KyPSC Case No. 2024-00354
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VERIFICATION

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

The undersigned, Sarah Lawler, VP Rates & Regulatory Strategy, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing post-hearing data requests, and that the answers contained therein are true and correct to the best of her knowledge, information and belief.

Sarah Lawler Affiant

Subscribed and sworn to before me by Sarah Lawler on this 10th day of June, 2025.

NOTARY PUBLIC

My Commission Expires: July 8, 2027

NOTARY PUBLIC STATE OF OHIO

EMILIE SUNDERMAN
Notary Public
State of Ohio
My Comm. Expires
July 8, 2027

VERIFICATION

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

The undersigned, Lisa D. Steinkuhl, Director Rates & Regulatory Planning, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing post-hearing 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 30th day of May, 2025.

Emilie Sunderman
NOTARY PUBLIC

My Commission Expires: July 8, 2027

NOTARY PUBLIC STATE OF OHIO
EMILIE SUNDERMAN
Notary Public
State of Ohio
My Comm. Expires
July 8, 2027

VERIFICATION

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

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

John Swez Affiant

Subscribed and sworn to before me by John Swez on this 3rd day of June, 2025.

NOTARY PUBLIC

My Commission Expires:

SHAMELL M WILSON
My Comm. Expires
NOTARY PUBLIC
July 06, 2026
MECKLENBURG COUNTY, NC

VERIFICATION

STATE OF SOUTH CAROLINA	)	
	)	SS:
COUNTY OF CHARLESTON	)	

The undersigned, Jacob Colley, Director Customer Reg. Planning, Support & Compliance, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing post-hearing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Jacob Colley, Affiant

Subscribed and sworn to before me by Jacob Colley on this 11 day of June 2025.

NOTARY PUBLIC

Janice Ladd
Notary Public
South Carolina
Comm. Expires April 30, 2031

My Commission Expires: 4/30/2031

VERIFICATION

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

The undersigned, John R. Panizza, Director, Tax Operations, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing post-hearing data requests and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

John R. Panizza

John R. Panizza Affiant

Subscribed and sworn to before me by John R. Panizza on this 5th day of June, 2025.

Teresa Ray

NOTARY PUBLIC

TERESA RAY
NOTARY PUBLIC
My Commission Expires 01-21-29
UNION COUNTY, NC

My Commission Expires: 01/21/29

STAFF-PHDR-01-001

REQUEST:

Refer to the Rebuttal Testimony of Sarah Lawler, page 11, lines 10-12. Provide the workpapers for this calculation in Excel format with all formulas intact and cells unlocked.

RESPONSE:

Please see STAFF-PHDR-01-001 Attachment for the calculation in Excel format with all formulas intact and cells unlocked.

The calculation of the decreased depreciation expense associated with the decommissioning costs for solar assets of $0.158 million is calculated on page 6 of 6 line 23 (excel row 311) on the first tab of the excel worksheet. The depreciation rate for the solar assets on the filed Sch B-3.2 on page 2 of 6 was changed to the solar depreciation rates without terminal net salvage supplied in AG-DR-02-060 and compared to the total depreciation expense filed in the Application. The impact of accumulated depreciation net of ADIT associated with the decommissioning costs for solar assets is calculated on page 6 of 6 lines 25 through 27 on the first tab of the excel worksheet. The calculated amount is $0.039 million. The amount included in the Rebuttal Testimony of Sarah Lawler of $0.011 million had a clerical error in the calculation (the tax rate was transposed). Therefore, the revenue reduction associated with removal of decommissioning costs of the solar assets using the as filed Gross Revenue Conversion Factor is $0.156 million as shown on page 6 of 6 line 30 (excel row 325) on the first tab of the excel worksheet.

PERSON RESPONSIBLE: Sarah E. Lawler

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2024-00354
DEPRECIATION AND AMORTIZATION ACCRUAL RATES AND
JURISDICTIONAL ACCUMULATED BALANCES BY ACCOUNTS,
FUNCTIONAL CLASS OR MAJOR PROPERTY GROUP
THIRTEEN MONTH AVERAGE AS OF JUNE 30, 2026

STEAM PRODUCTION PLANT

DATA: BASE PERIOD "X" FORECASTED PERIOD
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NOS.: SCHEDULE B-2.1, SCHEDULE B-3

SCHEDULE B-3.2
PAGE 1 OF 6
WITNESS RESPONSIBLE:
G. S. CARPENTER / S. S. MITCHELL

Line No. (A)	FERC Acct. No. (B-1)	Company Acct. No. (B-2)	Account Title or Major Property Grouping (C)	Adjusted Jurisdiction 13-Month Average Plant Investment (1) (D)	Adjusted Jurisdiction 13-Month Average Accumulated Balance (E)	Proposed Accrual Rate (F)	Calculated Depr/Amort Expense (G=DxF)	% Net Salvage (H)	Average Service Life (I)	Curve Form (J)
				$	$		$			
1	310	3100	Land and Land Rights	7,270,233	105,677	0.00%	0	Perpetual Life		
2	311	3110	Structures & Improvements	130,360,214	62,866,643	5.41%	7,052,488	-10.00%	65	S1
3	312	3120	Boiler Plant Equipment	580,229,539	334,171,765	3.87%	22,454,883	-10.00%	50	S0
4	312	3123	Boiler Plant Equip - SCR Catalyst	8,054,003	6,967,253	4.18%	336,657	0.00%	15	R3
5	314	3140	Turbogenerator Equipment	122,525,657	50,650,221	5.24%	6,420,344	-10.00%	35	S0.5
6	315	3150	Accessory Electric Equipment	49,741,207	32,120,886	3.17%	1,576,796	-10.00%	60	R2
7	316	3160	Miscellaneous Powerplant Equipment	25,942,235	14,087,996	4.21%	1,092,168	-10.00%	55	S0
8	317	3170	AROs	0	0	Various		Depr charged to reg asset account		
9			Case 2015-120 Acq of DPL Share of East Bend	7,695,137	0	-	591,934	Amort. adjusted for 2038 retirement date		
10			Completed Construction Not Classified	0	0	4.32%	0			
11		108	Retirement Work in Progress	0	(29,021,875)		0			
12			Total Steam Production Plant	931,818,225	471,948,566		39,525,270			

(1) Plant Investment includes Completed Construction Not Classified (Account 106).

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2024-00354
DEPRECIATION AND AMORTIZATION ACCRUAL RATES AND
JURISDICTIONAL ACCUMULATED BALANCES BY ACCOUNTS,
FUNCTIONAL CLASS OR MAJOR PROPERTY GROUP
THIRTEEN MONTH AVERAGE AS OF JUNE 30, 2026

OTHER PRODUCTION PLANT

DATA: BASE PERIOD "X" FORECASTED PERIOD
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NOS.: SCHEDULE B-2.1, SCHEDULE B-3

SCHEDULE B-3.2
PAGE 2 OF 6
WITNESS RESPONSIBLE:
G. S. CARPENTER / S. S. MITCHELL

Line No. (A)	FERC Acct. No. (B-1)	Company Acct. No. (B-2)	Account Title or Major Property Grouping (C)	Adjusted Jurisdiction 13-Month Average Plant Investment (1) (D)	Adjusted Jurisdiction 13-Month Average Accumulated Balance (E)	Proposed Accrual Rate (F)	Calculated Depr/Amort Expense (G=DxF)	% Net Salvage (H)	Average Service Life (I)	Curve Form (J)
				$	$		$			
1	340	3400	Land and Land Rights	2,409,908	5,123	0.00%	0	Perpetual Life		
2	340	3401	Rights of Way	0	0	0.00%	0	0.00%	0	0
3	341	3410	Structures & Improvements	39,105,237	30,603,674	1.74%	680,431	-8.00%	60	R4
4	342	3420	Fuel Holders, Producers, Accessories	65,797,312	15,797,254	5.93%	3,901,781	-8.00%	40	S1.5
5	343	3430	Prime Movers	9,412,658	(2,760,370)	6.67%	627,824	-8.00%	25	S1
6	344	3440	Generators	230,946,272	159,949,585	2.76%	6,374,117	-8.00%	38	S0.5
7	344	3446	Solar Generators	16,116,637	4,094,745	4.37%	704,297	Various	25	S2.5
8	345	3450	Accessory Electric Equipment	21,311,175	14,919,616	2.67%	569,008	-8.00%	45	S1
9	345	3456	Solar Accessory Electric Equipment	3,676,452	695,640	3.93%	144,485	Various	30	S2.5
10	346	3460	Miscellaneous Plant Equipment	5,919,120	3,947,050	2.80%	165,735	-8.00%	45	R1.5
11	347	3476	ARO - Solar - Other Production	0	0	Various		Depr charged to reg asset account		
12			Completed Construction Not Classified	0	0	3.41%	0			
13		108	Retirement Work in Progress	0	(125,215)					
14			Total Other Production Plant	394,694,771	227,127,102		13,167,678			

(1) Plant Investment includes Completed Construction Not Classified (Account 106).

Per Sch-B-3.2 - Prop from Depr Study for Composite Average

3446	CRITTENDEN	4,472,284.81	5.23	23,390,050
	WALTON	6,005,765.45	5.29	31,770,499
	AERO	808,767.37	4.76	3,849,733
		11,286,817.63	5.23	59,010,281
3456	CRITTENDEN	687,705.87	4.80	3,300,988
	WALTON	1,037,180.86	4.85	5,030,327
	AERO	3,827,389.27	4.30	16,457,774
		5,552,276.00	4.46	24,789,089

See Response to AG 2-060

From Depr Study for Composite Average - With No Terminal Net Salvage

3446	CRITTENDEN	4,472,284.81	4.38	19,588,607
	WALTON	6,005,765.45	4.38	26,305,253
	AERO	808,767.37	4.29	3,469,612
		11,286,817.63	4.37	49,363,472
3456	CRITTENDEN	687,705.87	4.05	2,785,209
	WALTON	1,037,180.86	4.05	4,200,582
	AERO	3,827,389.27	3.88	14,850,270
		5,552,276.00	3.93	21,836,062

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2024-00354
DEPRECIATION AND AMORTIZATION ACCRUAL RATES AND
JURISDICTIONAL ACCUMULATED BALANCES BY ACCOUNTS,
FUNCTIONAL CLASS OR MAJOR PROPERTY GROUP
THIRTEEN MONTH AVERAGE AS OF JUNE 30, 2026

TRANSMISSION PLANT

DATA: BASE PERIOD "X" FORECASTED PERIOD
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NOS.: SCHEDULE B-2.1, SCHEDULE B-3

SCHEDULE B-3.2
PAGE 3 OF 6
WITNESS RESPONSIBLE:
G. S. CARPENTER / S. S. MITCHELL

Line No. (A)	FERC Acct. No. (B-1)	Company Acct. No. (B-2)	Account Title or Major Property Grouping (C)	Adjusted Jurisdiction 13-Month Average Plant Investment (1) (D)	Adjusted Jurisdiction 13-Month Average Accumulated Balance (E)	Proposed Accrual Rate (F)	Calculated Depr/Amort Expense (G=DxF)	% Net Salvage (H)	Average Service Life (I)	Curve Form (J)
				$	$		$			
1	350	3500	Land	357,042	324	0.00%	0	Perpetual Life		
2	350	3501	Rights of Way	10,654,574	1,025,454	1.30%	138,509	0.00%	75	R4
3	352	3520	Structures & Improvements	6,986,560	870,892	1.76%	122,963	-15.00%	70	R2.5
4	353	3530	Station Equipment	37,723,393	4,770,018	2.23%	841,232	-10.00%	50	R1
5	353	3531	Station Equipment - Step Up	10,844,053	5,583,415	2.50%	271,101	-10.00%	50	R3
6	353	3532	Station Equipment - Major	13,244,554	3,097,491	1.78%	235,753	-10.00%	60	R2.5
7	353	3534	Station Equipment - Step Up Equipment	8,872,106	3,064,316	2.72%	241,321	-10.00%	40	R2.5
8	355	3550	Poles & Fixtures	46,250,360	(4,105,066)	2.45%	1,133,134	-30.00%	55	R1
9	356	3560	Overhead Conductors & Devices	22,467,590	3,024,749	2.23%	501,027	-25.00%	55	R1
10	356	3561	Overhead Conductors - Clear R/W	3,303,607	254,768	1.53%	50,545	0.00%	65	R3
11			Completed Construction Not Classified	0	0	2.21%	0			
12		108	Retirement Work in Progress	0	(4,842,092)		0			
13			Total Transmission Plant	160,703,839	12,744,269		3,535,585			

(1) Plant Investment includes Completed Construction Not Classified (Account 106).

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2024-00354
DEPRECIATION AND AMORTIZATION ACCRUAL RATES AND
JURISDICTIONAL ACCUMULATED BALANCES BY ACCOUNTS,
FUNCTIONAL CLASS OR MAJOR PROPERTY GROUP
THIRTEEN MONTH AVERAGE AS OF JUNE 30, 2026

DISTRIBUTION PLANT

DATA: BASE PERIOD "X" FORECASTED PERIOD
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NOS.: SCHEDULE B-2.1, SCHEDULE B-3

SCHEDULE B-3.2
PAGE 4 OF 6
WITNESS RESPONSIBLE:
G. S. CARPENTER / S. S. MITCHELL

Line No. (A)	FERC Acct. No. (B-1)	Company Acct. No. (B-2)	Account Title or Major Property Grouping (C)	Adjusted Jurisdiction 13-Month Average: Plant Investment (1) (D)	Adjusted Jurisdiction 13-Month Average: Accumulated Balance (E)	Proposed Accrual Rate (F)	Calculated Depr/Amort Expense (G=DxF)	% Net Salvage (H)	Average Service Life (I)	Curve Form (J)
				$	$		$			
1	360	3600	Land and Land Rights	18,539,153	35,448	0.00%	0	Perpetual Life		
2	360	3601	Rights of Way	6,075,504	3,366,108	0.71%	43,136	0.00%	75	R4
3	361	3610	Structures & Improvements	3,462,289	105,148	1.72%	59,551	-15.00%	70	R2.5
4	362	3620	Station Equipment	104,578,229	20,947,546	3.51%	3,670,696	-10.00%	32	R0.5
5	362	3622	Station Equipment - Major	54,712,564	12,381,127	1.77%	968,412	-10.00%	60	R2.5
6	363	3630	Storage Battery Equipment	0	0		0	0.00%		
7	364	3640	Poles, Towers & Fixtures	89,912,849	30,115,243	2.46%	2,211,856	-50.00%	55	R0.5
8	365	3650	Overhead Conductors & Devices	173,850,609	36,966,481	2.57%	4,467,961	-40.00%	53	O1
9	365	3651	Overhead Conductors - Clear R/W	9,830,247	1,049,899	1.50%	147,454	0.00%	65	R3
10	366	3660	Underground Conduit	56,165,678	11,686,738	1.60%	898,651	-25.00%	75	R3
11	367	3670	Underground Conductors & Devices	114,333,811	27,493,586	2.51%	2,869,779	-35.00%	56	R2
12	368	3680	Line Transformers	98,810,327	28,786,456	2.08%	2,055,255	-15.00%	48	R0.5
13	368	3682	Customers Transformer Installation	309,394	280,782	0.56%	1,733	-15.00%	55	R1.5
14	369	3691	Services - Underground	3,219,840	989,964	2.03%	65,363	-40.00%	65	R3
15	369	3692	Services - Overhead	20,305,135	11,210,754	1.66%	337,065	-40.00%	60	R1
16	370	3700	Meters	4,263,919	1,595,703	3.61%	153,927	-2.00%	24	L1
17	370	3702	AMI Meters	32,132,669	12,610,555	6.10%	1,960,093	0.00%	15	S2.5
18	371	3711, 3712	Company Owned Outdoor Lighting	1,914,967	329,217	13.65%	261,393	Various	Various	Various
19	372	3720	Leased Property on Customers	10,907	9,668	N/A (2)	N/A	0.00%	30	L3
20	373	3731	Street Lighting - Overhead	2,832,017	2,299,101	1.06%	30,019	-15.00%	34	L0.5
21	373	3732	Street Lighting - Boulevard	3,879,619	2,823,180	1.01%	39,184	-20.00%	55	R1.5
22	373	3733	Street Lighting - Cust, Private Outdoor Lighting	0	0	4.78%	0	-10.00%	25	L0
23	373	3734	Light Choice OLE	0	0	4.78%	0	-10.00%	25	L0
24			Completed Construction Not Classified	0	0	2.61%	0			
25		108	Retirement Work in Progress	0	(25,130,677)		0			
26			Total Distribution Plant	799,139,727	179,952,027		20,241,528			

(1) Plant Investment includes Completed Construction Not Classified (Account 106).
(2) This account is fully depreciated.

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2024-00354
DEPRECIATION AND AMORTIZATION ACCRUAL RATES AND
JURISDICTIONAL ACCUMULATED BALANCES BY ACCOUNTS,
FUNCTIONAL CLASS OR MAJOR PROPERTY GROUP
THIRTEEN MONTH AVERAGE AS OF JUNE 30, 2026

GENERAL PLANT

DATA: BASE PERIOD "X" FORECASTED PERIOD
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NOS.: SCHEDULE B-2.1, SCHEDULE B-3

SCHEDULE B-3.2
PAGE 5 OF 6
WITNESS RESPONSIBLE:
G. S. CARPENTER / S. S. MITCHELL

Line No. (A)	FERC Acct. No. (B-1)	Company Acct. No. (B-2)	Account Title or Major Property Grouping (C)	Adjusted Jurisdiction 13-Month Average Plant Investment (1) (D)	Adjusted Jurisdiction 13-Month Average Accumulated Balance (E)	Proposed Accrual Rate (F)		Calculated Depr/Amort Expense (G=DxF)	% Net Salvage (H)	Average Service Life (I)	Curve Form (J)
				$	$			$			
1	303	3030	Miscellaneous Intangible Plant	57,142,504	23,532,655	Various		5,181,547	Various		
2	390	3900	Structures & Improvements	260,891	79,947	2.98%		7,775	-10.00%	40	S1
3	391	3910	Office Furniture & Equipment	585,107	69,298	5.00%		29,255	0.00%	20	SQ
4	391	3910-URR	Office Furniture & Equipment		0	NA	(2)	(1,744)	N/A	N/A	N/A
5	391	3911	Electronic Data Proc Equip	7,548,018	2,841,630	20.00%		1,509,604	0.00%	5	SQ
6	391	3911-URR	Electronic Data Proc Equip		0	NA	(2)	(16,380)	N/A	N/A	N/A
7	392	3920	Transportation Equipment	1,453,958	591,035	6.11%		Transp Expense	0.00%	12	S3
8	392	3921	Trailers	427,975	230,282	1.37%		Transp Expense	5.00%	20	R2.5
9	394	3940	Tools, Shop & Garage Equipment	6,449,067	1,673,008	4.00%		257,963	0.00%	25	SQ
10	394	3940-URR	Tools, Shop & Garage Equipment		0	NA	(2)	8,000	N/A	N/A	N/A
11	396	3960	Power Operated Equipment	18,515	10,883	2.59%		Transp Expense	0.00%	15	L2
12	397	3970	Communication Equipment	33,800,485	7,666,922	6.67%		2,254,492	0.00%	15	SQ
13	397-URR	3970	Communication Equipment		0	NA	(2)	(5,942)	N/A	N/A	N/A
14			Completed Construction Not Classified	0	0	8.71%		0			
15		108	Retirement Work in Progress	0	11,104						
16			Total General Plant	107,686,520	36,706,764			9,224,570			
17			Total Electric Plant	2,394,043,082	928,478,728			85,694,631			

(1) Plant Investment includes Completed Construction Not Classified (Account 106).
(2) 5 year life for Unrecovered Reserve for Amortization

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2024-00354
DEPRECIATION AND AMORTIZATION ACCRUAL RATES AND
JURISDICTIONAL ACCUMULATED BALANCES BY ACCOUNTS,
FUNCTIONAL CLASS OR MAJOR PROPERTY GROUP
THIRTEEN MONTH AVERAGE AS OF JUNE 30, 2026

COMMON PLANT

DATA: BASE PERIOD "X" FORECASTED PERIOD
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NOS.: SCHEDULE B-2.1, SCHEDULE B-3

SCHEDULE B-3.2
PAGE 6 OF 6
WITNESS RESPONSIBLE:
G. S. CARPENTER / S. S. MITCHELL

Line No. (A)	FERC Acct. No. (B-1)	Company Acct. No. (B-2)	Account Title or Major Property Grouping (C)	Adjusted Jurisdiction 13-Month Average: Plant Investment (1) (D)	Adjusted Jurisdiction 13-Month Average: Accumulated Balance (E)	Proposed Accrual Rate (F)		Calculated Depr/Amort Expense (G=DxF)	% Net Salvage (H)	Average Service Life (I)	Curve Form (J)
				$	$			$			
1		1030	Miscellaneous Intangible Plant	22,442,698	22,397,810	Various	(4)	0	Amortizes over 60 months		
2		1890	Land and Land Rights	1,041,678	0	0.00%		0	Perpetual Life		
3		1900	Structures & Improvements	21,955,911	3,418,098	4.17%	(2)	915,561	-10.00%	Various	Various
4		1910	Office Furniture & Equipment	1,560,369	489,792	5.00%		78,018	0.00%	20	SQ
5		1910-URR	Office Furniture & Equipment		0	NA	(3)	(12,200)	N/A	N/A	N/A
6		1911	Office Furniture & Equipment - EDP Equipment	(8,282)	(13,946)	20.00%		(1,656)	0.00%	5	SQ
7		1911-URR	Office Furniture & Equipment - EDP Equipment		0	NA	(3)	6,208	N/A	N/A	N/A
8		1940	Tools, Shop & Garage Equipment	107,198	75,673	4.00%		4,288	0.00%	25	SQ
9		1940-URR	Tools, Shop & Garage Equipment		0	NA	(3)	(4,480)	N/A	N/A	N/A
10		1970	Communication Equipment	3,872,062	509,492	6.67%		258,267	0.00%	15	SQ
11		1970-URR	Communication Equipment		0	NA	(3)	(699,420)	N/A	N/A	N/A
12		1980	Miscellaneous Equipment	95,301	58,045	6.67%		6,357	0.00%	15	SQ
13		1980-URR	Miscellaneous Equipment		0	NA	(3)	750	N/A	N/A	N/A
14		1990	ARO - Common Plant		0	Various		Depr charged to reg asset account			
15			Completed Construction Not Classified		0	4.78%		0			
16		108	Retirement Work in Progress		4,011						
17			Total Common Plant	51,066,935	26,938,975			551,693			
			Common Plant Allocated to Electric								
18		70.75%	Original Cost	36,129,858							
19		70.75%	Reserve		19,059,325						
20		70.75%	Annual Provision					390,323			
21			Total Electric Plant Including Allocated Common	2,430,172,940	947,538,053			86,084,954			

(1) Plant Investment includes Completed Construction Not Classified (Account 106).
(2) Composite of four groups in Structures & Improvements account.
(3) 5 year life for Unrecovered Reserve for Amortization
(4) Fully Amortized

Line	Description		Depr Exp	TY	Tax Rate	Amount
22	**Depreciation Expense from Application per Sch B-3.2 Proposed, page 6 of 6, line 21, column G**					86,243,042
23	AG Recommendation #2 (Remove Terminal Net Salvage) - Change in Depreciation Expense					(158,088)
24	Adjustment to Depreciation Expense with Expense Gross Up for KPSC Maint Fees & BD Gross Up Factor Source: Duke_Energy_KY_Rev_Req_-_AG Recommendations_Workpapers_1 As Filed	1.01088				(159,808)
25	Change to A/D		158,088	50%		79,044
26	Change to ADIT		(158,088)		24.9251%	(39,404)
27	Change in Rate Base					39,640
28	Grossed Up Cost of Capital - As Filed					9.97%
29	Return on Changes to Rate Base					3,954
30	Reduction in Revenue Requirement - AG Recommendation #1 (Remove Terminal Net Salvage)					(155,854)

Duke Energy Kentucky, Inc. Gross Revenue Conversion Factor
As Filed and With AG Recommendations
KPSC Case No. 2024-00354
Forecasted Test Period: Twelve Months Ended June 30, 2026

Source: Duke_Energy_KY_Rev_Req_-_AG Recommendations_Workpapers_1

Source: Schedule H Page 2 of 2	As Filed Duke Energy	As Filed KPSC Maint Fee & BD Only Duke Energy	As Adjusted To Lower Uncollectible Ratio Duke Energy	As Adjusted KPSC Maint Fee & BD Only Duke Energy	As Filed KPSC Maint Fee Only Duke Energy	As Filed Income Tax Only Duke Energy
Additional Revenue	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%
Less: KPSC Maintenance Fee	0.1554%	0.1554%	0.1554%	0.1554%	0.1554%	0.0000%
Uncollectible Accounts Expense	0.9210%	0.9210%	0.4540%	0.4540%	0.0000%	0.0000%
Total KPSC Maintenance Fee and Uncollectible Expense	1.0764%	1.0764%	0.6094%	0.6094%	0.1554%	0.0000%
Income Before Income Taxes	98.9236%	98.9236%	99.3906%	99.3906%	99.8446%	100.0000%
Less: State Income Taxes (5.0% * 99.37%)	4.915%	0.0000%	4.938%	0.0000%	0.0000%	4.969%
Taxable Income for Federal Income Tax	94.0086%	98.9236%	94.4524%	99.3906%	99.8446%	95.0315%
Less: Federal Income Taxes (21%)	19.7418%	0.0000%	19.8350%	0.0000%	0.0000%	19.9566%
Operating Income Percentage	74.2668%	98.9236%	74.6174%	99.3906%	99.8446%	75.0749%
Gross Revenue Conversion Factor	1.3464970	1.0108811	1.3401703	1.0061314	1.0015564	1.3320035
Combined Effective Income Tax Rate						24.9251%

Duke Energy Kentucky, Inc.
Cost of Capital - With AG Recommended Adjustments
KPSC Case No. 2024-00354
Forecasted Test Period: Twelve Months Ended June 30, 2026
($ Millions)

Source: Duke_Energy_KY_Rev_Req_-_AG Recommendations_Workpapers_1

I. DEK Cost of Capital Per Filing

	Capital Amount	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	Pretax
Short Term Debt	105.177	4.79%	3.20%	0.15%	0.15%	
Long Term Debt	933.065	42.48%	4.93%	2.09%	2.12%	
Common Equity	1,158.102	52.73%	10.85%	5.72%	7.70%	14.6%
Total Capital	2,196.344	100.0%		7.97%	9.97%	

II. DEK Cost of Capital Per Filing and Adjusted Gross Up Factor for Uncollectible Expense

	Capital Amount	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	105.177	4.79%	3.20%	0.15%	0.15%
Long Term Debt	933.065	42.48%	4.93%	2.09%	2.11%
Common Equity	1,158.102	52.73%	10.85%	5.72%	7.67%
Total Capital	2,196.344	100.0%		7.97%	9.93%

Adjustment to Uncollectible Expense Based on As Filed Revenue Requirement Reflected on Summary Table as Last Operating Income Adjustment.

III. DEK Cost of Capital Adjusted to Include AG Recommended ROE of 9.65%

	Capital Amount	Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost	
Short Term Debt	105.177	4.79%	3.20%	0.15%	0.15%	
Long Term Debt	933.065	42.48%	4.93%	2.09%	2.11%	
Common Equity	1,158.102	52.73%	9.65%	5.09%	6.82%	13.0%
Total Capital	2,196.344	100.0%		7.34%	9.08%	

Change in Grossed Up Weighted Avg Cost of Capital	-0.85%
Rate Base Recommended by AG	1,219.039
Revenue Requirement Effect of Adjustment	(10.341)
Every 1% ROE Change	(8.618)
Every 0.1% ROE Change	(0.862)

REQUEST:

Explain how Duke Kentucky is billed the Billing Line Items (BLI) by PJM and how Duke Kentucky tracks the recovery and payment of those PJM BLIs. Provide an example of the billing sheet provided by PJM to Duke Kentucky to assist in the explanation.

RESPONSE:

PJM Manual 29: Billing focuses on the monthly and weekly billing statements, which are prepared by PJM Settlement, Inc. The manual describes the structure of the bills, as well as the billing and payment process. The link to the manual is below:

https://www.pjm.com/pjmfiles/directory/manuals/m29/index.html#about.html

PJM Settlement, Inc. issues month-to-date billing statements on a weekly basis and final monthly billing statements to facilitate settlement activity in PJM's markets and usage of transmission service in a given month. Monthly billing statements provide a final true up of the activity settled through weekly billing statements and also settle the remainder of the billing line items that are not settled via the weekly billing statements. Per Section 1.2 of PJM Manual 29, PJM Members and Transmission Customers with billing statements displaying a net amount due to PJM Settlement are obligated to pay such amount in full. All payments tendered in satisfaction of a PJM Member's or other entity's obligations to PJM Settlement shall be made in the form of immediately available funds payable to PJM Settlement or by wire transfer to a bank name by PJM Settlement. Payment terms are included on the cover sheet of each weekly and monthly billing statement. The link below is an example of the billing sheet provided by PJM to Duke Energy Kentucky: https://www.pjm.com/markets-and-operations/billing-settlements-and-credit/msrs-reports-documentation/billing-example

Attachment JDS-3 of John D. Swez's direct testimony shows the current Commission approved recovery of all the PJM BLIs. The current recovery was approved in the April 13, 2018, Order in Case No. 2017-00321. John D. Swez's direct testimony in that proceeding, page 16 through 26, discusses the recovery of the PJM BLIs and why it is reasonable and appropriate. The PJM BLIs, from the monthly PJM invoice, are either recovered in both the FAC (classified as Native FAC) and PSM (classified as Non-Native PSM), PSM only (classified as Non-Native PSM), or base rates. PJM BLIs included in both the FAC and PSM are considered fuel related and the BLIs are allocated based on the allocation methodology explained in STAFF-PHDR-003(b). Fuel related PJM BLIs are included in the PSM in the Off System Sales (OSS) section and in the FAC as Economy Purchases or Net Fuel Related Regional Transmission Organization (RTO) Billing Line Items, dependent on the BLI. PJM BLIs included in the PSM only are either Non-Fuel Related RTO charges and credits or Capacity Transactions. PJM BLIs recovered through base rates are not included in either the FAC or PSM.

During the month end closing process, each PJM BLI in the monthly PJM invoice is assigned a recovery classification corresponding to the approved recovery by the Commission: base rates, FAC (Native FAC), or PSM (Non-Native PSM). The BLIs that are allocated to both the FAC and PSM are reconciled to ensure the allocated amounts for Native FAC and Non-Native PSM equal the total BLI amount on the invoice. There is also a reconciliation to ensure the base rate amounts plus the Native FAC amounts and Non-Native PSM amounts equal the total monthly PJM Invoice amounts.

PERSON RESPONSIBLE: Lisa D. Steinkuhl

STAFF-PHDR-01-003

REQUEST:

Refer to the Application, Volume 12, Schedule L-2.2, pages 74 through 77.

a. Provide a copy of any policy or similar document explaining the cost allocation methodology used by Duke Kentucky to allocate PJM BLIs that appear in the Fuel Adjustment Clause (FAC) and Rider Profit Sharing Mechanism (PSM).

b. If no written methodology exists, provide a step-by-step explanation of the methodology.

c. Provide a specific definition of "native" and "non-native" as those terms are used in the FAC and Rider PSM tariffs to allocate portions of BLIs.

RESPONSE:

a. No formal written policy exists. However, the business rules are explained in section (b) below.

b. The primary tool used to allocate Duke Energy Kentucky metered fuel expenses between off-system sales (non-native sales) and native load is a production costing model, Sumatra, which is jointly supported by Power Costs, Inc., and Duke Energy information technology resources. The model incorporates generator information such as heat rates, emission rates, generating unit fuel costs, emissions allowance costs, and variable operating and maintenance costs. This is the same data used in the Energy Cost Manual, which is also the basis for the supply offers to PJM. We also include as inputs to the model actual hourly data, including native load demand, generating unit output (*i.e.*, megawatt-hour generation) from PJM, and actual native load purchased power information from the billing system.

Sumatra then "economically dispatches" or matches, on an hourly basis, the demand (load) with available supply resources (*i.e.*, generation or purchases) that are economically "stacked," *i.e.*, generally prioritized based on production costs, lowest cost to highest cost. Consequently, the Sumatra model economically allocates the production costs for serving native load. All the Company's generating resources are generally included as available resources in this process. Post-analysis data includes information such as actual unit forced and maintenance outages.

If Duke Energy Kentucky's hourly real-time metered load is greater than the actual hourly real-time metered generation, then Duke Energy Kentucky will purchase energy from PJM to make-up the difference. If Duke Energy Kentucky's hourly real-time metered load is less than the actual hourly real-time metered generation, then any excess generation is considered as a non-native energy market sale. All costs associated with generators allocated to non-native energy market sales are assigned to a non-native cost allocation. Duke Energy Kentucky native customers will only pay for fuel and/or PJM charges associated with the units that are assigned to them.

Non-metered fuel related PJM BLIs are allocated based on Load Ratio, Market Ratio, or Generation Ratio. If a fuel related PJM BLI is used for only serving customer load (Load Ratio), primarily ancillary services (ASM) and FTR/ARR activities, these charges or credits are assigned to metered load (native). If a fuel related BLI is related to charges or credits caused by participating in the PJM market as both a generation provider and load server (Market Ratio), these charges and credits are allocated using both the metered load and metered generation in the allocation calculation. If a fuel related BLI is only for generation produced during the period (Generation Ratio), the charges and credits are allocated using metered generation in the allocation calculation.

c. In the FAC tariff section 2(e) "the native portion of fuel-related costs," native refers to the total electric demand of the Duke Energy Kentucky customers.

In the PSM tariff OSS section "non-native portion of fuel related costs," non-native refers to the off-system sales.

PERSON RESPONSIBLE: Lisa D. Steinkuhl
John D. Swez

STAFF-PHDR-01-004

REQUEST:

Refer to the Application, Volume 12, Schedule L-2.2, pages 76 through 77. Duke Kentucky's proposal includes PJM BLIs 1980, 2980, and 1999 in three of the Rider PSM Rider components: the OSS; the NF; and the CAP. Explain how Duke Kentucky plans to differentiate these PJM BLIs between each component to ensure that there is not a double recovery.

RESPONSE:

<u>PJM BLIs 1980 and 2980 – Miscellaneous Bilateral</u>

BLIs 1980 and 2980 are used when PJM Settlement, Inc. administers agreed upon requests between specific PJM Members to bilaterally adjust their billing statements. A Miscellaneous Bilateral can be for any of the items that PJM settles; therefore, BLI 1980 and 2980 were included in the OSS, NF, and CAP sections of Rider PSM.

The Company researches the reason for all Miscellaneous Bilateral transactions and determines the underlying PJM BLIs that would have been charged/credited if PJM processed the transaction through its normal settlement's process. Once the underlying PJM BLIs have been determined, the amounts are recorded on the books based on underlying PJM BLIs and the recovery is based on the approval of the Commission of the underlying PJM BLIs and included in the appropriate section of the Rider PSM or FAC, if applicable. These PJM BLIs were approved in Case No. 2017-00321[1] to be included in the FAC or PSM based on the underlying PJM BLIs. These PJM BLIs were not originally included on the tariffs because the inclusion in the FAC and PSM is dependent on the reason for the Miscellaneous Bilateral and the underlying PJM BLIs associated with the transaction. If the underlying reason for the Miscellaneous Bilateral is related to PJM BLIs included in base rates, the Miscellaneous Bilateral would not be included in either the FAC or PSM. The PJM BLIs are being included on the FAC and PSM tariff now for transparency.

One example of when a Miscellaneous Bilateral must be used is when a correction is needed for load and the PJM 60-day settlement process is completed for that period. This occurred in July 2022 and was included in the FAC as a prior period adjustment in January 2023 because 100% of the load reconciliation was related to purchased power for native load. If any of the load corrections would have been related to Off System Sales (non-native), the portion related to Off System Sales would have been included in the Rider PSM in the OSS section. This transaction was reviewed in Case No. 2023-00012[2] (2-year FAC review) and the Commission approved the charges and credits billed by the Company through its FAC for the period November 1, 2020, through October 31, 2022, in the May 6, 2024, Order. The prior period adjustment was included in expense month of January 2023 and the Commission approved the charges and credits billed by the Company through

[1] *See, In the Matter of the Electronic Application of Duke Energy Kentucky, Inc. for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief;* Case No. 2017-00321, Direct Testimony of John D. Swez, Attachment JDS-4 (Sept. 1, 2021).

[2] *See, In the Matter of An Electronic Examination of the Application of the Fuel Adjustment Clause of Duke Energy Kentucky, Inc. from November 1, 2020 through October 31, 2022*, Case No. 2023-00012, Duke Energy Kentucky's response to Commission Staff's Second Request for Information, Item 23, Error #3, p. 3 (Oct. 20, 2023).

its FAC for the period November 1, 2022, through April 30, 2023, in the March 19, 2025, Order in Case No. 2024-00140.

PJM BLI 1999 – PJM Customer Payment Default

BLI 1999 is used by the PJM Board of Managers to allocate to non-defaulting PJM members amounts not paid or recovered from a defaulting member. Per Customer Guide to PJM Billing page 19, the default allocation assessment is equal to .1 * (1 / the total number of Members) + .9 * (the Member's gross activity as determined by summing the absolute values of the charges and credits for each of the Activity Line items as accounted for and billed for the month of default and the two previous months / the sum of gross activity for all eligible members). The assessment value of (0.1*(1 / number of eligible members)) shall not exceed $10,000 per Member per calendar year, cumulative of all defaults, or more than once per Member default if Default Allocation Assessment charges for a single Member default span multiple calendar years. The link to the PJM Customer Billing Guide is:

https://www.pjm.com/-/media/DotCom/markets-ops/settlements/custgd.pdf

In this proceeding, the Company is requesting the same treatment of PJM BLI 1999 as it currently has for PJM BLI 1980 and 2980. The Company would research the reason for the PJM Customer Default Payment and determine the underlying PJM BLIs that would have been impacted if the default did not occur. Once the underlying PJM BLIs have been determined, the amount would be recorded on the books based on underlying PJM BLIs and the recovery would be based on the approval of the Commission of the underlying PJM BLIs and included in the appropriate section of the Rider PSM or FAC, if applicable. If the underlying reason for the Miscellaneous Bilateral is related to PJM BLIs included in base rates, the Miscellaneous Bilateral would not be included in either the FAC or PSM.

PERSON RESPONSIBLE: Lisa D. Steinkuhl

STAFF-PHDR-01-005

REQUEST:

Refer to the Application, Volume 12, Schedule L-2.2, pages 76 through 77, Duke Kentucky's proposal includes PJM BLIs 1216, 1980, 2980, and 1999 in the FAC and in the PSM Rider. Explain in detail how Duke Kentucky plans to differentiate these PJM BLIs between the FAC Rider and PSM Rider to ensure that there is not a double recovery.

RESPONSE:

See the response to STAFF-PHDR-01-004 with respect to PJM BLI 1980, 2980, and 1999. The Company researches the reason for all Miscellaneous Bilateral transactions and determines the underlying PJM BLIs that would have been charged/credited if PJM processed the transaction through its normal settlement's process. Once the underlying PJM BLIs are determined and if the PJM BLI is related to fuel, it will be allocated to FAC (native) and PSM (non-native) based on the allocation process in the response to STAFF-PHDR-01-003. The Company records the amounts on the books using specific accounting codes to differentiate between the FAC and PSM recovery. The recovery is based on the approval of the Commission of the underlying PJM BLIs and the allocation process, if applicable. Only fuel-related charges/credits for native load are included in the FAC, and the non-native fuel-related charges/credits are included in the OSS section of the PSM. If the underlying reason for the Miscellaneous Bilateral is related to PJM BLIs for Non-Fuel or Capacity PJM BLIs, the charges/credits will be included in the NF and CAP sections of the PSM, respectively. If the underlying reason for the Miscellaneous Bilateral is related to PJM BLIs included in base rates, the Miscellaneous Bilateral would not be included in either the FAC or PSM.

For BLI 1999, PJM Customer Payment Default, the Company is requesting to follow the same procedures as it does when analyzing BLIs 1980 and 2980 to determine its recovery in the FAC, PSM, or base rates.

Per the Direct Testimony of John D. Swez on page 41, PJM BLI 1216, Pseudo-Tie Balancing Congestion Refund, is a fuel related PJM BLI; therefore, the Company is requesting this be included in both the FAC and PSM by using the allocation methodology explained in response to STAFF-DR-01-003.

As discussed in the response to STAFF-PHDR-01-002, during the end of month closing process, each PJM BLI in the monthly PJM invoice is assigned a recovery classification corresponding to the approved recovery by the Commission: base rates, FAC (Native FAC), or PSM (Non-Native PSM). The BLIs that are allocated are reconciled to ensure the allocated amounts for Native FAC and Non-Native PSM equal the total BLI amount on the invoice. There is also a reconciliation to ensure the base rates amounts plus the Native FAC amounts and Non-Native PSM amounts equal the total monthly PJM Invoice amounts. This process would be applied to PJM BLIs 1216, 1980, 2980, and 1999 to ensure there is no double recovery.

PERSON RESPONSIBLE: Lisa D. Steinkuhl

STAFF-PHDR-01-006

REQUEST:

Refer to the Commission's final Order in Case No. 2024-00285 issued on May 16, 2025.

a. Provide a tariff sheet showing Duke Kentucky's currently approved Rider PSM Tariff redlined with edits currently proposed in this case. If there are no changes to the redlined tariffs included in Volume 12, Schedule L-2.2, pages 76 through 77, you may respond to this request by simply indicating the same.

b. Provide a tariff sheet showing Duke Kentucky's Rider PSM Tariff, as currently proposed in this case, redlined with amendments to the Rider PSM approved in Case No. 2024-00285 after the transition to the RPM construct.

RESPONSE:

a. Please see STAFF-PHDR-01-006(a) Attachment for a redlined tariff with the edits currently proposed in this case. The following redline edits were added to the redlined tariff in Volume 12, Schedule L-2.2, pages 76 through 77:

- The statement "but not limited to those costs identified in the following Billing Line Items, as may be amended from time to time by PJM Interconnection LLC" was removed in the OSS section, NF section, and CAP section.
- In the CAP section, the statement "and the Commission's Order in Case No. 2024-00354, dated ________ xx, xxxx" was added. Once the Order is received, the date of the Order will be updated.

- In the CAP section, the PJM BLIs 1666 and 2666 were removed. These PJM BLIs capacity costs can be charged or credited to FRR or RPM participants. Since the Commission denied these two BLIs to be included in the PSM in Case No. 2024-00354 as an RPM participant, they were removed on STAFF-PHDR-01-006(a) Attachment as an FRR participant.

b. Please see STAFF-PHDR-01-006(b) Attachment for the Company's Rider PSM Tariff sheet as currently proposed in this case and redlined with amendments to the Rider PSM approved in Case No. 2024-00285 after the transition to the RPM construct. The edits included in STAFF-DR-PHDR-01-006(a) Attachment were accepted as the starting point for STAFF-PHDR-01-006(b) Attachment. The redline changes in the CAP section were added to include the changes due to Case No. 2024-00285 and to transparently show the Commission Order which approved the various capacity related PJM BLI charges and credits.

In Case No. 2024-00285, the Company inadvertently requested PJM BLI 2640 – Incremental Capacity Transfer Rights (CTRs) be included in Rider PSM. Per the Customer Guide to PJM Billing, CTRs are provided to fund for transmission upgrades that increase import capability into a constrained Locational Deliverability Area (LDA). Transmission upgrades or Regional Transmission Enhancement Projects, PJM BLIs 1108 and 2108, are included in base rates; therefore, BLI 2640 should be included in base rates as well. Attachments to John D. Swez's Direct Testimony in this proceeding, JDS-3 (Current Recovery of PJM BLIs) and Attachment JDS-4 (Proposed Recovery of PJM BLIs), shows correctly that PJM BLI 2640 is recovered in base rates. The CAP section of the PSM tariff related to the Commission Order in Case No. 2024-00285 of STAFF-PHDR-01-006(b) Attachment does not include PJM BLI 2640.

PERSON RESPONSIBLE: Lisa D. Steinkuhl

KY.P.S.C. Electric No. 2
Seventy-Eighth ~~Seventh~~ Revised Sheet
No 82
Duke Energy Kentucky, Inc.
1262 Cox Road
Erlanger, KY 41018

Cancels and Supersedes
Seventy-Seventh ~~Sixth~~ Revised Sheet
No 82
Page 1 of 3

RIDER PSM
PROFIT SHARING MECHANISM

APPLICABILITY

Applicable to all retail sales in the Company's electric service area, excluding interdepartmental sales, beginning with the billing month September 2024. ~~T~~

PROFIT SHARING RIDER FACTORS

On a quarterly basis, the applicable energy charges for electric service shall be increased or decreased to the nearest $0.000001 per kWh to reflect the sharing of net proceeds as outlined in the formula below.

Rider PSM Factor = (((OSS + NF + CAP + CPI + GS + REC) x 0.90) + R) / S (T)

where:

OSS= Net proceeds from off-system power sales.

Includes the non-native portion of fuel-related costs charged to the Company by PJM Interconnection LLC including ~~but not limited to those costs identified in the following Billing Line Items, as may be amended from time to time by PJM Interconnection LLC:~~ Billing Line Items 1210, ~~2210,~~ 1215, 1216, 1218, 2217, 2218, 1230, 1250, 1260, 2260, 1370, 2370, 1375, 2375, 1400, 1410, 1420, 1430, 1478, 1340, 2340, 1460, 1350, 2350, 1360, 2360, 2366, 1470, 1377, 2377, 1480, 1378, 2378, 1490, 1500, 2420, 2220, 1200, 1205, 1220, 1225, 2500, 2510, 1930, 2211, 2215, 2415, ~~and~~ 2930, 1980, 2980 and 1999. (T) (T) (T) (T) (T)

Issued by authority of an Order of the Kentucky Public Service Commission dated in Case No. 2024-00354
Issued: December 2, 2024 ~~August 2, 2024~~
Effective: January 2, 2025 ~~September 3, 2024~~
Issued by: Amy B. Spiller, President /s/ Amy B. Spiller

PROFIT SHARING RIDER FACTORS Contd.

NF = Net proceeds from non-fuel related Regional Transmission Organization charges and credits not recovered via other mechanisms.

Includes non-fuel related costs charged to the Company by PJM Interconnection LLC including ~~but not limited to those costs identified in the following Billing Line Items, as may amended from time to time by PJM Interconnection LLC:~~ Billing Line Items ~~1240,~~ 2240, ~~1241,~~ 2241, 1242, 1243, 1245, 2245, 1246, 2246, 1330, 2330, 1361, 2361, 2367, 1471, 1362, 2362, 2368, 1472, ~~1365, 2365,~~ 1475, 1371, 2371, 1376, 2376, 1380, ~~and~~ 2380, 1390, 2390, 1980, 2980, and 1999. (T) (T) (T) (T) (T) (T)

CAP= Net proceeds from: PJM charges and credits as provided for in the Commission's Order in Case No. 2017-00321~~2014-00201~~, dated April 13, 2018 and the Commission's Order in Case No. 2024-00354, dated xx, xxxx~~December 4, 2014~~, capacity sales; capacity purchases; capacity performance credits; and capacity performance assessments. (T) (T) (T)

Includes FRR capacity costs charged to the Company by PJM Interconnection LLC including ~~but not limited to those costs identified in the following Billing Line Items, as may amended from time to time by PJM Interconnection LLC:~~ Billing Line Items 1600, 2600, ~~1666, 2666,~~ 1667, 2667, 1669, 2669, 1670, 2670, 1681, 2681, 1980, 2980, 1985, and 1999. (T) (T) (T) (T) (T)

CPI= Net proceeds of capacity performance insurance. (T)

GS= Net proceeds from the sale of surplus gas on the pipelines. (T)

REC= Net proceeds from the sales of renewable energy credits.

R = Reconciliation of prior period Rider PSM actual revenue to amount calculated for the period.

S = Current period sales in kWh as used in the Rider FAC calculation.

KY.P.S.C. Electric No. 2
Seventy-Eighth ~~Seventh~~ Revised Sheet
No 82
Duke Energy Kentucky, Inc.
1262 Cox Road
Erlanger, KY 41018

Cancels and Supersedes
Seventy-Seventh ~~Sixth~~ Revised Sheet
No 82
Page 3 of 3

Rate Group	Rate ($/ kWh)	
Rate RS, Residential Service	0.002475	~~(R)~~
Rate DS, Service at Secondary Distribution Voltage	0.002475	~~(R)~~
Rate DP, Service at Primary Distribution Voltage	0.002475	~~(R)~~
Rate DT, Time-of-Day Rate for Service at Distribution Voltage	0.002475	~~(R)~~
Rate EH, Optional Rate for Electric Space Heating	0.002475	~~(R)~~
Rate GS-FL, General Service Rate for Small Fixed Loads	0.002475	~~(R)~~
Rate SP, Seasonal Sports Service	0.002475	~~(R)~~
Rate SL, Street Lighting Service	0.002475	~~(R)~~
Rate TL, Traffic Lighting Service	0.002475	~~(R)~~
Rate UOLS, Unmetered Outdoor Lighting	0.002475	~~(R)~~
Rate NSU, Street Lighting Service for Non-Standard Units	0.002475	~~(R)~~
Rate SC, Street Lighting Service – Customer Owned	0.002475	~~(R)~~
Rate SE, Street Lighting Service – Overhead Equivalent	0.002475	~~(R)~~
Rate LED, LED Street Lighting Service	0.002475	~~(R)~~
Rate TT, Time-of-Day Rate for Service at Transmission Voltage	0.002475	~~(R)~~
Other	0.002475	~~(R)~~

Rider PSM credits, reductions to bills, are shown as positive numbers without parentheses. Rider PSM charges, increases to bills, are shown in parentheses.

SERVICE REGULATIONS
The supplying of, and billing for, service and all conditions applying thereto are subject to the jurisdiction of the Kentucky Public Service Commission, and to the Company's Service Regulations currently in effect, as filed with the Kentucky Public Service Commission as provided by law.

Issued by authority of an Order of the Kentucky Public Service Commission dated in Case No. 2024-00354
Issued: December 2, 2024~~August 2, 2024~~
Effective: January 2, 2025~~September 3, 2024~~
Issued by: Amy B. Spiller, President /s/ Amy B. Spiller

RIDER PSM
PROFIT SHARING MECHANISM

APPLICABILITY

Applicable to all retail sales in the Company's electric service area, excluding interdepartmental sales, beginning with the billing month September 2024.

PROFIT SHARING RIDER FACTORS

On a quarterly basis, the applicable energy charges for electric service shall be increased or decreased to the nearest $0.000001 per kWh to reflect the sharing of net proceeds as outlined in the formula below.

$$\text{Rider PSM Factor} = (((OSS + NF + CAP + CPI + GS + REC) \times 0.90) + R) / S$$

where:

OSS= Net proceeds from off-system power sales.

Includes the non-native portion of fuel-related costs charged to the Company by PJM Interconnection LLC including Billing Line Items 1210, 1215, 1216, 1218, 2217, 2218, 1230, 1250, 1260, 2260, 1370, 2370, 1375, 2375, 1400, 1410, 1420, 1430, 1478, 1340, 2340, 1460, 1350, 2350, 1360, 2360, 2366, 1470, 1377, 2377, 1480, 1378, 2378, 1490, 1500, 2420, 2220, 1200, 1205, 1220, 1225, 2500, 2510, 1930, 2211, 2215, 2415, 2930,1980, 2980 and 1999.

PROFIT SHARING RIDER FACTORS Contd.

NF = Net proceeds from non-fuel related Regional Transmission Organization charges and credits not recovered via other mechanisms.

Includes non-fuel related costs charged to the Company by PJM Interconnection LLC including Billing Line Items 2240, 2241, 1242, 1243, 1245, 2245, 1246, 2246, 1330, 2330, 1361, 2361, 2367, 1471, 1362, 2362, 2368, 1472, 1475, 1371, 2371, 1376, 2376, 1380, 2380, 1390, 2390, 1980, 2980, and 1999.

CAP= Net proceeds from~~: ~~ PJM charges and credits for ~~as provided for in the Commission's Order in Case No. 2017-00321, dated April 13, 2018 and the Commission's Order in Case No. 2024-00354, dated _______ xx, xxxx,~~ capacity sales; capacity purchases; capacity performance credits; and capacity performance assessments.

~~Includes FRR capacity costs charged to the Company by PJM Interconnection LLC including Billing Line Items 1600, 2600, 1667, 2667, 1669, 2669, 1670, 2670, 1681, 2681, 1980, 2980, 1985, and 1999.~~PJM charges and credits as provided for in the Commission's Order in Case No. 2017-00321, dated April 13, 2018, includes capacity costs as both an FRR and RPM participant charged to the Company by PJM Interconnection LLC including Billing Line Items 1600, 2600, 1667, 2667, 1980, and 2980.

PJM charges and credits as provided for in the Commission's Order in Case No. 2024-00354, dated xx, xxxx, includes capacity costs as both an FRR and RPM participant charged to the Company by PJM Interconnection LLC including Billing Line Items 1669, 2669, 2681, 1985 and 1999. It also includes capacity costs as only an FRR participant charged to the Company by PJM Interconnection LLC including Billing Line Items 1670, 2670, and 1681.

PJM charges and credits as provided for in the Commission Order in Case No. 2024-00285 dated May 16, 2025, includes capacity costs as only an RPM participant charged to the Company by PJM Interconnection LLC: Billing Line Items 1610, 1650, 2605, 2625, 2630, and 2650.

CPI= Net proceeds of capacity performance insurance.

GS= Net proceeds from the sale of surplus gas on the pipelines.

REC= Net proceeds from the sales of renewable energy credits.

R = Reconciliation of prior period Rider PSM actual revenue to amount calculated for the period.

S = Current period sales in kWh as used in the Rider FAC calculation.

Duke Energy Kentucky, Inc.
1262 Cox Road
Erlanger, KY 41018

Rate Group	Rate ($/ kWh)
Rate RS, Residential Service	0.002475
Rate DS, Service at Secondary Distribution Voltage	0.002475
Rate DP, Service at Primary Distribution Voltage	0.002475
Rate DT, Time-of-Day Rate for Service at Distribution Voltage	0.002475
Rate EH, Optional Rate for Electric Space Heating	0.002475
Rate GS-FL, General Service Rate for Small Fixed Loads	0.002475
Rate SP, Seasonal Sports Service	0.002475
Rate SL, Street Lighting Service	0.002475
Rate TL, Traffic Lighting Service	0.002475
Rate UOLS, Unmetered Outdoor Lighting	0.002475
Rate NSU, Street Lighting Service for Non-Standard Units	0.002475
Rate SC, Street Lighting Service – Customer Owned	0.002475
Rate SE, Street Lighting Service – Overhead Equivalent	0.002475
Rate LED, LED Street Lighting Service	0.002475
Rate TT, Time-of-Day Rate for Service at Transmission Voltage	0.002475
Other	0.002475

Rider PSM credits, reductions to bills, are shown as positive numbers without parentheses. Rider PSM charges, increases to bills, are shown in parentheses.

SERVICE REGULATIONS

The supplying of, and billing for, service and all conditions applying thereto are subject to the jurisdiction of the Kentucky Public Service Commission, and to the Company's Service Regulations currently in effect, as filed with the Kentucky Public Service Commission as provided by law.

Duke Energy Kentucky
Case No. 2024-00354
STAFF's Post-Hearing Data Requests
Date Received: May 30, 2025

STAFF-PHDR-01-007

REQUEST:

Refer to the Direct Testimony of John D. Swez, at page 35 through 48.

a. Explain how Duke Kentucky is notified, or otherwise becomes aware, that it may be subject to a penalty from PJM, including whether it is informed of a penalty prior to receiving a bill from PJM.

b. Explain how a penalty is reported to the Commission if Duke Kentucky receives a penalty from PJM.

c. For the last five-year, provide each instance Duke Kentucky has received a penalty from PJM, describe the penalty in detail, identify the method in which the Commission was notified of the penalty, and identify and describe any corresponding credits.

RESPONSE:

a. Note that any applicable PJM BLI that contains the word "penalty," "failure," "deficiency," or "non-performance" in the name of a PJM Billing Line Item was used to create the set of "penalty" BLI's discussed in this response. Additionally, it must be considered that there are corresponding BLIs that are credits related to the BLIs that operate as a charge/cost. Additionally, depending upon the situation, some of the BLIs that are labeled as being a "penalty" failure," "deficiency," or "non-performance" related may also be a negative or reverse charge - meaning it operates as a credit/revenue.

In most instances, the Company is aware of an upcoming individual PJM Billing Line Item (BLI) “penalty” charge **or credit** before receipt of the actual PJM invoice and may even be able to closely approximate the actual amount. However, there are some situations where the Company only learns of a penalty charge or credit after receipt of the actual invoice.

As an example, as referenced in the response to STAFF-DR-04-015, part (c) and (d), for the Fuel Cost Policy Penalty BLI’s, the Company has been charged $502 to date for BLI 1390 but has also received a credit of $32,994 to date for the related BLI 2390. In the case of the $502 charge for BLI 1390, the Company was aware of the impending charge immediately after the market closed on that day since the Company compares the cost-based offer to the allowable offer price and was able to calculate the approximate expected charge amount and monitored receipt for the actual charge once received on the PJM invoice. However, for the credit received related to the Fuel Cost Policy in BLI 2390, since the Company has no knowledge of other entities’ actions, the Company must wait until the PJM invoice is received to be become aware that a credit was received and the amount of that credit. For all penalty BLI’s under discussion in this data response, a listing of how the Company becomes aware of a BLI is listed in column (e) of the table supplied in the response to part (c) below.

b. See column (d) in the table supplied in the response to part (c) below for a listing of how each PJM penalty BLI was reported to the Commission.

c. See the table below for the total credit and total charge in each instance Duke Energy Kentucky has received a penalty BLI from PJM during the last 5 years (2020 through 2024), the method in which the Commission was notified of the penalty, and if the

Company was aware of the BLI before receipt of the PJM invoice. For each BLI that the Company has either paid a charge or received a credit, a detailed description is included afterwards for that BLI.

PJM BLI Number (a)	Description (b)	Amount (2020-2024) (c)	Commission Notification from Company: (d)	Company Knowledge of the PJM BLI Charges/Credits (e)
CHARGES:				
1390	Fuel Cost Policy Penalty	$502.16	None – Not included in PSM Filing[2]	Yes [A]
1661	Capacity Resource Deficiency	$0	None – RPM participant only[1]	Yes [A]
1662	Generation Resource Rating Test Failure	$0	None – RPM participant only[1]	Yes [A]
1663	Qualifying Transmission Upgrade Compliance Penalty	$0	None – RPM participant only[1]	Yes [A]
1666	Load Management Test Failure	$0	None – FRR and RPM participant[1]	Yes [A]
1667	Non-Performance	$0	Per Order in Case No. 2017-00321, notify the Commission within 7 days of incurring any capacity performance assessments from PJM	Yes [A]
1669	PRD Commitment Compliance Penalty	$0	None - FRR and RPM participant[2]	Yes [A]
1681	FRR LSE Capacity Resource Deficiency	$0	None – FRR participant only[2]	Yes [A]
1985	PJM Weekly Miscellaneous (Capacity Performance related)	$0	None - FRR and RPM participant[2]	Yes [A]
CREDITS:				
2390	Fuel Cost Policy Penalty	$20,086.94	None – Not included in PSM Filing[3]	No [B]
2661	Capacity Resource Deficiency	$0	None - RPM participant only[1]	No [B]
2662	Generation Resource Rating Test Failure	$0	None - RPM participant only[1]	No [B]
2663	Qualifying Transmission Upgrade Compliance Penalty	$0	None - RPM participant only[1]	No [B]
2666	Load Management Test Failure	$0	None - FRR and RPM participant[1]	No [B]
2667	Bonus Performance	$886,125.45	Included in PSM filing	Yes [A]
2669	PRD Commitment Compliance Penalty	$0	None - FRR and RPM participant[2]	No [B]
2681	FRR LSE Capacity Resource Deficiency	$0	None - FRR and RPM participant[2]	No [B]

[1] The Order in Case No. 2024-00285 denied recovery of this PJM BLI in the PSM.
[2] Requested this PJM BLI to be recovered in the PSM in this proceeding.
[3] The Order in Case No. 2024-00285 approved recovery of this PJM BLI in the PSM. Once the PJM BLI is included in the PSM, the notification to the Commission will be the PSM filing.

[A] The Company is aware that a specific charge or credit for the PJM BLI will be received prior to receiving the monthly PJM invoice because of operational situational awareness.
[B] The Company is not aware of the charge or credit until the monthly PJM invoice is received.

<u>1390 - Fuel Cost Policy Penalty and 2390 - Fuel Cost Policy Penalty</u>: The Company, as does all other PJM entities that offer generators into the PJM Energy Market, make both a price-based and cost-based offer for its generators. For the cost-based offers, the Company

creates and then must follow a PJM approved cost-based offer policy. Each day, PJM compares the generators submitted cost-based offer to a calculated cost-based offer using the entities Fuel Cost Policy. If an entity submits a cost-based offer outside of an allowable range, the entity is assessed a penalty (BLI 1390). Additionally, penalties assessed to entities are credited to other PJM participants based on real-time load ratio share for the hour the penalty was assessed (BLI 2390). To date, the Company has received substantially more credits under BLI 2390 than charges under BLI 1390. Since no fuel is consumed for either of these BLIs, the Company is requesting the inclusion of both BLIs in the PSM.

2667 – Bonus Performance: Capacity Performance Resource capacity commitments and Price Responsive Demand (PRD) capacity commitments are exposed to Non-Performance Charges for underperformance during Emergency Actions throughout the entire Delivery Year. A Non-Performance Assessment will compare each Capacity Resource’s Expected Performance against its Actual Performance for each Performance Assessment Interval Resources that over-perform may be eligible for Bonus Performance Credit.

PERSON RESPONSIBLE: John D. Swez
Lisa D. Steinkuhl

Duke Energy Kentucky
Case No. 2024-00354
STAFF's Post-Hearing Data Requests
Date Received: May 30, 2025

STAFF-PHDR-01-008

REQUEST:

Regarding Duke Kentucky's request to expand the fee-free payment options available to residential customers to include payments by debit, credit, prepaid cards, and electronic check.

a. Provide the current percentage of Duke Kentucky customers that pay by debit, credit, prepaid cards, or electronic check.

b. In other Duke Energy Corporation subsidiary service territories where a current fee-free program for card payers is in place, provide the percentage of customers that pay by debit, credit, prepaid cards, or electronic check.

c. If the fee-free payment request were approved, provide Duke Kentucky's estimated percentage of customers who would make payments by debit, credit, prepaid card, or electronic check, and explain how that estimate was determined.

d. If the fee-free payment request were approved, explain whether Duke Kentucky estimates that the percentage of customers who pay by debit, credit, prepaid cards, or electronic check would closely mirror other Duke Energy Corporation subsidiary service territories where a fee-free program is already in place. Explain why or why not.

e. If the fee-free payment request were approved, provide the impact on the bill of an average residential customer in Duke Kentucky's territory.

f. Provide the per transaction cost and total test year expense to process residential customer payments via check, money order, cash, automated bank draft, and electronic funds transfer.

RESPONSE:

a. In 2025 (Jan.-April), ~24% of Duke Energy Kentucky payment transactions were made through the card payment channel by debit, credit, prepaid cards, or electronic check.

b. In 2025 (Jan.-April), ~28% of payment transactions for Duke Energy Progress (NC and SC), Duke Energy Carolinas (NC and SC), and Duke Energy Florida were made through the card payment channel. Each of these affiliates has had an approved fee-free card payment program.

c. As discussed in Witness Colley's testimony (page 22, line 4-12), the Company did not include growth in its request, and therefore the future card payment utilization was not formally analyzed or estimated. However, for this response, the Company compared actual 2025 YTD channel usage to usage during the same period in 2024, and there has been an approximate 1% increase.

d. By simply comparing Duke Energy Kentucky's current utilization rate of ~24% to other Duke Energy affiliates rate of ~28%, it seems reasonable to predict that card payment transactions as a percentage of total payment transactions will increase *over time* to a similar level as observed in affiliates with an established fee-free program. It is important to note that the affiliates have operated their fee-free program for multiple years.

e. If the fee-free card payment program were to be approved, the typical residential customer using 1,000 kwh would see an approximate $0.18 increase in their monthly bill.

f. The Company's payment cost study yielded the below payment processing costs per transaction. These costs include internal company expenses such as labor, maintenance of processing equipment, and processing fees and do not include any incremental processing fees that may be charged directly to a customer at the point of transaction. The Company does not individually track each payment channel's total expenses and therefore can only approximate the test year expense utilizing actual transaction counts and the associated per transaction processing costs.

Payment Type	Per Transaction Cost	Estimated Test Year Expense
Mail-In	\$0.15	~\$31,000
Walk-In Locations	\$0.03	~\$600
AutoPay, Electronic Funds Transfer	\$0.08	~\$38,000
One-time ACH (web/mobile)	\$0.13	~\$28,000

PERSON RESPONSIBLE: Jacob S. Colley

STAFF-PHDR-01-009

REQUEST:

Refer to Duke Kentucky's response to the Attorney General's Second Request for Information, Item 48, AG-DR-02-048 Conf Attachment.xlsx.

a. Explain why the amount reflected in G38 of Tab 2023 – Consolidated is a negative number and the amount in G39 of Tab 2023 – Consolidated is a positive number and provide workpapers showing the calculation of those amounts.

b. For Tabs 2023 – Consolidated and 2024 – Consolidated, explain what the amounts reflected on Excel lines 43 and 70 represent as well as how and why portions of those amounts are allocated to Duke Kentucky.

c. For Tab 2024 Summary, explain what the amounts in B18 and B21 represent, how they are calculated, how they are distinct from the amounts in D18 and D19, respectively, and why the amounts in B21 are used to calculate the ratios in Column C.

d. For Tab 2023 Summary, explain what the amounts in B18 and B21 represent, how they are calculated, how they are distinct from the amounts in D18 and D19, respectively, and why the amounts in B21 are used to calculate the ratios in Column C.

e. Explain how the amount in I39 of Tab 2024 – Consolidated is calculated and why it is not the sum of the amounts in E39 and G39.

f. Explain why any deferred tax assets associated with a net operating loss carryforward, if any, attributed to Duke Kentucky should not be assumed to be eliminated for ratemaking purposes if the net operating loss carryforward, if any, attributed to Duke

Kentucky is assumed to be fully utilized when calculating the extent to which the CAMT deferred tax asset should be allocated to Duke Kentucky.

g. Explain whether the amount in G39 of Tab 2024 – Consolidated would be zero on a similar consolidated sheet for 2025, and if so, how that would affect the allocation in 2025. If the amount in G39 would not be zero on a similar consolidated sheet for 2025, explain why it would not be zero.

h. State whether any deferred tax assets arising from net operating loss carryforwards are included in rate base for the base period, and if so, identify where and the amount of those deferred tax assets in each month of the base period.

RESPONSE:

a. Row 39 represents the NOL utilized from a consolidated perspective to reduce the regular tax liability (in column E). Once it was determined that regular tax from a consolidated perspective was zero (Cell E44), there was no need for separate company regular tax calculations because the CAMT, which is calculated on a consolidated basis, would be compared back to the regular tax liability of zero. Therefore, we shaded the amounts in black in Column G – because they were irrelevant to the overall CAMT calculation and allocation. The incremental CAMT is then allocated as described in response to (c) below. NOLs were utilized in accordance with the tax sharing agreement.

The amount in cell G38 represents Duke Energy Kentucky's regular federal taxable loss. Please see STAFF-PHDR-01-009(a) Attachment for calculation. The amount in cell G39 was calculated by multiplying the federal taxable loss (in cell G38) by 80%. 80% represents the standard NOL deduction limitation.

b. Row 43 represents foreign tax credits (FTCs) utilized to bring consolidated regular tax liability to zero (in column E). FTCs can be used to reduce the regular tax, but not the CAMT. Once it was determined that regular tax from a consolidated perspective was zero, there was no need for separate company regular tax calculations because the CAMT, which is calculated on a consolidated basis, would be compared back to the regular tax liability of zero (which is why the amounts were not shown in column G). The incremental CAMT is then allocated as described in response c, below. Tax credits used to reduce regular tax were utilized in accordance with the tax sharing agreement.

Row 70 represents general business credits (GBCs) utilized to offset the CAMT liability. GBCs can offset up to 75% of the CAMT liability. The amount in cell E70 was calculated by multiplying the AMT liability by 75%. GBCs can also offset the regular tax liability, but certain ordering rules are applied. FTCs are used before GBCs with these ordering rules. FTCs reduced the regular tax liability to zero without having to use GBCs.

c. Duke Energy's consolidated alternative minimum tax (AMT) (in cell C12) is allocated based on each subsidiaries' proportionate share of book minimum tax (BMT) liability for the taxable year.

The amount in cell B18 represents all of Duke Energy Corporation's subsidiaries, excluding Duke Energy Kentucky, with a BMT liability. The amount in cell B21 represents the total of all Duke Energy Corporation's subsidiaries, including Duke Energy Kentucky, with a BMT liability.

The total of the subsidiaries with a BMT liability in cell B21 is used in column C to determine the subsidiaries' proportionate share of Duke Energy's consolidated AMT.

The amount in cell D18 represents the amount of Duke Energy's total consolidated AMT that is allocated to the subsidiaries, excluding Duke Energy Kentucky. The amount in cell D19 represents the amount of Duke Energy's total consolidated AMT that is allocated to the subsidiaries, including Duke Energy Kentucky.

d. Duke Energy's consolidated alternative minimum tax (AMT) (in cell C11) is allocated based on each subsidiaries' proportionate share of book minimum tax (BMT) liability for the taxable year.

The amount in cells B18 and B21 represent the total of all Duke Energy Corporation's subsidiaries, including Duke Energy Kentucky, with a BMT liability.

The amount in cell D18 represents the amount of Duke Energy's total consolidated AMT that is allocated to the subsidiaries, including Duke Energy Kentucky. The amount in cell D19 is blank.

The total of the subsidiaries with a BMT liability in cell B21 is used in column C to determine the subsidiaries' proportionate share of Duke Energy's consolidated AMT.

e. The amount in cell I39 is calculated by multiplying the federal taxable income in cell I38 by 80%. 80% represents the standard NOL deduction limitation. The NOL in I39 should have been limited to the amount in cell E39. Had this occurred, the calculation then would have increased the foreign tax credits utilized in cell I43 to reduce the regular federal income tax to zero, resulting in the same book minimum tax.

f. There are no deferred tax assets associated with a net operating loss to eliminate because there are no net operating loss carryforwards included in the test period.

g. There was no NOL included in the 2025 CAMT calculation, as Duke Energy utilized all remaining NOLs in 2024. Therefore, there would be no change to the 2025 allocation.

h. There is a deferred tax asset associated with a state net operating loss carryforward of $34,725 included in March 2024 – October 2024 of the base period (see attachment "AG-DR-01-112 Attachment", tab "112(b) ADIT by Month", cells Q53-Y53). There is no deferred tax asset associated with a federal net operating loss carryforward included in the base period.

PERSON RESPONSIBLE: John R. Panizza

	Duke Energy Kentucky 12/31/2023
Total Pre-Tax Book Income:	
UPTBI: Pre-Tax Book Income	80,488,322
Total Total Pre-Tax Book Income	80,488,322
Deductible State Tax:	
KY: Kentucky	(4,053,729)
Total Deductible State Tax	4,053,729
Permanent Differences:	
P11A20: Lobbying	360,000
P11A22: Meals	171,000
P11A23: Entertainment	19,000
P11A71: Transportation Benefits-Emp Parking	24,000
P11A77: AFUDC Equity	(1,057,191)
P11A95: After Tax ADC,M&E,ITC Permanent	(114,574)
Total Permanent Differences	(597,765)
Financial Taxable Income	83,944,286
Temporary Differences:	
T11A02: Bad Debts - Tax over Book	214,846
T11B16: OFFSITE GAS STORAGE COSTS	392,864
T13A04: AFUDC Interest	(4,117,502)
T13A08: Book Depreciation/Amortization	80,187,655
T13A10: Adjustment to Book Depreciation	(490,618)
T13A11: Lease Right of Use Asset	585,629
T13A12: Book Gain/Loss on Property	(30,978)
T13A14: Contributions in Aid (CIAC's)	4,411,526
T13A16: Cost of Removal	(16,496,244)
T13A18: Capitalized Hardware/Software	43,086
T13A19: After Tax ADC,M&E, ITC Temporary	114,574
T13A26: Tax Interest Capitalized	3,469,617
T13A28: Tax Depreciation/Amortization	(78,200,000)
T13A30: Tax Gains/Losses	(360,000)
T13A74: Capitalized 174 R&D Exp	1,000,000
T13B08: ASSET RETIREMENT OBLIGATION	1,622,701
T13B09: Book Depreciation Charged to Other Accounts	117,252
T13B23: Non-Cash Overhead Basis Adj	247,459
T13B26: Equipment Repairs - Annual Adj	(16,982,261)
T13B31: Impairment of Plant Assets	55,354
T13B32: T & D Repairs 481(a) (pursuant to 3115)	(102,631,102)
T13B33: T & D Repairs - Annual Adj.	(21,396,007)
T13B45: Asset Retirement Obligation - Coal Ash	(21,425,901)
T15A22: Mark to Market - LT	(487,765)
T15A24: Loss on Reacquired Debt-Amort	118,160
T15A95: Unamortized Debt Premium	(8,844)
T15B02: Reg Asset/Liab Def Revenue	(7,377,203)
T15B07: Cash Flow Hedge - Reg Asset/Liab	442,097
T15B17: Reg Liab RSLI & Other Misc Dfd Costs	289,599
T15B28: Reg Asset - Rate Case Expense	91,648

T15B29: Reg Asset-Pension Post Retirement PAA-FAS87Qual and Otl	141,516
T15B35: Regulatory Asset - Carbon Management	199,996
T15B37: Reg Asset-Pension Post Retirement PAA-FAS87NQ and Oth	(96)
T15B38: Reg Asset-Pension Post Retirement PAA-FAS 106 and Oth	(31,134)
T15B41: Reg Asset - Accr Pension FAS158 - FAS 106/112	(1,229,854)
T15B43: Reg Asset - Transition from MISO to PJM	(218,404)
T15B52: Storm Cost Deferral- Asset	210,211
T15B77: Non-AMI Meters Retired Early - NBV	368,588
T15B81: Reg Asset_Liab - Outage Costs	(888,412)
T15B83: Reg Asset - Rate Case Expense - Amortization - NC	(424,812)
T17A01: Vacation Carryover - Reg Asset	9,471
T17A02: Accrued Vacation	(45,425)
T17A30: Property Tax Reserves	(7,650,166)
T17A40: SEVERANCE RESERVE - LT	684,250
T18A02: Deferred Revenue	258,049
T19A22: Miscellaneous NC Taxable Income Adj - DTA	2,121,737
T19A51: Extra Facility Lighting	18,520
T19A55: Workers Com Reserve	245,042
T19A60: Deferred Cost - Customer Connect	124,047
T19A71: Reg Asset/Liab - ESM Deferral	(154,131)
T19A89: GAS SUPPLIER REFUNDS	(595,616)
T19A94: UNBILLED REVENUE - FUEL	3,895,257
T20A30: REPS Incremental Costs	(917)
T20A38: Regulatory Asset - Deferred Plant Costs	4,215,791
T20A41: Rate Refunds	(163,539)
T20A54: Reg Liability - Rate Case Expense - Amortization - NC	67,834
T22A06: Operating Lease Obligation	(524,030)
T22A15: Operating Lease Deferral	(639,734)
T22A23: Retirement Plan Expense - Overfunded	(2,057,820)
T22A28: Retirement Plan Expense - Underfunded	148,104
T22A30: Retirement Plan Funding - Underfunded	(700,000)
T22A56: Environmental Reserve	(29,869)
T22B13: ANNUAL INCENTIVE PLAN COMP	(364,019)
T22B15: PAYABLE 401 (K) MATCH	(85,883)
T22B16: Miscellaneous NC Taxable Income Adj - DTL	209,446
T22E02: OPEB Expense Accrual	576,891
T22E06: FAS 112 Medical Expenses Accrual	(289,958)
T22H09: Decommissioning Liability	22,101,835
T22H11: Asset Retirement Costs - ARO	(406,297)
T22H12: ARO Regulatory Asset	(23,398,168)
T22H45: Asset Retirement Costs - Coal Ash	45,308,338
T22H46: ARO Regulatory Asset - Coal Ash	(23,806,653)
T22H47: Coal Ash Capitalized for Tax	8,142,143
T22H48: Coal Ash Spend Reg Asset - Contra Equity	(94,620)
T22H51: Coal Ash Spend Reg Asset Approved - Retail (SC & FL)	4,543,396
T22H54: Coal Ash Spend Reg Asset Approved - Retail (NC & MW)	1,636,946
Total Temporary Differences	(145,172,507)
Federal Taxable Income (Pre-NOL)	(61,228,221)