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February 20, 2014

RECEIVED
FEB 20 2014
PUBLIC SERVICE COMMISSION

HAND DELIVERED

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

RE: Case No. 2013-00475

Dear Mr. Derouen:

Enclosed please find and accept for filing the original and ten copies of the Company's responses to Staff's February 4, 2014 data requests, and the Company's public responses to Sierra Club's February 5, 2014 data requests.

Also enclosed is the Company's motion for confidential treatment and attached confidential portions of the Company's responses to Sierra Club data requests 1-2, 1-3, 1-14, 1-21, and 1-24.

Copies of the responses and the motion are being served by overnight delivery today on the persons listed below.

Very truly yours,

Mark R. Overstreet

MRO
cc: Michael L. Kurtz
Kristin Henry
Shannon Fisk
Joe F. Childers

RECEIVED

FEB 20 2014

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

INTEGRATED RESOURCE PLANNING REPORT OF	**)**	
KENTUCKY POWER COMPANY TO THE	**)**	**CASE NO. 2013-00475**
KENTUCKY PUBLIC SERVICE COMMISSION	**)**	

KENTUCKY POWER COMPANY RESPONSES
TO COMMISSION STAFF' S INITIAL SET OF DATA REQUESTS

February 20, 2014

VERIFICATION

The undersigned, Will K. Castle, being duly sworn, deposes and says he is the Director Resource and DSM Planning for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing responses 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

Will K Castle

Will K. Castle

STATE OF OHIO)

) Case No. 2013-00475

COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State by Will K. Castle, this the 6th day of February 2014.

Charmaine S. Hamilton

Notary Public

My Commission Expires: ____________

NOTARIAL SEAL STATE OF OHIO

CHARMAINE S. HAMILTON
Notary Public, State of Ohio
My Commission Expires 05-14-2017

VERIFICATION

The undersigned, John F. Torpey, being duly sworn, deposes and says he is the Director Integrated Resource Planning for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing responses 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

John F. Torpey

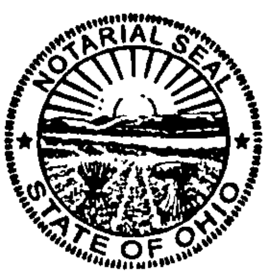
John F. Torpey

STATE OF OHIO)
) Case No. 2013-00475
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by John F. Torpey, this the 6th day of February 2014.

Josephine Coner

Notary Public



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

My Commission Expires: 09-20-2016

VERIFICATION

The undersigned, Ranie K. Wohnhas, being duly sworn, deposes and says he is the Managing Director Regulatory and Finance for Kentucky Power, that he has personal knowledge of the matters set forth in the forgoing responses 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

Ranie K. Wohnhas

Ranie K. Wohnhas

COMMONWEALTH OF KENTUCKY)
) Case No. 2013-00475
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 17th day of February 2014.

Judy K Rosquist 481393

Notary Public

My Commission Expires: January 23, 2017

Kentucky Power Company

REQUEST

Refer to the second paragraph on page ES-3 of the Executive Summary which states in part that "the Plexos® modeling was performed through the year 2040 so as to properly consider various cost-based 'end-effects' for the resource alternatives being considered."

a. Explain what is meant by "properly consider various cost-based 'end-effects'."

b. Identify and explain what changes the various cost-based end effects had on the assumptions and conclusions made for the 15-year period of the IRP.

RESPONSE

a. To determine a more accurate calculation of the net present value of revenue requirements associated with a specific portfolio, it is necessary to model the impacts of resource decisions beyond the 15 year IRP period. Modeling the impacts beyond 15 years is necessary because resources typically operate for more than 15 years. For example, a resource with low variable costs will have a greater benefit each year as market prices increase in the future; therefore, showing only near term costs may understate the value of such a resource.

b. Refer to Table 20 on page 166, which identifies the difference in costs between the preferred plan and the optimized plan. Note that the difference in costs between the plans is greater when the analysis is extended to 2040; however, the relative difference in costs is still minimal.

WITNESS: John F Torpey

Kentucky Power Company

REQUEST

Refer to Section 1.1, General Remarks, at page 2 of Kentucky Power's 2013 Integrated Resource Plan ("IRP"). Describe the current status of the proceeding at the Federal Energy Regulatory Commission regarding the agreements discussed in footnote 6.

RESPONSE

On December 23, 2013, FERC issued an Order accepting the Bridge Agreement and Power Coordination Agreement (PCA) in Docket Nos. ER13-233, 234, 235, 236 and 237.

WITNESS: John F Torpey

Kentucky Power Company

REQUEST

Refer to Section 1.2, Planning Objectives, at page 4 of Kentucky Power's 2013 IRP, specifically, the objective of "encouraging the wise and efficient use of energy." In recent years, several of East Kentucky Power Cooperative's distribution cooperatives located in eastern Kentucky have implemented prepay metering programs that produced substantial energy conservation results. Given that much of Kentucky Power's service territory is similar to that of such cooperatives, explain in detail what consideration has been given to implementing a prepay metering program.

RESPONSE

Kentucky Power has reviewed prepay metering and has decided it is not in the best interest of the Company's customers at this time. Current deployment configurations for prepay metering systems typically require the functionality of smart meter technology infrastructure to provide the two-way communications capability necessary to track customer electricity usage levels and credit meters with payments. Kentucky Power's AMR metering lacks such capability. The infrastructure necessary to support such communications is not only expensive, but would require the early retirement of the current AMR metering.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to page 34 of Kentucky Power's 2013 IRP, Section 2.3.2, Short-term Forecasting Models. Explain how and why January 2003 through January 2013 was chosen as the estimation period for the short-term models.

RESPONSE

The Company uses a rolling 10 years of historical data in its short-term forecasting models in order to focus on the most recent trends and relationships. The January 2003 through January 2013 data reflected the most recent 10 years of historical data available at the time the forecasts were developed.

WITNESS: John F Torpey

Kentucky Power Company

REQUEST

Refer to Section 2.3.2.2, Industrial Energy Sales, at page 34 of Kentucky Power's 2013 IRP, section 2.3.3.4.2, Mine Power, at page 40 of IRP, and Exhibit 2-2 at page 56 of the IRP. The text on pages 34 and 40 indicates that the mining load is treated separately in both the short- and long-term forecasting models. In the exhibit all industrial load is aggregated. For the exhibit's forecasted years, provide a breakdown of industrial sales showing mining-sector sales separately from other industrial sales.

RESPONSE

The long-term forecast of mine power sales is provided on KPSC 1-5 Attachment 1.

WITNESS: William K Castle

KENTUCKY POWER COMPANY
MINE POWER ENERGY SALES
ACTUAL AND FORECAST
(GWh Sales & Percentage Growth)

Year	ENERGY SALES	GROWTH RATE
1984	851.19	.
1985	890.554	4.6
1986	881.696	-1.0
1987	902.84	2.4
1988	911.859	1.0
1989	984.603	8.0
1990	1041.789	5.8
1991	1039.883	-0.2
1992	1057.457	1.7
1993	1084.543	2.6
1994	1106.365	2.0
1995	1073.916	-2.9
1996	1099.599	2.4
1997	1083.644	-1.5
1998	1125.329	3.8
1999	1053.809	-6.4
2000	1064.271	1.0
2001	1131.507	6.3
2002	1120.078	-1.0
2003	1083.831	-3.2
2004	1070.281	-1.3
2005	1101.528	2.9
2006	1103.476	0.2
2007	1035.241	-6.2
2008	1066.54	3.0
2009	1006.26	-5.7
2010	979.0084	-2.7
2011	961.8455	-1.8
2012	779.3772	-19.0
2013	693.2906	-11.0
2014	672.8727	-2.9
2015	671.006	-0.3
2016	677.2272	0.9
2017	679.8264	0.4
2018	677.4984	-0.3
2019	676.5194	-0.1
2020	677.9142	0.2
2021	676.7515	-0.2
2022	683.7763	1.0
2023	687.19	0.5
2024	685.9161	-0.2
2025	683.465	-0.4
2026	684.5279	0.2
2027	683.8461	-0.1
2028	681.6467	-0.3
2029	683.9661	0.3
2030	688.6194	0.7

KENTUCKY POWER COMPANY
MINE POWER ENERGY SALES
ACTUAL AND FORECAST
(GWh Sales & Percentage Growth)

Year	ENERGY SALES	GROWTH RATE
2031	686.9187	-0.2
2032	683.6504	-0.5
2033	680.8463	-0.4
2034	682.0303	0.2
2035	682.651	0.1
2036	676.1311	-1.0
2037	678.1244	0.3
2038	674.3644	-0.6
2039	672.1888	-0.3
2040	668.9542	-0.5
2041	666.7032	-0.3
2042	664.5479	-0.3

Kentucky Power Company

REQUEST

Refer to Section 2.3.3.2.2, Residential Energy Usage Per Customer, at page 38 of Kentucky Power's 2013 IRP, specifically, the first sentence of the partial paragraph beginning at the bottom of the page. Explain how January 1995 through February 2013 was chosen as the period for the Statistically Adjusted End-Use ("SAE") model used to estimate residential usage.

RESPONSE

The January 1995 starting point reflects the longest estimation period, given the information provided in the Itron SAE files. The February 2013 ending point reflects the most recent data point available at the time of the model estimation.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to Section 2.3.3.3, Commercial Energy Sales, of Kentucky Power's 2013 IRP, specifically, the last paragraph on page 39.

a. Explain why the saturations and related items are from "DOE's 2012 Annual Energy Outlook" when regional U.S. natural gas price forecasts referenced on page 36 were obtained from the more recent 2013 Annual Energy Outlook.

b. At the top of page 40 in the same section, the first sentence reads, The SAE is a linear regression for the period January 2000 through February 2013." Explain why this period differs from the period for the SAE model used for residential energy sales.

RESPONSE

a. The SAE model information from Itron was completed in mid-2012 and it relied on the 2012 Annual Energy Outlook, which was the most recent data available at the time of Itron's analysis. The 2012 SAE model information was the most recent information available to the Company in preparing the 2013 IRP. The natural gas price forecast was developed in early 2013 and the most recent EIA forecast available was the 2013 Annual Energy Outlook.

b. The period selected for the commercial model reflects the diminished growth in the Company's commercial sector. Commercial sales grew at an average annual rate of 3.1% in the 1990s, and it has tapered off sharply since then. When the model was developed, the Company determined that this pattern of growth did not adequately reflect current activity or expectations for future growth in the service area. The 2000-2013 period was used in the modeling because it represented a reasonable forecast in light of recent trends and expectations related to economic growth and other considerations.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to Section 2.3.3.6, Blending Short- and Long-Term Sales, at page 41 of Kentucky Power's 2013 IRP.

a. Explain whether the reference to "one of the wholesale customers" in the last sentence of the section refers to one of the two municipal customers served by Kentucky Power.

b. If the response to part a. of this request is affirmative, explain in greater detail the reasons for using the long-term forecast throughout the forecast period for one of the municipal customers.

RESPONSE

a. Yes. The long-term forecast was used for one of the municipal customers and the forecast was blended for the other municipal customer.

b. The goal of the blending process is to leverage the relative strengths of the short-term and long-term models to produce the most reliable forecast possible. During the review process, it was determined that the blended forecast worked well for one of the municipal customers while the long term forecast better predicted the short and long-term outlook for the other municipal customer.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to page 45 of Kentucky Power's 2013 IRP, the last paragraph of Section 2.6, Impact of Conservation and Demand-Side Management. Explain why the SAE models reflect the "EIA assessment of efficiency trends as provided in the 2012 Annual Energy Outlook" when regional U.S. natural gas price forecasts referenced on page 36 were obtained from the more recent 2013 Annual Energy Outlook.

RESPONSE

Please see the response to KPSC 1-7(a).

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to the second full paragraph on page 48 of Kentucky Power's 2013 IRP in Section 2.8, Forecast Uncertainty and Range of Forecasts. Confirm that "3% per year for the base case" in the last sentence of the paragraph should be 0.3%.

RESPONSE

Yes. As reported on Exhibit 2-13 at page 67, the average annual growth rate for summer peak demand in the base case is 0.3% per year.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to Section 2.9.1, Energy Forecast, at page 49 of Kentucky Power's 2013 IRP. Provide a general explanation for why the losses forecast decreased by as much as 46 percent compared to Kentucky Power's 2009 forecast.

RESPONSE

The most recent loss estimates reflect decreased expectations for load growth and recent trends in estimated losses.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to Section 2.9.3, Forecasting Methodology, at page 50 of Kentucky Power's 2013 IRP, which states that Kentucky Power explores opportunities to enhance forecasting methods on a continuing basis.

a. State whether the forecasts in this IRP reflect any changes from the methods used in developing the forecasts included in Kentucky Power's 2009 IRP.

b. If there were changes in methods since the 2009 IRP, identify and describe all such changes and explain why they were made.

RESPONSE

a. The basic forecasting methods have not changed from the 2009 IRP. The residential and commercial models are still developed using Itron's Statistically Adjusted End-Use models and the other sectors are forecast using econometric models.

b. N/A.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to Section 2.10, Additional Load Information, at page 51 of Kentucky Power's 2013 IRP, the last full paragraph of the section.

a. Confirm that the reference to the most recent residential customer survey conducted in the winter of 2013 refers to the 2012-2013 winter.

b. State when the previous survey, which was relied upon for this IRP, was conducted.

RESPONSE

a. Yes. The most recent survey was conducted in the 2012-2013 winter.

b. The most recent survey included in the analysis in this IRP was conducted in the 2009-2010 winter. The residential model relies on analysis from a number of prior surveys and not just the 2009-2010 survey.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

On page 51 of Kentucky Power's 2013 IRP, in Section 2.12.1, Residential Energy Sales Forecast Performance, reference is made to the number of residential customers declining from 2009 to 2012. On page 52, Section 2.12.2, Peak Demand Forecast Performance, contains the statement that "the residential customer base has eroded. . ." A review of Exhibit 2-19 on page 73 of the IRP shows that residential heating customers slightly increased over the 2009-2012 period, while residential non- heating customers declined 3,146, roughly 5.4 percent. Given that it has been and is expected to continue to be a winter-peaking system, describe how Kentucky Power's residential forecasts reflect and/or incorporate the fact that the decline in customers has occurred within the non-heating sub-group of the residential customer class.

RESPONSE

The residential energy sales are modelled in aggregate in the SAE model. When discussing the residential sector changes, it is important to consider both the number of customers and the energy consumed. Exhibit 2-20 on page 74 provides energy consumed by both customers with and without electric heat. For both heating and non-heating customers, energy sales have declined over the 2009 through 2012 period. Also, the usage per customer for both categories has declined, with residential heating customers experiencing a sharper decline. This erosion in the residential sector has an impact on the peak demand forecast. After incorporating the expectations for customer growth and usage per customer along with energy efficiency gains, the residential class is expected to decline in the forecast.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to Exhibit 2-25 at page 77 of Kentucky Power's 2013 IRP, which indicates that data from the National Oceanographic and Atmospheric Administration ("NOAA") is used for average daily temperatures at the time of daily peak loads.

a. The interval shown for the NOAA data is 1982-2012. State when Kentucky Power began using NOAA data and how long it has used a 30-year interval.

b. NOAA publishes 30-year weather "normals" every 10 years with the most recent covering the 30 years ending in 2010. Explain whether Kentucky Power relies on data from NOAA or develops internal weather data to update the 30-year normals.

c. Explain why Kentucky Power uses a 30-year interval and describe what consideration, if any, it has given to using an interval other than 30 years.

RESPONSE

a. The Company has always used NOAA weather data and a 30-year weather normal in its load forecast modeling.

b. The Company uses NOAA data but maintains a rolling 30-year average of heating and cooling degree-days.

c. The Company has adhered to the preferred 30-year interval that NOAA uses to develop average degree-days. The only difference is that the Company uses a rolling 30-year average. The Company periodically tests other intervals and has not found statistical differences using alternative intervals.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to page 81 of Kentucky Power's 2013 IRP, Section 3.1.1, Changing Conditions. Kentucky Power states that since the last IRP, the size of its DSM programs has increased, spending on the program has effectively tripled, and claimed energy savings, as measured by "first year" energy savings, have quadrupled.

a. Provide the spending level at the time of last IRP.
b. Provide the anticipated level of spending reflected in the last IRP.
c. Describe the reasons for the increase in spending.

RESPONSE

a. There were seven residential DSM programs administered during 2009 totaling $942,697.

b. The 2009 IRP contemplated $125 million of annual costs for the AEP-East companies; approximately $5 million would have been representative of Kentucky's annual cost.

c. The Company increased spending to expand the Kentucky Power DSM portfolio to include the commercial customer sector. Additionally, the Company made investments to expand the DSM programs offered to residential customers and to pilot a Load Management program. Five new DSM programs were filed and received approval in 2010.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

On page 51 of Kentucky Power's 2013 IRP, in Section 2.12.1, Residential Energy Sales Forecast Performance, reference is made to the number of residential customers declining from 2009 to 2012. On page 52, Section 2.12.2, Peak Demand Forecast Performance, contains the statement that "the residential customer base has eroded. . ." A review of Exhibit 2-19 on page 73 of the IRP shows that residential heating customers slightly increased over the 2009-2012 period, while residential non- heating customers declined 3,146, roughly 5.4 percent. Given that it has been and is expected to continue to be a winter-peaking system, describe how Kentucky Power's residential forecasts reflect and/or incorporate the fact that the decline in customers has occurred within the non-heating sub-group of the residential customer class.

RESPONSE

The residential energy sales are modelled in aggregate in the SAE model. When discussing the residential sector changes, it is important to consider both the number of customers and the energy consumed. Exhibit 2-20 on page 74 provides energy consumed by both customers with and without electric heat. For both heating and non-heating customers, energy sales have declined over the 2009 through 2012 period. Also, the usage per customer for both categories has declined, with residential heating customers experiencing a sharper decline. This erosion in the residential sector has an impact on the peak demand forecast. After incorporating the expectations for customer growth and usage per customer along with energy efficiency gains, the residential class is expected to decline in the forecast.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to the last paragraph on page 86, Section 3.4.2 Existing Program Screening Process,
of Kentucky Power's 2013 IRP regarding the major supply-side benefits used in the cost-benefit analysis of Demand-Side Management ("DSM") programs: avoided energy (production) costs and avoided demand/capacity costs (for generation, transmission and distribution).

a. Explain how the avoided energy and demand/capacity costs were determined for peak and of-peak periods by season in the cost-benefit analysis.

b. Provide the avoided energy and demand/capacity costs for peak and on non-peak periods by season used in the cost-benefit analysis in each year from 2014 through 2028.

RESPONSE

a. Avoided energy and capacity costs within PJM are modeled with the Aurora XMP proprietary software package.

b. Please see KPSC 1-18, Attachment 1.

WITNESS: William K Castle

Month	er Prices ($/MWh) -Nomina PJM - AEP GEN HUB On-Peak	Off-Peak	Emissions ($/ton) -Nominal $'s SO_2	AEP SO_2	NO_x Annual	AEP NO_x Annual	NO_x Summer	($/metric tonne) -Nominal $'s CO_2	Capacity Prices ($/MW-day) -Nominal $'s AEP GEN HUB Hub Cap.	Inflation Factor
Jan-13	31.57	24.07	0.00	0.00	0	0	0	0.00	18.46	2.10%
Feb-13	30.19	24.20	0.00	0.00	0	0	0	0.00	18.46	2.10%
Mar-13	31.24	24.03	0.00	0.00	0	0	0	0.00	18.46	2.10%
Apr-13	32.03	22.19	0.00	0.00	0	0	0	0.00	18.46	2.10%
May-13	32.71	21.76	0.00	0.00	0	0	0	0.00	18.46	2.10%
Jun-13	35.38	23.12	0.00	0.00	0	0	0	0.00	27.73	2.10%
Jul-13	37.66	22.60	0.00	0.00	0	0	0	0.00	27.73	2.10%
Aug-13	42.45	24.94	0.00	0.00	0	0	0	0.00	27.73	2.10%
Sep-13	37.18	24.16	0.00	0.00	0	0	0	0.00	27.73	2.10%
Oct-13	33.66	21.52	0.00	0.00	0	0	0	0.00	27.73	2.10%
Nov-13	33.73	23.42	0.00	0.00	0	0	0	0.00	27.73	2.10%
Dec-13	34.45	24.69	0.00	0.00	0	0	0	0.00	27.73	2.10%
Jan-14	41.91	26.89	0.00	0.00	0	0	0	0.00	27.73	2.10%
Feb-14	38.06	27.22	0.00	0.00	0	0	0	0.00	27.73	2.10%
Mar-14	38.14	24.87	0.00	0.00	0	0	0	0.00	27.73	2.10%
Apr-14	34.39	23.70	0.00	0.00	0	0	0	0.00	27.73	2.10%
May-14	35.82	22.22	0.00	0.00	0	0	0	0.00	27.73	2.10%
Jun-14	38.85	24.22	0.00	0.00	0	0	0	0.00	125.99	2.10%
Jul-14	39.31	23.90	0.00	0.00	0	0	0	0.00	125.99	2.10%
Aug-14	40.83	24.65	0.00	0.00	0	0	0	0.00	125.99	2.10%
Sep-14	36.13	22.85	0.00	0.00	0	0	0	0.00	125.99	2.10%
Oct-14	35.78	22.30	0.00	0.00	0	0	0	0.00	125.99	2.10%
Nov-14	38.70	25.84	0.00	0.00	0	0	0	0.00	125.99	2.10%
Dec-14	37.49	25.44	0.00	0.00	0	0	0	0.00	125.99	2.10%
Jan-15	52.33	32.34	0.00	0.00	0	0	0	0.00	125.99	2.50%
Feb-15	47.27	30.04	0.00	0.00	0	0	0	0.00	125.99	2.50%
Mar-15	45.04	28.30	0.00	0.00	0	0	0	0.00	125.99	2.50%
Apr-15	42.11	28.54	0.00	0.00	0	0	0	0.00	125.99	2.50%
May-15	42.71	25.31	0.00	0.00	0	0	0	0.00	125.99	2.50%
Jun-15	51.15	28.33	0.00	0.00	0	0	0	0.00	136.00	2.50%
Jul-15	56.56	29.17	0.00	0.00	0	0	0	0.00	136.00	2.50%
Aug-15	61.55	30.84	0.00	0.00	0	0	0	0.00	136.00	2.50%
Sep-15	45.45	26.29	0.00	0.00	0	0	0	0.00	136.00	2.50%
Oct-15	42.31	26.03	0.00	0.00	0	0	0	0.00	136.00	2.50%
Nov-15	46.27	28.49	0.00	0.00	0	0	0	0.00	136.00	2.50%
Dec-15	47.53	30.61	0.00	0.00	0	0	0	0.00	136.00	2.50%
Jan-16	57.72	39.41	0.00	0.00	0	0	0	0.00	136.00	2.60%
Feb-16	52.69	36.47	0.00	0.00	0	0	0	0.00	136.00	2.60%
Mar-16	51.08	34.19	0.00	0.00	0	0	0	0.00	136.00	2.60%
Apr-16	47.01	31.28	0.00	0.00	0	0	0	0.00	136.00	2.60%
May-16	46.47	28.99	0.00	0.00	0	0	0	0.00	136.00	2.60%
Jun-16	63.03	33.80	0.00	0.00	0	0	0	0.00	59.37	2.60%
Jul-16	72.54	36.85	0.00	0.00	0	0	0	0.00	59.37	2.60%
Aug-16	74.82	35.41	0.00	0.00	0	0	0	0.00	59.37	2.60%

Month	er Prices ($/MWh) -Nomina PJM - AEP GEN HUB On-Peak	Off-Peak	Emissions ($/ton) -Nominal $'s SO_2	AEP SO_2	NO_x Annual	AEP NO_x Annual	NO_x Summer	($/metric tonne) - Nominal $'s CO_2	Capacity Prices ($/MW-day) -Nominal $'s AEP GEN HUB Hub Cap.	Inflation Factor
Sep-16	51.19	29.42	0.00	0.00	0	0	0	0.00	59.37	2.60%
Oct-16	47.52	31.47	0.00	0.00	0	0	0	0.00	59.37	2.60%
Nov-16	51.24	34.06	0.00	0.00	0	0	0	0.00	59.37	2.60%
Dec-16	54.95	37.48	0.00	0.00	0	0	0	0.00	59.37	2.60%
Jan-17	59.43	43.08	0.00	0.00	0	0	0	0.00	59.37	2.50%
Feb-17	54.18	40.29	0.00	0.00	0	0	0	0.00	59.37	2.50%
Mar-17	52.65	38.27	0.00	0.00	0	0	0	0.00	59.37	2.50%
Apr-17	48.78	34.94	0.00	0.00	0	0	0	0.00	59.37	2.50%
May-17	48.07	31.17	0.00	0.00	0	0	0	0.00	59.37	2.50%
Jun-17	66.18	36.84	0.00	0.00	0	0	0	0.00	184.71	2.50%
Jul-17	78.69	39.53	0.00	0.00	0	0	0	0.00	184.71	2.50%
Aug-17	79.09	36.54	0.00	0.00	0	0	0	0.00	184.71	2.50%
Sep-17	53.94	32.81	0.00	0.00	0	0	0	0.00	184.71	2.50%
Oct-17	49.10	34.70	0.00	0.00	0	0	0	0.00	184.71	2.50%
Nov-17	53.22	37.31	0.00	0.00	0	0	0	0.00	184.71	2.50%
Dec-17	55.74	40.83	0.00	0.00	0	0	0	0.00	184.71	2.50%
Jan-18	58.88	42.77	0.00	0.00	0	0	0	0.00	199.74	2.30%
Feb-18	55.71	42.79	0.00	0.00	0	0	0	0.00	199.74	2.30%
Mar-18	53.59	40.14	0.00	0.00	0	0	0	0.00	199.74	2.30%
Apr-18	49.65	35.29	0.00	0.00	0	0	0	0.00	199.74	2.30%
May-19	49.27	33.47	0.00	0.00	0	0	0	0.00	199.74	2.30%
Jun-18	82.67	35.74	0.00	0.00	0	0	0	0.00	199.74	2.30%
Jul-18	74.04	39.73	0.00	0.00	0	0	0	0.00	199.74	2.30%
Aug-18	82.41	39.99	0.00	0.00	0	0	0	0.00	199.74	2.30%
Sep-18	60.83	35.88	0.00	0.00	0	0	0	0.00	199.74	2.30%
Oct-18	50.11	34.89	0.00	0.00	0	0	0	0.00	199.74	2.30%
Nov-18	53.44	38.22	0.00	0.00	0	0	0	0.00	199.74	2.30%
Dec-18	58.94	41.68	0.00	0.00	0	0	0	0.00	199.74	2.30%
Jan-19	59.45	43.14	0.00	0.00	0	0	0	0.00	215.54	2.30%
Feb-19	55.86	43.34	0.00	0.00	0	0	0	0.00	215.54	2.30%
Mar-19	53.45	41.10	0.00	0.00	0	0	0	0.00	215.54	2.30%
Apr-19	50.40	38.07	0.00	0.00	0	0	0	0.00	215.54	2.30%
May-19	49.93	34.51	0.00	0.00	0	0	0	0.00	215.54	2.30%
Jun-19	64.89	37.30	0.00	0.00	0	0	0	0.00	215.54	2.30%
Jul-19	76.54	40.34	0.00	0.00	0	0	0	0.00	215.54	2.30%
Aug-19	83.23	41.44	0.00	0.00	0	0	0	0.00	215.54	2.30%
Sep-19	80.89	36.06	0.00	0.00	0	0	0	0.00	215.54	2.30%
Oct-19	50.18	38.25	0.00	0.00	0	0	0	0.00	215.54	2.30%
Nov-19	54.47	39.03	0.00	0.00	0	0	0	0.00	215.54	2.30%
Dec-19	56.83	42.39	0.00	0.00	0	0	0	0.00	215.54	2.30%
Jan-20	81.07	45.13	0.00	0.00	0	0	0	0.00	231.74	2.30%
Feb-20	57.60	44.59	0.00	0.00	0	0	0	0.00	231.74	2.30%
Mar-20	55.31	42.05	0.00	0.00	0	0	0	0.00	231.74	2.30%
Apr-20	51.98	37.58	0.00	0.00	0	0	0	0.00	231.74	2.30%

Month	...er Prices ($/MWh) -Nomina... PJM - AEP GEN HUB On-Peak	Off-Peak	Emissions ($/ton) -Nominal $'s SO_2	AEP SO_2	NO_x Annual	AEP NO_x Annual	NO_x Summer	($/metric tonne) - Nominal $'s CO_2	Capacity Prices ($/MW-day) -Nominal $'s AEP GEN HUB Hub Cap.	Inflation Factor
May-20	51.99	38.68	0.00	0.00	0	0	0	0.00	231.74	2.30%
Jun-20	68.41	40.29	0.00	0.00	0	0	0	0.00	231.74	2.30%
Jul-20	80.57	41.14	0.00	0.00	0	0	0	0.00	231.74	2.30%
Aug-20	82.23	42.04	0.00	0.00	0	0	0	0.00	231.74	2.30%
Sep-20	60.38	36.83	0.00	0.00	0	0	0	0.00	231.74	2.30%
Oct-20	52.98	37.87	0.00	0.00	0	0	0	0.00	231.74	2.30%
Nov-20	55.49	40.68	0.00	0.00	0	0	0	0.00	231.74	2.30%
Dec-20	59.21	44.45	0.00	0.00	0	0	0	0.00	231.74	2.30%
Jan-21	64.34	47.87	0.00	0.00	0	0	0	0.00	248.55	2.20%
Feb-21	59.95	46.29	0.00	0.00	0	0	0	0.00	248.55	2.20%
Mar-21	58.01	43.53	0.00	0.00	0	0	0	0.00	248.55	2.20%
Apr-21	53.93	38.79	0.00	0.00	0	0	0	0.00	248.55	2.20%
May-21	53.36	37.43	0.00	0.00	0	0	0	0.00	248.55	2.20%
Jun-21	72.81	41.42	0.00	0.00	0	0	0	0.00	248.55	2.20%
Jul-21	84.21	43.51	0.00	0.00	0	0	0	0.00	248.55	2.20%
Aug-21	84.48	42.99	0.00	0.00	0	0	0	0.00	248.55	2.20%
Sep-21	62.91	37.88	0.00	0.00	0	0	0	0.00	248.55	2.20%
Oct-21	54.78	39.08	0.00	0.00	0	0	0	0.00	248.55	2.20%
Nov-21	57.44	42.28	0.00	0.00	0	0	0	0.00	248.55	2.20%
Dec-21	61.44	46.14	0.00	0.00	0	0	0	0.00	248.55	2.20%
Jan-22	71.88	58.98	0.00	0.00	0	0	0	15.08	265.99	2.30%
Feb-22	68.99	57.51	0.00	0.00	0	0	0	15.08	265.99	2.30%
Mar-22	65.98	54.78	0.00	0.00	0	0	0	15.08	265.99	2.30%
Apr-22	62.25	51.85	0.00	0.00	0	0	0	15.08	265.99	2.30%
May-22	62.30	49.26	0.00	0.00	0	0	0	15.08	265.99	2.30%
Jun-22	81.08	52.39	0.00	0.00	0	0	0	15.08	265.99	2.30%
Jul-22	94.85	55.26	0.00	0.00	0	0	0	15.08	265.99	2.30%
Aug-22	97.52	54.03	0.00	0.00	0	0	0	15.08	265.99	2.30%
Sep-22	69.19	50.79	0.00	0.00	0	0	0	15.08	265.99	2.30%
Oct-22	83.38	51.25	0.00	0.00	0	0	0	15.08	265.99	2.30%
Nov-22	65.58	53.46	0.00	0.00	0	0	0	15.08	265.99	2.30%
Dec-22	66.89	57.01	0.00	0.00	0	0	0	15.08	265.99	2.30%
Jan-23	73.48	59.73	0.00	0.00	0	0	0	15.28	284.08	2.20%
Feb-23	69.04	58.04	0.00	0.00	0	0	0	15.28	284.08	2.20%
Mar-23	67.05	55.72	0.00	0.00	0	0	0	15.28	284.08	2.20%
Apr-23	62.88	52.71	0.00	0.00	0	0	0	15.28	284.08	2.20%
May-23	83.23	49.45	0.00	0.00	0	0	0	15.28	284.08	2.20%
Jun-23	84.03	53.71	0.00	0.00	0	0	0	15.28	284.08	2.20%
Jul-23	97.99	56.26	0.00	0.00	0	0	0	15.28	284.08	2.20%
Aug-23	98.40	55.31	0.00	0.00	0	0	0	15.28	284.08	2.20%
Sep-23	72.27	51.45	0.00	0.00	0	0	0	15.28	284.08	2.20%
Oct-23	64.18	52.67	0.00	0.00	0	0	0	15.28	284.08	2.20%
Nov-23	66.99	54.71	0.00	0.00	0	0	0	15.28	284.08	2.20%
Dec-23	71.56	58.42	0.00	0.00	0	0	0	15.28	284.08	2.20%

	er Prices ($/MWh) -Nomina		Emissions ($/ton) -Nominal $'s					($/metric tonne) - Nominal $'s	Capacity Prices ($/MW-day) -Nominal $'s	Inflation Factor
	PJM - AEP GEN HUB									
Month	On-Peak	Off-Peak	SO_2	AEP SO_2	NO_x Annual	AEP NO_x Annual	NO_x Summer	CO_2	AEP GEN HUB Hub Cap.	
Jan-24	73.38	59.57	0.00	0.00	0	0	0	15.48	302.83	2.20%
Feb-24	71.78	60.25	0.00	0.00	0	0	0	15.48	302.83	2.20%
Mar-24	68.69	57.85	0.00	0.00	0	0	0	15.48	302.83	2.20%
Apr-24	65.32	54.12	0.00	0.00	0	0	0	15.48	302.83	2.20%
May-24	64.88	51.88	0.00	0.00	0	0	0	15.48	302.83	2.20%
Jun-24	78.88	54.25	0.00	0.00	0	0	0	15.48	302.83	2.20%
Jul-24	98.69	58.27	0.00	0.00	0	0	0	15.48	302.83	2.20%
Aug-24	101.32	58.99	0.00	0.00	0	0	0	15.48	302.83	2.20%
Sep-24	61.34	54.48	0.00	0.00	0	0	0	15.48	302.83	2.20%
Oct-24	65.51	52.22	0.00	0.00	0	0	0	15.48	302.83	2.20%
Nov-24	68.64	55.69	0.00	0.00	0	0	0	15.48	302.83	2.20%
Dec-24	70.96	58.74	0.00	0.00	0	0	0	15.48	302.83	2.20%
Jan-25	75.71	61.40	0.00	0.00	0	0	0	15.67	321.95	2.20%
Feb-25	72.63	61.46	0.00	0.00	0	0	0	15.67	321.95	2.20%
Mar-25	70.94	59.60	0.00	0.00	0	0	0	15.67	321.95	2.20%
Apr-25	67.00	55.06	0.00	0.00	0	0	0	15.67	321.95	2.20%
May-25	67.15	53.40	0.00	0.00	0	0	0	15.67	321.95	2.20%
Jun-25	83.88	55.44	0.00	0.00	0	0	0	15.67	321.95	2.20%
Jul-25	99.50	57.25	0.00	0.00	0	0	0	15.67	321.95	2.20%
Aug-25	101.53	58.23	0.00	0.00	0	0	0	15.67	321.95	2.20%
Sep-25	80.83	53.87	0.00	0.00	0	0	0	15.67	321.95	2.20%
Oct-25	67.10	53.25	0.00	0.00	0	0	0	15.67	321.95	2.20%
Nov-25	70.02	57.58	0.00	0.00	0	0	0	15.67	321.95	2.20%
Dec-25	73.51	60.41	0.00	0.00	0	0	0	15.67	321.95	2.20%
Jan-26	77.30	62.99	0.00	0.00	0	0	0	15.88	341.74	2.20%
Feb-26	73.97	62.34	0.00	0.00	0	0	0	15.88	341.74	2.20%
Mar-26	72.18	59.65	0.00	0.00	0	0	0	15.88	341.74	2.20%
Apr-26	67.76	55.87	0.00	0.00	0	0	0	15.88	341.74	2.20%
May-26	67.89	53.68	0.00	0.00	0	0	0	15.88	341.74	2.20%
Jun-26	85.93	58.14	0.00	0.00	0	0	0	15.88	341.74	2.20%
Jul-26	101.12	57.16	0.00	0.00	0	0	0	15.88	341.74	2.20%
Aug-26	105.38	60.86	0.00	0.00	0	0	0	15.88	341.74	2.20%
Sep-26	80.37	54.68	0.00	0.00	0	0	0	15.88	341.74	2.20%
Oct-26	68.03	55.08	0.00	0.00	0	0	0	15.88	341.74	2.20%
Nov-26	71.42	58.48	0.00	0.00	0	0	0	15.88	341.74	2.20%
Dec-26	74.15	61.12	0.00	0.00	0	0	0	15.88	341.74	2.20%
Jan-27	79.16	64.43	0.00	0.00	0	0	0	16.08	362.23	2.20%
Feb-27	75.34	62.76	0.00	0.00	0	0	0	16.08	362.23	2.20%
Mar-27	72.24	59.80	0.00	0.00	0	0	0	16.08	362.23	2.20%
Apr-27	69.23	58.22	0.00	0.00	0	0	0	16.08	362.23	2.20%
May-27	68.45	54.37	0.00	0.00	0	0	0	16.08	362.23	2.20%
Jun-27	88.58	57.62	0.00	0.00	0	0	0	16.08	362.23	2.20%
Jul-27	106.18	60.52	0.00	0.00	0	0	0	16.08	362.23	2.20%
Aug-27	106.67	59.83	0.00	0.00	0	0	0	16.08	362.23	2.20%

	er Prices ($/MWh) -Nomina		Emissions ($/ton) -Nominal $'s					($/metric tonne) - Nominal $'s	Capacity Prices ($/MW-day) -Nominal $'s	Inflation Factor
	PJM - AEP GEN HUB									
Month	On-Peak	Off-Peak	SO_2	AEP SO_2	NO_x Annual	AEP NO_x Annual	NO_x Summer	CO_2	AEP GEN HUB Hub Cap.	
Sep-27	61.58	55.42	0.00	0.00	0	0	0	16.08	362.23	2.20%
Oct-27	70.08	56.30	0.00	0.00	0	0	0	16.08	362.23	2.20%
Nov-27	72.59	59.03	0.00	0.00	0	0	0	16.08	362.23	2.20%
Dec-27	76.07	62.48	0.00	0.00	0	0	0	16.08	362.23	2.20%
Jan-28	80.66	65.10	0.00	0.00	0	0	0	16.29	383.42	2.10%
Feb-28	76.19	63.61	0.00	0.00	0	0	0	16.29	383.42	2.10%
Mar-28	73.74	61.11	0.00	0.00	0	0	0	16.29	383.42	2.10%
Apr-28	70.17	57.32	0.00	0.00	0	0	0	16.29	383.42	2.10%
May-28	70.10	54.46	0.00	0.00	0	0	0	16.29	383.42	2.10%
Jun-28	95.99	60.23	0.00	0.00	0	0	0	16.29	383.42	2.10%
Jul-28	108.57	62.11	0.00	0.00	0	0	0	16.29	383.42	2.10%
Aug-28	106.13	60.04	0.00	0.00	0	0	0	16.29	383.42	2.10%
Sep-28	79.67	56.35	0.00	0.00	0	0	0	16.29	383.42	2.10%
Oct-28	70.60	57.28	0.00	0.00	0	0	0	16.29	383.42	2.10%
Nov-28	73.67	60.25	0.00	0.00	0	0	0	16.29	383.42	2.10%
Dec-28	77.52	64.13	0.00	0.00	0	0	0	16.29	383.42	2.10%
Jan-29	80.93	66.09	0.00	0.00	0	0	0	16.50	394.85	2.10%
Feb-29	78.38	66.19	0.00	0.00	0	0	0	16.50	394.85	2.10%
Mar-29	75.63	63.52	0.00	0.00	0	0	0	16.50	394.85	2.10%
Apr-29	72.23	59.77	0.00	0.00	0	0	0	16.50	394.85	2.10%
May-29	72.05	57.06	0.00	0.00	0	0	0	16.50	394.85	2.10%
Jun-29	99.28	59.11	0.00	0.00	0	0	0	16.50	394.85	2.10%
Jul-29	109.74	62.33	0.00	0.00	0	0	0	16.50	394.85	2.10%
Aug-29	112.49	62.79	0.00	0.00	0	0	0	16.50	394.85	2.10%
Sep-29	87.35	56.27	0.00	0.00	0	0	0	16.50	394.85	2.10%
Oct-29	72.05	56.88	0.00	0.00	0	0	0	16.50	394.85	2.10%
Nov-29	74.59	60.37	0.00	0.00	0	0	0	16.50	394.85	2.10%
Dec-29	78.37	65.15	0.00	0.00	0	0	0	16.50	394.85	2.10%
Jan-30	62.99	67.99	0.00	0.00	0	0	0	16.72	403.15	2.10%
Feb-30	79.99	68.10	0.00	0.00	0	0	0	16.72	403.15	2.10%
Mar-30	76.58	64.91	0.00	0.00	0	0	0	16.72	403.15	2.10%
Apr-30	73.08	59.65	0.00	0.00	0	0	0	16.72	403.15	2.10%
May-30	72.66	58.00	0.00	0.00	0	0	0	16.72	403.15	2.10%
Jun-30	81.85	61.28	0.00	0.00	0	0	0	16.72	403.15	2.10%
Jul-30	108.79	61.94	0.00	0.00	0	0	0	16.72	403.15	2.10%
Aug-30	109.96	64.29	0.00	0.00	0	0	0	16.72	403.15	2.10%
Sep-30	89.51	58.88	0.00	0.00	0	0	0	16.72	403.15	2.10%
Oct-30	72.69	58.13	0.00	0.00	0	0	0	16.72	403.15	2.10%
Nov-30	75.92	62.79	0.00	0.00	0	0	0	16.72	403.15	2.10%
Dec-30	79.43	66.41	0.00	0.00	0	0	0	16.72	403.15	2.10%
Jan-31	84.57	69.97	0.00	0.00	0	0	0	16.94	411.61	2.10%
Feb-31	80.69	69.31	0.00	0.00	0	0	0	16.94	411.61	2.10%
Mar-31	77.95	66.04	0.00	0.00	0	0	0	16.94	411.61	2.10%
Apr-31	74.29	61.17	0.00	0.00	0	0	0	16.94	411.61	2.10%

Month	er Prices ($/MWh) -Nomina PJM - AEP GEN HUB On-Peak	Off-Peak	Emissions ($/ton) -Nominal $'s SO_2	AEP SO_2	NO_x Annual	AEP NO_x Annual	NO_x Summer	($/metric tonne) - Nominal $'s CO_2	Capacity Prices ($/MW-day) -Nominal $'s AEP GEN HUB Hub Cap.	Inflation Factor
May-31	74.79	59.79	0.00	0.00	0	0	0	16.94	411.61	2.10%
Jun-31	93.55	61.66	0.00	0.00	0	0	0	18.94	411.61	2.10%
Jul-31	112.06	64.84	0.00	0.00	0	0	0	19.94	411.61	2.10%
Aug-31	113.07	66.01	0.00	0.00	0	0	0	16.94	411.61	2.10%
Sep-31	88.79	60.20	0.00	0.00	0	0	0	16.94	411.61	2.10%
Oct-31	75.10	60.36	0.00	0.00	0	0	0	16.94	411.61	2.10%
Nov-31	77.30	64.00	0.00	0.00	0	0	0	16.94	411.61	2.10%
Dec-31	79.95	67.17	0.00	0.00	0	0	0	19.94	411.61	2.10%
Jan-32	86.38	72.77	0.00	0.00	0	0	0	17.16	420.26	2.10%
Feb-32	81.87	70.39	0.00	0.00	0	0	0	17.16	420.26	2.10%
Mar-32	79.17	67.35	0.00	0.00	0	0	0	17.16	420.26	2.10%
Apr-32	75.77	63.00	0.00	0.00	0	0	0	17.16	420.26	2.10%
May-32	75.06	61.26	0.00	0.00	0	0	0	17.16	420.26	2.10%
Jun-32	96.48	64.40	0.00	0.00	0	0	0	17.16	420.26	2.10%
Jul-32	114.79	67.19	0.00	0.00	0	0	0	17.16	420.26	2.10%
Aug-32	120.70	67.58	0.00	0.00	0	0	0	17.16	420.26	2.10%
Sep-32	88.62	62.05	0.00	0.00	0	0	0	17.16	420.26	2.10%
Oct-32	76.42	62.68	0.00	0.00	0	0	0	17.16	420.26	2.10%
Nov-32	79.83	65.65	0.00	0.00	0	0	0	17.16	420.26	2.10%
Dec-32	82.57	69.67	0.00	0.00	0	0	0	17.16	420.26	2.10%
Jan-33	87.10	73.59	0.00	0.00	0	0	0	17.38	429.08	2.10%
Feb-33	83.99	73.54	0.00	0.00	0	0	0	17.38	429.08	2.10%
Mar-33	81.29	70.21	0.00	0.00	0	0	0	17.38	429.08	2.10%
Apr-33	77.54	66.32	0.00	0.00	0	0	0	17.38	429.08	2.10%
May-33	77.37	62.88	0.00	0.00	0	0	0	17.38	429.09	2.10%
Jun-33	101.64	67.15	0.00	0.00	0	0	0	17.38	429.08	2.10%
Jul-33	119.07	69.64	0.00	0.00	0	0	0	17.38	429.08	2.10%
Aug-33	119.50	66.95	0.00	0.00	0	0	0	17.38	429.08	2.10%
Sep-33	91.12	64.98	0.00	0.00	0	0	0	17.38	429.08	2.10%
Oct-33	76.26	64.97	0.00	0.00	0	0	0	17.38	429.08	2.10%
Nov-33	80.67	67.90	0.00	0.00	0	0	0	17.38	429.08	2.10%
Dec-33	84.84	72.02	0.00	0.00	0	0	0	17.38	429.08	2.10%
Jan-34	85.70	75.93	0.00	0.00	0	0	0	17.60	438.09	2.10%
Feb-34	83.85	74.21	0.00	0.00	0	0	0	17.60	438.09	2.10%
Mar-34	81.99	72.33	0.00	0.00	0	0	0	17.60	438.09	2.10%
Apr-34	78.84	69.39	0.00	0.00	0	0	0	17.60	438.09	2.10%
May-34	79.38	64.12	0.00	0.00	0	0	0	17.60	438.09	2.10%
Jun-34	97.19	68.31	0.00	0.00	0	0	0	17.60	438.09	2.10%
Jul-34	114.60	70.48	0.00	0.00	0	0	0	17.60	438.09	2.10%
Aug-34	115.11	70.10	0.00	0.00	0	0	0	17.60	438.09	2.10%
Sep-34	65.88	64.73	0.00	0.00	0	0	0	17.60	438.09	2.10%
Oct-34	78.60	67.30	0.00	0.00	0	0	0	17.60	438.09	2.10%
Nov-34	61.48	70.12	0.00	0.00	0	0	0	17.60	438.09	2.10%
Dec-34	84.77	73.97	0.00	0.00	0	0	0	17.60	438.09	2.10%

	er Prices ($/MWh) -Nomina		Emissions ($/ton) -Nominal $'s					($/metric tonne) - Nominal $'s	Capacity Prices ($/MW-day) -Nominal $'s	Inflation Factor
	PJM - AEP GEN HUB									
Month	On-Peak	Off-Peak	SO_2	AEP SO_2	NO_x Annual	AEP NO_x Annual	NO_x Summer	CO_2	AEP GEN HUB Hub Cap.	
Jan-35	87.70	76.39	0.00	0.00	0	0	0	17.84	447.29	2.10%
Feb-35	86.71	77.57	0.00	0.00	0	0	0	17.84	447.29	2.10%
Mar-35	83.61	74.34	0.00	0.00	0	0	0	17.84	447.29	2.10%
Apr-35	80.12	69.51	0.00	0.00	0	0	0	17.84	447.29	2.10%
May-35	80.26	66.95	0.00	0.00	0	0	0	17.84	447.29	2.10%
Jun-35	93.99	68.20	0.00	0.00	0	0	0	17.84	447.29	2.10%
Jul-35	115.00	72.58	0.00	0.00	0	0	0	17.84	447.29	2.10%
Aug-35	122.40	72.43	0.00	0.00	0	0	0	17.84	447.29	2.10%
Sep-35	94.35	68.27	0.00	0.00	0	0	0	17.84	447.29	2.10%
Oct-35	80.59	67.26	0.00	0.00	0	0	0	17.84	447.29	2.10%
Nov-35	83.43	71.57	0.00	0.00	0	0	0	17.84	447.29	2.10%
Dec-35	85.79	75.61	0.00	0.00	0	0	0	17.84	447.29	2.10%

Kentucky Power Company

REQUEST

Refer to the first full paragraph on page 87, Section 3.4.2 Existing Program Screening Process, of Kentucky Power's 2013 IRP, which states that, "the analysis considered the benefits of SO2 emission credits, NOx market price, estimates for CO2 costs based on expected legislation, and expected additional system sales, thereby improving the cost effectiveness of each DSM measure." Explain in detail how each benefit was determined, as well as the amount of cost used for each benefit in each year from 2014 through 2028.

RESPONSE

Annual energy savings are the product of the cost assumptions developed for those emissions in the Aurora XMP model and the energy savings associated with the energy efficiency savings. Please see the Company's response to KPSC 1-18(b) for cost assumptions.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to the last paragraph on page 87, Section 3.5.1 Assessment of Achievable Potential, of Kentucky Power's 2013 IRP, which states, "Barriers such as lack of access to capital and lack of information are addressed with utility-based EE and DR programs." In Case No. 2012-0484,[1] the Commission approved the Kentucky Energy Retrofit Rider for several eastern Kentucky distribution cooperatives to establish an on-bill financing program to encourage customers to implement energy-efficiency measures. Given that much of Kentucky Power's territory is similar to that of such cooperatives, explain in detail what consideration Kentucky Power has given to seeking Commission approval for an on-bill financing program for energy-efficiency measures.

RESPONSE

Kentucky Power has not sought Commission approval for on-bill financing for energy efficiency measures. Kentucky Power does not oppose the concept of financing for energy efficiency measures; however, Kentucky Power does not believe that it should be the vehicle for such arrangements. Consumer lending is not the core competency of the Company. Even if third-party lenders provide the financing, it is an administrative burden for Kentucky Power to handle the loan repayment procedures. Kentucky Power systems are not designed to process consumer loan payments, and they are not staffed to handle such activity. Implementing such arrangements would require investment in systems, processes and staff resources, all of which would need recovered in rates. Also, the commingling of customer bill payments and loan repayments creates both procedural and administrative challenges related to credit and collections, service disconnection procedures that the Commission already has in place, and other complicating issues.

For these reasons, Kentucky Power asserts it is best for its customers to avail themselves of the many consumer lending arrangements that are available to them for their financing needs from providers with such expertise.

WITNESS: Ranie K Wohnhas

[1] Case No. 2012-00484, Joint Application of Big Sandy Rural Electric Cooperative Corp , Fleming-Mason Energy Cooperative, Inc., Grayson Rural Electric Cooperative Corp. for an Order Approving KY Energy Retrofit Rider Permanent Tariff (Ky. PSC Aug. 26, 2013).

Kentucky Power Company

REQUEST

Refer to page 90, Section 3.5.1.2, Smart Meters, of Kentucky Power's 2013 IRP. For each class of retail customers, provide the number and percentage of customers with smart meters.

RESPONSE

Kentucky Power has not deployed a smart metering network to any customer classes.

Kentucky Power defines a smart meter as an advanced electronic meter that has the capability to both send and receive electric utility meter information to a remote, central utility collector and/or to a Home Area Network (HAN), either wireless or through a hardwired communication connection. The smart meter can respond and react to commands communicated to provide consumption information, remote connection and disconnection of electric service, power outage status, and possibly near-real time pricing information. Smart meters typically exist within an Advanced Metering Information (AMI) system where two-way communication occurs within a separate and distinct communication infrastructure.

Kentucky Power does have Automated Meter Reading (AMR) meters installed throughout its service territory at nearly every meter location. Kentucky Power AMR meters are electronic meters that contain one-way communication capability to communicate meter readings with wireless signal collection via a signal collector mounted to a passing-by Kentucky Power vehicle.

Kentucky Power has more advanced metering systems installed with some larger Commercial and Industrial (C&I) customers. While these meters collect more detailed information, such as voltage and current, they are typically not considered 'smart meters' because they do not have persistent two-way communications capability. However, one large C&I customer does have meters installed that are connected via Ethernet to Kentucky Power, providing constant two-way communications.

Kentucky Power did initiate a small Load Management pilot program in September 2011 where 49 residential customers were provided with a 2-way communicating meter. When prompted by the back office at Kentucky Power, these meters transmitted a control signal to thermostats and hot water heaters on the customers' premises. The program ended in December 2012, and all meters have been removed and replaced with standard AMR meters.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to the continuation paragraph on page 92, Section 3.5.1.3, Demand Response, of Kentucky Power's 2013 IRP, which states, "Given Kentucky Power's current and expected capacity position within PJM, it is not necessary to aggressively pursue all available demand response at this time."

a. Provide any research or analysis relied upon by Kentucky Power in making this statement.

b. Describe all research and analysis Kentucky Power has performed with respect to bidding Energy Efficiency ("EE")/DSM and demand response into the PJM markets.

c. State whether any of Kentucky Power's American Electric Power affiliates have participated in bidding EE/DSM or demand response into the PJM markets. If the response is yes, describe such participation in detail.

d. Identify the circumstances under which Kentucky Power's capacity position would be such that it would aggressively pursue bidding demand response into PJM.

RESPONSE

a. Kentucky Power's "going in" capacity position is detailed in Exhibit 4-7, page 184. See Column 19 for the capacity position without additions.

b. Kentucky Power has not researched "bidding in" energy efficiency or demand response into PJM markets.

c. Kentucky Power affiliate Ohio Power, an "RPM"company within PJM beginning in 2015/16, has committed 211 MW of EE resources to the 2015/16 base residual auction and 117 MW into the 2016/17 auction. Other resources, such as demand response, have comprised part of affiliates' FRR plans but have not been, as a rule, committed into an RPM auction. KPCo does not have information regarding the activity in this arena of its unregulated affiliate.

d. Kentucky Power, as an FRR entity, would need sufficient length to meet its reserve requirement plus a PJM-mandated threshold before it could commit some of its resources to the PJM RPM market. Further, Kentucky Power would have to have a quantity of EE resources large enough to justify the expense associated with measurement and verification. As an FRR entity, there is no tangible benefit for including EE resources in an FRR plan unless they are a necessary component of reaching a minimum reserve requirement.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to pages 92-93 of Kentucky Power's 2013 IRP, Section 3.5.1.4, Volt VAR Optimization (VVO), Table ES-1 on page ES-7. Describe in detail what actions Kentucky Power will undertake to achieve the 4 MW of VVO reduction in end-use consumption from 2014 through 2020 and 8 MW reduction from 2021 through 2028.

RESPONSE

Kentucky Power is currently installing VVO equipment on 26 circuits which should result in 7 MW of load reduction and a reduction in customer energy usage of 32,000 MWH. Prior to 2021, if subsequent analyses continue to support its deployment, Kentucky Power will seek appropriate recovery for continued investment.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to page 93, Section 3.5.1.5, Distributed Generation ("DG"), of Kentucky Power's 2013 IRP.

a. With respect to DG, state whether Kentucky Power intends to request Commission approval of any changes in its net metering tariff as a result of accommodating any of the multiple forms of DG listed in the discussion.

b. If yes, identify and describe all such changes.

RESPONSE

a. Kentucky Power has no current plans to request changes to its net metering tariff.

b. N/A.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to page 96, Section 3.5.2, Determining Expanded Programs for the IRP — Energy Efficiency, of Kentucky Power's 2013 IRP, which states, "In the recent Mitchell Transfer Stipulation and Settlement Agreement, Kentucky Power agreed to increase spending on cost-effective (energy efficiency) programs from the current level of approximately $3 million annually to $4 million in 2014, $5 million in 2015, and $6 million thereafter."

a. Explain how Kentucky Power will determine which programs will be expanded as a result of the additional funding.

b. Identify any changes Kentucky Power anticipates with its evaluation, measurement, and verification procedures related to energy and peak-demand savings related to existing and expanded EE/DSM programs.

RESPONSE

a. The Company received budgetary proposals from implementation contractors to expand the target participant levels for three existing DSM programs; Residential Modified Energy Fitness (weatherization), Residential Efficient Products (lighting), and Commercial Incentive (Custom, Prescriptive, New Construction, Direct Install). The Company is also developing new program applications based on review of successful DSM programs within other AEP Operating Companies and/or other utilities. A market potential study has also been proposed with the most recent DSM Status Report filing to study all customer sectors within the Kentucky Power service area and develop a market potential plan for DSM programs over a ten-year period.

b. No changes are anticipated.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Explain whether there has been any change, intemally or externally, in the methods of evaluation, measurement and verification used by Kentucky Power for existing, or proposed, DSM programs. Identify the cost associated with such changes, if they exist.

RESPONSE

The methods of EM&V may continue to be refined but are not materially different from methods employed historically.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

807 KAR 5:058, Section 8(2), states:

The utility shall describe and discuss all options considered for inclusion in the plan including:

(a) Improvements to and more efficient utilization of existing utility generation, transmission, and distribution facilities;

(b) Conservation and load management or other demand-side programs not already in place;

(c) Expansion of generating facilities, including assessment of economic opportunities for coordination with other utilities in constructing and operating new units; and

(d) Assessment of non-utility generation, including generating capacity provided by cogeneration, technologies relying on renewable resources, and other non-utility sources.

The Cross Reference Table at pages 23-28 of the 2013 IRP reflects that the above requirement is addressed in Section 4.3.2.2, Retrofit or Life Optimization of Existing Facilities. At page 173, in Section 4.11, KPSC Staff Issues Addressed, Item 6 indicates that Section 4.4.1.1, General Description, includes discussion regarding improvements to and more efficient utilization of transmission and distribution facilities. Section 4.3.2.2 provides only a short broad discussion of Retrofit or Life Optimization of Existing Facilities and Sections 4.4.1.1 through 4.4.1.9 address transmission, but not distribution.

a. Provide a detailed discussion of any improvements to or steps taken to ensure more efficient utilization of Kentucky Power's distribution facilities. If there are none, explain why not.

b. Provide a detailed discussion of the impact of greater customer net metering on the distribution or transmission system.

c. Explain whether the increased amount of net metering load will require improvements or additions to the transmission and/or distribution system.

d. Explain whether the increased amount of net metering load will result in improvements to the transmission and/or distribution system.

RESPONSE

a. Kentucky Power is installing Volt VAR Optimization (VVO) on 26 circuits. The VAR optimization function of this system will improve circuit power factors closer to unity and thus reduce losses on the circuits. The Voltage optimization function results in a decrease in demand and energy consumption at the customers and thus decreases the loading on the circuit which will further contribute to loss reduction. The "no-load" losses of the transformers on the circuit will also be reduced with lower voltages.

b-d. Based on the current limits of 30 kW / premise and an aggregate of 1% of Kentucky Power's peak load, it is unlikely that greater net metering will have an impact on the distribution or transmission system. If greater limits are allowed, the impacts would depend upon the new limit, the circuits affected, and would require additional study by the Company.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to page 110 of Kentucky Power's 2013 IRP, Section 4.2.2, Generation Reliability Criterion. Identify the commission referenced in relation to Cause Nos. 42350 and 42352.

RESPONSE

The reference is incorrect, the sentence should read: "This transfer was approved by the Kentucky Public Service Commission in Case No. 2002-00475 Order dated May 19, 2004." The cases referenced in the report were approved by the Indiana Utility Regulatory Commission.

WITNESS: John F Torpey

Kentucky Power Company

REQUEST

Refer to page 110 of Kentucky Power's 2013 IRP, Section 4.2.2, Generation Reliability Criterion, which contains a discussion of the decision made by American Electric Power ("AEP") in 2007 to join PJM under the FRR construct when Kentucky Power was part of the AEP-East power pool.

a. Historically Kentucky Power has been a capacity-short utility at the time of its system peak. State whether it is currently capacity short at its winter peak and whether it will be similarly capacity short during the planning period of this IRP.

b. If the answer to a. is yes, explain how the 2007 FRR decision will affect the ratepayers of Kentucky Power during this IRP planning period.

c. Explain whether the 2007 FRR decision holds Kentucky Power, as a stand-alone company, to a reserve margin which is higher than that to which it would currently be held under the RPM construct.

d. Explain at what management level and how the future evaluation and decision on whether to remain in the FRR market will be made.

RESPONSE

a. Kentucky Power is not currently capacity short at its winter peak and will not be capacity short at its winter peak during the planning period of this IRP. Please see IRP Exhibit 4-13 at page 189, columns 16 and 17 to see Kentucky Power's winter capacity position and reserve margin, respectively, throughout the IRP planning period.

b. Kentucky Power's capacity position during the winter has no bearing on its stand-alone PJM capacity position, nor did it influence the decision to participate as an FRR entity. The initial 2007 FRR decision applied through the 2010/2011 plan year and only committed the Company to FRR through the 2011/2012 planning year, so it had no impact with regard to the current IRP.

c. FRR has historically had a lower reserve margin requirement than that required under RPM for all of the auctions held to date. Consequently, the historic choice of FRR for KPCo, whether as a member of the AEP Interconnection Agreement or as a stand-alone company, has resulted in Kentucky Power being held to a *lower* reserve margin requirement, not higher.

d. Kentucky Power senior management will make the annual decision to elect FRR or move to RPM. If RPM is ever elected, PJM rules will then require a minimum 5-year RPM election before FRR can once again be considered. The decision process is the following:

(a) evaluations are prepared for Kentucky Power by AEPSC prior to the election;

(b) following its review, other information, evaluations, etc. are provided to Kentucky Power as requested;

(c) Kentucky Power will then elect FRR or RPM. Kentucky Power and one or more of the other AEP-East operating companies may elect a joint FRR plan by mutual agreement as provided for under the Power Coordination Agreement.

WITNESS: John F Torpey

Kentucky Power Company

REQUEST

Refer to page 111 of Kentucky Power's 2013 IRP, Section 4.2.2, Generation Reliability Criterion. Kentucky Power states that it will met PJM's installed reserve margin ("IRM") of 15.6 percent.

a. Explain how the fact that Kentucky Power and PJM peak in winter and summer, respectively, affects the calculation of the 15.6 percent IRM under the Fixed Resource Requirement ("FR") construct in PJM.

b. Explain how the different peaking seasons would affect calculation of the IRM under PJM's Reliability Pricing Model ("RPM") construct.

RESPONSE

a. The 15.6 percent IRM was developed independently by PJM to determine the amount of capacity resources required to serve the forecast PJM peak load and satisfy the reliability criterion. The Kentucky Power peak that is coincident with the PJM peak is the relevant data point when considering Kentucky Power's obligation.

b. The different peaking seasons have no impact on the IRM under PJM's RPM construct.

WITNESS: John F Torpey

Kentucky Power Company

REQUEST

Refer to page 111 of Kentucky Power's 2013 IRP, Section 4.2.2, Generation Reliability Criterion. Provide a detailed explanation regarding the difference between the PJM Installed Reserve Margin ("IRM"), PJM Unforced Capacity, and PJM Installed Capacity. Identify and correlate the PJM requirements for Kentucky Power for each.

RESPONSE

Installed Reserve Margin (IRM) determines the amount of capacity resources required to serve the forecast peak load and satisfy the reliability criterion. The reliability criterion is based on Loss of Load Expectation (LOLE) not exceeding one event in ten years.

The PJM Installed Capacity (ICAP) value of a unit is based on the summer net dependable rating of a unit as determined in accordance with PJM's Rules and Procedures.

The PJM Unforced Capacity (UCAP) value of a unit is the ICAP that is not on average experiencing a forced outage or forced derating.

UCAP = ICAP x (1 - EFORd)

Equivalent Demand Forced Outage Rate (EFORd) is a measure of the probability of a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to operate.

To understand how these concepts apply to Kentucky Power, the term "Forecast Pool Requirement" (FPR) must also be defined:

Forecast Pool Requirement (FPR) is used to establish level of unforced capacity resources that will provide an acceptable level of reliability:

FPR = (1 + IRM)*(1-pool-wide avg. EFORd).

To correlate these terms to Kentucky Power, please refer to Kentucky Power's 2013 IRP, Volume A, Exhibit 4-12 on page 188. For each year of the planning period, ICAP is shown in Column (16), UCAP is in Column (18), EFORd is in Column (17) and FPR is in Column (7).

WITNESS: John F Torpey

Kentucky Power Company

REQUEST

Refer to page 112 of Kentucky Power's 2013 IRP, Section 4.2.3.1, Interconnection Agreement. Kentucky Power was aware of the AEP pool's breakup prior to December 2010. Provide any records of discussion concerning the future impacts the pool's breakup would have on the PJM market, specifically the choice to remain as a FRR participant and the five-year notice to abandon the FRR or RPM construct.

RESPONSE

When the decision was made in December 2010 to exercise the three-year notice to terminate the existing Interconnection Agreement, it was not yet known what type of subsequent agreement might be developed, if any, as an appropriate successor.

As a result, the Company has no records of discussion during this early time frame as to what impacts the elimination of the old pool would have on its future FRR/RPM election in the PJM market since it was still in the preliminary stages of investigating its future affiliate agreement options.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to pages 113-122 of Kentucky Power's 2013 IRP, Section 4.2.4, Environmental Compliance. This section does not appear to address the cost of environmental compliance. For all different compliance requirements and strategies Kentucky Power has modeled, provide its most recent estimates of the cost of environmental compliance to Kentucky Power and its ratepayers.

RESPONSE

Long term modeling utilized in developing the IRP takes into account all variable costs and the incremental fixed costs that vary among the resource portfolios. Because all of the portfolios evaluated in Kentucky Power's 2013 IRP included the same existing generation assets, there was no need to include any incremental fixed costs for those assets, because the fixed costs for these existing assets would be the same in all portfolios.

We do prepare estimates of the incremental capital costs for environmental compliance on a forward-looking basis for three years, and for Kentucky Power the incremental capital investments for environmental compliance projects are estimated to be $32 million in 2014, $33 million in 2015, and $27 million in 2016. The actual amounts of incremental capital incurred in any specific year may vary.

There are a number of emerging environmental requirements that have not been finalized, including effluent guideline and cooling water intake proposals under the Clean Water Act, coal ash management requirements under the Solid Waste Disposal Act, and future greenhouse gas emission standards and other future requirements under the Clean Air Act. Until these rules are issued in final form any estimates of future compliance costs, and the timing of those investments, is highly uncertain.

WITNESS: John F Torpey

Kentucky Power Company

REQUEST

Refer to page 123 of Kentucky Power's 2013 IRP, Section 4.3.2.3, Renewable Energy Plans. Kentucky Power states that renewable-energy options are expected to compete economically with traditional supply-side options in the future.

a. When does Kentucky Power expect renewables to be competitive?

b. By capacity type, identify and describe the drivers of Kentucky Power's projection that renewables are expected to compete economically with traditional supply-side options in the future.

RESPONSE

a. Kentucky Power currently projects utility-scale solar power to be competitive with. supply options by 2020. Some wind projects that are PTC-eligible are competitive now. Without the reinstatement of a wind PTC, Kentucky Power does not expect wind to be cost-competitive before 2020. Distributed resources such as solar, wind, CHP are not competitive under current net metering policies. Any resource that provides energy at the cogen rate is immediately competitive.

b. The primary drivers that will accelerate the cost competitiveness of utility wind and solar are: PJM market prices and the installed cost of the renewable generators. Kentucky Power expects the PJM prices to increase and installed solar and wind costs to decrease. Similarly, if net metering rates decline relative to PJM costs, their economics will also improve. Finally, the availability of a REC market for eligible generation would improve economics for both utility and distributed economics.

WITNESS: John F Torpey

Kentucky Power Company

REQUEST

Refer to page 124 of Kentucky Power's 2013 IRP, Section 4.3.2.4, Demands, Capabilities, and Reserve Margins — Going In, which states that Exhibit 4-7 provides a projection of its reserve margins for the summer season from 2014 — 2028.

Provide the calculations used to determine these margins.

RESPONSE

The reserve margins are stated in terms of Kentucky Power's capacity position (in MW) relative to the PJM installed reserve margin (IRM). The PJM IRM varies by year as indicated in note "e" of Exhibit 4-7. To calculate the MW position for each year relative to those reserve margins, subtract "Available UCAP" (Column 18) from the "Total UCAP Obligation" (Column 10).

WITNESS: John F Torpey

Kentucky Power Company

REQUEST

Refer to pages 129-131 of Kentucky Power's 2013 IRP, Section 4.3.4.5, Renewable Alternatives. Other than for solar, explain what consideration Kentucky Power gave to other forms of net metering (wind, biomass, biogas, or hydro).

RESPONSE

Kentucky Power did not specifically model other distributed options. These options are typically more expensive for distributed customers to install relative to their electricity generation. Under net metering, Kentucky Power credits the same amount for each kWh produced and is independent of the generating technology. The value within PJM is high for solar for each kWh produced because power is generated at times of peak pricing and relatively coincident with the PJM peak (a hot summer day). Thus, distributed solar is the distributed technology that has the greatest likelihood of being adopted by customers and typically has the most PJM value relative to net metering payments.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to page 131 of Kentucky Power's 2013 IRP, in Section 4.3.4.5, Renewable Alternatives, Sub-section a., Utility-Scale Solar. Kentucky Power projects distributed and utility scale solar proposals becoming economically justifiable. Define "economically justifiable" and discuss the drivers which would make this possible.

RESPONSE

"Economically justifiable" means that the present value of revenue requirements for solar projects is less than it is for a market (or other) alternative. Installed costs of solar and prevailing market costs within PJM are the main determinants. Kentucky Power expects PJM market costs to increase and installed costs of solar (both utility scale and distributed) to decline.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to page 134 of Kentucky Power's 2013 IRP, in Section 4.3.4.5, Renewable Alternatives, Sub-section b.1, Modeling Wind Resources. Explain the differences in the values noted in the references concerning wind power: "A variable source of power in most non-coastal locales, with capacity factors ranging from 30 percent (in the eastern portion of the U.S.) to 50 percent (largely in more westerly portions of the U.S. . . ." and the statement further along in that paragraph, "In the PJM region, wind is credited with 13% useful capacity. . . ."

RESPONSE

The PJM default value for "useful capacity" or "capacity value" refers to the output of wind resources as a percentage of nameplate capability at the time of PJM peak. The"capacity factor" refers to the percentage of total energy produced relative to the maximum possible annual generation.

The "13% useful capacity" is the first-year PJM Capacity Value for wind resources as established by PJM (Manual 21) for PJM planning purposes. The PJM Capacity Value only takes into consideration Peak Hours during the Summer Period. Once a Facility has operated for more than a year, the Facility's actual performance data is taken into consideration in determining the PJM Capacity Value.

Example: A 100 MW (nameplate) Wind Facility beginning operation on 1/1/2013. The first year PJM Capacity Value is calculated as follows:

PJM Capacity Value = 13% of the Wind Facility's nameplate capacity
PJM Capacity Value = 13% x 100 MW
PJM Capacity Value = 13 MW

PJM Definitions / References

- Peak Hours – those hours ending 3, 4, 5, and 6 PM Local Prevailing Time
- Summer Period – June 1 through August 31, inclusive.
- PJM Manual 21 is located at http://pjm.com/~/media/documents/manuals/m21.ashx

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to page 136 of Kentucky Power's 2012 IRP, in Section 4.3.4.5, Renewable Alternatives, Sub-section c., Hydro. Kentucky Power states that there was no consideration given to incremental hydroelectric power production resources due to environmental issues, permitting time length, and high initial construction costs. Explain why there are no analyses or explanations supporting this dismissal. Explain also why smaller-scale, more reasonably priced, less intrusive, run-of-the-river systems were not investigated or given any consideration.

RESPONSE

Current hydroelectric projects in the region which are not yet in service are projected to cost \$7,000 (Meldahl 105 MW)-\$9,625/kW (Cannelton 84 MW, Smithland 72 MW, Willow Island 35 MW).

Small-scale hydroelectric resources were not specifically modeled largely because of the limited availability of the resource and the lack of verifiable cost and performance data for these resources. These resources are eligible for net metering or co-generation tariffs and would be incorporated in future plans should they materialize.

WITNESS: John F Torpey

Kentucky Power Company

REQUEST

Refer to pages 136-137 of Kentucky Power's 2013 IRP, in Section 4.3.4.5, Renewable Alternatives, Sub-section e. Cogeneration. Kentucky Power notes the small amount of cogeneration or combined heat and power ("CHP") in its system. Explain why this source of electric power production has not been more aggressively pursued when there are chemical, primary metal, etc., industries in Kentucky Power's service territory, the types of customers which typically make use of CHP opportunities.

RESPONSE

Kentucky Power, previously as part of the AEP-East System and currently as a stand-alone company, enjoys a long capacity position. There has been no need to aggressively pursue CHP resources. Historically, the cost of energy from CHP has exceeded Kentucky Power's avoided cost.

WITNESS: John F Torpey

Kentucky Power Company

REQUEST

Refer to page 152 of Kentucky Power's 2013 IRP, in Section 4.6.3, Capacity Modeling Constraints, which describes limits agreed to by the AEP East Fleet under the Modified New Source Review Consent Decree. As Kentucky Power is no longer a member of the AEP-East Power Pool, describe the effects and demands that remain for Kentucky Power.

RESPONSE

The termination of the AEP-East Interconnection Agreement has no bearing on Kentucky Power's obligations under the Modified NSR Consent Decree. Kentucky Power must still meet the milestone dates contained therein.

WITNESS: John F Torpey

Kentucky Power Company

REQUEST

Refer to page 153 of Kentucky Power's 2013 IRP, in Section 4.6.3, Capacity Modeling Constraints, which discusses supply-side options and lists them per technology type. Explain how a gas-fired Big Sandy Unit 1 would be modeled and in which group it would reside.

RESPONSE

A gas-fired Big Sandy Unit 1 was modeled based on operating and cost characteristics developed by AEP Generation Engineering. The Big Sandy gas-fired Unit 1 would have performance characteristics of both "peaking" duty-cycle generating assets, as well as an "intermediate" (i.e., 'load-following', with regulation capability) duty cycle assets.

WITNESS: John F Torpey

Kentucky Power Company

REQUEST

Refer to page 159 of Kentucky Power's 2013 IRP, Section 4.7, Modeling Results. Kentucky Power states that, although it has sufficient capacity to satisfy the PJM summer capacity criterion reserve margin, the Plexos optimization model will continue to add resources that are economic based. Explain the impact on Kentucky Power's reserve margin and its importance/value in the decision to add the capacity.

Provide the discussion for both FRR and RPM scenarios.

RESPONSE

The addition of the economic based resources will increase Kentucky Power's reserve margin; however, as the resources being considered are intermittent in nature, the PJM capacity value is significantly less (compared to traditional fossil resources) than the resource nameplate value. For example, a 100 MW wind project will have an initial PJM capacity value of 13 MW. The impact these resources have on the reserve margin does not play a significant part in the decision to add the resource, rather these resources would be considered if the effect of adding them reduces customers' costs.

The addition of economic resources includes consideration of both the capacity and energy need and the value of the resources (with the energy determined through Plexos modeling). The MW capacity value of these resources is identical under either FRR or RPM scenarios. However, historically the installed reserve margin requirement that the load must carry has been greater under RPM, which can result in less opportunities for capacity sales and/or more exposure to certain capacity charges if Kentucky Power opted to go RPM.

WITNESS: John F Torpey

Kentucky Power Company

REQUEST

Refer to page 160 of Kentucky Power's 2013 IRP, Section 4.7, Modeling Results. Explain the statement that the addition of non-traditional resources would then serve as a hedge to reduce exposure to PJM energy markets.

RESPONSE

The non-traditional resources (wind, solar) are assumed to have either a contracted (e.g., fixed or fixed with escalation) cost, as with a PPA, or a small variable cost, as with utility-scale solar. The PJM energy market will be subject to price volatility due to a number of factors, such as experienced during this winter season. (Note: For example, PJM day-ahead energy pricing for the AEP Gen Hub cleared above $300/Mwh for selected hours on January 7, 23, 24, 27 & 28). Being that Kentucky Power will still rely on the energy markets, especially in the winter, having resources with low, or contracted variable costs will reduce the impact of market driven price spikes.

WITNESS: John F Torpey

Kentucky Power Company

REQUEST

Refer to page 161 of Kentucky Power's 2013 IRP, Section 4.7.1, Construction of the Preferred Portfolio. Kentucky Power states that its supply-side resources are relatively firm and the outcomes from five different economic scenarios modeled leave a rather muted picture. Explain in detail what is meant by the statement, "that result in itself, is valuable information in that it helps to solidify the path forward."

RESPONSE

The intent of that statement is to impart to the reader that the Preferred Portfolio does not produce any deleterious outcomes in any of the scenarios and can therefore be considered to be a fairly robust path forward.

WITNESS: John F Torpey

Kentucky Power Company

REQUEST

Refer to page 162 of Kentucky Power's 2013 IRP, Section 4.7.1, Construction of the Preferred Portfolio. Clarify the relationship between the winter-peaking nature of Kentucky Power and the cost-effectiveness of solar investment.

RESPONSE

Solar has been valued on the basis of energy prices during all of the months of the year. Its capacity value is based on its capacity at the time of PJM's (summer peak). Additional value that might accrue from the transmission and distribution system was discounted due to the winter peaking nature of the T&D systems. Figure 23 on pg. 163 shows this relationship.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to page 163 of Kentucky Power's 2013 IRP, Section 4.7.1, Construction of the Preferred Portfolio. Define and clarify "net metering economics."

RESPONSE

Net metering economics refers to the economics from the standpoint of a customer that receives the full retail rate credit under the Company's net metering tariff relative to the cost of installing the distributed generation.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to page 173 of Kentucky Power's 2013 IRP, Section 4.11, KPSC Staff Issues Addressed, Item 4, which refers to Sections 4.3.5.2 and 4.7.1 for the discussion regarding the specific identification and description of the net metering equipment and systems installed and a detailed discussion of the manner in which such resources were considered in its IRP. It does not appear that the specific identification and description of the net metering equipment and systems installed on the Kentucky Power system were provided in those sections. Provide the requested information.

RESPONSE

There are currently three net metering installations in the Kentucky Power service territory. All three are school accounts and all are solar photovoltaic (PV) installations. The information below provides additional information.

Name	City	Installed kW
Ashland Board of Education	Ashland	1.2
Leslie County Board of Education	Wooton	29.4
Magoffin County Board of Education	Salyersville	7.7

For the customer with the smaller 1.2kW installation, the net metering equipment measures power that is delivered to the customer. Since the two larger installations of 29.4kW and 7.7kW have the potential to push excess power to the grid, both of these installations have meters that measure both power delivered to, and power received from, the customer.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to Exhibit 4-6, page 3 of 3, at page 183 of Kentucky Power's 2013 IRP. Explain why there is a consistent difference in the projected average heat rates of the two Mitchell generating units throughout the forecast period.

RESPONSE

Heat rates are projected based on actual observed heat rates. In recent years, Mitchell 2 has had a lower heat rate than Mitchell 1, so this trend is assumed to continue.

WITNESS: John F Torpey