VERIFICATION

STATE OF OHIO	**)**	
	)	**SS:**
COUNTY OF HAMILTON	**)**	

The undersigned, Lisa D. Steinkuhl, Lead Rates Analyst, OH/KY Rate Recovery & Analysis, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of her knowledge, information and belief.

Lisa D. Steinkuhl

Lisa D. Steinkuhl, Affiant

Subscribed and sworn to before me by Lisa D. Steinkuhl on this 23RD day of September, 2014.

ADELE M. FRISCH
Notary Public, State of Ohio
My Commission Expires 01-05-2019

Adele M. Frisch

NOTARY PUBLIC

My Commission Expires: 1/5/2019

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, John D. Swez, Director of General Dispatch & Operations, Power Trading and Dispatch, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

John D. Swez, Affiant

Subscribed and sworn to before me by John D. Swez on this 19th day of September, 2014.

Jennifer C. B

NOTARY PUBLIC

My Commission Expires: Feb. 14, 2017

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STAFF-DR-02-001

REQUEST:

Refer to Duke Kentucky's response to Item 26 of the Commission's August 13, 2014 Request for Information ("August 13, 2014 Request").

a. Refer to the response to Item 26.a. The response states that "[t]he FAC for the periods January 2014 through April 2014 incorporated the day-ahead/real-time blended LMP pricing; therefore, the impact of the change has been reflected in the FAC filings." For comparison purposes, provide the same information for January 2014 through April 2014 that was provided for November 2012 through December 2013.

b. Refer to the response to Item 26.b.(3). The response states, "Native-load customers are not necessarily assigned higher fuel costs in these situations. During off-peak hours the cost of purchased power can be less than the cost of generation from Duke Energy Kentucky units."

   1. Confirm that the response indicates that native load customers are assigned higher fuel costs in situations in which Duke Kentucky purchases power to serve native load when generation is committed to non-native load and those purchase power costs are higher than the cost of generation.

   2. Explain why, when the situation described in subpart (1) above occurs, Duke Kentucky does not assign the lower fuel costs to native load customers. Include

in the response whether there is any sort of prohibition against assigning the lower fuel costs to native load customers in these situations.

3. For each month of the period November 2012 through April 2014, provide the difference in fuel costs that would have been recovered through the fuel adjustment clause ("FAC") had the lowest fuel cost always have been assigned to native load customers in the situation described in subpart (1) above.

RESPONSE:

a. See Staff-DR-02-001(a) Attachment for the updated schedule showing the effect of using the day-ahead/real-time blended LMP for pricing of Purchased Power for the period November 2012 through April 2014. The impact of the forced outage adjustment was inadvertently omitted in the original data response to Staff-DR-01-026(a). The impact of the change not included in the FAC filing for November 2012 through December 2013 was $426,763. The impact of the change included in the FAC filing for January 2014 through April 2014 was $2,813,928.

b.

1. Duke Energy Kentucky buys its forecasted load and offers to sell all of its available generation into PJM's day-ahead energy market. Together, PJM's day-ahead and real time markets ensure that Duke Energy Kentucky's customers receive the least cost generation available at the time, respectively, based upon firm financial commitments binding upon both the Company and PJM. Duke Energy Kentucky's modeling/ stacking process is designed to align with and

follow the financial commitments made in the PJM day-ahead and real-time energy markets and in accordance with PJM's tariffs.

To clarify the Company's previous response, as part of this stacking process, native customers always receive the lowest cost generation (first call) in the day-ahead market. Any of the Company's generation that is cleared in the market in excess of native load requirements is then committed to non-native sales. Native customers share in net revenues of these non-native sales through the profit sharing mechanism (Rider PSM).

Any of the Company's generation that clears the PJM day-ahead energy market that is in excess of day-ahead (native) load commitment is then assigned to and committed in the day-ahead market as non-native sales. These day-ahead native and non-native commitments then carry forward and are updated through the PJM real-time energy markets. Native customers continue to receive the least-cost generation that cleared and was assigned to them from the day-ahead market.

Similarly, the non-native customers continue to receive the generation that was cleared and assigned to them in the day-ahead market. Then, utilizing the actual real-time generation and load in PJM, everything is restacked to account for deviations from the day-ahead market while honoring those prior commitments. Duke Energy Kentucky native load in the real time energy market that is in excess of what was bid in the day-ahead market is then assigned the lowest cost generation that is available in the real-time market whether it is from purchased power or through Company generation that did not clear for non-native load in the day-ahead market, but was dispatched in the real-time energy market. Therefore, in the real-time market, native customers receive the least cost and available generation (either through purchased power, or through Duke Energy Kentucky-owned assets) that was not already financially committed in the day ahead market. Only 0.24% of generation between November 1, 2012 and April 30, 2014 was committed to non-native load in the day-ahead market.

2. Native load customers are given first call on all generation in the day-ahead market. Utilization of separate day-ahead and real-time stacks is consistent with the physical and financial nature of PJM's day-ahead and real-time markets. PJM's day-ahead market is financially binding. Therefore, generation allocated to a non-native sale in the day-ahead market is committed to support the same sale in the real-time market. Profits from any non-native sale are shared with customers via the PSM.

3. As stated above, native customers always receive the least cost generation in the day-ahead market. In the real time market, native customers also receive the least cost generation available at the time, honoring prior day-ahead commitments. Please see Confidential table below for a summary of the difference in fuel costs that would have been recovered through the fuel adjustment clause ("FAC") had the commitments in the financially binding day-ahead market not been modeled.

Nov-12	$0
Dec-12	$0
Jan-13	$0
Feb-13	($28)
Mar-13	$0
Apr-13	$236
May-13	$2,769
Jun-13	$697

Jul-13	$12,793
Aug-13	$0
Sep-13	$0
Oct-13	$819
Nov-13	$1,631
Dec-13	$0
Jan-14	$378,321
Feb-14	$25,546
Mar-14	$0
Apr-14	$0

PERSON RESPONSIBLE: Lisa Steinkuhl / John Swez

Duke Energy Kentucky

	Purchased Power				Forced Outage Adjustment (3)			
	MWhs Purchased Power (a)	Cost at DA/RT LMP Blend (New Method) (b)	Cost at RT LMP (Old Method) (c)	New Method less Old Method (b) - (c)=(d)	Cost at DA/RT LMP Blend (New Method) (e)	Cost at RT LMP (Old Method) (f)	New Method less Old Method (e)-(f)=(g)	**Total Impact (d)-(g)**
November-12	48,927	$ 1,862,778	$ 1,881,944	$ (19,167)	$ 564,127	$ 578,161	$ (14,034)	$ (5,133)
December-12	66,310	$ 2,072,678	$ 2,004,844	$ 67,835	$ 261,741	$ 213,824	$ 47,917	$ 19,918
January-13	62,653	$ 1,842,352	$ 1,871,033	$ (28,681)	$ 298,561	$ 311,179	$ (12,618)	$ (16,063)
February-13	78,497	$ 2,529,411	$ 2,475,513	$ 53,898	$ 348,628	$ 294,817	$ 53,811	$ 87
March-13	36,428	$ 1,490,716	$ 1,381,109	$ 109,608	$ 434,506	$ 335,489	$ 99,017	$ 10,590
April-13	161,692	$ 6,232,276	$ 6,069,285	$ 162,990	$ 258,196	$ 317,573	$ (59,377)	$ 222,367
May-13	39,474	$ 1,726,958	$ 1,717,059	$ 9,899	$ 426,675	$ 377,218	$ 49,457	$ (39,558)
June-13	112,318	$ 4,093,946	$ 4,023,905	$ 70,040	$ 598,753	$ 597,681	$ 1,072	$ 68,968
July-13	141,360	$ 6,074,857	$ 6,016,477	$ 58,380	$ 552,621	$ 516,810	$ 35,811	$ 22,569
August-13	84,534	$ 3,050,264	$ 2,927,144	$ 123,120	$ 201,618	$ 137,545	$ 64,073	$ 59,047
September-13	39,545	$ 1,659,182	$ 1,585,380	$ 73,802	$ 133,100	$ 75,458	$ 57,642	$ 16,160
October-13	12,121	$ 469,151	$ 452,876	$ 16,275	$ 147,998	$ 136,571	$ 11,428	$ 4,848
November-13	45,583	$ 1,576,002	$ 1,489,374	$ 86,628	$ 464,879	$ 379,855	$ 85,024	$ 1,603
December-13	98,816	$ 3,515,574	$ 3,238,365	$ 277,209	$ 745,537	$ 529,687	$ 215,850	$ 61,359
	Increase in Purchased Power Costs			$ 1,061,837	Increase in Forced Outage Adjustment		$ 635,074	$ 426,763 (1)
January-14	97,773	$ 13,292,404	$ 11,090,003	$ 2,202,400	$ 6,174,444	$ 5,826,178	$ 348,265	$ 1,854,135
February-14	68,313	$ 5,078,063	$ 4,331,966	$ 746,098	$ 2,035,106	$ 1,532,212	$ 502,894	$ 243,204
March-14	231,640	$ 12,709,481	$ 12,662,494	$ 46,987	$ 2,143,959	$ 2,304,699	$ (160,740)	$ 207,727
April-14	191,828	$ 8,000,068	$ 7,491,211	$ 508,856	$ 11	$ 16	$ (5)	$ 508,862
	Increase in Purchased Power Costs			$ 3,504,342	Increase in Forced Outage Adjustment		$ 690,414	$ 2,813,928 (2)

(1) The increase in costs was not included in the FAC filings for this time frame.

(2) The increase in costs was included in the FAC filings for this time frame.

(3) The forced outage adjustment is difference between the cost of replacement power and the prior month average fuel cost of the unit on a forced outage.

REQUEST:

Refer to Duke Kentucky's response to Items 27 and 28 of the August 13, 2014 Request.

a. State whether Duke Kentucky is familiar with the Commission's May 2, 2002 Order in Case No. 2000-00495-B[1] and May 2, 2002 Order in Case No. 2000-00496-B[2] which state on page 4 of each Order:

> We view "economy energy purchases" that are recoverable through an electric utility's FAC as purchases that an electric utility makes to serve native load, that displaces its higher cost of generation, and that have an energy cost less than the avoided variable generation cost of the utility's highest cost generating unit available to serve native load during that FAC expense month.

b. State whether Duke Kentucky considers power purchases made during a planned outage to be "economy purchases." If so, explain how the purchases meet the definition of "economy purchases." If not, confirm that Duke Kentucky would agree that the purchases would be defined as "non-economy purchases."

c. State whether Duke Kentucky considers power purchases made when it is not experiencing an outage but must purchase power to meet load to be "economy purchases." If so, explain how the purchases meet the definition of "economy

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[1] Case No. 2000-00495-B, An Examination by the Public Service Commission of the Fuel Adjustment Clause of American Electric Power Company from May 1, 2001 to October 31, 2001 (Ky. PSC May 2, 2002).

[2] Case No. 2000-00496-B, An Examination by the Public Service Commission of the Fuel Adjustment Clause of East Kentucky Power Cooperative, Inc. from May 1, 2001 to October 31, 2001 (Ky. PSC May 2, 2002).

purchases". If not, confirm that Duke Kentucky would agree that the purchases would be defined as "non-economy purchases".

d. State whether Duke Kentucky is familiar with page 5 of those same Orders which state:

> We interpret Administrative Regulation 807 KAR 5:056 as permitting an electric utility to recover through its FAC only the lower of the actual energy costs of the non-economy purchased energy or the fuel cost of its highest cost generating unit available to be dispatched to serve native load during the reporting expense month. Costs for non-economy energy purchases that are not recoverable through an electric utility's FAC are considered "non-FAC expenses" and, if reasonably incurred, are otherwise eligible for recovery through base rates.

e. Given the language in those Orders, explain why Duke Kentucky believes the entire cost of power purchases made during a planned outage and the entire cost of power purchases made when it is not experiencing an outage but are made to meet load are includable for recovery through the FAC.

f. For each month from November 2012 through April 2014, provide the dollar amount that was included in the calculation of the FAC for the power purchases that were made during a planned outage, as well as the dollar amount of power purchases that would have been included in the calculation of the FAC if recovery of those purchases through the FAC had been limited to the cost of Duke Kentucky's highest-cost generating unit available.

g. For each month from November 2012 through April 2014, provide the dollar amount that was included in the calculation of the FAC for the power purchases that were made in order to meet demand when all available Duke Kentucky generation was operating, as well as the dollar amount of power purchases that would have been included in the calculation of the FAC if recovery of those purchases through the FAC had been limited to the cost of Duke Kentucky's highest-cost generating unit available.

RESPONSE:

a) Duke Energy Kentucky is familiar with this order which was issued in the infant stages of of RTO participation in Kentucky, and the subsequent decoupling of capacity from other energy-related products in a RTO such as PJM.

b) Yes. Purchased power during any outage, scheduled or forced, is economic if (1) it is cheaper than the generation available from Duke Energy Kentucky's own resources and obtained outside of PJM's Day-Ahead or Real-Time markets or (2) it is purchased in the PJM Day-Ahead and Real-Time markets under security constrained economic dispatch and commitment. 807 KAR 5:056 Section 1 then limits the recovery of energy purchased during times of forced outages. Energy purchases from PJM for scheduled outages (or any reason) are economic by definition because, by operation of both the Day-Ahead and Real-Time Energy markets, such purchases replace a higher cost unit that was not dispatched. The purchases made at that time are necessarily economic pursuant to FERC-approved tariffs governing PJM's energy markets.

As a member of PJM, Duke Energy Kentucky's generation, along with all generation participating in PJM's Day-Ahead and Real-Time energy markets, is economically dispatched and the Company's customers thereby have access to all generation resources in PJM to meet their needs. This is done pursuant to FERC-approved tariffs whereby Duke Energy Kentucky offers all available generation to PJM and purchases its expected or actual customer load from the PJM Day-Ahead or Real-Time energy markets, respectively. PJM performs a security constrained economic commitment and security constrained economic dispatch process for all generation in its footprint, including the Company's generation, in determining which assets to commit and dispatch.

The purchases in the Day-Ahead and Real-Time energy markets are, by the efficient nature of PJM's dispatch methodology, the most economic purchase available to meet customer load and are economic by definition. Likewise, when the Company's generation is dispatched in PJM's energy markets, it is because its generation *is more economic* than other higher priced generation. Conversely, if the Company's available generation is not dispatched, it is because it is not the most economic available generation. Therefore, the Company maintains that all purchase power made to serve native load is, by virtue, economic regardless of whether it is necessary because a Company-owned asset is unavailable due to a scheduled outage, or if PJM did not dispatch a Company owned asset because cheaper generation was available for dispatch in the market.

Through the after-the-fact dispatch modeling process, the Company calculates the amount of generation and economy energy that is attributable to native versus non-native load and all energy purchased from PJM is done on an economic basis. Limiting the definition of economic purchases to Company-owned generation (beyond forced outages) does not make sense in an RTO because a utility's highest cost generating unit available to serve native load, due to the PJM system-wide dispatch and commitment of the PJM market could be virtually any unit in PJM. Thus, it is impossible to determine which of the Company's units at any given hour would have been the highest cost in PJM as any available unit not dispatched by PJM will always be a greater cost than the price of energy purchased. Finally, if only Duke Energy Kentucky generating units are used to determine the utility's highest cost available generating unit, multiple assumptions would have to be made, including but not limited to, that there was Company-owned generation available to meet load, whether a unit was off-line or merely limited by its ramp rate, allocation of a unit's start-up cost due to start-up time, minimum run time requirements, and other commitment parameters, thereby ignoring the Company's participation in an RTO.

c) Please see response to b) above.

d) Duke Energy Kentucky is familiar with the Commission's interpretation of 807 KAR 5:056.

e) See response to part b above. The guidance provided by the Commission indicates that the cost of purchased power is limited to the fuel cost of the utility's highest cost of generation available to be dispatched. PJM is performing a combined system-wide generating unit commitment and dispatch process such that when these purchases are made, they displace a higher cost of generation, which could include the Company's own generation when it is not also dispatched by PJM. The displaced higher cost of generation could be virtually any generating unit in the PJM market; including the Company's and consequently, all MWhs purchased either for planned outages or when not experiencing a planned outage but are made to meet load, should be eligible for recovery and not be limited by that provision.

f) Please see responses to b) and e) above. Purchased power for this period, by month, is shown in the table below.

	Total Purchased Power (a)=(b)+(c)+(d)	Purchased Power for Scheduled Outages (b)	Purchased Power for Forced Outages[(1)] (c)	Purchase Power (d)
November-12	$1,881,944	$0	$1,762,490	$119,454
December-12	$2,004,844	$75,062	$1,727,026	$202,755
January-13	$1,871,033	$418,704	$1,072,541	$379,788
February-13	$2,475,513	$0	$2,205,341	$270,172
March-13	$1,381,109	$0	$1,232,357	$148,752
April-13	$6,069,285	$4,763,663	$1,166,622	$139,001
May-13	$1,717,059	$0	$1,256,009	$461,050
June-13	$4,023,905	$570,555	$2,200,735	$1,252,615
July-13	$6,016,477	$1,732,276	$1,807,822	$2,476,379
August-13	$2,927,144	$103,561	$1,072,016	$1,751,566
September-13	$1,585,380	$0	$611,205	$974,175
October-13	$452,876	$0	$351,654	$101,222
November-13	$1,489,374	$0	$1,437,999	$51,374
December-13	$3,238,365	$0	$2,702,014	$536,351
January-14	$13,292,404	$0	$7,547,712	$5,744,691
February-14	$5,078,063	$0	$3,358,607	$1,719,457
March-14	$12,709,481	$9,597,837	$3,080,222	$31,421
April-14	$8,000,068	$8,000,046	$22	$0

(1) For recovery in the FAC filing, purchase power for forced outages is limited by the prior month average fuel cost of the unit experiencing a forced outage as required by 807 KAR 5:056 Section 1(4).

A utility's highest cost generating unit available to serve native load, due to the PJM system-wide dispatch and commitment of the PJM market, could be virtually any unit in PJM. Thus it is impossible to determine which of the Company's units, at any given hour, would have been the highest cost in PJM as any available unit that was not dispatched by PJM will always be a greater cost than the price of energy purchased. Such is the nature and operation of the PJM markets.

Finally, if only Duke Energy Kentucky generating units are used to determine the utility's highest cost available generating unit at any given hour, multiple assumptions would have to be made, including but not limited to, that there was Company-owned generation available to meet load, whether a unit was not dispatched by PJM because it was off-line or limited by its ramp rate, must also factor in allocation of a unit's start-up cost due to start-up time, minimum run time requirements, and other commitment parameters. Such a calculation is not reconcilable with the operation and participation in PJM.

g) Please see column d to response to f) above for the dollar amount that was included in the calculation of the FAC for the power purchases that were made in order to meet demand when all available Duke Kentucky generation was operating.

A utility's highest cost generating unit available to serve native load, due to the PJM system-wide dispatch and commitment of the PJM market, could be virtually any unit in PJM. Thus it is impossible to determine which of the Company's units, at any given hour, would have been the highest cost in PJM as any available unit that was not dispatched by PJM will always be a greater cost than the price of energy purchased. Such is the nature and operation of the PJM markets.

Finally, if only Duke Energy Kentucky generating units are used to determine the utility's highest cost available generating unit at any given hour, multiple assumptions would have to be made, including but not limited to, that there was Company-owned generation available to meet load, whether a unit was not dispatched by PJM because it was off-line or limited by its ramp rate, must also factor in allocation of a unit's start-up cost due to start-up time, minimum run time requirements, and other commitment parameters. Such a calculation is not reconcilable with the operation and participation in PJM.

PERSON RESPONSIBLE: John Swez / Lisa Steinkuhl

REQUEST:

Refer to Duke Kentucky's response to Item 32.b. of the August 13, 2014 Request. The response states that "[t]he portion of the aerial survey adjustment allocated to native is included in the calculation of the FAC rate."

a. State whether the portion allocated to non-native is included in the calculation of the FAC on Schedule 2, Section C. If not, explain why it is not included.

b. Provide the tonnage and dollar amounts of the most recent adjustment and allocation between native and non-native, the date the adjustment was made, and the location of this information in the FAC supplemental files filed monthly by Duke Kentucky.

RESPONSE:

a. Yes, the non-native portion of the aerial survey adjustment is included in the calculation of the FAC on Schedule 2, Section C. In the calculation of the FAC on Schedule 2, 100% of the aerial adjustment is included in Section A, then the non-native portion is included in Section C of Schedule 2 as a reduction to total expenses. Therefore, only the native portion is recovered in the FAC rate.

b. See table below for the tonnage and dollar amounts of the most recent adjustment and allocation between native and non-native. The adjustment was made in the December 2013 expense month when it was recorded on the financial statements of Duke Energy

Kentucky. The adjustment was included on the December 2013 FAC supplemental files in the fuel burned line of the Coal Inventory Schedule.

2013 Coal Inventory Aerial Survey Adjustment

	Aerial Survey Tonnage Adj	Aerial Survey $ Adj	Consumption Ownership	Duke Energy Kentucky's portion of the Aerial Adjustment	Native	Non-Native
East Bend	(19,026.04)	($987,261.22)	68.71%	($678,347.18)	($618,629.20)	($59,717.98)
Miami Fort 6	5,057.00	$288,600.43	100.00%	$288,600.43	$279,802.78	$8,797.65
Decrease in Inventory Account				($389,746.76)	($338,826.43)	($50,920.33)

PERSON RESPONSIBLE: Lisa Steinkuhl