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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 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**

AMENDED

DIRECT TESTIMONY

AND EXHIBITS

OF

PHILIP HAYET

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

April 1, 2013

COMMONWEALTH OF KENTUCKY

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TABLE OF CONTENTS

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DIRECT TESTIMONY OF PHILIP HAYET

QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Philip Hayet, and my business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia, 30075.

Q. What is your occupation and your business title?

A. I am an Electrical Engineer, and my title is Director of Consulting.

Q. Please summarize your education and professional experience.

A. I received a Bachelor of Electrical Engineering degree from Purdue University and a Master of Electrical Engineering degree from the Georgia Institute of Technology, with a specialization in Power Systems.

I have over thirty years of experience in the electric utility industry, in which I have worked in the areas of generation resource planning, economic analysis, and rate analysis. I began my career with Energy Management Associates ("EMA" now known as Venytx), an Atlanta based utility consulting firm, in which I supported PROMOD IV™ ("PROMOD") and Strategist clients. Strategist is the long-term resource planning model that Kentucky Power Company ("KPCO" or "the Company") and its owner American Electric Power ("AEP") relied on for this filing. In addition to supporting and training PROMOD and Strategist clients, I also performed numerous consulting assignments using these planning tools to develop and evaluate resource plans for electric utilities.

In 1996 I began my own consulting firm, Hayet Power Systems Consulting, in which I continue to work on projects involving generation resource planning and analysis, rate case support, and new generation technology analysis. In July 2000, I joined Kennedy and Associates on a non-exclusive basis, to make my production cost modeling and resource planning skills available in their regulatory consulting practice. A list of my specific regulatory appearances can be found in Exhibit___(PH-1).

Q. Have you previously filed testimony at the Kentucky Public Service Commission ("Commission" or "PSC")?

A. I recently filed testimony concerning resource planning issues in a Big Rivers Electric Corporation ("Big Rivers") proceeding in Case No. 2012-00063, in which Big River sought approval of its 2012 Environmental Compliance Plan. I have also filed testimony and testified before other state regulatory commissions and before the Federal Energy Regulatory Commission. Most, if not all, of these projects and testimony involved production cost and resource planning issues.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC"), which is a group of large customers served by KPCO.

Q. Please summarize your testimony.

A. I conducted a review of the analyses AEP performed supporting KPCO's request for approval of a transfer to the Company of an undivided 50% interest in Plant Mitchell Unit 1 and 2. My evaluation and testimony primarily concerns the work performed and the testimony filed by Company witnesses Mark Becker, Scott Weaver and Karl Bletzacker. These witnesses had the primary responsibility for developing data assumptions and performing modeling analyses that led to the decision to acquire the Mitchell resource. Company witness Becker performed the long-term expansion plan modeling analyses using the Ventyx Strategist model, witness Bletzacker, who is Director, Fundamental Analysis, at the American Electric Power Service Corporation ("AEPSC"), developed commodity price forecasts and conducted other production cost modeling analyses using the

EPIS Aurora model, and witness Weaver presents and explains the results of the analyses that were performed. For purposes of my evaluation, I also acquired the same Strategist model and all of the data assumptions that the Company used to conduct a review of the Company's evaluations and perform alternative modeling studies. I present the results of my evaluation, and KIUC witness, Mr. Lane Kollen and I present support for KIUC's recommendation for an alternative action plan for the Company to follow.

Q. Please summarize KIUC's recommendation and conclusions.

A. KIUC recommends that the Commission authorize the Company to acquire 20% of the Mitchell generating units contemporaneous with the planned shutdown and retirement of Big Sandy 2 on June 1, 2015. I am informed that under Kentucky law, the pricing of this affiliate transaction must be at the lower of cost or market. This acquisition would be combined with a Big Sandy 1 conversion to become a gas-fired steam turbine unit, and with market purchases to satisfy any short term requirements that may still exist. This plan minimizes environmental and market risks, provides the Company with fuel diversity benefits, reduces up front capital expenditures, and provides the Company with added flexibility with regard to future resource planning decisions.

Based on my analysis, I have reached the following conclusions:

- The Company's economic evaluations were based on outdated (2011) assumptions that do not reflect the current state of the natural gas and coal markets. Had the Company relied on more up-to-date assumptions, as I have used in my analyses, it is likely it would have determined that the acquisition of a 50% interest in Mitchell provides less economic benefit to

KPCO's customers than other alternatives. My analysis shows that the Company's plan is not least cost to consumers.

- The data assumptions for the Mitchell units that the Company used in this proceeding are more favorable than assumptions the Company used in another study it performed to assess the value of the Mitchell units, known as an Impairment Analysis.
- The Company's decision to acquire 50% of Mitchell 2 would result in the Company continuing to be heavily dependent on coal, with little flexibility to be able to diversify its fuel supply.
- The Company's plan is based on known environmental requirements, but ignores the possibility that future environmental requirements may lead to the need to pursue additional environmental upgrades. No contingencies have been included in the Company's analyses for the possibility that future environmental requirements may impose additional costs to the Mitchell plant.
- The Company's plan to acquire 50% of Mitchell is subject to risk associated with potential CO2 taxes.
- A 20% acquisition of Mitchell in mid-2015, and a conversion of Big Sandy 1 to natural gas promotes fuel diversity and provides flexibility for additional options in the future. For example, if the Company converted to a gas fired steam turbine it may be possible to convert even further to a larger re-powered combined cycle unit in the future.
- KIUC's recommendation will lead to KPCO continuing to maintain some generation in Kentucky, which would provide some local economic benefits such as continuing tax payments and employment opportunities.
- Since filing testimony on April 1, 2013, I have concluded that the Company's Strategist modeling overstates the Installed Capacity ("ICAP") revenues associated with acquiring the Mitchell capacity on January 1, 2014. A portion of the PJM capacity revenue must be eliminated since Mitchell is already committed to AEP's Fixed Resource Requirement ("FRR") plan and no additional ICAP revenues will be available prior to June 1, 2015. If this capacity revenue is eliminated from the Strategist modeling, then it further improves the economics of the KIUC recommendation to acquire 20% of the Mitchell units on June 1, 2015 rather than on January 1, 2014. The savings will increase to $37 million from the $27 million that I previously quantified. The savings will increase even more if the Company were to acquire 50% of the Mitchell units. I have revised the tables in this amended testimony to reflect these changes in ICAP revenues.

KPCO'S MODELING ANALYSES AND RESULTS

Q. Please describe KPCO's proposal.

A. KPCO's decision to acquire a 50% interest in Plant Mitchell relates back to an earlier decision in 2012 to withdraw the application it had filed in Case No. 2011-00401 to install a scrubber at the Big Sandy 2 ("BS2") coal-fired unit. According to Company witness Mr. Gregory Pauley, President and Chief Operating Office of KPCO, the Company decided not to go forward with the upgrades at BS2 due to developments that occurred between when the Company filed its BS2 upgrade application on December 5, 2011 and when it withdrew its application on May 30, 2012.[1]

Q. What was a key development that affected the Company's decision not to perform environmental upgrades at BS2?

A. One key development appears to be the Company's realization that capacity would be available at Plant Mitchell. The Company states that subsequent to making its December 2011 filing in Kentucky to upgrade BS2, 20% of the Mitchell capacity became available to Kentucky Power. Then, it appears that after the Public Utility Commission of Ohio issued a decision on February 23, 2012 to withdraw KPCO's affiliate, Ohio Power Company's previously approved corporate separation plan that "...the possibility that more than twenty percent of the Mitchell generating station might be available to Kentucky Power". [Pauley

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[1] Gregory Pauley's December 19, 2012 Direct Testimony at page 10.

Direct Testimony, page 11 at 16]. After the Company withdrew its application to upgrade BS2 in May 2012, it conducted studies and determined that it would be less costly to acquire 50% of Mitchell and to retire BS2 by June 2015.

Q. What studies did the Company perform that led to the decision to acquire the Mitchell capacity?

A. Company witness Scott Weaver's Resource Planning group was responsible for conducting the analyses, which Mr. Pauley described at page 12 of his Direct Testimony as follows:

> ...the Company examined eleven unique variations involving six discrete options assumed to be available to Kentucky Power to address the unit disposition decisions facing both Big Sandy Units 1 and 2. The Company performed this analysis in light of the availability of an ownership interest in the Mitchell generating station, as well as the major known and emerging federal rulemaking facing Kentucky Power's coal-fired generating assets. In undertaking these evaluations, the Company employed proprietary long-term resource optimization tools and examined a 30-year economic study period (2014 through 2040) to determine the relative least cost alternative.

Q. Did Mr. Weaver provide a description of the eleven variations of six unique options that it analyzed?

A. Yes, Mr. Weaver explained the eleven disposition cases that AEP evaluated in Table 1 at page 5 of his testimony, and he provided further discussion of the planning process the Company performed of these disposition cases in the exhibits found as an appendix to his testimony. Exhibit SCW-2 of Mr. Weaver's testimony, contains an additional summary table of the eleven disposition cases.

Q. Recognizing that Mr. Weaver provides these details, can you briefly summarize the eleven cases that were performed?

A. Yes, two of the eleven cases (Options 1a and 1b) included performing environmental upgrades at BS2 and retiring Big Sandy Unit 1 ("BS1"). In the nine remaining cases, BS2 was retired initially and replaced with different types of capacity including market purchases, combined cycle ("CC") capacity, or the acquisition of a 50% interest in Plant Mitchell. In those nine cases, BS1 was disposed of in different ways including being retired, repowered to a CC unit, or converted to a gas-fired steam turbine unit.

Q. Were sensitivity studies performed?

A. Yes, both Strategist based discreet analyses were performed using alternative "projected future scenarios", and risk analyses using the Aurora Model were performed to study the impact of random forecast assumption changes on projected Company operating costs. Five discreet "projected future scenarios" were examined including low, mod and high commodity forecast assumptions, all including the same forecast of CO2 prices that began in 2022. The two additional discreet forecasts that were evaluated included one with no CO2 prices and another with CO2 prices starting earlier (2017).

Q. Please discuss the Strategist Model that was used to conduct the discreet modeling analyses.

A. Strategist was employed as the primary production cost and long-range resource planning model in this study.[2] Strategist performed three primary functions, 1) it was used to develop annual production cost estimates using monthly processing, and using sub-period dispatch algorithms; 2) it evaluated capital revenue requirements associated with capacity resource alternatives; and 3) it developed long-term expansion plans to meet the Company's load requirements through 2040. Although the Company's database included modeling data and developed production cost estimates for four of the AEP Operating Companies, the Company setup the database so that each Operating Company would operate independently of the others, and each would buy and sell against the PJM market. Only the KPCO results were included in the study evaluations. Individual Strategist runs were performed for each of the eleven BS1 and BS2 disposition options and for each of the five commodity sensitivity cases, so that in total 55 Strategist cases were performed. The result of each of the 55 cases was an optimal expansion plan for each case, production related revenue requirements, and capital related revenue requirements. Once the Strategist results of each case were completed, they were fed into a separate spreadsheet model where additional assumptions were made and results were developed and added to the Strategist results. One analysis performed was a calculation of PJM market capacity purchases and capacity purchase costs, which were required when KPCO fell below its capacity reserve requirements (8.6%) in the PJM market (PJM UCAP Obligation). Likewise, revenues from capacity sales to the PJM market were

[2] I first became acquainted with Strategist in 1980 when I began working for Energy Management Associates.

derived when KPCO exceeded its capacity reserve requirement (also 8.6%) in the PJM market. Finally, the spreadsheet model combined all costs and revenues, including fuel expenses, O&M costs, transaction expenses, market energy purchase costs and sales revenues, incremental resource addition capital related revenue requirements, and market capacity purchase costs and sales revenues to derive year-by-year incremental costs associated with the specific resource plan alternative. A cumulative present value of revenue requirements was determined for each case, and the results of each of the 11 cases performed were compared to develop a ranking of resource plans.

Q. What were KPCO's conclusions based on its Strategist analysis?

A. Regardless of the projected future scenario based on the different commodity forecast, KPCO determined that the option to retire BS2 and acquire a 50% interest in the Mitchell plant was part of the least cost long-term resource plan for KPCO.

Q. What conclusion did the Company reach regarding the disposition of the BS1 capacity?

A. The Company did not reach a conclusive decision with regarding BS1. Its modeling results indicated that the ultimate least cost long-term resource plan would be to acquire 50% of the Mitchell capacity, and to convert BS1 to a natural gas steam turbine unit. However, the Company has not committed to the BS1 conversion as it has decided to defer a final decision pending the results of performing a competitive solicitation comparing the cost of converting BS1 to the cost of acquiring capacity from the market.

Q. What reason did the Company give for the necessity of performing a competitive solicitation for capacity to replace the BS1 unit, but not for the BS2 unit?

A. Essentially, Company witnesses Weaver and McDermott believe that there may be capacity available through the market which is cheaper than the cost of converting ($192/kW) and operating BS1 on gas; however, they state with absolute conviction that there would not be any capacity that could be purchased and operated cheaper than the cost to purchase ($758/kW) and operate the Mitchell capacity.

Q. Does KIUC agree that a competitive solicitation to replace the BS2 unit was unnecessary?

A. No it does not. Mr. Kollen discusses this at length in Section 2 of his testimony, and he discusses the possibility that a RFP could result in finding a resource alternative available at a cost below the cost of acquiring Mitchell. Only by conducting a thorough competitive solicitation based on using up-to-date assumptions could the cost of acquiring and operating the Mitchell unit be compared against other alternatives that may be available in the market. The Company has not demonstrated that the cost of Mitchell is lower than its market value.

Q. How did the Company's Aurora risk analyses support the Company's decision to acquire a 50% interest in the Mitchell plant?

A. In my view, the Aurora risk analysis results did not provide evidence that the acquisition of 50% of the Mitchell plant was the optimal result. The results of the Company's Aurora analysis, presented in Mr. Weaver's exhibit SCW-6, indicates that Disposition Option 3A (20% of Mitchell capacity and BS1 repowered to a CC unit) was the highest ranked resource plan (ranked 1st) and the Company's plan to acquire only 50% of Mitchell (Option 6) was the 5th highest ranked plan. In fact, based on the Company's modeling assumptions, which I will soon explain are out-of-date, all options that included some portion of Mitchell capacity and plans to convert BS1 to some type of gas unit ranked higher than KPCO's plans to acquire 50% of the Mitchell coal unit.

Q. What did these results suggest to you?

A. These results led me to believe that there may be some resource plan involving the conversion of BS1 to some type of gas unit along with the acquisition of Mitchell capacity, possibly less than 50%, that would be lower cost and lower risk for KPCO. Therefore, for purposes of KIUC's analyses, I investigated disposition options in which BS1 was converted to a gas-fired steam turbine unit, and 20% of the Mitchell Plant was acquired. In addition, I examined the Company's commodity forecasts and developed alternative forecasts as I believed the Company's were based on outdated 2011 assumptions.

KIUC'S ANALYSES

Q. Did KPCO develop current modeling assumptions for this study?

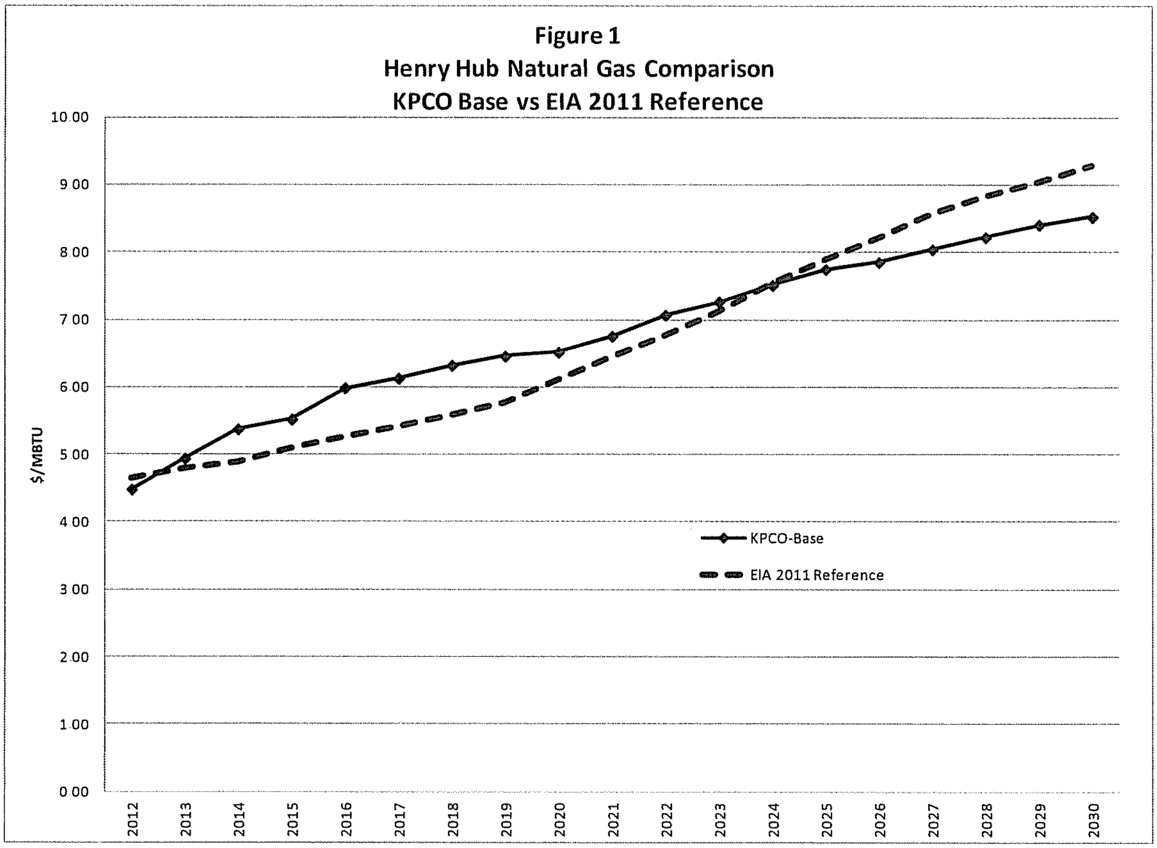
A. No it did not. The Company's commodity price forecasts were developed by Company witness Bletzacker's Fundamental Analysis Department at AEP, however, the forecasts are dated November 2011, which means that based on when they were possibly first created, potentially in early 2011, they are now about 2 years old. Even if the forecasts were created around November 2011, on page 5 of Mr. Bleztacker's testimony, he compares the natural gas forecast to other forecasts such as the Energy Information Administration ("EIA") forecasts and those were created in late 2010.[3] The commodity forecasts that Mr. Bletzacker's group developed include Henry Hub ("HH") natural gas prices, CO2 costs, coal prices (Northern Appalachian and Central Appalachian), on-peak and off-peak PJM-AEP Generation Hub prices ($/MWH), and PJM RTO RPM market capacity values ($/MW-Day). The forecasts were presented in an exhibit to Mr. Weaver's testimony, Exhibit SCW-3.

Q. What evaluations did you perform of the Company's forecasts?

A. First, I examined the natural gas forecasts that the Company developed, and initially I focused on the Company's base case assumptions. Since the Company used data from 2011, I compared the Company's natural gas price forecast to the

[3] See the figure on page 5 of Mr. Bletzacker's testimony, which includes the EIA base case forecast from May 2011. EIA's May 2011 forecast was actually first released in December 2010, so the assumptions for that forecast had to be derived in 2010.

EIA 2011 forecast, which is the same forecast comparison Mr. Bletzacker presented on page 5 of his testimony. The following figure presents this comparison.



This figure indicates that EIA 2011 HH forecast, and the Company's HH commodity gas forecast are very close and in fact indicates that the EIA 2011 forecast could substitute as a reasonable proxy for the commodity forecast that the Company derived.

Q. Do you believe that the EIA 2011 HH forecast would also be reasonable to be used for studies today based on what is now known about the gas market?

A. No I do not. Most people in the industry today are aware of the expanded reserves of natural gas that have been identified in the last few years, which when coupled with advanced exploration and production technologies have resulted in low natural gas price forecasts, which are expected to continue. Even since 2011 natural gas price forecasts have been lowered based on the expectation that the availability of low cost natural gas will persist given the expected amount of proven reserves. One indication of this may be seen from a comparison of EIA's 2011 and EIA's 2013 Reference HH Gas price forecasts. On average the 2013 EIA forecast is approximately 23% lower than the 2011 EIA forecast.

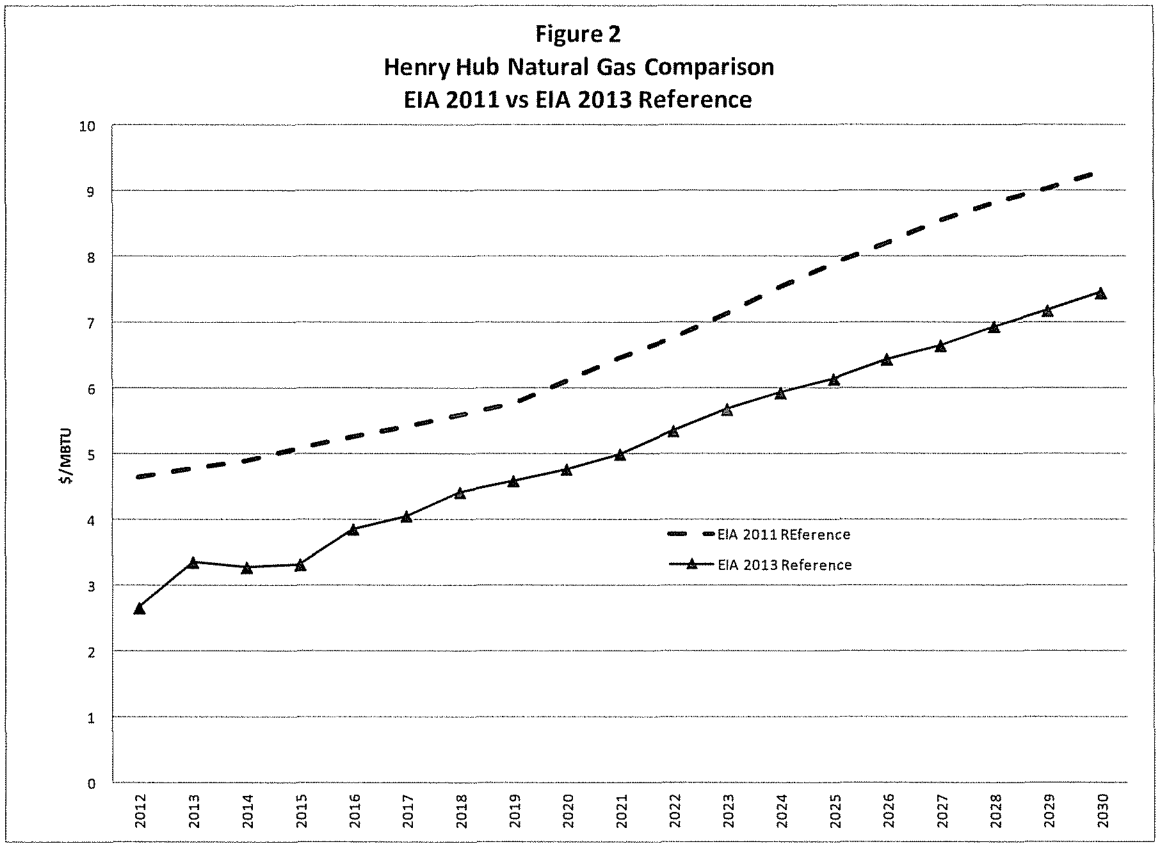
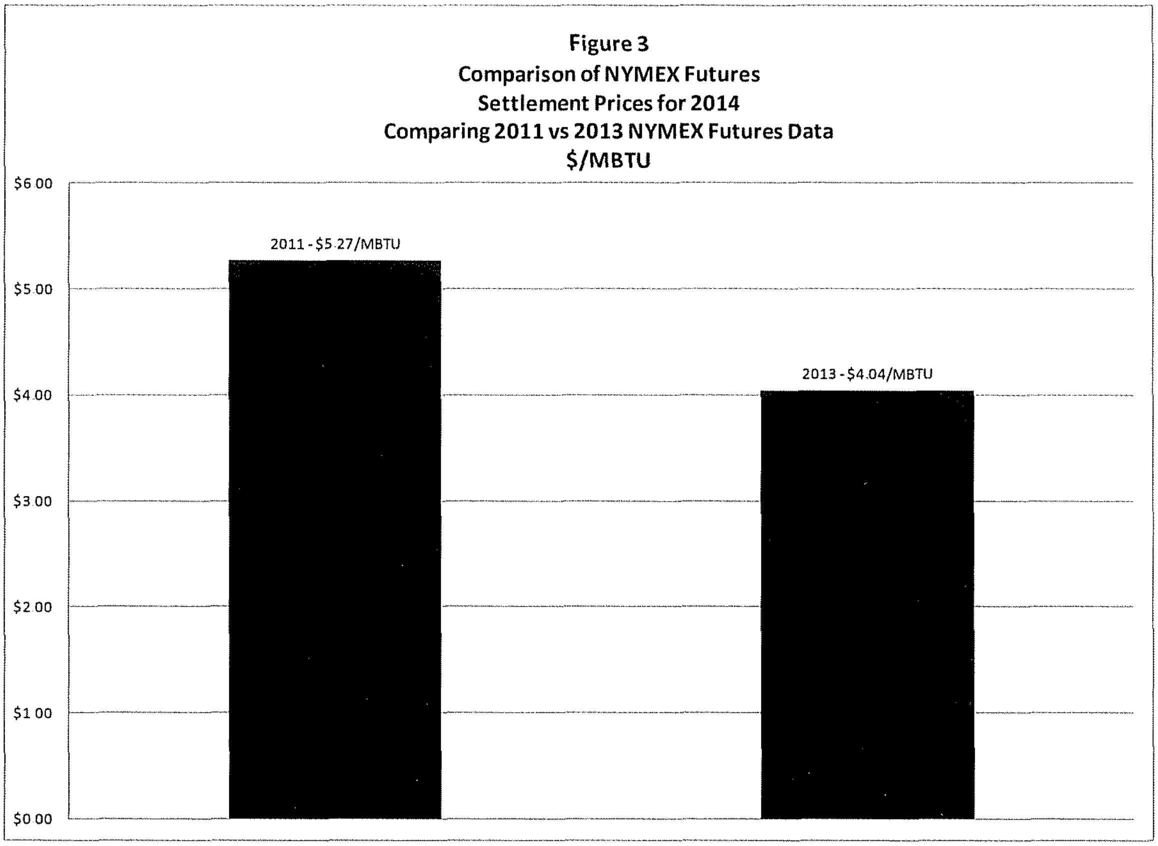


Figure 2
Henry Hub Natural Gas Comparison
EIA 2011 vs EIA 2013 Reference

Q. Have you developed any other evidence to support the use of more current forecast data?

A. Yes, I examined NYMEX HH futures prices that were reported in 2011 and I compared that data to futures prices that have been reported thus far in 2013. I picked 2014 as the future projection year to examine. In other words, I averaged the NYMEX futures prices that were reported in 2011 for the future year 2014, and I did the same thing for future prices that have thus far been reported in 2013 for the future year 2014. To reach a conclusion that the Company's natural gas price forecast that it developed in 2011 would be reasonable to use as a natural gas price projection today, it would stand to reason that the NYMEX forecast as developed in 2011 would be similar to the NYMEX forecast as developed today. I found that this was not the case. The following graph compares the average price for 2014 as determined based on both 2011 and 2013 NYMEX data. It indicates that NYMEX futures prices have dropped by approximately 23% when comparing NYMEX prices that were derived in 2011 to prices derived in 2013. This is the same result that I found when examining the EIA 2011 and EIA 2013 forecasts.



Q. The Company may contend that 2013 data was not available at the time it conducted its studies of the Mitchell capacity. Do you believe it would be reasonable for the Commission to rely on the Company's outdated planning assumptions in making a decision regarding the approval of the Mitchell acquisition?

A. No I do not. I believe the Commission should be aware of results derived from more current data assumptions, and give those results more significant weight in its decision making process. To aid the Commission, I have conducted alternative analyses using more up-to-date data assumptions. I believe that it would be reasonable for the Commission to rely on the 2013 EIA gas price forecast. I have made use of the 2013 EIA forecast as basis for the commodity gas price forecast used in my analyses.

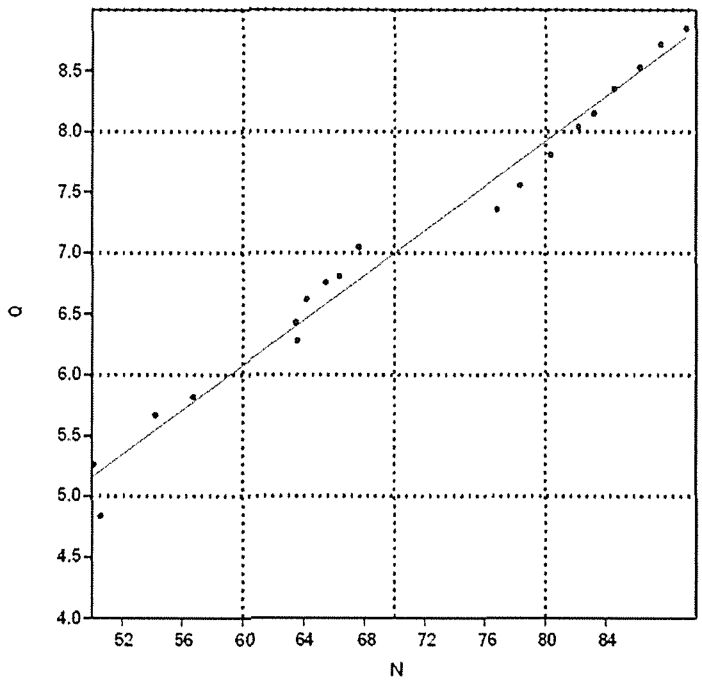
Q. If the Company's natural gas price forecast was out of date, did you also consider the reasonableness of its market energy price forecast?

A. Yes, and like the Company's natural gas price forecasts, I also found that its market energy price forecast was out-of-date, and too high as well.

Q. What adjustment are you proposing to the Company's market energy price forecast?

A. Typically, natural gas forecasts and market energy price forecasts are highly correlated, and a fairly linear relationship exists between the two forecasts. It appears that the Company's data is consistent with this correlation, although based on out of date information. I performed a statistical analysis of the Company's base market energy prices and base natural gas forecast, and plotted the data to prove that a linear relationship exists between the Company's two forecasts, as shown below. The x axis of the graph represents market energy prices ($/MWH), and the y axis represents fuel prices. The trend line added to the graph confirms that there is a linear relationship between the Company's fuel prices and market energy prices.

Figure 4
x/y Plot of KPCO Natural Gas Prices
and Market Energy Prices



Based on this analysis, I concluded it would be reasonable to apply the same adjustment to the Company's base case market energy price forecast as I applied to derive a new gas price forecast. In essence, I reduced the Company's market base case energy price forecast by 23% to derive a new market energy price forecast.[4]

Q. Did you perform Strategist analyses based on revised natural gas and market price forecasts?

A. Yes, in the first set of results that I present, I developed natural gas price forecasts and market price assumptions consistent with the 2013 EIA natural gas price forecasts. Furthermore, the disposition option that I used assumed BS1 unit

[4] After developing a new market energy price forecast, I also derived new emergency power price inputs consistent with the new market energy price forecast.

would be converted to natural gas by July 2015, and 20% of Mitchell would be acquired January 1, 2014. I assumed Mitchell would be acquired January 1, 2014 for purposes of consistency with the Company's modeling assumptions, however, as Mr. Kollen explains, KIUC's primary recommendation is to acquire Mitchell 1 on June 1, 2015 contemporaneous with when the Big Sandy unit is set to retire. Acquiring any amount of Mitchell before it is needed significantly increases the cost to consumers. During the 17 month period January 2015 to June 2015, Mitchell would have very little market capacity value and, based on actual PJM forward pricing data, market energy margins would be very small as well. ,Mr. Kollen explains that acquiring any amount of Mitchell before Big Sandy 2 is retired has substantial rate impacts.

Q. Did you make any other adjustments to the Company's data assumptions in this first set of runs.

A. Yes, as a sensitivity I also adjusted the PJM ICAP market capacity prices that the Company included. The model assumes these are costs that companies in PJM would pay for capacity purchases from the PJM market when they are short of capacity, or revenues that they would receive when they are long on capacity. The Company's estimates of market capacity prices ranges from $85.05/MW-day in 2014 to $436.27/MW-day in 2040, and the first significant jump in market price occurs in 2015 when the price increases to $215.25/MW-day. The Company provides very little support for these values, and they seem quite high especially in light of the base residual auction results, which indicate that the PJM

RTO price for annual resources in the 2015/2016 auction was $136/per MW-day.[5] By using an outdated 2011 commodity forecast, AEP includes capacity pricing that is now know to be incorrect. Fundamentally, the Company seems to be suggesting over the next 30 years, very little capacity, demand response, or energy efficiency will be added in PJM.

Q. What did you use as an alternative for the capacity market prices.

A. As Mr. Kollen discusses in his testimony, the Company performed an Impairment Analysis in November 2012, which the Company discussed in its response to KIUC 2-55. The Company supplied the results of the Impairment testing for the Mitchell Plant. Mr. Kollen explains that he would expect the assumptions included in the Impairment Analysis to be highly scrutinized and more reliable and objective than might normally be expected given the attestations required by upper management associated with the Impairment Analysis. Both Mr. Kollen and I have found that the Company's planning assumptions used to support the Mitchell acquisition in this CPCN proceeding were generally more favorable than the assumptions that were used in the Impairment test. For purposes of my sensitivity analysis using alternative market capacity prices, I used data that the Company relied on in the Impairment Analysis.

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[5] http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/20120518-2015-16-base-residual-auction-report.ashx

Q. Is there another incorrect assumption in the Company's modeling that you have corrected since you initially filed testimony on April 1, 2013?

A. Yes. Since filing testimony on April 1, 2013, I have determined that the Company overstated the ICAP revenues available from acquiring the Mitchell capacity on January 1, 2014 rather than when it is needed on June 1, 2015. The Company assumed that the Mitchell capacity could be sold into the PJM market at the BRA capacity prices as soon as KPCO acquires the capacity. However, the Mitchell capacity is already committed to AEP's FRR plan to self-supply its PJM load obligations. Thus, KPCO will not be able to sell the capacity into the BRA until June 1, 2015 and it cannot obtain ICAP revenues from the BRA prior to June 1, 2015.

I have revised the tables presented below to reflect the elimination of these ICAP revenues. In each table, I show the values as initially filed with lines through them and I show the revised values to the right of the original values.

Q. Please discuss your first set of results.

A. The following table compares the Company's base case forecast assumptions to KIUC's assumptions, which are based on up-to-date fuel and market price forecasts. In this initial set of runs, no changes were made to the coal price assumptions. A set of three results are provided based on the Company's preferred disposition option to acquire 50% of Mitchell only, and then a set of three results are provided based on KIUC's recommendation that the Company acquire only 20% of Mitchell and also convert BS1 to a gas-fired steam turbine unit. As stated earlier, for purposes of making a consistent comparison with the Company's proposal I assumed that the 20% Mitchell purchase would be effective as of January 2014, rather than June 2015 when it will be needed. Delaying the Mitchell purchase until June 2015 would provide consumers with considerable additional savings.

REVISED - Table 1
Natural Gas and Energy Market Forecast Adjustments

							TESTIMONY		REVISED	
Case	Mitchell	BS1 Gas Conv	Gas	Coal	Market $/MWH	ICAP $/MW-Day	NPV (k$)	Diff (k$)	NPV (k$)	Diff (k$)
KPCO	50%	N	2011 AEP	2011 AEP	2011 AEP		~~$5,787,072~~		$5,821,342	
KPCO	50%	N	2013 EIA	2011 AEP	tied to 2013 EIA Gas		~~$5,615,842~~		$5,650,113	
KPCO	50%	N	2013 EIA	2011 AEP	tied to 2013 EIA Gas	Impair	~~$5,587,336~~		$5,610,511	
KIUC	20%	Y	2011 AEP	2011 AEP	2011 AEP		~~$5,881,503~~	~~$94,431~~	$5,895,211	$73,869
KIUC	20%	Y	2013 EIA	2011 AEP	tied to 2013 EIA Gas		~~$5,464,620~~	~~($151,222)~~	$5,478,328	($171,785)
KIUC	20%	Y	2013 EIA	2011 AEP	tied to 2013 EIA Gas	Impair	~~$5,383,163~~	~~($204,173)~~	$5,392,433	($218,078)

Each calculated difference value shown compares the KIUC case to the equivalent KPCO case. The first comparison indicates that when the Company's preferred disposition option is compared to KIUC's preferred disposition option, based on the Company's outdated gas and market price assumptions, the Company's option is more economic by approximately $~~94~~74 million. However, this option is unrealistic as the Company's forecasts of natural gas and market prices are clearly too high. If the Company were to acquire 50% of Mitchell as it proposes, then customers would be subjected to market risks associated with having to make opportunity sales from the Mitchell units. In other words, with lower market prices it is unlikely the Company would be able to make as many off-system sales as expected, and the revenues from those sales would most likely be much lower than the Company expects.

The difference between the second rows in this table is the use of the lower 2013 EIA natural gas and market price forecasts. With lower natural gas and market prices, Mitchell provides much less value, and KIUC's recommendation to acquire less Mitchell capacity and to convert BS1 to gas is more economic by $~~151~~172 million.

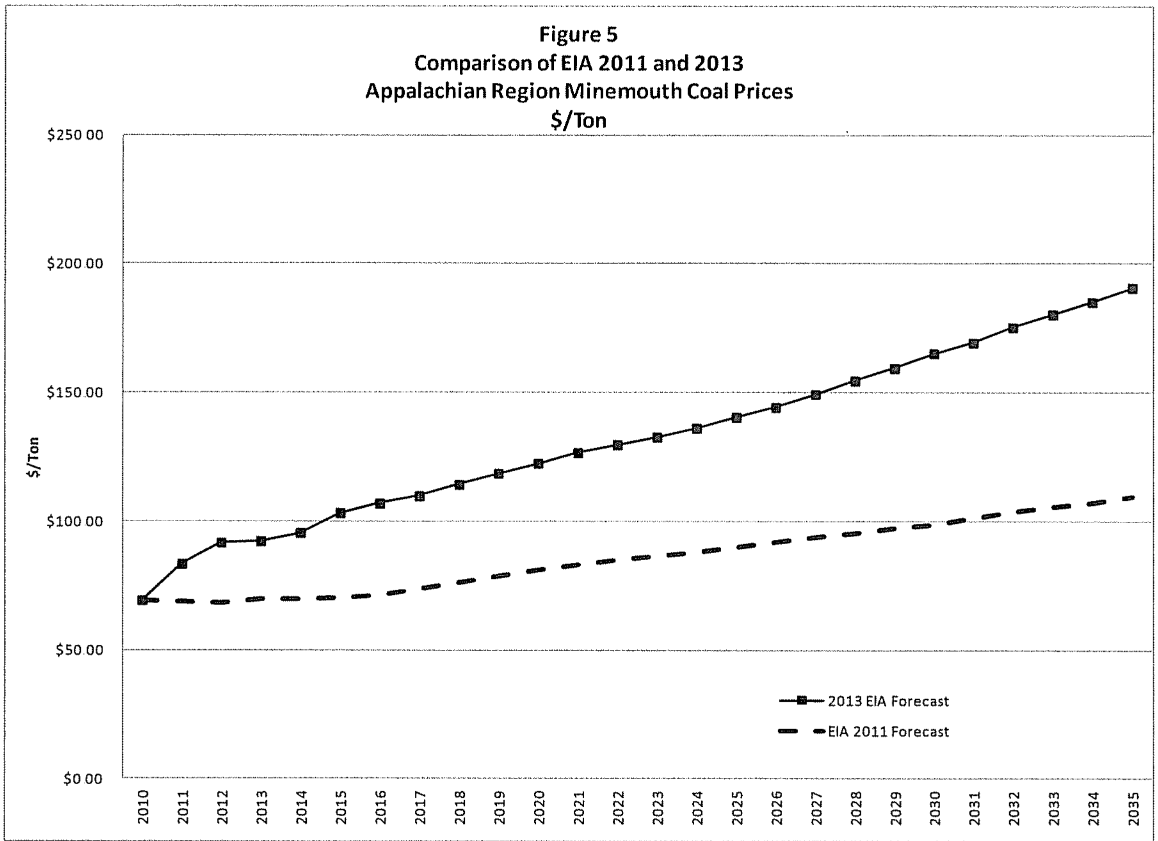
The third row reflects the sensitivity case in which lower market capacity prices are assumed based on use of market capacity prices from the Company's Impairment Analysis. In this case, KIUC's preferred alternative is more economic compared to KPCO's recommendation by $~~204~~218 million.

Q. Please explain the parameters of your second set of results.

A. For the second set of results, I performed the same set of runs, but I also incorporated an updated coal price forecast in addition to the Impairment Analysis capacity value and updated natural gas and market price forecast.

Q. What are your findings regarding the Company's coal forecast?

A. Similar to its natural gas and market energy price forecasts, the Company's coal price forecast is also out-of-date. However, unlike the natural gas forecast, coal price forecasts have increased since 2011 largely due to the EPA's efforts to reduce the utilization of coal. The following graph demonstrates a significant increase in the EIA forecast for Appalachian Region coal prices. Based on this, I believe the Company's coal price forecast is too low and should be increased.



I based the updated coal forecast on the EIA 2013 forecast data similar to the way that I developed the gas price forecast from the EIA 2013 forecast since I determined that the Company's coal price forecasts were similar to EIA's 2011 forecasts.

Q. Please discuss the results of this set of analyses.

A. The results of my second set of analyses are included in Table 2.

REVISED - Table 2
Natural Gas, Energy Market, and Coal Forecast Adjustments

							TESTIMONY		REVISED	
Case	Mitchell	BS1 Gas Conv	Gas	Coal	Market $/MWH	ICAP $/MW-Day	NPV (k$)	Diff (k$)	NPV (k$)	Diff (k$)
KPCO	50%	N	2011 AEP	2011 AEP	2011 AEP		~~$5,787,072~~		$5,821,342	
KPCO	50%	N	2013 EIA	2013 EIA	tied to 2013 EIA Gas		~~$5,938,272~~		$5,972,542	
KPCO	50%	N	2013 EIA	2013 EIA	tied to 2013 EIA Gas	Impair	~~$5,909,766~~		$5,932,941	
KIUC	20%	Y	2011 AEP	2011 AEP	2011 AEP		~~$5,881,503~~	~~$94,431~~	$5,895,211	$73,869
KIUC	20%	Y	2013 EIA	2013 EIA	tied to 2013 EIA Gas		~~$5,662,509~~	~~($275,763)~~	$5,676,217	($296,325)
KIUC	20%	Y	2013 EIA	2013 EIA	tied to 2013 EIA Gas	Impair	~~$5,581,052~~	~~($328,714)~~	$5,590,322	($342,619)

Once again, the first row of the KPCO and KIUC cases depict the preferred disposition options under the Company's forecast assumptions, and indicates that under the outdated and higher forecasts the option to acquire a greater share of Mitchell is more economic. As mentioned already, that option is unrealistic due to KPCO's out-of-date forecasts, and row two compares each case with alternative gas, energy and coal price assumptions based on EIA 2013 forecasts, which are much more realistic than KPCO's forecasts. The difference in these forecasts is that the 2013 EIA gas and market prices decrease compared to KPCO's forecasts, which is unfavorable to the Mitchell acquisition, and the 2013 EIA coal forecast increases substantially, which again is unfavorable to the Mitchell acquisition. KIUC believes that a 20% share of Mitchell presents far less risk to KPCO's customers and is more economic. With just the changes to use the EIA 2013 gas, market and coal forecasts, the KIUC recommended plan is more economic by $~~275~~296 million compared to the Company's preference to acquire 50% of Mitchell. Furthermore, with the additional sensitivity case that includes the lower market capacity costs, KIUC's preferred case is $~~328~~343 million lower in cost compared to the KPCO case. Again, as stated earlier, delaying the acquisition of 20% of Mitchell until June 2015 would provide a significant additional economic benefit for consumers.

Q. Mr. Kollen discusses an Impairment Analysis the Company performed. Did you conduct any analyses using data from that study?

A. Yes, Table 3 below contains results that I developed based on using Mitchell assumptions just from the Impairment Analysis. The Company's response to KIUC 1-55 contained an evaluation that included assumptions about the cost of operating the Mitchell units and the prices that Mitchell would receive when selling capacity and energy to the PJM market. These assumptions were different and in general less favorable to the Mitchell capacity than the assumptions the Company incorporated in its Strategist analyses used to evaluate the acquisition of Mitchell. As Mr. Kollen explains there is every reason to expect that the assumptions used in the Impairment Analysis would be more highly scrutinized and more reliable and objective than assumptions that the Company might used in other planning studies.

Q. What assumptions did you utilize from AEP's February 2013 Impairment Analysis?

A. With regard to Mitchell costs, I used the Mitchell fuel and variable O&M expenses, fixed O&M costs, and on-going construction expenditures. Although many of the assumptions in the Impairment Analysis were less favorable to the

Mitchell units, there were also some assumptions from the February 2013 Impairment Analysis that were actually more favorable such as the fact that the Impairment Analysis included lower capital addition costs. Nevertheless, I still used the values from the Impairment Analysis in this study. With regard to the revenues derived from Mitchell, I used the data from the Impairment Analysis to derive new market energy and market capacity prices. These are the same market capacity costs that I had used in the studies identified in Tables 1 and 2 above. In sum, I did not change any of AEP's Impairment Analysis assumptions.

Q. Please discuss the results.

A. The following table compares both KPCO's and KIUC's preferred resource plan using the impairment assumptions.

REVISED - Table 3
Mitchell Assumptions Based on Impairment Analysis

							TESTIMONY		REVISED	
Case	Mitchell	BS1 Gas Conv	Gas	Coal	Market $/MWH	ICAP $/MW-Day	NPV (k$)	Diff (k$)	NPV (k$)	Diff (k$)
KPCO	50%	N	2011 AEP	Impair	Impair	Impair	~~$6,107,425~~		$6,130,600	
KIUC	20%	Y	2011 AEP	Impair	Impair	Impair	~~$5,971,679~~	~~($135,746)~~	$5,980,949	($149,651)

These results indicate that using just the Mitchell assumptions from AEP's Impairment Analysis, the cost of acquiring 20% of Mitchell and converting BS1 to gas is more economic by approximately $~~136~~149 compared to the option of acquiring 50% of the Mitchell plant. The Impairment Analysis did not have an explicit gas forecast. Therefore, to be extremely conservative I used AEP's 2011 gas forecast. Had I used updated 2013 gas prices, rather than AEP's outdated

2011 gas price forecast, the KIUC proposal would have out preformed the Company's plan by even more.

Q. Have you evaluated the risk of any other environmental upgrade costs that the Company might have to pay for if it acquires some portion of the Mitchell capacity?

A. While I have not assessed the likelihood that the Company would have to install any additional equipment, I noticed that the Kentucky Public Service Commission Staff identified the possibility that the Company may have to install a baghouse at Mitchell at a potential cost of $133 million in 2019. It is obvious that the KIUC preferred alternative to acquire less Mitchell capacity would result in a benefit in the event that significant additional environmental costs are identified in the future. In the Company's response to KPSC 2-27 concerning the KPSC's baghouse question, the Company supplied information that could be used to determine that KPCO customers would save approximately $60 million dollars on a net present value basis over the period of 2011 to 2040 if KPCO only acquires a 20% interest in Mitchell compared to the Company's preference to acquire 50%.

Q. You stated earlier that KIUC's actual recommendation is to acquire Mitchell on June 1, 2015, contemporaneous with the retirement of BS2. Did you conduct any delay scenario analyses using this acquisition date?

A. Yes, I conducted one analysis to examine the potential impacts that would result from delaying the acquisition of Mitchell until June 1, 2015. In sum, the delay would impact fuel costs, O&M expenses, capital revenue requirement costs, and market capacity and energy purchases and sales. Given that the Company would continue to operate Big Sandy 2 all during 2014 and during part of 2015, it would have excess capacity for a period in excess of 80% [Weaver Exhibit SCW-1]. I conducted an analysis in which I utilized KIUC's natural gas and market energy forecast assumptions and I delayed the start date of Mitchell until June 1, 2015.

Q. What were the results of this analysis?

A. In a comparison of KIUC's preferred case using the assumptions described above, I determined that there would be a savings of approximately $~~27~~<u>37</u> million if Mitchell were delayed until June 2015. This may be conservative as there are other factors that I did not have time to address. One factor for example, is whether the Company would be able to sell capacity based on Base Residual Auction prices beginning January 2014 when it first acquires the Mitchell capacity. The Company may be limited to only being able to sell based on costs derived in the incremental auctions, which are lower than the prices paid in the Base Residual Auctions. This is an issue that I will continue to explore and would be able to make additional findings available upon request.

<u>**Q. It appears that the ICAP correction you discussed earlier also affected the delay scenario. Is that correct?**</u>

<u>A. Yes it did. The delay scenario required changes to the Mitchell ICAP revenue calculation, and I identified other changes that had to be made to the delay</u>

scenario associated with the Mitchell capital revenue requirement calculation. Since I have created new workpapers associated with the changes to Tables 1, 2, 3, and the Delay Scenario, discussed above, I provide a description of all changes that were made in revised data responses.

One additional note with regard to the ICAP revenue adjustment, the elimination of the ICAP revenue from the analysis prior to June 1, 2015 does not mean that AEP will not be fully compensated for the Mitchell units. As described by Mr.Kollen, AEP will fully recover a cost based rate associated with the Mitchell units from Ohio ratepayers through June 2015. This led Mr. Kollen to conclude that placing Mitchell in Kentucky Power's rate base beginning January 2014 would result in double recovery.

Q. Are there any additional issues you wish to address?

A. Yes, I am concerned about the assumptions the Company used to model its generic CC capacity, as the capital cost it used appears to be overstated. Since the CC units are generally not selected prior to 2021, this may not be a significant concern; however, it is something that affects the resource planning decisions, and should be addressed by the Company when it files its next round of testimony. Based on a comparison of the Company's assumptions to other available data including EIA data and data available from Louisville Gas and Electric's ("LG&E") Certificate for Public Convenience and Necessity for the Cane Run CC unit, the cost of the Company's Brownfield CC unit seems to be overstated. In Case No. 2011-0075, LGE reported the installed cost of constructing its 640 MW

CC unit would be $583 million, which is equivalent to $910 per kilowatt. By comparison, Mr. Weaver's Table 3 indicates the cost of a CC unit would be $1168/kW, which is significantly higher than LG&E's estimate. EIA's estimate for a CC unit is also similar to LG&E's cost. Furthermore, the value that appears in Mr. Weaver's Table 3 does not match the input for the cost to construct a CC unit that the Company included in Strategist, although it is fairly close. However, $1168/kW is not the entirety of the capital cost that the Company modeled, as it also included additional capital cost related items in the Strategist fixed O&M input for the CC unit. Again, while this may not have much effect on the Mitchell decision, the Company should still provide additional justification for why its assumption the cost of combined cycle capacity is so high.

Q. Does this complete your 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	**)**	**Case No. 2012-00578**
Of The Assumption By Kentucky Power Company 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	**)**	

EXHIBITS

OF

PHILIP HAYET

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

April 1, 2013