Fundamentals-Based Capacity Pricing):											
Cost / <Savings> vs. "Option #6"	490,027 8.5%	697,085 12.0%	347,273 6.0%	560,129 9.7%	423,068 7.3%	632,765 10.9%	410,676 7.1%	434,922 7.5%	(156,437) -2.7%	257,786 4.5%	-
REVISED w/ Modified 'Capacity Value' (per Impairment Analysis)											
Cost / <Savings> vs. "Option #5A"	619,663 10.9%	735,591 13.0%	518,714 9.2%	653,838 11.5%	550,516 9.7%	682,480 12.0%	420,669 7.4%	345,002 6.1%	- -	281,291 5.0%	116,043 2.0%
"As-Filed" (w/ Fundamentals-Based Capacity Pricing):											
Cost / <Savings> vs. "Option #5A"	646,464 11.5%	853,523 15.2%	503,710 8.9%	716,566 12.7%	579,505 10.3%	789,202 14.0%	567,113 10.1%	591,359 10.5%	- -	414,223 7.4%	156,437 2.8%
SENSITIVITY: **RELATIVE IMPACT of 'Alternative' (Aep-Ohio Impairment Analysis) Capacity Value**											
2011- 2040 CPW ($000)											
Cost / <Savings> vs. "Option #6"	13,593	(77,537)	55,398	(22,335)	11,405	(66,328)	(106,050)	(205,963)	40,394	(92,537)	-
Cost / <Savings> vs. "Option #5A"	(26,801)	(117,931)	15,004	(62,729)	(28,989)	(106,722)	(146,444)	(246,357)	-	(132,932)	(40,394)

Exhibit SCW-4R

AEP Ohio Generation Spread-Option Model-Pricing Parameters for Impairment Analysis (vs. Fundamental Forecasts used in KPCo BS Unit Disposition Analysis)

CAPACITY

PJM-RPM Planning Yr	Per Fundamental Analysis "FT-CSAPR" (Base) Scenario PJM-RPM ICAP Value $/MW-Week NOMINAL $	$/MW-Day NOMINAL $	Management Adjusted Proxy... Lower Level PJM-RPM UCAP Value $/MW-Day NOMINAL $	Converted to... ICAP Value $/MW-Week NOMINAL $ Mitchell 1	$/MW-Week NOMINAL $ Mitchell 2	$/MW-Week NOMINAL $ Wtd. Avg.	ICAP Value Delta $/MW-Week	%
2012/13	$1,122	$160	[redacted]	[redacted]				
2013/14	$161	$23						
2014/15	$595	$85						
2015/16	$1,507	$215						
2016/17	$1,973	$281						
2017/18	$1,652	$235						
2018/19	$1,403	$200						
2019/20	$1,572	$224						
2020/21	$1,774	$253						
2021/22	$1,960	$279						
2022/23	$2,129	$303						
2023/24	$2,280	$325						
2024/25	$2,412	$344						
2025/26	$2,524	$360						
2026/27	$2,615	$373						
2027/28	$2,685	$383						
2028/29	$2,731	$389						
2029/30	$2,751	$392						
2030/31	$2,745	$391						

Supporting Spread-Option Model Calculation (Conversion of UCAP Value to ICAP Value)...

UCAP Value Used in Impairment Analysis For 'Calendar' Yr (5 mos. Cur PY; + 7 mos. Cur PY-1)	To Convert to SO Model-Required 'ICAP' Value x (1- 'X'%) EFORd Estimates ML1	ML2	= Equivalent (Calendar) "ICAP" Values Mitchell 1 $/MW-Day	Mitchell 2	+ Versus... Planned Outage Estimates ML1	ML2	= x (1- 'X'%) Unavailability Estimates ML1	ML2	(A) To Convert to SO Model-Required 'ICAP' Value = Equivalent (Calendar) "ICAP" Values ML1 $/MW-Day	(B) ML2	(C) (Response to SC 2-55 (CONFIDENTIAL)) Detailed Spr-Opt Model Output Mitchell 1 $/kW-Yr	Converted to $/MW-Week	Converted to $/MW-Day	(C) - (A) VAR	(D) Detailed Spr-Opt Model Output Mitchell 2 $/kW-Yr	Converted to $/MW-Week	Converted to $/MW-Day	(D) - (B) VAR
2014	[redacted]										[redacted]							
2015																		
2016																		
2017																		
2018																		
2019																		
2020																		
2021																		
2022																		
2023																		
2024																		
2025																		
2026																		
2027																		
2028																		
2029																		
2030																		
2031																		

ENERGY

Per Fundamental Analysis "FT-CSAPR" (Base) Scenario | *Per Fundamental Analysis "FT-LOWER Band" Scenario*

[redacted]

ENERGY
NOMINAL $

	ON-Peak (@ AEP Gen Hub) $/Mwh	ON-Peak (@ AEP Gen Hub) $/Mwh	Delta $/Mwh	Delta %
2012	[redacted]	[redacted]		
2013				
2014				
2015(A)	$56.71	$53.60	($3.11)	-5.5%
2016	$63.56	$58.75	($4.81)	-7.6%
2017	$63.48	$59.20	($4.28)	-6.7%
2018	$64.18	$60.06	($4.13)	-6.4%
2019	$65.44	$60.90	($4.54)	-6.9%
2020	$66.33	$60.86	($5.47)	-8.2%
2021	$67.64	$62.38	($5.26)	-7.8%
2022	$76.79	$72.64	($4.15)	-5.4%
2023	$78.33	$74.25	($4.08)	-5.2%
2024	$80.34	$74.99	($5.35)	-6.7%
2025	$82.18	$76.25	($5.93)	-7.2%
2026	$83.23	$77.71	($5.52)	-6.6%
2027	$84.57	$79.22	($5.35)	-6.3%
2028	$86.25	$80.55	($5.70)	-6.6%
2029	$87.64	$81.53	($6.11)	-7.0%
2030	$89.34	$82.78	($6.56)	-7.3%

(A) Would begin to utilize fundamental energy pricing effective: 6/1/2015

Exhibit SCW-5R
(PUBLIC)

Mitchell Units 1&2 Total-O&M Costs (excluding Consumable Costs) <u>Included in Strategist Modeling</u>:

"Option #6"

INCLUDED IN KPCO STRATEGIST MODELING

	KPCo (50%) Mitchell 1 Transfer					KPCo (50%) Mitchell 2 Transfer					KPCo (50%) ML 1& 2	KPCo (50%) ML 1& 2			KPCo (50%) ML 1& 2	KPCo (50%) ML 1& 2	TOTAL (100%) ML 1& 2 Per Strategist Modeling	TOTAL (100%) ML 1& 2 Per Kollen Direct (Pg. 31) (Fr. Rate Impact Study)	TOTAL (100%) ML 1& 2 Per Kollen Direct (Pg. 30)
	Fixed O&M ($000)	(Non-Consumable) Variable O&M ($/MWh)	Generation (GWh)	(Non-Consumable) Variable O&M ($000)	Unit (Direct) O&M Cost ($000)	Fixed O&M ($000)	(Non-Consumable) Variable O&M ($/MWh)	Generation (GWh)	(Non-Consumable) Variable O&M ($000)	Unit (Direct) O&M Cost ($000)	Plant (Direct) O&M Cost ($000)	Plus: "A&G" Component of Carrying Charge Capital Invest. ($000)	Cumul. Capex ($000)	x A&G Rate * (Lvlzd Comp)	Plant A&G Cost ($000)	Plant 'TOTAL' O&M (incl. A&G; excl Consumables) ($000)	x 2 Plant 'TOTAL' O&M (incl. A&G; excl Consumables) ($000)	versus Plant 'TOTAL' O&M (excl. Consumables) (2011-2012) ($000)	OR Plant 'TOTAL' O&M (excl. Consumables) (2014-2015)
2011	0	1.48	0	0	0	0	1.48	0	0	0	0			1.08%			0	2011(A) 67,741	
2012	0	1.50	0	0	0	0	1.50	0	0	0	0						0	2012(A) 68,108	
2013	0	1.54	0	0	0	0	1.54	0	0	0	0	*535,911*	*<= Transfer Price*				0		
2014	12,296	1.59	2,084	3,313	15,609	12,199	1.59	2,250	3,578	15,777	31,386	*80,910*	*616,821*		6,662	38,048	76,096		48,991
2015	12,321	1.62	2,137	3,461	15,782	15,661	1.62	1,776	2,878	18,539	34,321	*58,779*	*675,600*		7,296	41,618	83,235		55,964
2016	17,654	1.65	1,960	3,234	20,889	15,040	1.65	2,394	3,950	18,990	39,879	*29,284*	*704,884*		7,613	47,491	94,983		*Ignores:*
2017	14,429	1.68	2,332	3,918	18,347	14,764	1.68	2,469	4,148	18,912	37,259	*46,552*	*751,436*		8,116	45,375	90,750		*o Variable O&M*
2018	15,102	1.70	2,340	3,978	19,081	16,953	1.70	2,215	3,766	20,719	39,799	*63,034*	*814,471*		8,796	48,596	97,191		*o A&G Component*
2019	18,246	1.73	2,081	3,599	21,845	16,100	1.73	2,517	4,355	20,455	42,300	*36,611*	*851,082*		9,192	51,492	102,984		
2020	17,499	1.76	2,255	3,968	21,467	17,589	1.76	2,485	4,373	21,962	43,430	*33,055*	*884,136*		9,549	52,978	105,957		
2021	13,660	1.79	2,370	4,243	17,903	13,520	1.79	2,217	3,969	17,489	35,392	*54,644*	*938,780*		10,139	45,531	91,063		
2022	16,345	1.82	1,713	3,118	19,463	16,341	1.82	2,179	3,965	20,307	39,770	*31,022*	*969,802*		10,474	50,244	100,488		
2023	16,672	1.85	1,856	3,434	20,106	16,668	1.85	2,145	3,967	20,636	40,742	*31,797*	*1,001,599*		10,817	51,559	103,118		
2024	17,005	1.88	1,982	3,726	20,731	17,002	1.88	1,838	3,455	20,457	41,188	*32,592*	*1,034,191*		11,169	52,358	104,715		
2025	17,345	1.91	1,613	3,080	20,426	17,342	1.91	2,146	4,098	21,440	41,866	*33,407*	*1,067,598*		11,530	53,396	106,792		
2026	17,692	1.94	2,103	4,079	21,772	17,689	1.94	2,251	4,367	22,056	43,828	*34,242*	*1,101,840*		11,900	55,727	111,455		
2027	18,046	1.97	2,149	4,234	22,280	18,042	1.97	1,909	3,761	21,803	44,084	*35,098*	*1,136,938*		12,279	56,363	112,725		
2028	18,407	2.00	1,864	3,728	22,135	18,403	2.00	2,250	4,501	22,904	45,039	*35,976*	*1,172,913*		12,667	57,706	115,413		
2029	18,775	2.03	2,101	4,265	23,040	18,771	2.03	2,244	4,556	23,327	46,367	*36,875*	*1,209,788*		13,066	59,433	118,866		
2030	19,151	2.06	2,047	4,217	23,367	19,147	2.06	1,858	3,828	22,975	46,342	*37,797*	*1,247,585*		13,474	59,816	119,633		
2031	19,534	2.09	1,795	3,751	23,285	19,530	2.09	2,187	4,571	24,101	47,385	*38,742*	*1,286,327*		13,892	61,278	122,556		
2032	19,924	2.12	2,023	4,289	24,213	19,920	2.12	2,191	4,645	24,565	48,778	*39,710*	*1,326,037*		14,321	63,099	126,198		
2033	20,323	2.16	1,958	4,230	24,553	20,319	2.16	1,818	3,927	24,245	48,798	*40,703*	*1,366,740*		14,761	63,559	127,118		
2034	20,729	2.19	1,737	3,805	24,534	20,725	2.19	2,127	4,658	25,382	49,917	*41,721*	*1,408,460*		15,211	65,128	130,256		
2035	21,144	2.22	1,833	4,070	25,214	21,139	2.22	2,072	4,599	25,739	50,952	*42,764*	*1,451,224*		15,673	66,626	133,251		
2036	21,567	2.26	1,892	4,275	25,842	21,562	2.26	1,771	4,003	25,565	51,407	*35,066*	*1,486,290*		16,052	67,459	134,917		
2037	21,998	2.29	1,665	3,812	25,810	21,993	2.29	2,071	4,743	26,737	52,547	*21,566*	*1,507,856*		16,285	68,832	137,663		
2038	22,438	2.32	1,829	4,242	26,680	22,433	2.32	2,080	4,826	27,260	53,940	*8,842*	*1,516,698*		16,380	70,320	140,641		
2039	22,887	2.35	1,873	4,403	27,289	22,882	2.35	1,785	4,194	27,076	54,365	*1,813*	*1,518,510*		16,400	70,765	141,531		
2040	23,345	2.39	1,570	3,752	27,097	23,340	2.39	2,040	4,876	28,216	55,313	*0*	*1,518,510*		16,400	71,712	143,425		
Source	ML12 Transfer STRAT INPUT DATA4.xls	INPUT.GAF.THERMAL UNIT.THERMAL UNIT, YEAR Variable O and M Cost ($/MWh)	OUTPUT.GAF.UNIT DATA.THERMAL UNIT, YEAR Generation(GWh)			ML12 Transfer STRAT INPUT DATA4.xls	INPUT.GAF.THERMAL UNIT.THERMAL UNIT, YEAR Variable O and M Cost ($/MWh)	OUTPUT.GAF.UNIT DATA.THERMAL UNIT, YEAR Generation(GWh)											

* Reflects 67.5% of (1.60%) "Administrative, General and Property Taxes" component of KPCo levelized carrying charge rate used in modeling

Exhibit SCW-6R

KPCo Big Sandy Unit Disposition Options

Strategist® Sensitivity Modeling

Based on

(Restated) "2013 EIA Company-Modified" Commodity Pricing

Option	KPCo Option #5A	KIUC Option
Big Sandy 1 Disposition	Gas Conversion 7/2015	
Big Sandy 2 Disposition	Retire 6/2015	
Mitchell 1&2 Transfer (1/2014)	50%	20%
BS Repl-Build Capacity at Big Sandy Site	None (thru 2027)	None (thru 2026)
BS Repl-Build Capacity at Generic Site	None	None (thru 2026)
Market Puchase Duration	None	To 2026(~400 MW)
2011		
2012		
2013		
2014	2- 50% ML,	2- 20% ML,
2015	1- 260 MW BSGAS,	1- 260 MW BSGAS,
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		1- 381 MW BFCC,
2027		
2028		
2029		4 -85 MW CTs,
2030		
2031	1- 381 MW BFCC,	
2032		
2033		
2034		
2035		
2036		
2037		4 -85 MW CTs,
2038		
2039		
2040		
2011- 2040 CPW ($000)		
KPCO Production and Capital Cost	5,705,494	5,593,192
Less: Value of ICAP Revenue	48,974	(158,399)
Total KPCO Revenue Requirement, Net	5,656,520	5,751,591
Plus: CPW Adjustment for Removal of 1/2014-5/2015 (Mitchell) Capacity Value	34,417	13,767
Total KPCO Revenue Requirement, Net (Adj)	5,690,937	5,765,358
Cost / <Savings> vs. AEP Option #5A		74,421

Results for KIUC 'Impairment Analysis' S[illegible]gist Runs ("Table 3")

Determination of KIUC-Modeled Mitchell "Fuel Cost" Overstatement

		KPCo (Option #6)						KIUC Option						000 MMBtu DELTA (Opt 6 v. KIUC)		X Hayet Fuel Cost Rate Overstatement (Below)	= Relative Hayet 'Fuel Cost' Overstatement (Opt 6 v. KIUC)	(A) Relative CPW Impact Re: 'Fuel Cost' Overstatement
		Generation (GWh)		Capacity Factor (%)		000 MMBtu		Generation (GWh)		Capacity Factor (%)		000 MMBtu						
		Mitchell 1	Mitchell 2	Mitchell 1	Mitchell 2	Mitchell 1	Mitchell 2	Mitchell 1	Mitchell 2	Mitchell 1	Mitchell 2	Mitchell 1	Mitchell 2	Mitchell 1	Mitchell 2	($/MMBtu)	($000)	($000)
2014	"Pre" Projected Carbon Tax	972	1,392	29	40	9,463	13,519	372	497	28	36	3,622	4,831	5,842	8,687	$ 1.18	17,120	13,359
2015		1,105	1,204	33	35	10,763	11,687	522	502	39	36	5,069	4,875	5,694	6,812	$ 1.19	14,861	10,676
2016		1,260	1,806	37	52	12,271	17,529	632	803	47	58	6,142	7,792	6,129	9,736	$ 0.94	14,847	9,820
2017		1,471	1,937	44	56	14,335	18,801	782	858	58	62	7,600	8,333	6,735	10,467	$ 0.92	15,754	9,592
2018		2,012	1,229	60	36	19,545	11,951	878	641	65	46	8,520	6,226	11,024	5,725	$ 0.68	11,362	6,369
2019		1,301	1,893	39	55	12,669	18,383	683	855	51	62	6,631	8,305	6,038	10,079	$ 0.57	9,201	4,748
2020		2,073	1,422	61	41	20,134	13,830	900	745	67	54	8,738	7,242	11,396	6,588	$ 0.75	13,548	6,437
2021		1,590	1,810	47	52	15,486	17,562	806	791	60	57	7,832	7,683	7,654	9,879	$ 0.47	8,276	3,620
2022	"Post" Projected Carbon Tax	687	1,224	20	35	6,703	11,899	243	356	18	26	2,366	3,463	4,337	8,436	$ 1.96	25,013	10,073
2023		762	1,272	23	37	7,438	12,366	299	415	22	30	2,908	4,034	4,530	8,332	$ 1.88	24,179	8,964
2024		1,301	656	39	19	12,677	6,384	399	253	30	18	3,881	2,464	8,796	3,920	$ 1.83	23,279	7,946
2025		724	1,283	21	37	7,062	12,476	297	418	22	30	2,894	4,061	4,168	8,416	$ 1.89	23,728	7,456
2026		805	1,241	24	36	7,851	12,060	307	404	23	29	2,985	3,922	4,866	8,138	$ 1.77	22,981	6,648
2027		1,226	658	36	19	11,941	6,408	398	246	30	18	3,868	2,387	8,072	4,021	$ 1.89	22,837	6,082
2028		733	1,213	22	35	7,148	11,792	289	392	21	28	2,809	3,810	4,338	7,981	$ 2.06	25,432	6,236
2029		812	1,246	24	36	7,923	12,109	313	381	23	28	3,040	3,698	4,883	8,411	$ 1.86	24,758	5,589
2030		858	1,075	25	31	8,376	10,439	298	314	22	23	2,893	3,050	5,482	7,389	$ 2.05	26,371	5,481
2031		1,182	808	35	23	11,502	7,864	377	316	28	23	3,664	3,075	7,839	4,789	$ 2.11	26,671	5,103
2032		1,329	795	39	23	12,933	7,737	426	310	32	22	4,140	3,012	8,793	4,725	$ 2.15	28,998	5,108
2033		1,265	679	38	20	12,322	6,611	407	263	30	19	3,956	2,560	8,366	4,051	$ 2.18	27,055	4,388
2034		1,158	766	34	22	11,271	7,464	361	298	27	22	3,509	2,897	7,762	4,567	$ 2.21	27,307	4,077
2035		1,304	728	39	21	12,691	7,086	403	279	30	20	3,914	2,716	8,778	4,370	$ 2.25	29,576	4,065
2036		1,221	633	36	18	11,893	6,164	384	242	28	17	3,732	2,350	8,161	3,814	$ 2.29	27,363	3,463
2037		1,129	702	33	20	10,987	6,844	340	267	25	19	3,306	2,594	7,681	4,250	$ 2.32	27,712	3,229
2038		1,265	668	37	19	12,315	6,513	378	250	28	18	3,672	2,434	8,643	4,079	$ 2.36	30,010	3,219
2039		1,170	584	35	17	11,402	5,687	357	217	26	16	3,476	2,107	7,926	3,580	$ 2.40	27,571	2,723
2040		1,123	644	33	19	10,943	6,280	318	234	24	17	3,093	2,274	7,850	4,006	$ 2.44	28,874	2,625

Source: Hayet file Run11R20.SAV for AEP Option #6 data and Run11R20a.SAV for KIUC Option data

Sum: CPW = 167,097

($/MMBtu)	KIUC Fuel Price (Excl. VOM) MITC_1	MITC_2	ML Total (Gen Wtd.)	Per Spread Option (Impairment Analysis) MITC_1	MITC_2	ML Total (Gen Wtd.)	Hayet Fuel Cost Rate Overstatement ($/MMBtu)
2014	3.88	3.88	3.88	2.70	2.70	2.70	1.18
2015	3.88	3.88	3.88	2.69	2.69	2.69	1.19
2016	3.52	3.78	3.68	2.74	2.74	2.74	0.94
2017	3.80	3.79	3.80	2.88	2.88	2.88	0.92
2018	3.89	3.54	3.76	3.08	3.08	3.08	0.68
2019	3.31	4.02	3.73	3.16	3.16	3.16	0.57
2020	3.99	4.01	3.99	3.24	3.24	3.24	0.75
2021	3.98	3.63	3.79	3.32	3.32	3.32	0.47
2022	5.24	5.44	5.37	3.41	3.41	3.41	1.96
2023	5.53	5.55	5.54	3.66	3.66	3.66	1.88
2024	5.64	5.43	5.57	3.74	3.74	3.74	1.83
2025	5.58	5.78	5.71	3.82	3.82	3.82	1.89
2026	5.84	5.56	5.67	3.90	3.90	3.90	1.77
2027	5.80	6.00	5.87	3.98	3.98	3.98	1.89
2028	6.05	6.17	6.12	4.06	4.06	4.06	2.06
2029	6.15	5.90	6.00	4.14	4.14	4.14	1.86
2030	6.16	6.35	6.27	4.22	4.22	4.22	2.05
2031	6.41	6.43	6.42	4.31	4.31	4.31	2.11
2032 *	*6.52*	*6.54*	*6.52*	*4.38*	*4.38*	*4.38*	2.15
2033	*6.62*	*6.64*	*6.63*	*4.45*	*4.45*	*4.45*	2.18
2034	*6.73*	*6.75*	*6.74*	*4.52*	*4.52*	*4.52*	2.21
2035	*6.83*	*6.86*	*6.84*	*4.59*	*4.59*	*4.59*	2.25
2036	*6.94*	*6.97*	*6.95*	*4.67*	*4.67*	*4.67*	2.29
2037	*7.05*	*7.08*	*7.06*	*4.74*	*4.74*	*4.74*	2.32
2038	*7.17*	*7.19*	*7.18*	*4.82*	*4.82*	*4.82*	2.36
2039	*7.28*	*7.30*	*7.29*	*4.89*	*4.89*	*4.89*	2.40
2040	*7.40*	*7.42*	*7.41*	*4.97*	*4.97*	*4.97*	2.44

* Post-2031 fuels costs were escalated at 1.6% per year (based on prior 3-yr growth rate)

Exhibit SCW-8R

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF:

The Application Of Kentucky Power Company For: (1) A Certificate Of Public Convenience And Necessity Authorizing The Transfer To The Company Of An Undivided Fifty Percent Interest In The Mitchell Generating Station And Associated Assets; (2) Approval Of The Assumption By Kentucky Power Company Of Certain Liabilities In Connection With The Transfer Of The Mitchell Generating Station; (3) Declaratory Rulings; (4) Deferral Of Costs Incurred In Connection With The Company's Efforts To Meet Federal Clean Air Act And Related Requirements; And (5) For All Other Required Approvals And Relief	) Case No. 2012-00578

REBUTTAL TESTIMONY

OF

RANIE K. WOHNHAS

May 3, 2013

VERIFICATION

The undersigned, Ranie K. Wohnhas being duly sworn, deposes and says he is the Managing Director Regulatory and Finance for Kentucky Power Company, that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Ranie K. Wohnhas

RANIE K. WOHNHAS

COMMONWEALTH OF KENTUCKY)
) Case No. 2012-00578
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Ranie K. Wohnhas, this the 1st day of May 2013.

Judy K Rosquist 481393
Notary Public

My Commission Expires: January 23, 2017

REBUTTAL TESTIMONY OF
RANIE K. WOHNHAS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2012-00578

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**REBUTTAL TESTIMONY OF
RANIE K. WOHNHAS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

I. INTRODUCTION

Q: PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Ranie K. Wohnhas. My position is Managing Director, Regulatory and Finance, Kentucky Power Company (Kentucky Power or Company). My business address is 101 A Enterprise Drive, Frankfort, Kentucky 40602.

Q: ARE YOU THE SAME RANIE K. WOHNHAS THAT FILED DIRECT TESTIMONY IN THIS PROCEEDING ON BEHALF OF KENTUCKY POWER?

A. Yes, I am.

II. PURPOSE OF TESTIMONY

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A: The purpose of my testimony is to correct KIUC witness Kollen's description of the Big Sandy Unit 2 FGD Investigation Costs being requested by Kentucky Power Company to be deferred and established as a regulatory asset, explain the financing risks associated with delaying the Mitchell Asset Transfer, including addressing Mr. Kollen's contention that the Commission should find the market risk accompanying his proposal acceptable, and address the KIUC-suggested changes to the Company's Tariff S.C.C. and off-system sales.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. No, I am not.

III. THE COMPANY'S FGD INVESTIGATION COSTS SHOULD BE DEFERRED AND A REGULATORY ASSET ESTABLISHED.

Q. DOES MR. KOLLEN PROPERLY DESCRIBE THE BIG SANDY UNIT 2 FGD INVESTIGATION COSTS?

A. No. Mr. Kollen's testimony beginning on page 40, line 18 through page 44, line 19 completely mischaracterizes the costs incurred for FGD investigation costs.

Q. COULD YOU IDENTIFY THE ERRORS IN MR. KOLLEN'S CHARACTERIZATION?

A. Yes. First, Mr. Kollen describes the Company's deferral request of $29.287 million as of November 30, 2012 as related to two separate and distinct investigations of scrubber retrofit alternatives for Big Sandy Unit 2. In fact, the Company's request relates to one investigation as I state in my direct testimony beginning on page 10, line 19 through page 11, line 3. Although the investigation was suspended in 2006 and then re-started in 2010, all the costs were tracked as one project for accounting and budgeting purposes. The fact that during the course of the investigation, the type of FGD being considered changed from a wet Flue Gas Desulfurization (WFGD) system to a dry Flue Gas Desulfurization (DFGD) system does not mean there were two separate investigations. The prudency of the investigation including both the WFGD and DFGD systems, are further addressed by Company witness Walton.

Second, Mr. Kollen states that the costs should have been expensed. These costs should not be expensed. Instead of expensing the FGD investigation costs the Company properly accounted for the costs in FERC Account 183. The FGD investigation costs were reclassified to FERC Account 183 from FERC Account 107 in late 2012 when the Company recommended that a FGD for Big Sandy Unit 2 not be pursued. FERC Account 183 includes all expenditures for preliminary surveys, plans and investigations made for the purpose of determining the feasibility of utility projects under contemplation. The costs should remain in FERC Account 183 until a final decision on the disposition of Big Sandy Unit 2 is reached by the Commission or the Commission approves Kentucky Power's request in this proceeding to defer the costs as a regulatory asset with recovery to be determined in its next base rate proceeding. If the Commission agrees with the Company's proposal not to retrofit Big Sandy Unit 2 but does not approve the Company's request for deferral, with subsequent recovery to be determined in the next base case filing, then the amounts in FERC Account 183 would need to be expensed at the time of the Commission order.

Third, Mr. Kollen states that the Company sought ratemaking recognition of its deferrals in Case No. 2011-00401 filed in December 2011. Again, this is incorrect. In Case No. 2011-00401, the Company requested that the FGD investigation costs be treated as construction work in process (FERC Account 107) and be capitalized as part of the total cost to install a DFGD on Big Sandy Unit 2. This request was withdrawn in May 2012.

Q. IS THERE ANYTHING ELSE THAT MR. KOLLEN INCORRECTLY DESCRIBES WITH REGARD TO THE FGD INVESTIGATION COSTS?

A. Yes. Mr. Kollen states in his testimony on page 42, line 18 that the Company's request is retroactive ratemaking. This is incorrect. The investigation costs have not been expensed and will not be until (1) the Commission makes a final determination on the disposition of Big Sandy Unit 2 that does not include installing a FGD system, and (2) the Commission disallows regulatory treatment of the costs. As stated earlier, the Company reclassified the FGD investigation costs to FERC Account 183 in late 2012 following a Company decision not to recommend the installation of a FGD at Big Sandy Unit 2. Accordingly, the Company has properly and timely requested in this proceeding for those costs to be deferred as a regulatory asset.

IV. KIUC'S PROPOSAL EXPOSES KENTUCKY POWER'S CUSTOMERS TO UNNECESSARY FINANCING AND MARKET RISKS.

Q. IN MR. PAULEY'S REBUTTAL TESTIMONY, HE REFERRED TO FINANCING-RELATED RISKS IF THE MITCHELL ASSEST TRANSFER IS DELAYED. WOULD YOU PLEASE ELABORATE ON THOSE RISKS?

A. Yes. KIUC's proposal to delay the transfer of the Mitchell units for 17 months (January 1, 2014 – May 31, 2015) results in multiple financings of the Mitchell units which will increase the cost to Kentucky Power's customers.

If the transfer is delayed and AEP Generation Resources Inc. ("AEP Generation Resources") is to hold the assets for Kentucky Power pending the retirement of Big Sandy Unit 2, as proposed by KIUC, AEP Generation

Resources would be required to finance these long-term assets for a short-term period. As the future long-term owner, Kentucky Power cannot be financially indifferent to this financing. If AEP Generation Resources finances the assets on a short-term basis, the increased cost of this financing must be passed on to Kentucky Power as the assets would have been held for Kentucky Power. In the alternative, if long-term financing is to be put in place, then the Company, as the ultimate long-term owner of the 50% (or 20% as proposed by KIUC) interest in the Mitchell generating station would assume the costs of this financing as part of the transfer from AEP Generation Resources. Either way, Kentucky Power is affected financially.

Any costs incurred by AEP Generation Resources in connection with KIUC's proposal to delay the Mitchell transfer will be properly borne by, and flow back to, Kentucky Power's customers.

Q. ARE THERE OTHER FINANCING-RELATED RISKS AND COSTS ASSOCIATED WITH KIUC'S PROPOSAL THAT MR. KOLLEN FAILED TO ADDRESS?

A. Yes. Kentucky Power also would be exposed to interest rate risk during the delay period. Interest rates are at historically low levels, and every month that goes by increases the likelihood that interest rates will begin to increase. Delaying the transfer of the Mitchell units to Kentucky Power could result in interest rate increases and subject the Company to a profoundly different set of financial market conditions under which it would be required to finance the new assets. While interest rates conceivably could remain at these historically-low levels, or even decline further, the current forward-looking 10-year Treasury rate is expected to increase approximately 50 basis points, or 24% between the projected December 31, 2013 level and the projected May 30, 2015 level as set forth below.

Projected Rates for 10-Year U.S. Treasury Bonds

	April 19, 2013	12/31/2013	12/31/2014	5/30/2015
10 Yr. Treasury	1.7806%	2.0087%	2.334%	2.4834%

Source: Bloomberg 4/19/2013

Q. **COULD THE ABSENCE OF CERTAINTY CONCERNING THE ULTIMATE "DESTINATION" OF THE MITCHELL UNITS AFFECT THE FINANCING COSTS ASSOCIATED WITH KIUC'S PROPOSED DELAY IN THE TRANSFER OF THE MITCHELL UNITS?**

A. Yes. This interest rate risk (and its associated costs) may be exacerbated by any uncertainty in the ultimate ownership. Under the KIUC's proposal, and because AEP Generation Resources will own only unregulated generation assets, it is likely that AEP Generation Resources' credit costs may be higher than those of Kentucky Power. Consequently, the increased cost would have to borne by Kentucky Power customers.

Q. **WILL KIUC'S PROPOSAL ALSO SUBJECT KENTUCKY POWER'S CUSTOMERS TO UNNECESSARY MARKET RISKS?**

A. Yes. On page 19, Mr. Kollen asserts that it is better to have insufficient resources and take the price and market risk by purchasing from the market than it is to have any additional generation and take the risk of selling that generation when he believes that the Company does not require it. Clearly, there are a number of circumstances that would cause Kentucky Power to make significant purchases in the market if the transfer of the Mitchell units does not occur. Mitigating this market risk is one of the reasons for the Company's proposed timing of the transfer.

KIUC's proposal leaves the Company without generation to rely on in the event its existing units have either scheduled or forced outages. Prior to January 1, 2014, Kentucky Power could rely on the purchases under the Interconnection Agreement to meet its needs during such periods. However, if the proposed transfer of a 50% share of the Mitchell units to Kentucky Power is delayed, the Company will be exposed to significantly more market risk. As shown in the rebuttal testimony of Company witness Weaver, during the 17-month period at issue, Kentucky Power would need to purchase an amount of energy from the market in a range between 1,069 and 5,415 GWhs under KIUC's proposal to delay the transfer...

KIUC also proposes to convert Big Sandy 1 to gas with service effective June 1, 2015. Should this ultimately be determined to be the least-cost alternative for the disposition of Big Sandy Unit 1, conversion would require that Big Sandy 1 be out of service for a period of time. Based on KIUC's proposal, that outage would have to occur during the 17-month period when KIUC witnesses contend that Kentucky Power does not need the Mitchell units. However, during the conversion outage, Kentucky Power will not have sufficient energy to meet its needs and therefore would rely on the market. This is another example of where KIUC's proposal is incomplete and does not consider the additional market risk its proposal will force on Kentucky Power's customers. This risk is an important reason why the proposed transfer of the Mitchell units should not be delayed.

Because Kentucky Power would be more exposed to more market risk during the 17-month period if it lacks the proposed interest in the Mitchell assets, KIUC's proposal is in fact at odds with Mr. Kollen's assertion that the Company's proposal, under which the Company will own the assets prior to the retirement of Big Sandy Unit 2, creates more market risk.

Q. DOES THE KIUC PROPOSAL ADDRESS THE POSSBILE EARLY RETIRMENT OF BIG SANDY 2?

A. No, it does not. During the subject 17-month period, Kentucky Power will have to make on-going and appropriate decisions as to how much capital resources to invest in Big Sandy Unit 2 knowing that the unit will soon be retired. Depending on the nature and cost of these expenditures, it may be economically more advantageous to retire Big Sandy Unit 2 prior to its scheduled May 2015 retirement. In addition, the Company must consider the possibility that the unit could be retired prior to May 31, 2015 if operational issues occur. Company witness LaFleur further addresses this issue. Similarly, Big Sandy Unit 1 will either retire or be converted in the same time period and the same decision making process will apply. Ownership of 50% of the Mitchell units during the

17-month period prior to the retirement or conversion of the units provides proper risk mitigation in connection with the operation of the Big Sandy units. Without this risk mitigation, Kentucky Power and its customers will be exposed to even greater market risk than described above.

Q. DOES THE FINANCIAL AND MARKET RISK OF DELAYING THE MITCHELL ASSET TRANSFER HAVE ANY IMPACT ON THE ESTIMATED RATE IMPACT TO KENTUCKY POWER CUSTOMERS?

A. Yes. KIUC wants rates reduced with the elimination of the Pool Agreement, but fails to acknowledge that with the elimination of the Pool Agreement comes increased market risk. He likewise ignores that the transfer of the Mitchell units when the Pool Agreement terminates mitigates that market risk. Mr. Kollen is correct that the rate impacts provided by the Company based upon actual 2011 and 2012 data are just estimates. However, the Company has, as thoroughly as possible, provided estimated increases and decreases resulting from the various cost issues in order to provide the Commission with its best estimate of the final rate impact. Regardless of whether using the 2011or 2012 data, all of the estimates support that transferring the Mitchell assets to Kentucky Power because it is the least cost alternative.

V. <u>THE COMPANY'S TARIFF S.S.C.</u>

Q. MR. KOLLEN'S TESTIMONY ADDRESSES THE COMPANY'S TARIFF S.S.C. IN THAT TESTIMONY HE ALSO PROVIDES HIS RECOMMENDATIONS FOR HOW THE COMMISSION SHOULD TREAT THE CLAUSE IN FUTURE PROCEEDINGS. BEFORE

ADDRESSING HIS TESTIMONY, PLEASE DESCRIBE TARIFF S.S.C. AND ITS OPERATION.

A. Tariff S.S.C. is a long-standing net revenue sharing mechanism by which the Company and its customers split the difference between the Company's monthly net revenues from off-system sales and the amount of the corresponding monthly base net revenues from off-system sales set out in Tariff S.S.C. If the monthly net revenues from off-system sales are ***greater than*** the corresponding monthly base amount in Tariff S.S.C., the customers share the excess amount with the Company on a 60%/40% basis. That is, the customers receive a credit (applied to the fuel adjustment clause) equal to their kWh share of 60% of the amount by which the Company's monthly net off-system sales revenues for that month exceed that month's base amount as set out in Tariff S.S.C. The Company retains the other 40% of net revenues.

Conversely, in any month in which the Company's monthly net revenues from off-system sales are ***less than*** the corresponding monthly base amount in Tariff S.S.C., the customers are responsible for paying 60% of the shortfall to the Company.

Q. WHAT IS MR. KOLLEN'S RECOMMENDATION CONCERNING TARIFF S.S.C.?

A. Mr. Kollen first notes that Company witness Weaver's Strategist modeling assumed that 100% of the difference between the Company's monthly net revenues from off-system sales and the corresponding monthly base net revenues from off-system sales contained in Tariff S.S.C. is allocated to customers. Based on this he argues that if the Commission authorizes the transfer of any portion of the Mitchell generating station to Kentucky Power then it should condition any such approval on customers receiving 100% of the off-system sales "margins." This would mean that 100% of the amount by which the monthly off-system margins exceed the corresponding month's base amount in Tariff S.S.C. would be credited to customers. It also means, but is never recognized or stated by Mr. Kollen, that the customers would be responsible for 100% of any shortfall in monthly net off-system sales revenues.

Q. WHAT IS THE COMPANY'S RESPONSE TO MR. KOLLEN'S PROPOSAL?

A. As a rate, Tariff S.S.C. would be best addressed in the Company's next base rate case when the Company plans to present a proposal concerning its future operation. At that time, the Commission, the intervenors in this proceeding, and the other likely intervenors in any base rate case who are not part of this proceeding, will have the opportunity to evaluate the issue fully including the time period for any proposal, and to judge whether the resulting rates are fair, just and reasonable.

VI. <u>CONCLUSION</u>

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. First, the investigation costs related to the installation of an FGD on Big Sandy Unit 2 were the result of a single investigation, and those costs have been treated properly for accounting purposes. Once the final decision was made not to recommend the installation of a FGD on Big Sandy Unit 2, the Company properly asked for authorization to defer those costs as a regulatory asset to be reviewed for recovery in its next base rate proceeding. The Company's request is not retroactive ratemaking. Second, the financial and market risks inherent in KIUC's proposal to delay the Mitchell Asset Transfer will penalize Kentucky Power's customers and such a delay should be rejected by the Commission. Finally, any issues relating to Tariff S.S.C. are properly addressed in the Company's next base rate case proceeding.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.